THEPOWERCOMPANYLTD

Asset Management Plan 2012 to 2022

Publicly disclosed in March 2012

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The information and statements made in this AMP are prepared on assumptions, projections and forecasts made by The Power Company Limited and represent The Power Company Limited's intentions and opinions at the date of issue (31 March 2012). Circumstances may change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and The Power Company Limited may, at a later date, decide to take different actions to those that it currently intends to take. The Power Company Limited may also change any information in this document at any time.

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0. Summary

This section summarises some of the main points from the Asset Management Plan.

0.1 Background and Objectives

The purpose of the AMP is to provide a governance and management framework that ensures that The Power Company Limited (TPCL):

- Sets service levels for TPCL's electricity network that will meet customer, community and regulatory requirements.
- Understands 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 robust and transparent processes in place for managing all phases of the network life cycle from commissioning to disposal.
- Has adequately considered the classes of risk TPCL's network business faces and that there are systematic processes in place to mitigate identified risks.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of TPCL's asset locations, ages, conditions and the assets' likely future behaviour as they age and may be required to perform at different levels.

TPCL works to the below strategies at the corporate and asset level:

Corporate Strategies

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

Asset Management Strategies	Manage its operations in a progressive and commercial manner.	Undertake new investments, which are 'core business', appropriate return for risk involved, and maximise commercial value.	Strive to become an efficient and effective operation.	Provide its customers with above average levels of service.
Improve reliability by sectionising poorly performing feeders.	✓			✓
Migrate from a 33kV subtransmission network to 66kV, where appropriate.	✓		✓	
Continue to expand the meshed area of the network, by closing gaps between radial feeders.		✓	✓	✓
Utilise 22kV in locations where economic.			✓	
Consider differing drivers, particularly restoration of supply to dairy or residences.	✓			✓
Expand remote controllability of the distribution network.			✓	✓
Replace critical assets near to their technical end-of-life.				✓
Undertake safety and environmental improvements.	✓			
Achieve 100% regulatory compliance.	✓			

This plan covers the period 1 April 2012 to 31 March 2022, and was approved by the TPCL Board on 28 March 2012.

Management of the assets is undertaken by PowerNet Limited which uses external contractors to operate, maintain, renew, upsize and expand the network. As some works are tendered, costs of individual projects are not publicly disclosed in this document.

The processes and systems used by PowerNet are described in section 8.

0.2 Details of the assets

TPCL supplies 34,431 customers in Southland and Western Otago, with a population of 58,595. Key industries within TPCL's network area include sheep, beef and dairy farming, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism.

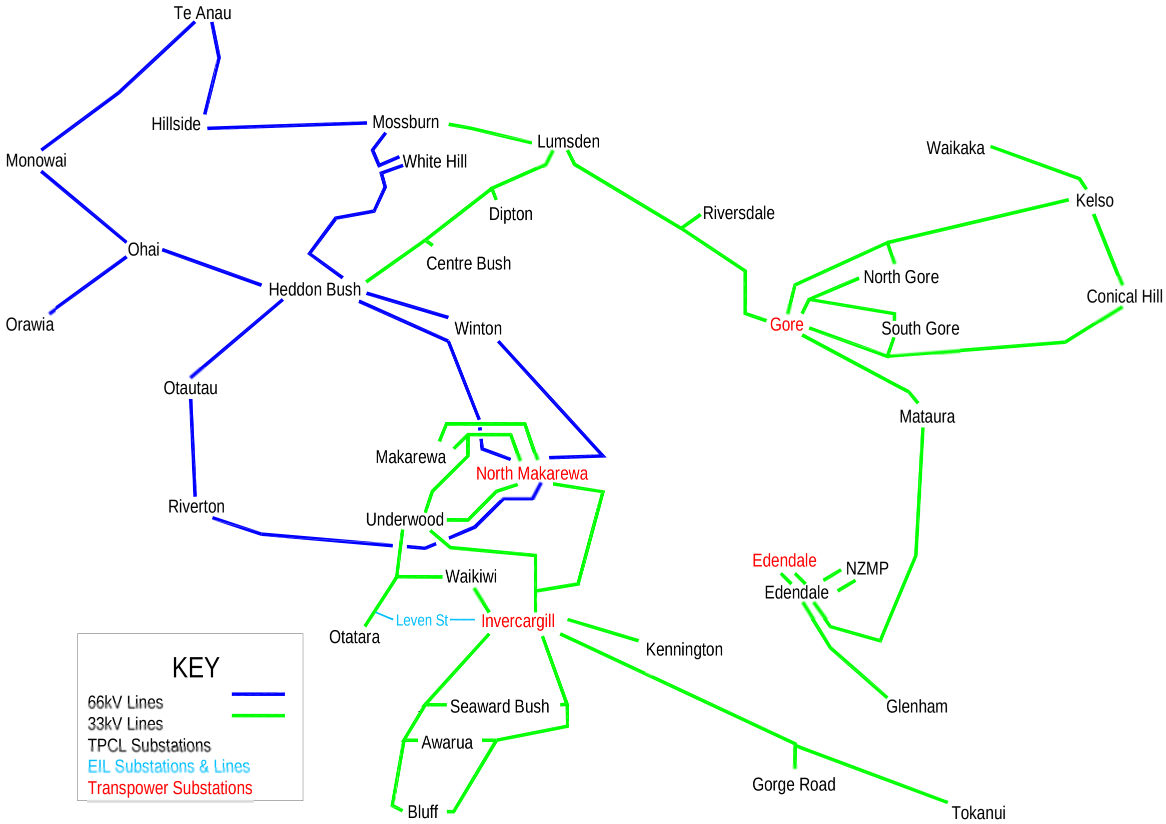


Figure 1 Overview of TPCL Subtransmission Network 1 April 2011

There is:

- 383km of 66kV lines and 452km of 33kV lines and cables.
- 33 zone substations to transform High Voltage (HV) to Medium Voltage (MV).
- One 11kV feeder supplied from Electricity Invercargill Limited's Racecourse Road Substation.
- 6,636 km of 11kV lines and 117km of 11kV cables.
- 10,575 distribution transformers supplying 34,431 customers.
- 28 Voltage regulator sites, controlling local voltage.
- The low voltage (230V) has 833 km of lines and 201km of cable.

The age of the network is average with approximately 52% of its Standard Life (as prescribed in the Commerce Commission ODV Handbook) remaining and most assets are in good condition.

0.3 Proposed Service Levels

Customers are content with the present level of service and no major changes in service levels are proposed. This was the outcome of customer consultation undertaken by telephone survey, one-on-one meetings and public meetings.

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

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

TPCL's targets for these measures for the next ten years ending 31 March 2022 are set out below.

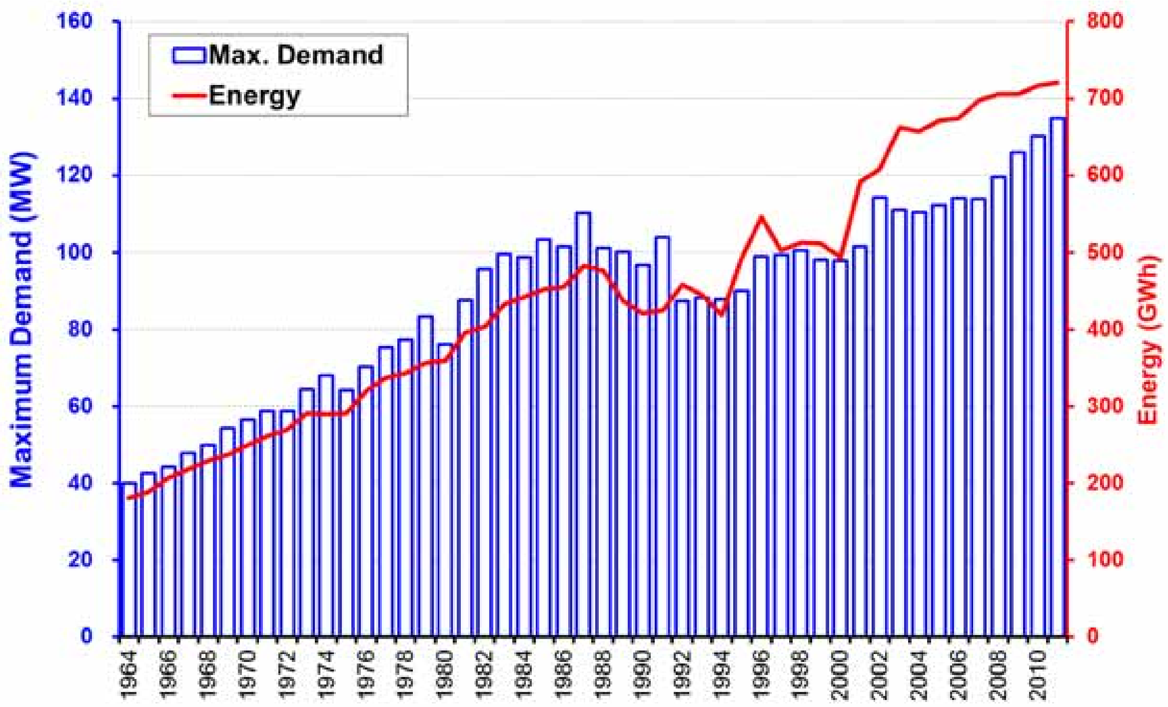
	SAIDI			SAIFI		
Year End	**Class B**	**Class C**	**Total**	**Class B**	**Class C**	**Total**
Limit[1]			**184.10**			**3.68**
31/03/13	61.11	101.05	**162.16**	0.41	2.81	**3.22**
31/03/14	60.95	100.80	**161.75**	0.41	2.80	**3.21**
31/03/15	60.80	100.55	**161.35**	0.40	2.80	**3.20**
31/03/16	60.65	100.30	**160.95**	0.40	2.79	**3.19**
31/03/17	60.50	100.05	**160.55**	0.40	2.78	**3.18**
31/03/18	60.35	99.80	**160.15**	0.40	2.77	**3.17**
31/03/19	60.20	99.55	**159.75**	0.40	2.76	**3.16**
31/03/20	60.05	99.30	**159.35**	0.40	2.75	**3.15**
31/03/21	59.90	99.05	**158.95**	0.40	2.74	**3.14**
31/03/22	59.75	98.80	**158.55**	0.40	2.73	**3.13**

Note this target is based on normalising extreme events to the following daily boundary values: SAIDI 10.09, SAIFI 0.21 i.e. cannot get more than 10.09 customer-minutes of SAIDI occurring on a single day.

The target for Losses (8.0%) and Load Factor (65%) are not planned to improve over the next ten years with Capacity utilisation improving from 30% to 31%.

0.4 Development Plans

The maximum demand on the network has increased 3.0% per annum over the last 10 years with energy increasing by 2.0% per annum.



[1] Limit calculated by the Commerce Commission Default Price-Quality Path methodology, with reference data from 1 April 2004 to 31 March 2009. The limit does not apply to TPCL as it is Consumer Owned, but is shown as the limit of acceptable reliability.

The network will be upsized to meet this expected growth with reviews of loadings at zone substations used to trigger actual projects. Large customer or generator connections will require major expansion of the present network and these will be budgeted for when their location and load requirements are known. Work programmed for Northern Southland is part of that required to service large customer growth and allow a suitable backup of supply.

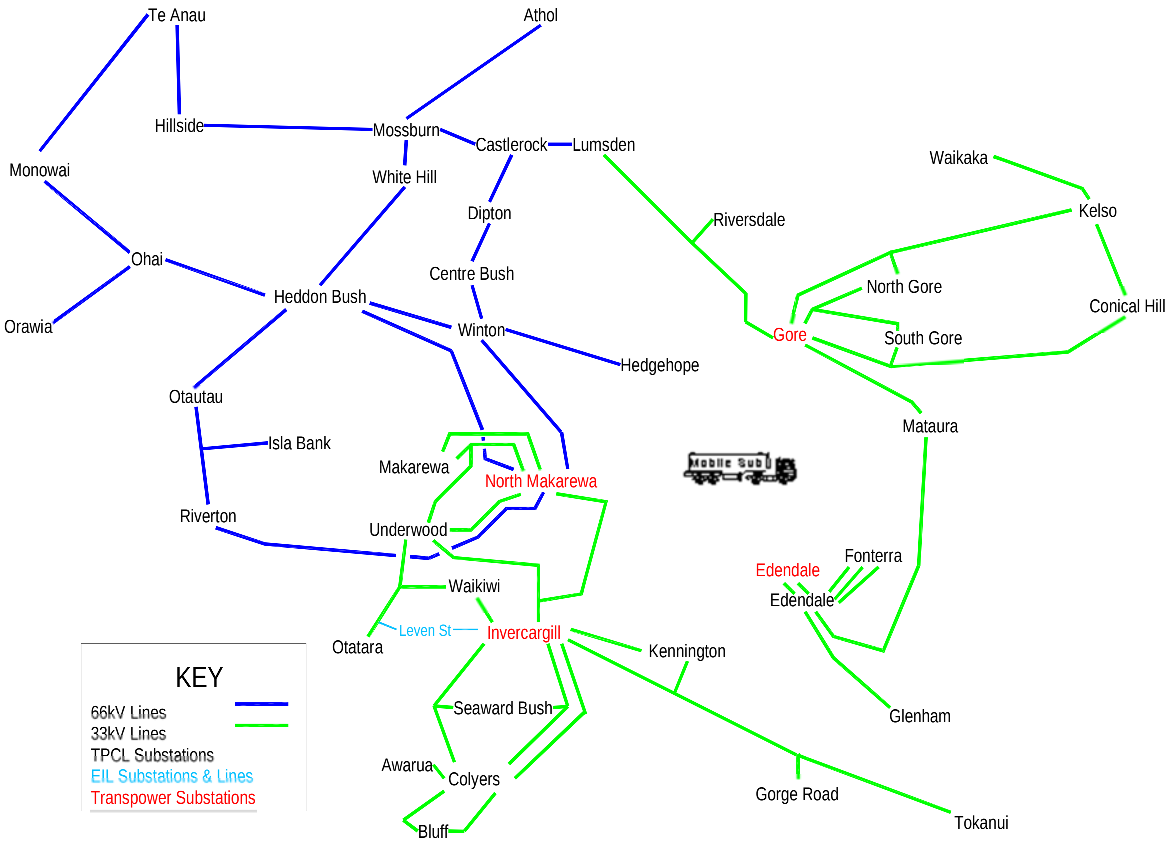
The focus for the next ten years is to maintain service levels by:

- Improving safety at zone substations.
- Upgrading areas to maintain acceptable voltages.
- Renewing unsafe and poorly performing assets.
- Meeting customer and distributed generator requests for new connections.
- Improving efficiency of the network by up-sizing of lines that have high losses and exchanging overloaded distribution transformers with currently installed underutilised units.
- Extending remote monitoring and control to field devices.

Renewals of lines, transformers, air break switches and drop-out fuses are expected to have a significant on-going cost.

Capital expenditure each year varies from $21.3 million in 2012/2013 to $16.8 million in 2021/2022.

Planned subtransmission network for 2022:



0.5 Managing the asset's lifecycle

The asset lifecycle used by TPCL once assets are built, is: Operation, Maintenance, Renewal, Up-sizing, Extensions and Retirement.

Analysis is done to review network operation to check if any trigger is exceeded and actions planned to maintain planned service levels.

Inspection, monitoring and routine maintenance of assets is expected to cost $2.3 million p.a.

Fault restoration and repairs is expected to cost $2.3 million p.a.

Tree trimming to comply with the Trees regulations is expected to cost $1.3 million and reduce in following years.

Asset refurbishment and renewal maintenance is planned to spend $0.8 million p.a.

0.6 Risk Management

The business is exposed to a wide range of risks. This section examines TPCL's risk exposures, describes what it has done and will do about these exposures and what it will do when disaster strikes.

Risk management is used to bring risk within acceptable levels.

0.7 Funding the business

TPCL's revenue is primarily from retailers who pay for conveying energy over TPCL's lines and from customer contributions for the uneconomic portion of new connections or upgrades.

Customer surveys found that 11% would like to pay more for an improvement in service, so is insufficient to warrant a change in the rate of maintaining and renewing the network.

0.8 Processes and systems

TPCL's management company PowerNet uses a system based on ISO9000 quality system but has not maintained certification. Asset information resides in three key locations: Geographical Information System (GIS), Asset Management System (AMS), and Supervisory Control And Data Acquisition (SCADA). Some of this information is excellent but the accuracy of pole ages is poor with 63% having estimated ages.

Condition information is planned to be better collected by use of a scanned form to collect the 20% of the network inspected each year. Planners can then use this data to plan work more efficiently.

0.9 Performance and improvement

Performance targets set in the 2010 - 2020 AMP have generally been achieved.

For the 2010/11 year the network has performed well but a storm in September caused TPCL to miss the SAIDI target of 162 customer-minutes by 47 customer-minutes, with the SAIFI just under the 3.24 target.

Capital expenditure was under the budgeted $18.3M due to planning, design and procurement delays. Maintenance was slightly over the $5.7M budget.

Some strategies are planned to improve performance and achieve targets.

0.10 Feedback and comments

Comment on this plan is welcome and should be addressed to the Chief Engineer, PowerNet Ltd, PO Box 1642, Invercargill or email amp powernet.co.nz. The next review of this AMP is planned for publishing in March 2013.

1. Background and objectives

The Power Company Limited (TPCL) is the electricity lines business that conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff) to approximately 34,431 customer connections on behalf of seven energy retailers. The wider TPCL entity also includes the following associations:

- A 50% stake in PowerNet, an electricity lines management company jointly owned with Electricity Invercargill. This is an unregulated entity and is therefore not subject to any disclosure requirements.
- A 50% stake in Electricity Southland Limited (ESL), which distributes electricity in the Frankton area of Central Otago. ESL is currently below the thresholds for disclosure.
- A 24.5% stake in OtagoNet. The entity for disclosure is OtagoNet JV, and its AMP is prepared and disclosed by PowerNet in Invercargill which manages the OtagoNet assets along with those of Electricity Invercargill and TPCL.
- A 24.5% stake in Otago Power Services Ltd, an electrical contracting company based in Balclutha.
- A 51% stake in Power Services Ltd, an electrical contracting company based in Invercargill.

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

This AMP deals solely with the TPCL electricity network assets.

1.1 Purpose of the Asset Management Plan

[Addresses the Handbook requirement 4.5.2(a)]

The purpose of the AMP is to provide a governance and management framework that ensures that The Power Company Limited (TPCL):

- Sets service levels for TPCL's electricity network that will meet customer, community and regulatory requirements.
- Understands 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 robust and transparent processes in place for managing all phases of the network life cycle from commissioning to disposal.
- Has adequately considered the classes of risk TPCL's network business faces and that there are systematic processes in place to mitigate identified risks.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of TPCL's asset locations, ages, conditions and the assets' likely future behaviour as they age and may be required to perform at different levels.

Disclosure of TPCL's AMP in this format will also assist in meeting the requirements of Section 7 and Schedule 14 of the Electricity Distribution (Information Disclosure) Requirements 2008.

This AMP is not intended to be a detailed description of TPCL'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 TPCL uses and will use to manage the assets.

1.2 Interaction with other goals and drivers

All of the assets exist within a strategic context that is shaped by a wide range of issues including TPCL's vision statement, asset strategy, the prevailing regulatory environment, government policy objectives, commercial and competitive pressures and technology trends. TPCL's assets are also influenced by technical regulations, asset deterioration, the laws of physics and risk exposures independent of the strategic context.

1.2.1 Strategic context

TPCL's strategic context includes many issues that range from the state of the local economy to developing technologies. Issues that TPCL considers include:

- The prevailing regulatory environment which monitors prices and reliability, and requires TPCL to compile and disclose performance and planning information.
- Government policy objectives, such as the promotion of distributed generation (particularly renewables).
- TPCL's commercial goal is primarily to deliver sustainable earnings to TPCL's owners that are the best use of their funds.
- Competitive pressures from other lines companies which might try to supply TPCL customers.
- Pressure from substitute fuels both at end-user level (such as substituting electricity with coal or oil at a facility level) and at bulk generation level (wind farms).
- Advancing technologies such as gas-fired fuel cells that could strand conventional wire utilities.
- Local, national and global economic cycles, in particular the trends in global pastoral commodity prices which can influence the use of land from very passive to very electro-intensive.
- The need for water to irrigate pasture land in Northern Southland, and the associated District and Regional polices.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- The economic climate and 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 TPCL's service requirements.

1.2.2 Independence from strategic context

It is also important to recognise that although TPCL's assets must be shaped by the strategic issues identified in section 1.2.1 they will also be influenced (and even constrained) by issues that are independent of the strategic context.

These issues include:

- Technical regulations including such matters as limiting harmonics to specified levels.
- Asset configuration, condition and deterioration. These parameters will significantly limit the rate at which TPCL can re-align 8,500km of lines and 10,000 transformers to fit ever-changing strategic goals.
- The laws of physics which govern such fundamental issues as power flows, 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 TPCL'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 Land Transport NZ required all poles to be moved back from the road edge).
- Safety requirements such as earthing of exposed metal and line clearances.

1.2.3 Annual business plan and works plans

Each year, the first year of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into TPCL's annual business plan. This defines the priorities and actions for the year ahead which will contribute to TPCL's long-term alignment with the strategic context, fully understanding that this alignment process is very much one of "moving goal posts".

An important component of the annual business plan is the annual works program which scopes and costs each individual activity or project that the company expects to undertake in the year ahead. A critical activity is to firstly ensure that this annual works program accurately reflects the current year's projects in the AMP and secondly ensure that each project is implemented according to the scope prescribed in the works program.

1.3 Key planning documents

[Addresses the Handbook requirement 4.5.2(b)]

The key planning documents are expanded below and the interactions of the key planning issues, processes and documents are shown in Figure 2:

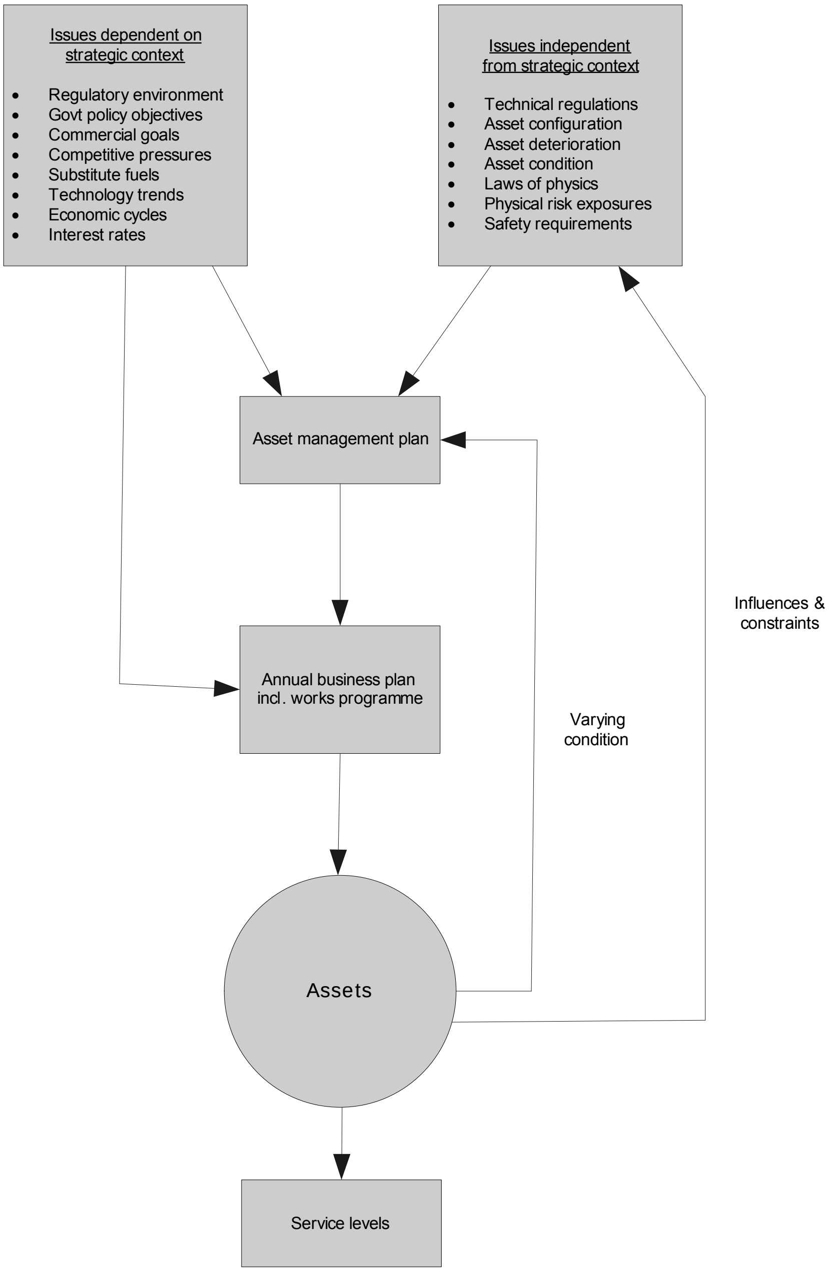


Figure 2 - Interaction of key plans

1.3.1 Statement of intent (SOI)

TPCL's SOI is a requirement under the constitution of the company, and forms the principal accountability mechanism between TPCL's board and the shareholder; the Southland Electric Power Supply Power Consumers Trust (SEPSCT). The SOI includes performance and reliability projections, which 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.

1.3.1.1 2011 Performance targets: Financial

EBIT% - Percentage Earnings Before Tax and Interest on Assets Employed

	2012	2013	2014	2015	2016
NPBT	15,774,019	16,303,609	18,447,114	19,616,350	20,603,093
Interest	1,406,950	1,233,385	1,020,524	964,619	982,688
Net Profit Before Interest & Tax	17,180,968	17,536,993	19,467,638	20,580,969	21,585,781
Total Assets	404,388,296	411,651,888	420,858,531	434,422,696	448,810,671
EBIT %	4.25%	4.26%	4.63%	4.74%	4.81%

NPAT% - Percentage Tax Paid Profit on Equity

	2012	2013	2014	2015	2016
NPAT	10,762,779	11,164,567	12,744,079	13,624,277	14,245,418
Equity	311,628,409	323,923,502	337,850,577	352,560,014	367,976,426
NPAT %	3.45%	3.45%	3.77%	3.86%	3.87%

Percentage of Consolidated Equity to Total Assets

	2012	2013	2014	2015	2016
Equity	311,628,409	323,923,502	337,850,577	352,560,014	367,976,426
Total Assets	404,388,296	411,651,888	420,858,531	434,422,696	448,810,671
% Equity/ Total Assets	77.06%	78.69%	80.28%	81.16%	81.99%

1.3.1.2 2011 Performance targets: Quality

SAIFI - System Average Interruption Frequency Index (the average number of times each customer connected to the network is without supply)

2012	2013	2014	2015	2016
3.23	3.22	3.21	3.20	3.19

SAIDI - System Average Interruption Duration Index (the average total time in minutes each customer connected to the network is without supply)

2012	2013	2014	2015	2016
162.57	162.16	161.75	161.35	160.95

The Commerce Commission Supply Quality Limits are:

SAIFI	3.71
SAIDI	185.28 minutes

1.3.2 Vision statement

To be recognised as the top performing trust owned rural line company and an excellent corporate citizen.

1.3.3 Strategic plan

Key asset management drivers from TPCL's Strategic Plan are:

1. Manage its operations in a progressive and commercial manner.
2. Undertake new investments, which are:
    - Relevant to the core business.
    - Aimed at yielding a return appropriate for the degree of risk.
    - Undertaken in a manner which will maximise the commercial value of the business.

3. Strive to become an efficient and effective operation within the electricity industry and provide its customers with competitive prices and above average levels of service.

1.3.4 Asset strategy

Although TPCL does not have a detailed asset strategy, the following guiding principles are followed:

- Improve reliability by sectionalising poorly performing feeders.
- Migrate from a 33kV subtransmission network to 66kV where appropriate.
- Continue to expand the meshed[2] area of the network by closing gaps between radial feeders.
- Utilise 22kV in locations where economic.
- Consider differing drivers, particularly restoration of supply to dairy or residences.
- Expand remote controllability of the distribution network.
- Replace critical assets near to their technical end-of-life.
- Undertake safety and environmental improvements.
- Achieve 100% regulatory compliance.

1.3.5 Prevailing regulatory environment

Because TPCL is consumer controlled, it will not be subject to the Default Price-Quality Path regime under Part 4 of the Commerce Act 1986.

However TPCL will continue to be subject to an information disclosure requirement (including the requirement to publish an AMP) along with other structural regulations such as restrictions on generating and retailing energy, and the requirement to connect embedded generation.

1.3.6 Government policy objectives

Electricity lines businesses are being increasingly required to give effect to many aspects of government policy, namely:

- Facilitating the connection of distributed generation on a regulated basis.
- Improving the already high levels of public safety around power lines and transformers.
- Offering increasingly variable tariffs to promote demand reduction. [Despite the most economically efficient tariff structure for a lines business being a fixed cost.]

1.3.7 Annual business plan

An Annual Business Plan (ABP) is produced by PowerNet and contains the following:

- Core Business, Vision Statement and Strategies.
- Commercial Objectives, The Nature and Scope of Commercial Activity and Company Polices.
- Annual Capital Works Programme and the Annual Works Plan (AWP) for the following four years.
- Business Plan Financials and Business Unit Reports.

1.3.8 Annual works plan

The Annual Works Plan (AWP) is produced by PowerNet and details the works to be undertaken for each financial year, and is incorporated into the ABP. All of next year's works, listed in the AMP, are included in the AWP.

[2] Meshed – where there is more than one line or cable supplying a group of customers

1.4 Interaction of goals / strategies

The below table shows the linkage between the Corporate and Asset Management Strategies.

Corporate Strategies

Asset Management Strategies	Manage its operations in a progressive and commercial manner.	Undertake new investments, which are 'core business', appropriate return for risk involved, and maximise commercial value.	Strive to become an efficient and effective operation.	Provide its customers with above average levels of service.
Improve reliability by sectionising poorly performing feeders.	✓			✓
Migrate from a 33kV subtransmission network to 66kV, where appropriate.	✓		✓	
Continue to expand the meshed area of the network by closing gaps between radial feeders[3].		✓	✓	✓
Utilise 22kV in locations where economic.			✓	
Consider differing drivers, particularly restoration of supply to dairy or residences.	✓			✓
Expand remote controllability of the distribution network.			✓	✓
Replace critical assets near to their technical end-of-life.				✓
Undertake safety and environmental improvements.	✓			
Achieve 100% regulatory compliance.	✓			

1.5 Period covered by the Asset Management Plan

[Addresses the Handbook requirement 4.5.2(c)]

This edition of TPCL's AMP covers the period 1 April 2012 to 31 March 2022. This AMP was prepared during November 2011 to March 2012, approved by TPCL's Board 28 March 2012 and publicly disclosed at the end of March 2012.

There is a degree of uncertainty in any predictions of the future, and accordingly the AMP is uncertain. Customer demand driven by turbulent commodity markets, public policy trends and possible generation opportunities within TPCL's demand profile means the future is perhaps less certain than many similar infrastructure businesses that have greater scale. Accordingly TPCL has attached the following certainties to the timeframes of the AMP:

Timeframe	Residential and Commercial	Large Industrial	Intending Generators
Year 1	Very certain	Reasonably certain	Reasonable certainty
Years 2 to 5	Certain	Little if any certainty	Little if any certainty
Years 6 to 10	Little if any certainty	Little if any certainty	Little if any certainty

[3] 'Radial feeder' – a single line or cable supply to a customer, with no alternative supply.

1.6 Stakeholder interests

[Addresses the Handbook requirement 4.5.2(d)]

1.6.1 Stakeholders

A stakeholder is defined as any person or class of persons who may do one or more of the following:

- Has a financial interest in TPCL (be it equity or debt).
- Pays money to TPCL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to TPCL's network.
- Uses TPCL's network for conveying electricity.
- Supplies TPCL 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 TPCL network's existence or operation (such as request disclosure data, regulate prices, investigate accidents, District plan requirements).

1.6.2 Stakeholder interests

The interests of the stakeholders are defined in Table 1 below:

Table 1 - Key stakeholder interests

	Interests				
	Viability	**Price**	**Quality**	**Safety**	**Compliance**
Shareholder - SEPSCT	✓	✓	✓	✓	✓
Bankers	✓	✓			✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Energy Retailers	✓	✓	✓		
Mass-market Representative Groups	✓	✓	✓		
Industry Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Suppliers of Goods and Services	✓				
Public (as distinct from customers)				✓	✓
Land owners				✓	✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Ministry of Economic Development		✓	✓	✓	✓
Energy Safety Service				✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Ministry of Consumer Affairs			✓		✓

Table 2 below demonstrates how stakeholder's expectations and requirements are identified.

Table 2 How Stakeholder's expectations are identified

Stakeholder	How expectations are identified
SEPS Consumer Trust	By their approval or required amendment of the SOI Regular meetings between the directors, executive and the trustees
Bankers	Regular meetings between the bankers and PowerNet's Chief Executive and Chief Financial Officer. By adhering to TPCL's treasury/borrowing policy By adhering to banking covenants
Connected Customers	Regular discussions with large industrial customers as part of their on-going development needs Annual customer surveys
Contracted Manager (PowerNet)	Board Chairman weekly meeting with the Chief Executive
Energy Retailers	Annual consultation with retailers
Mass-market Representative Groups	Informal contact with group representatives
Industry Representative Groups	Informal contact with group representatives
Staff & Contractors	Regular staff briefings Regular contractor meetings
Suppliers of Goods & Services	Regular supply meetings Newsletters
Public (as distinct from customers)	Informal talk / gossip around the district Feedback from the Trust's public meetings
Land Owners	Individual discussions as required
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
Ministry of Economic Development	Regular bulletins on various matters Release of legislation, regulations and discussion papers Analysis of submissions on discussion papers
Energy Safety Service	Promulgated regulations and codes of practice Audits of TPCL's activities Audit reports from other lines businesses
Commerce Commission	Regular bulletins on various matters Release of discussion papers Analysis of submissions on discussion papers Conferences following submission process
Electricity Authority	Weekly update Release of discussion papers Briefing sessions Analysis of submissions on discussion papers Conferences following submission process General information on their website
Electricity & Gas Complaints Commission	Reviewing their decisions in regard to other lines companies
Ministry of Consumer Affairs	Release of legislation, regulations and discussion papers General information on their website

1.6.3 Meeting stakeholders' interests

Table 3 provides a broad indication of how stakeholders' interests are accommodated:

Table 3 - Meeting stakeholder interests

Interest	Description	How TPCL meets interests
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 our staff and contractors is ensured by providing all necessary equipment, improving safe work practices and ensuring that they are stood down in unsafe conditions. Contractors will use all necessary safety equipment, improve their safe work practices and ensure that they stand 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.
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in TPCL.	Stakeholders' 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 TPCL's customers want.	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. TPCL's pricing methodology is expected to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.
Supply quality	Emphasis on continuity, restoration of supply and reducing flicker is essential to minimising interruptions to customers' businesses.	Stakeholders' 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.
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.

1.6.4 Managing conflicting interests

The process for handling conflicting stakeholder interests is as follows:

- Conflict identified.
- Analysis of issues and options using the following priority hierarchy:
  - Safety. Top priority is given to safety. The safety of staff, contractors and the public will not be compromised even if budgets are exceeded.
  - Viability. Second priority is viability (as defined above), because without it TPCL will cease to exist which makes supply quality and compliance pointless.
  - Pricing. TPCL will give third priority to pricing as a follow on from viability (noting that pricing is only one aspect of viability). TPCL 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.
  - Supply quality is the fourth priority. Good supply quality makes customers, and therefore TPCL, successful.
  - Compliance. A lower priority is given to compliance that is not safety and supply quality related.
- Report with recommendation made to management.
- Decision made by Management Team, or escalated to TPCL board.

1.6.5 Customer consultation

Consultation was undertaken by three methods: First was a phone survey of 400 customers undertaken by external consultants. A copy of the questionnaire used is attached in appendix A. Only 11% willing to pay $10 per month increase in the electricity bill to improve reliability, was 12% in previous survey. This plan therefore will attempt to maintain a similar level of reliability.

The second method was a face to face survey by the survey company with seven key clients. The outcome was that all didn't want to pay more for improved reliability and wanted more personal contact from PowerNet's Engineers.

Lastly, individual customers are consulted as they undertake connection to the network. For example, the connection of the distributed generation at White Hill required numerous options and negotiation before the final contract for supply was agreed.

1.7 Accountabilities for asset management

[Addresses the Handbook requirement 4.5.2(e)]

TPCL's ownership, governance and management structure is depicted below in Figure 3:

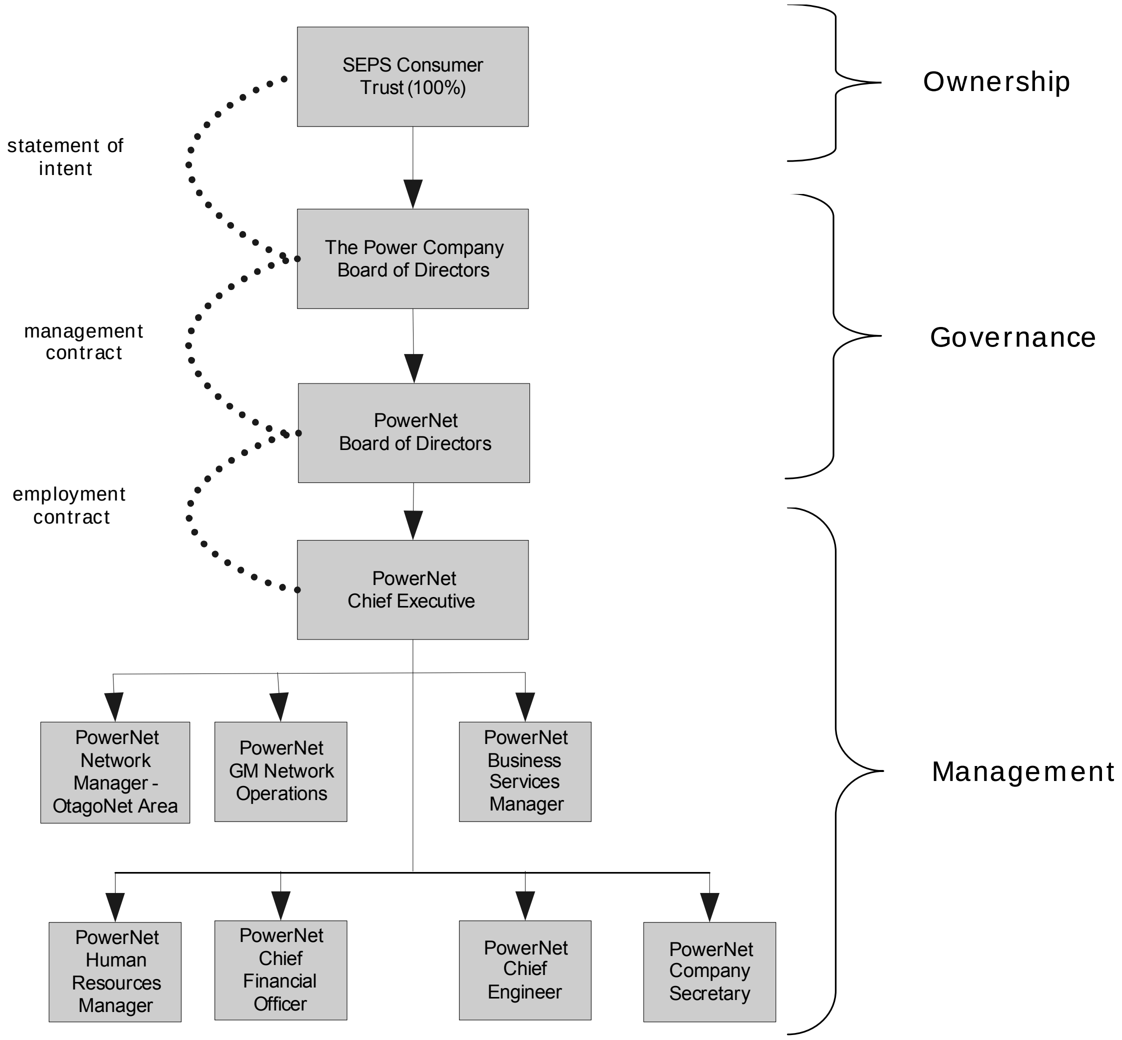


Figure 3 - Governance and management accountabilities

The ultimate accountability is to the connected customers, and it is therefore pleasing to note that the Commerce Amendment Bill has recognised this accountability and removes the price path threshold for such consumer controlled lines businesses.

1.7.1 Accountability at ownership level

TPCL has a single shareholder – the SEPS Consumer Trust. The Trust currently has five trustees who collectively possess 65,751,836 shares in TPCL on behalf of the Trust:

- Jim Hargest (Chairman)
- Wade Devine
- Ron McDonald
- Graham Sycamore
- Vaughan Templeton

The Trust is subject to the following accountability mechanisms:

- By an election process in which two or three trustees stand for election by connected customers every two years. Trustees stand for a term of four years.
- By the Trust Deed which holds all Trustees collectively accountable to the New Zealand judiciary for compliance with the Deed.

1.7.2 Accountability at governance level

As TPCL uses a contracted management company (PowerNet Limited) to manage the assets, there is effectively a two-tier governance structure as follows:

The first tier of governance accountability is between TPCL's Board and shareholder with the principal mechanism being the Statement of Intent. Inclusion of reliability targets in this statement makes TPCL's Board intimately accountable to TPCL's shareholder for these important asset management outcomes whilst the inclusion of financial targets in the statement makes TPCL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and reliability.

TPCL currently has four directors:

- Alan Harper (Chairman)
- Duncan Fea
- Douglas Fraser
- Maryann Macpherson

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

1.7.3 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 TPCL's Board and PowerNet.

1.7.4 Accountability at management level

There are seven 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 preparation of the AMP which will guide the nature and direction of the other managers' work.

1.7.5 Accountability at operational level

PowerNet operations team manages the work to the external contractors, to achieve the outcomes in the Annual Works Plan. Contracts are structured on the following mechanisms:

- Purchase Order – generally only minor work
- Fixed Lump Sum (FLS) Contract – generally on-going work: faults service, checks and inspections
- 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.

Data and information from the contractor's inspections and checks are used to plan works for the following years.

1.7.6 Accountability at work-face level

All field work is done by external contractors managed by the PowerNet Operations Team.

There are three contractors with long term contracts with PowerNet.

- Power Services Limited
- Otago Power Services Limited
- Transfield Services E & T NZ Limited

Some of the other contractors used include:

- DECOM Limited
- Electrix Services Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Total Power Services Limited
- Asplundh Tree Expert (NZ) Limited
- MasterTrade Limited
- Consultants (S Sinclair, Sinclair Knight Mertz, Millpower)

The principal accountability mechanism is through contracts that reflect the outcomes PowerNet must create for TPCL.

1.7.7 Key reporting lines

The trust receives a monthly report from the Chief Executive and Chief Financial Officer.

The TPCL board receives a monthly report that covers 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 voltage 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 fees received.
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network.
- Works Programme – monthly and year-to-date (YTD) expenditure on each works programme item and percentage complete, with notes on major variations.

Each level of management has defined financial limits in the PowerNet Financial Authorities Policy. This requires any new project over $100,000 or variation to the approved Annual Works Plan by more than +10% or -30%, to have Board approval. Generally most projects are approved by the board in the Annual Business Plan process.

1.8 Systems and processes

[Addresses the Handbook requirement 4.5.2(f)]

Systems and processes are described in section 8 of this AMP.

2. Details of the assets

This section summarises TPCL's assets and asset configurations, but begins by describing TPCL'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 Distribution area

2.1.1 Geographical coverage

[Addresses the Handbook requirement 4.5.3(a)(i).]

TPCL's distribution area broadly covers all of Southland as depicted in Figure 4 except for Bluff and the parts of Invercargill that are west of Racecourse Road, south and east of the Waihopai Stream and north of Elizabeth, Moulson and Brown Streets and Tramway Road. TPCL's boundary corresponds with Fiordland National Park to northwest, Lake Wakatipu to the north and east to the Blue Mountains. Broadly corresponds to the Southland and Gore District Council jurisdictions.

Figure 4 - TPCL distribution area

Topography varies as follows:

- Flat fertile plains to the immediate east, north and west of Invercargill taking in the towns of Edendale, Wyndham, Mataura, Gore, Winton, Lumsden, Riverton, Otautau and Tuatapere.
- Rolling fertile plains beyond these areas taking in Tapanui, Waipahi, Mossburn, Garston and west towards Te Anau.
- Sparsely populated mountainous areas towards the north-east beyond the rolling fertile plains.
- Uninhabited mountains and bush in the west and north-west of the area.

2.1.2 Demographics

The population of TPCL's distribution area is approximately 58,595. Classification of areas within TPCL's distribution area is as follows:

		2006 Census[4]		2021 Projection[5]		
Description	Includes	Count	≥ 65	Medium	High	≥ 65
City	Parts of Invercargill not supplied by EIL	9,330	16%	8,930	9,930	23%
Large Town	Gore	7,660	21%	6,990	7,480	29%
	Otatara	2,500	8%	2,450	2,700	16%
	Winton	2,130	28%	2,030	2,170	33%
	Te Anau	1,950	12%	2,200	2,330	17%
	Mataura	1,610	14%	1,430	1,550	20%
	Riverton	1,550	21%	1,500	1,630	29%
Small Town	Tapanui	760	21%	650	700	26%
	Otautau	770	14%	720	780	19%
	Tuatapere	590	19%	550	590	25%
	Wallacetown	610	10%	610	650	16%
	Wyndham	530	17%	460	500	17%
	Edendale	510	20%	490	530	22%
	Lumsden	430	16%	390	430	18%
	Ohai	370	14%	330	350	21%
	Riversdale	410	17%	400	440	15%
	Nightcaps	320	19%	290	300	24%
	Woodlands	260	12%	240	260	21%
	Manapouri	310	13%	320	340	22%
	Mossburn	240	13%	210	230	24%
Rural	Anywhere else	25,755	9%	25,372	27,297	16%
Total		58,595	13%	56,562	61,187	20%

It is interesting to note the number of people 65 years and older is projected to increase from 13% in 2006 to 20% in 2021.

2.1.3 Key industries

Key industries within TPCL's network area include sheep, beef and dairy farming, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism. Most of the large and small towns listed in section 2.1.2 above are rural service towns. The area's economic fortunes will therefore be strongly influenced by:

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

The impact of these issues is broadly as follows:

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[4] 2006 Census Statistics
[5] 2006 Statistics NZ Population Projection, December 2007

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

The recent global economic slowdown may well dampen demand growth as the rural sector hesitates to increase dairy shed and irrigation capacity.

Major customers that have significant impact on network operations or asset management priorities are [Addresses handbook requirement 4.5.3(a)(ii)]:

- Meridian White Hill Wind Farm embedded generation with varying export of up to 58MW.
- Fonterra Co-operative Group Ltd dairy plant, Edendale - two 33kV cables each supplying an 11½/23MVA 33/11kV power transformer (N-1 requirement[6]).
- Alliance Group Ltd, freezing works at Lorneville, Mataura and Makarewa – generally one or two exclusive 11kV feeders (N-1 requirement).
- Bright Wood NZ Ltd, sawmill at Otautau – exclusive 11kV feeder from substation.
- Craigpine Timber Ltd, sawmill at Winton – supplied off local feeder.
- Niagara Sawmilling Co Ltd sawmill at Kennington – supplied off local feeder for industrial area.
- Lindsay & Dixon Ltd, sawmill at Tuatapere – supplied off local feeder.
- Blue Sky Meats Ltd, freezing works at Morton Mains – supplied off local feeder but requires regulators at Edendale Hill and Morton Mains on the main supply route and a backup supply from Waikiwi through two regulators. Has an automatic change-over control of supplying ABS's at connection point to the network (N-½ requirement[7]).
- Open Country Dairy, at Awarua – supplied off local feeder.
- South Pacific Meats, at Awarua – supplied off local feeder.
- Balance Agri-Nutrients Ltd, at Awarua – supplied off local feeder.
- Silver Fern Farms Ltd:
    - Venison abattoir at Mossburn – supplied off local feeder.
    - Venison abattoir at Kennington – supplied off local feeder.
    - General abattoir at Gore – supplied off local feeder.
- Various Hotels and Motels in Te Anau – supplied off local township feeders with backup capability from other township feeders.

[6] N -1 is defined as a full redundant supply so that full load can be supplied from two separate routes.

[7] N-½ is defined as a change-over scheme to an alternative supply but with a short interruption.

- Pioneer Generation, hydro generator at Monowai – connected onto 66kV ringed network (N-1 requirement).
- South Wood Export Ltd, chip mill at Awarua – exclusive 33/11kV 5MVA power transformer due to large synchronous chipper motor.
- Southland District Health Board, hospitals at Invercargill and Gore – supplied off township feeders with alternatives from other township feeders.

2.1.4 Load Characteristics

[Addresses handbook requirement 4.5.3(a)(iii)]

Domestic: Standard household usage with demand peaks in morning (8am) and evening (6:30pm). The use of heat pumps is increasing electricity usage, with no noticeable impact over summer hot period yet. Peaks normally occur in winter.

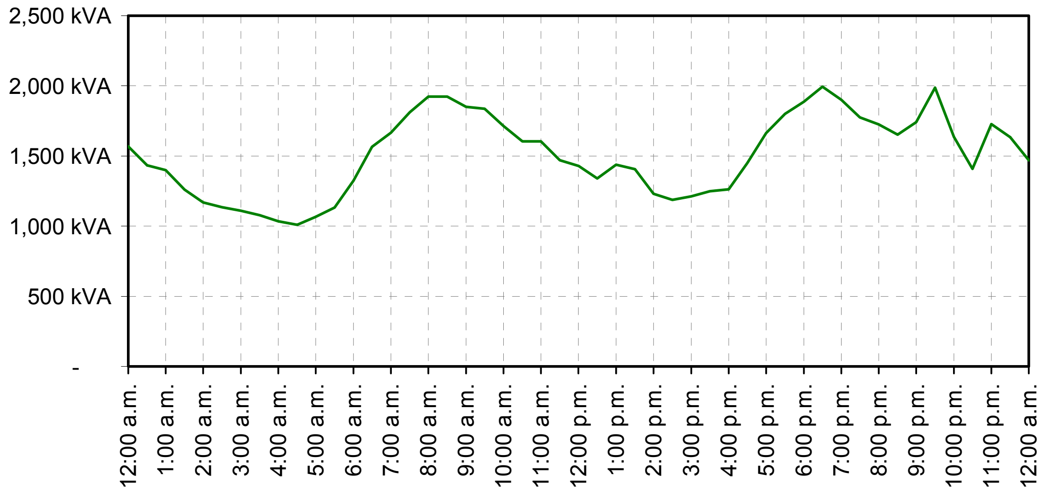

Figure 5 Typical Domestic Daily Load Profile (5 June 2008, Waikiwi CB3)

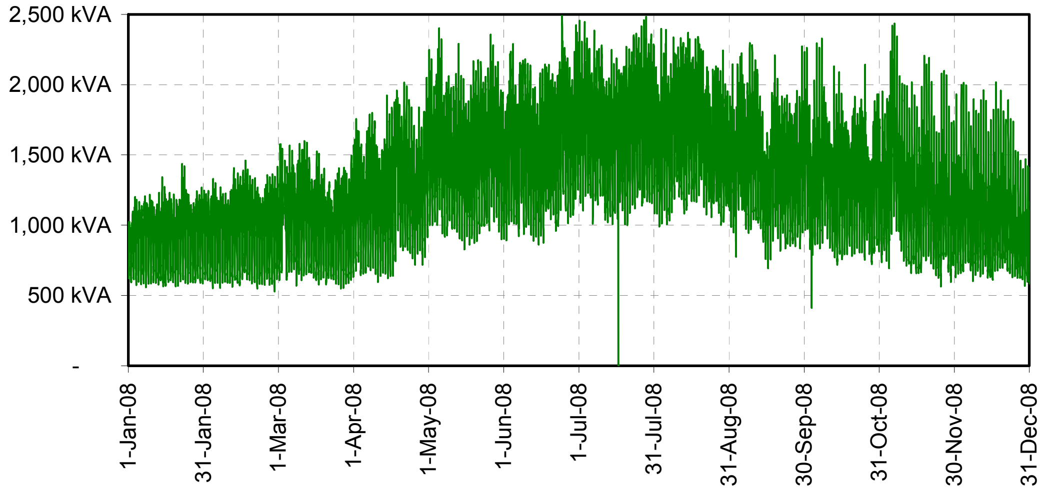

Figure 6 Typical Domestic Feeder Yearly Load Profile (Waikiwi CB3)

Farming: Normally only very low usage with some pumps and electric fences, with peak usage during the few days of shearing or crop harvesting.

Dairy: Milking season between August and May with morning and late afternoon peaks

Sawmills: Usage at sawmills due to processing and kiln drying of product. Some wood-chipping of logs for export, and these have some very large motors with poor starting characteristics.

Dairy Processing: Load characteristic is dependent on milk production with the 'flush' occurring in late October. One plant has 3.8 MW of cogeneration, which can create peaks if it is off.

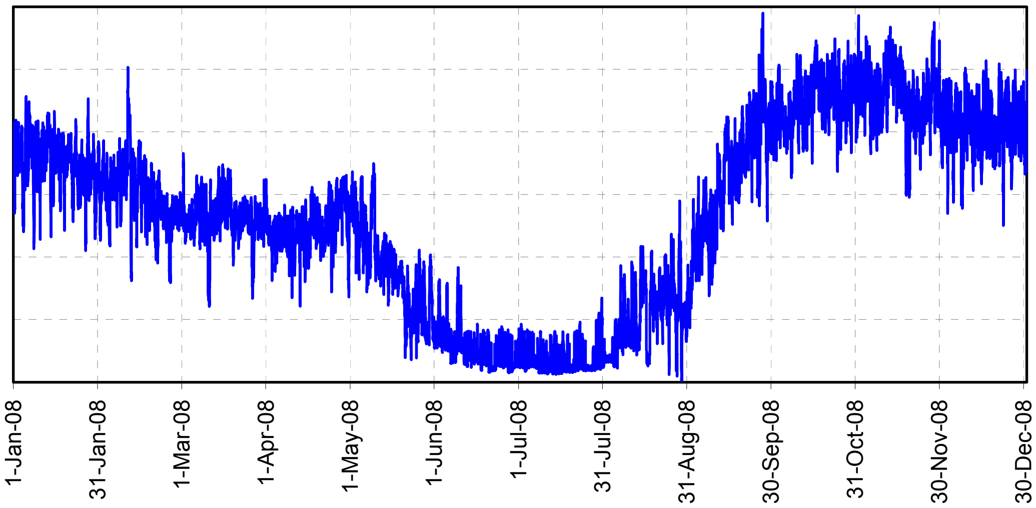

Figure 7 Dairy Processing Plant Yearly Load Profile

Tourism: Mostly over the summer period with steady stream of visitors to or through Fiordland.

2.1.5 Other drivers of electricity use

Other drivers of electricity use include:

- Low temperatures during winter (-5°C frosts are not uncommon in the area).
- The use of these heat pumps as air conditioners in the 25°C summer heat.
- Improving home insulation due to 'Warm Homes' project.
- Increased energy efficiency due to Government campaigns. (Compact Fluorescent light bulbs.)

2.1.6 Energy and demand characteristics

[Addresses handbook requirement 4.5.3(a)(iv)]

Key energy and demand figures for the year end (YE) 31 March 2011 are as follows:

Parameter	Value	Long-term trend (10yr)
Energy entering system for supply to customers[8]	720.6 GWh	Steady growth +2.0%
Maximum demand[9]	131.2 MW	Steady growth +3.0%[10]
Load factor	63%	Improving[10]
Losses	-6.8%	Steady

2.2 Network configuration

To supply TPCL's 34,431 customers the company owns and operates an electrically contiguous network which is supplied by four GXP's at Invercargill, North Makarewa, Edendale and Gore and by up to 66MW of injected generation from Meridian's White Hill wind farm and Pioneer Generation's Monowai hydro station.

[8] Was Energy Conveyed, but new Information Disclosure uses this definition (MP1, H74)

[9] This is different from the sum of the individual demands at each GXP, which will be greater than the coincident demand due to diversity. (MP1, H57)

[10] Step change in Maximum Demand occurred due to new Transpower Pricing Methodology, with individual GXP peaks now replaced by Lower South Island peaks across multiple GXP's.

2.2.1 Bulk supply assets and embedded generation

[Addresses handbook requirement 4.5.3(b)(i)]

2.2.1.1 Invercargill Grid eXit Point (GXP)

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 connection point 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 six 33kV feeders each supplied through its own circuit breaker.

TPCL owns the segments of 33kV line (but not the circuit breakers or bus[11]) that run within the GXP land area and also accommodates a control room that oversees the operation of the network. TPCL owns one of the two 33kV 216⅔Hz ripple injection plants on the west side of the GXP site. The second plant is owned by Electricity Invercargill Limited with each providing backup capability to the other.

2.2.1.2 North Makarewa GXP

North Makarewa is also a strong point in the 220kV grid which ties to Manapouri power station, Invercargill and Three Mile Hill GXP's and to the Tiwai Point smelter. The company takes supply from North Makarewa at 33kV from two 30/60MVA transformers.

TPCL owns the following assets within the GXP land area:

- Two 33/66kV 30/40MVA step-up transformers.
- One Neutral Earthing Resistor (NER).
- Oil containment and separator system.
- Nine 66kV circuit breakers.
- Four 66kV 5MVAr capacitor banks.
- 66kV bus.
- Six 33kV circuit breakers (but not the incoming 33kV circuit breakers or 33kV bus)
- One 33kV 216⅔Hz ripple injection plant on the southwest side of the GXP site, with backup provided from the 66kV 216⅔Hz ripple injection plant at Winton.

2.2.1.3 Edendale GXP

Edendale GXP is supplied by two 110kV single-circuit pole lines from Gore GXP via Brydone GXP and from Invercargill GXP. The company takes supply to its 33kV bus at Edendale by two incomers from two 30MVA transformers. Six 33kV feeders, a 33kV bus coupler, 33kV cables and lines within the GXP land area are owned by TPCL.

The company also owns one 33kV 216⅔Hz ripple injection plant on the north side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Gore.

2.2.1.4 Gore GXP

Gore GXP is supplied by three 110kV single circuit pole lines, from Roxburgh power station, Invercargill GXP via Edendale and Brydone and interconnected to Berwick and Halfway Bush GXP's. The company takes supply from the two 110/33kV 30MVA transformers at Gore to five 33kV feeders. TPCL owns the segments of 33kV line (but not the circuit breakers or bus) within the GXP land area.

The company also owns one 33kV 216⅔Hz ripple injection plant on the south side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Edendale.

[11] Bus – an electrical term, the point where a number of circuits connect. (Alt: Busbar.)

2.2.1.5 Bulk Supply Characteristics

Supply Point	Voltage	Rating	Firm Rating[12]	MD[13]	CD[14]
Invercargill GXP	220/33kV	2 x 120MVA	104.0MVA	97.1MW	84.8MW
North Makarewa GXP	220/33kV	2 x 60MVA	62.3MVA	46.7MW	23.6MW
Gore GXP	110/33kV	2 x 30MVA	36.6MVA	31.3MW	23.1MW
Edendale GXP	110/33kV	2 x 30MVA	31.6MVA	24.9MW	11.6MW
White Hill Wind Farm	66kV	1 x 65MVA	0MVA	-57.2MW	-4.5MW
Monowai Generation	66kV	2 x 5MVA	5MVA	-7.0MW	-6.1MW

2.2.1.6 White Hill generation

This wind farm consists of twenty-nine 2MW wind turbines connected into the Meridian substation by 22kV cable with a step-up transformer to supply into the Heddon Bush to Hillside 66kV line. The 66kV line being split and brought up the hill to the Meridian substation on a monopole dual circuit 66kV line. TPCL owns this line, the 66kV bus and two circuit breaker bays in the Meridian substation.

As part of the installation an American Superconductor's ± 8MVAr Dynamic VAR Compensator (D-VAR) is used to assist in fault capability and a 216⅔Hz blocking filter to reduce ripple frequency absorption.

First generation occurred on 1st June 2007.

2.2.1.7 Monowai generation

TPCL's predecessor, the Southland Electric Power Supply (SEPS), built the original 6.6MW Monowai power station in 1927 as part of the original power development in Southland. As a result of the Electricity Industry Reform Act 1998 Monowai is now owned by Pioneer Generation. Pioneer recently replaced all three 2.2MW generators with modern 2.5 MW units. Monowai currently injects up to 7.5MW into the TPCL 66kV substation.

2.2.1.8 Edendale generation

Fonterra operates a 3.8MW steam turbine generator at its Edendale plant. This generator is embedded within the Edendale plant and as steam is only produced during the milk production season, export of power from the site is rare.

2.2.1.9 Mataura generation

There are two hydro generators on the Mataura Falls connected onto the 11kV feeders out of Mataura substation.

The Alliance Group has an 800kW unit embedded inside its plant with no generation exported.

The Mataura Industrial Estate is operating the 800kW unit at the old Paper Mills on the East bank. The Paper Mills 1875kVA steam turbine generator has been disconnected and is not in service.

2.2.2 Subtransmission network

[Addresses handbook requirement 4.5.3(b)(ii)]

TPCL's subtransmission network is a meshed electrical network that takes supply from four GXP's at Invercargill, North Makarewa, Edendale and Gore as depicted in Figure 8.

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[12] Based on 24 hour post Contingency Rating from Transpower's Branch reports
[13] Maximum Demand 1 September 2010 to 31 August 2011
[14] Coincident Demand for Lower South Island (LSI) peak at 1330hrs 16 August 2011.

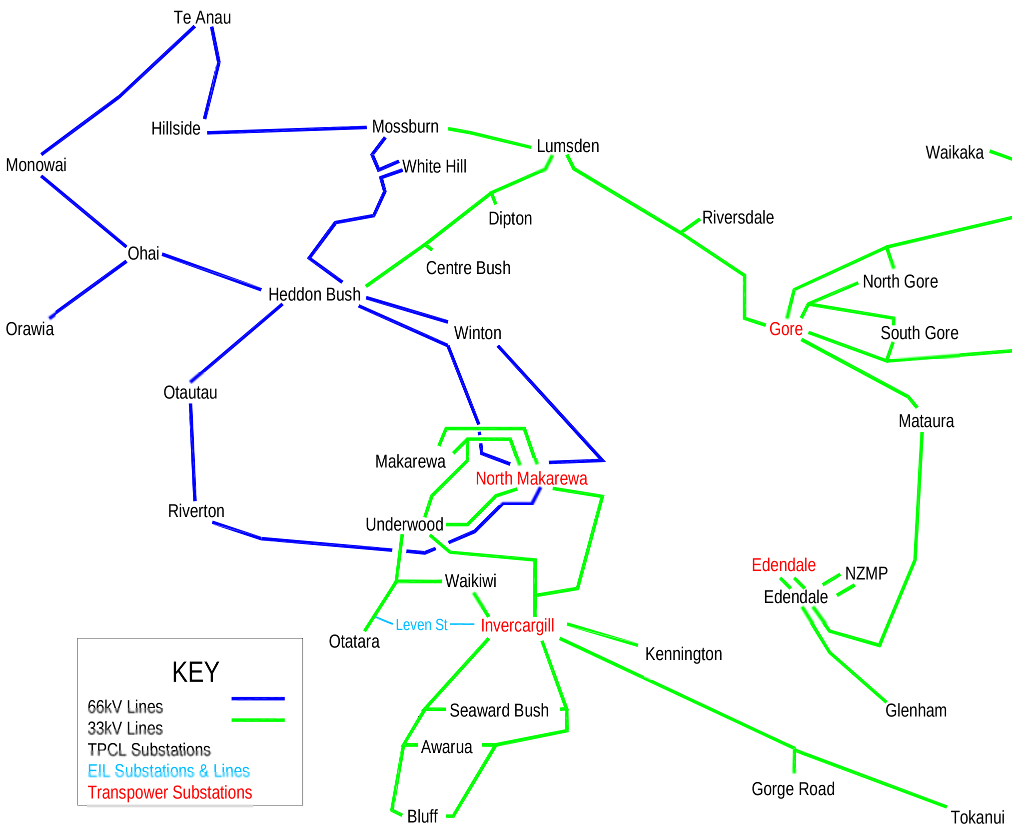


Figure 8 – Subtransmission network

The subtransmission network comprises 383km of 66kV line and 452km of 33kV line and has the following characteristics:

- It is almost totally overhead except for short cable runs at GXP's and zone substations. The notable exceptions are the inter-connects to Electricity Invercargill's Leven Street and Southern zone substations which are cabled from TPCL's Otatara and Seaward Bush lines respectively and some short sections of 33kV around corners on the Invercargill to Kennington 33kV circuit.
- It includes three different electrical topologies (ring, ladder and spur) as well as an interconnection of 66kV and 33kV at the North Makarewa GXP and at TPCL's Heddon Bush substation.
- It includes a large number of lightly-loaded zone substations because the long distances and loads are beyond the reach of 11kV.

2.2.3 Zone substations

TPCL owns and operates the following 33 zone substations and one feeder supplied from Electricity Invercargill Limited's Racecourse Road substation.

Substation	Nature of load	Description of substation
Awarua	Predominantly three large industrial customers with some minor rural load to the south-west.	Simple outdoor site with two 33/11kV transformers and associated outdoor 33kV and 11kV circuit breakers. Due to a large Synchronous Motor at Southwood Export no other customers are supplied from their feeder.
Bluff	Predominantly urban domestic load in Bluff, but including one large and a few medium industrial customers.	Medium complexity outdoor substation with two 33/11kV 6/12MVA transformers, these supply an indoor 11kV switchboard with three feeders.

Substation	Nature of load	Description of substation
Centre Bush	Predominantly rural load in the middle of the Southland Plains.	Simple tee connected 33/11kV 5MVA transformer with three outdoor 11kV feeders. Transformer is able to supply the 33kV with switching of the earthed star point from MV to HV.
Conical Hill	Predominantly rural load. Old sawmill next to site, which has been month-balled.	Large outdoor substation with 33kV circuit breakers on two incoming supplies from Gore via South Gore substation and also from Gore via Kelso substation. Two 33/11kV 5MVA transformers supply a full outdoor 11kV structure with four feeders.
Dipton	Predominantly rural load in the north of the Southland Plains.	Simple tee connected 33/11kV 1.5MVA transformer with two outdoor 11kV feeders.
Edendale Fonterra	Huge dairy factory with four large milk powder plants and other milk process plants.	Dual 33kV cable and 33/11kV 11.5/23MVA transformer supply to the Fonterra 11kV Switchboard.
Edendale	Rural towns of Edendale and Wyndham, small meat works at Morton Mains and rural farms.	Full 33kV switchboard with seven circuit breakers, two supply the local two 33/11kV 6/12MVA transformers, two to Edendale Fonterra, one to Glenham and one to Mataura. An indoor 11kV switchboard with seven feeders.
Glenham	Glenham village, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer with two 11kV feeders. Single 33kV line from Edendale.
Gorge Road	Gorge Road village, rural farms.	Simple outdoor dual 33/11kV 1.5MVA transformers with three 11kV feeders. 33kV line from Invercargill that continues on to supply Tokanui via a 33kV line circuit breaker.
Heddon Bush	Step down from 66kV to 33kV.	Large outdoor 66kV switchyard with a single 66/33kV 10/15MVA transformer. Has three 66kV supply routes from North Makarewa and supplies two end of the North-western 66kV ring.
Hillside	The Key village, rural farms.	Medium outdoor substation supplied by two 66kV lines with 66kV circuit breakers, a single 66/11kV 2.25MVA transformer, three single phase voltage regulators with three 11kV feeders.
Kelso	Tapanui township, rural farms.	Medium outdoor 33kV structure with two supplying lines from Gore and a 33kV feeder to Waikaka. Single 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Kennington	Industrial area with various manufacturing process and few residence.	Simple outdoor single 33/11kV 5MVA transformer with one incoming 33kV circuit breaker and 11kV feeder.
Lumsden	Lumsden township, rural farms with summer irrigation.	Medium outdoor 33kV structure with two supplying lines from Gore and Heddon Bush and a 33kV feeder to Mossburn. Single 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Makarewa	Rural farms with industrial plant.	Medium outdoor 33kV structure with two supplying lines from North Makarewa. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with five 11kV feeders.

Substation	Nature of load	Description of substation
Mataura	Township of Mataura, major Meat Processing Plant and rural farms.	Medium outdoor 33kV structure with main supplying line from Gore GXP, with a backup line to Edendale, and four 33kV circuit breakers. Two 33/11kV 10MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders.
Monowai	Remote rural farms.	11kV supply from Pioneer Generation to a Regulator, supplying two 11kV feeders.
Mossburn	Village of Mossburn, small Meat Processing Plant and rural farms.	Large outdoor 66kV yard with six 66kV circuit breakers. A 66/33/11kV 30/3MVA and a 33/11kV 1.5MVA transformer with four 11kV feeders. NER on 66kV and 11kV Neutrals. 66kV lines as part of North-western 66kV Ring. Future 66kV feeders for lines to future subs at Athol and Castlerock. Single 33kV backup line from/to Lumsden.
North Gore	Town of Gore and rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV transformers (10MVA and 10/20MVA) supplying an indoor 11kV switchboard with four 11kV feeders.
Ohai	Town of Ohai and rural farms. Supplies two open-cast Coal Mines.	Large 66kV structure with lines from North Makarewa GXP, via Winton and Heddon Bush and to Monowai Power Station. Also supplies Orawia 66kV circuit. Each circuit is protected by a 66kV circuit breaker. One 66/11kV 5/7.5MVA transformer that supplies an indoor 11kV switchboard with four feeders.
Orawia	Town of Tuatapere and village of Orawia, rural farms and sawmills at Tuatapere.	66kV Line onto a 66kV circuit breaker and 66/11kV 5/7.5MVA transformer supplying an outdoor 11kV structure with incomer and four 11kV feeders.
Otatara	Town of Otatara and a few farms.	Simple outdoor single 33/11kV 5MVA transformer with incomer and three 11kV feeders. 33kV line from Invercargill.
Otautau	Town of Otautau, rural farms.	Medium 66kV structure with tee onto a single 66kV circuit breaker supplying one 66/11kV 5/7.5MVA transformer. 66kV line from North Makarewa by the southern 66kV ring. Outdoor 11kV structure with incomer and five feeders.
Racecourse Road (EIL)	Eastern area next to Invercargill city, mix of urban, lifestyle blocks and rural. Includes major Hotel/Motel complex.	One 11kV feeder from the Electricity Invercargill Ltd Racecourse Road substation.
Riversdale	Town of Riversdale, village of Waikaia and rural farms, some with summer irrigation.	Small outdoor 33kV structure with main supplying line from Gore, with a back line to Heddon Bush via Lumsden. Single 33kV circuit breaker and 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.
Riverton	Town of Riverton, small fish processing, rural farms	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 5/7.5MVA transformers. Part of southern 66kV ring supplied from North Makarewa. Indoor 11kV switchboard with six feeders.

Substation	Nature of load	Description of substation
Seaward Bush	South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant, rural Farms.	Medium complexity outdoor substation with two 33/11kV 10MVA transformers, these supply an indoor 11kV switchboard with five feeders. Two 33kV lines from Invercargill GXP.
South Gore	Town of Gore, small meat processing plant, rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders. One 33kV line continues onto Conical Hill substation.
Te Anau	Towns of Te Anau and Manapouri, rural farms.	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 9/12MVA transformers. Part of northern 66kV ring supplied from Heddon Bush Indoor 11kV switchboard with five feeders.
Tokanui	Villages of Waikawa, Fortrose, Curio Bay and Tokanui, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer with incomer and two 11kV feeders. 33kV line from Invercargill via Gorge Road.
Underwood	Major Meat processing plant, town of Wallacetown, rural farms.	Large 33kV structure with three 33kV circuit breakers, supplying two 10/20MVA transformers. An indoor 11kV switchboard with four feeders. Two 33kV Lines from North Makarewa GXP and two from Invercargill GXP. Provides a backup to the EIL Leven St substation off one of the Invercargill lines so that Leven St can be supplied from North Makarewa GXP.
Waikaka	Village of Waikaka, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer, single 33kV circuit breaker with one 11kV feeder. Single 33kV line from Kelso.
Waikiwi	Mix of urban residential and urban light industrial load in northern suburbs of Invercargill.	Substantial two 33/11kV 6/12MVA transformer substation with (n-1) supply including possibility of supply from two different GXP's. Indoor 33kV switchboard with five circuit breakers. 11kV switchboard has four feeders.
Winton	Town of Winton, Villages of Lochiel and Browns, Large Sawmill, Limeworks, rural farms.	Winton is on the southern 66kV ring supplied from North Makarewa, with two lines from North Makarewa and Heddon Bush. Two 66/11kV 6/12MVA transformers supplying a full indoor 11kV switchboard with six feeders.

2.2.4 Distribution network

[Addresses handbook requirement 4.5.3(b)(iii)]

2.2.4.1 Configuration

In rural areas the configuration is mainly meshed between substations with reasonable backup capability. Most distribution off this main distribution is radial with only some meshing.

In urban areas a high degree of meshing between 11kV feeders is possible (although transformer loadings rather than distance tends to limit the ability to back-feed on the 11kV).

2.2.4.2 Construction

TPCL's network construction differs between rural and urban as follows:

- Rural areas are predominantly concrete pole, flat construction with wooden cross-arms and pin insulators.
- Suburban areas are either concrete pole with wooden cross-arms and pin insulators or PILC[15] or XLPE[16] cable.
- CBD areas tend to be PILC cable unless this has been replaced, which will almost always be with XLPE.

2.2.4.3 Per substation basis

TPCL's split of distribution network on a per substation basis is presented below in Table 4. Safety and reliability is TPCL's strongest driver of allocation of resources, with customer density providing an indication of priority of other works.

Table 4 – Distribution network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Awarua	12.5	1.8	33	2.3
Bluff(TPCL)	33.9	0.5	149	4.3
Centre Bush	236.6	-	559	2.4
Conical Hill	162.1	0.3	292	1.8
Dipton	184.8	0.2	359	1.9
Edendale	291.0	4.0	1,363	4.6
Edendale Fonterra	-	0.0	1	100.0
Glenham	190.8	-	345	1.8
Gorge Road	158.4	-	385	2.4
Hillside	225.5	2.1	346	1.5
Kelso	431.5	0.5	1,277	3.0
Kennington	4.2	0.9	75	14.8
Lumsden	393.9	8.9	1,158	2.9
Makarewa	274.5	2.4	1,150	4.2
Mataura	291.0	2.8	1,368	4.7
Monowai	47.2	0.3	96	2.0
Mossburn	236.3	1.1	493	2.1
North Gore	281.5	3.7	2,668	9.4
Ohai	208.3	0.5	749	3.6
Orawia	312.7	3.0	927	2.9
Otatara	61.0	4.7	1,219	18.5
Otautau	226.3	1.0	930	4.1
Racecourse Road (TPCL)	28.8	3.1	354	11.1
Riversdale	402.5	1.1	1,238	3.1
Riverton	311.8	6.9	2,046	6.4
Seaward Bush	185.6	6.0	2,580	13.5
South Gore	195.2	5.5	2,421	12.1
Te Anau	174.1	34.6	2,221	10.6
Tokanui	224.5	0.6	540	2.4
Underwood	67.0	1.6	572	8.3

[15] PILC = Paper Insulated Lead Covered – a standard underground cable construction format.

[16] XLPE = Cross-Linked Polyethylene – the modern underground cable construction format.

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Waikaka	108.1	0.2	243	2.2
Waikiwi	238.2	11.9	3,836	15.3
Winton	513.2	7.5	2,697	5.2
Unallocated	1.2	1.8	-	-
			Average	**5.1/km**

2.2.5 Distribution substations

[Addresses handbook requirement 4.5.3(b)(iv)]

Just as zone substation transformers form the interface between TPCL's subtransmission and TPCL's distribution networks, distribution transformers form the interface between TPCL's distribution and LV networks. TPCL's distribution substations range from 1-phase 0.5kVA pole-mounted transformers to 3-phase 1,000kVA ground-mounted transformers shown in Table 5.

Table 5 – Number of distribution substations

Rating	Pole	Ground
1-phase up to 15kVA	4262	20
1-phase 30kVA	620	6
1-phase 50kVA	8	1
3-phase up to 15kVA	1626	12
3-phase 30kVA	2167	34
3-phase 50kVA	860	21
3-phase 75kVA	210	9
3-phase 100kVA	157	66
3-phase 200kVA	128	160
3-phase 300kVA	52	84
3-phase 500kVA	4	35
3-phase 750kVA	2	19
3-phase 1,000kVA	1	9
3-phase 1,500kVA	0	2
Total	**10097**	**478**

Each distribution transformer has MV protection by 'Dropout' fuses. This is achieved in two configurations:

- Individual, with a dropout at each site, or,
- Group Fusing, where a single dropout is located at the take-off from the main line, with up to five downstream units. Each individual unit will have MV isolation where the dropout fuse is replaced with a solid link. This is done to speed fault restoration as fault staff can locate the faulty 'group' as the dropout is generally on the main road and check which unit is failed before restoration.

Low voltage protection is by DIN[17] standard HRC[18] fuses sized to protect overload of the distribution transformer.

[17] 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.

[18] High Rupture Capacity.

For management purposes TPCL's 11kV voltage regulators are classified as distribution transformers:

Location	Purpose
Bushy Park	Voltage improvement
Browns	Voltage improvement
Colac Bay	Voltage improvement
Devery's Corner	Enables backup alternative to Orawia
Dunrobin	Voltage improvement
Edendale Hill	Voltage improvement
Elders	Voltage improvement
Fairlight	Voltage improvement
Fairweather Road	Voltage improvement
Freshford	Voltage improvement
Five Rivers	Voltage improvement
Hilltop	Voltage improvement
Jacks Hill	Enables backup alternative to Tokanui
Kakapo Road	Voltage improvement
Kelso	Voltage improvement
Kingston Crossing	Voltage improvement
Mobile	Temporary voltage improvement for faults and planned works
Morton Mains	Voltage improvement
Opio	Voltage improvement
Oreti Hall	Voltage improvement
Otamita	Voltage improvement
Parawa	Voltage improvement
South Hillend	Voltage improvement
The Ridges	Voltage improvement
Tapanui	Voltage improvement
Tuatapere	Voltage improvement
Woodlands	Voltage improvement
Wyndham Ridges	Voltage improvement

2.2.6 LV network

[Addresses handbook requirement 4.5.3(b)(v)]

2.2.6.1 Coverage

TPCL's LV networks are predominantly clustered around each distribution transformer. The coverage of each individual LV network tends to be limited by volt-drop to about a 200m radius from each transformer hence LV coverage is not as extensive as 11kV.

2.2.6.2 Configuration

TPCL's LV networks are almost solely radial in rural areas but meshed in urban areas which provide some restoration of supply after faults and for planned work.

2.2.6.3 Construction

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

- Overhead LV only.
- LV under-built on 11kV.
- LV under-built on 33kV and 66kV.
- PILC cables only.
- XLPE cable only.
- Conjoint PILC – XLPE cable.

2.2.6.4 Per substation basis

On a per substation basis TPCL's split of LV network is shown in Table 6. Similar to the distribution network, safety and reliability is TPCL's strongest driver of allocation of resources, with customer density providing an indication of priority of other works.

Table 6 – LV network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Awarua	0.42	0.01	33	75.39
Bluff(TPCL)	6.09	0.01	149	24.43
Centre Bush	13.67	-	559	40.89
Conical Hill	8.35	0.05	292	34.74
Dipton	10.82	0.04	359	33.06
Edendale	45.37	0.73	1,363	29.57
Edendale Fonterra	-	-	1	
Glenham	12.80	0.02	345	26.91
Gorge Road	13.31	-	385	28.92
Hillside	3.27	0.01	346	105.49
Kelso	30.31	1.34	1,277	40.34
Kennington	3.86	0.02	75	19.33
Lumsden	22.22	3.70	1,158	44.68
Makarewa	42.51	0.16	1,150	26.95
Mataura	35.33	1.35	1,368	37.30
Monowai	0.95	-	96	101.50
Mossburn	8.99	0.18	493	53.71
North Gore	52.07	8.81	2,668	43.82
Ohai	24.94	0.16	749	29.84
Orawia	27.11	1.63	927	32.26
Otatara	27.30	3.18	1,219	40.00
Otautau	24.31	2.95	930	34.12
Racecourse Road (TPCL)	8.63	1.05	354	36.57
Riversdale	30.88	0.13	1,238	39.93
Riverton	62.07	1.75	2,046	32.06
Seaward Bush	47.69	19.60	2,580	38.35
South Gore	41.61	11.83	2,421	45.30
Te Anau	12.22	30.20	2,221	52.37
Tokanui	25.11	0.56	540	21.04
Underwood	16.17	0.52	572	34.28
Waikaka	6.34	0.02	243	38.17
Waikiwi	76.59	18.16	3,836	40.48
Winton	57.83	11.04	2,697	39.16
Unallocated*	33.77	81.79	-	-
			Average	**33.55/km**

* Data not allocated to a feeder.

2.2.7 Customer connection assets

TPCL has 34,431 customer connections; all of TPCL's "other assets" convey energy to these customer connections and essentially are a cost 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 7.

Table 7 – Classes of customer connections

	8kW 1ph	10% Fixed	20kW 1ph	15kW 3ph	30kW 3ph	50kW 3ph	75kW 3ph	100kW 3ph	Non Half-Hour Metered Individual	Half-Hour Metered Individual	Total
Apr 10	1,736	4,362	22,470	354	3,259	1,408	201	39	71	153	**34,053**
May 10	1,732	4,483	22,379	357	3,258	1,408	201	38	70	159	**34,085**
June 10	1,739	4,519	22,352	356	3,255	1,410	202	39	70	159	**34,101**
July 10	1,739	4,524	22,380	359	3,255	1,411	202	39	70	158	**34,137**
Aug 10	1,746	4,525	22,404	360	3,251	1,417	202	40	71	158	**34,174**
Sept 10	1,742	4,510	22,438	362	3,246	1,416	202	38	73	159	**34,186**
Oct 10	1,751	4,511	22,444	366	3,249	1,416	203	39	74	161	**34,214**
Nov 10	1,766	4,507	22,469	365	3,250	1,413	203	40	73	162	**34,248**
Dec 10	1,767	4,571	22,450	366	3,254	1,419	203	42	73	162	**34,307**
Jan 11	1,767	4,607	22,446	367	3,249	1,421	203	43	73	162	**34,338**
Feb 11	1,770	4,695	22,391	367	3,244	1,424	203	44	73	162	**34,373**
Mar 11	1,768	4,680	22,457	368	3,242	1,432	204	45	73	162	**34,431**

In most cases the fuse forms the demarcation point between TPCL'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. However in some cases a single customer is supplied by a length of line or cable (often on public land) configured as a spur off TPCL's network which is referred to as a "service line" (noting that successive revisions of the Electricity Supply Regulations in the late 1970's and early 1980's confused the two definitions). In such cases ownership of the service line has been retained by TPCL but the customer is responsible for funding and maintaining its safety and connectivity to TPCL's network.

2.2.8 Secondary assets and systems

[Addresses handbook requirement 4.5.3(b)(vi)]

2.2.8.1 Load control assets

The company currently owns and operates the following load control transmitter facilities for control of ripple relays:

- Four main 33kV 216⅔Hz 125kVA injection plants at Invercargill, North Makarewa, Gore and Edendale.
- One backup 66kV 216⅔Hz 125kVA injection plant at Winton.

2.2.8.2 Protection and control

(a) Key protection systems

TPCL's network protection includes the following broad classifications of systems:

Circuit Breakers

- Circuit breakers provide powered switching (usually charged springs or DC coil) enabling operational control of isolation and interruption of faults.
- Circuit breaker protection relays which include over-current, earth-fault and auto-reclose functions. More recent equipment also includes voltage, frequency, directional, distance and circuit breaker fail functionality in addition to the basic functions.
- May also be driven by the following to protect downstream devices:
  - Transformer and tap changer temperature sensors.
  - Surge sensors.
  - Explosion vents.
  - Oil level sensors.

Fuses

- Fuses provide fault interruption of some faults and may be utilised by manual operation to provide isolation.
- As fuses are a simple over current device they do not provide a reliable earth fault operation or any other protection function.

Switches (ABS)

- Switches provide no protection function but allow manual operation to provide control and/or isolation.

Switches (AABS)

- Switches provide no protection function but allow remote operation to provide control and/or isolation.

Links

- Links provide no protection function but allow difficult manual operation to provide control/isolation.

(b) **DC power supplies**

Batteries, battery chargers and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions. This allows continued operation of plant throughout any power outage.

(c) **Tap changer controls**

Voltage Regulating Relays (VRR) provides automatic control of the 'Tap Change On Load' (TCOL) equipment on power transformers to regulate the outgoing voltage to within set limits.

2.2.8.3 SCADA and communications

SCADA is used for control and monitoring of zone substations and remote switching devices and for activating load control plant.

(a) **Master station**

TPCL's SCADA master station is located at TPCL'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.

(b) **Communications links**

The following communication links are owned and operated by the company:

- Three microwave links.
- Twenty Eight UHF links.
- Seven Dataradio UHF channels (one shared with EIL).
- One low power unlicensed link.
- Five VHF Land Mobile channels (one shared with EIL).

(c) **Remote terminal units**

The following remote terminal units (RTU) are owned and operated by TPCL:

Zone substations	RTU	Zone Sub / Field Device	RTU
Awarua	D25	Tokanui	KF
Bluff	KF	Underwood	KF
Centre Bush	C68	Waikaka	SEL
Conical Hill	KF	Waikiwi	D20ME
Dipton	Mini (2)	Winton	D20ME
Edendale	D20C	Winton Injection	C68
Glenham	KF	White Hill	KF
Gore Injection Plant	KF		
Gorge Road	KF		

Zone substations	RTU	Zone Sub / Field Device	RTU
Heddon Bush	D20	**Field substations**	**RTU**
Hillside	KF		
Invercargill Injection Plant	C68	Blue Sky Meats ABS's	KF – LP1
Kelso	C68	Dunrobin Reg	Nulec
Kennington	D25	Freshford N circuit breaker	SEL
Lumsden	KF	Freshford W circuit breaker	SEL
Makarewa	C68	Gap Road circuit breaker	SEL
Mataura	KF	Haldane circuit breaker	KF
Monowai	KF	Holmes Corner CB	Form 5
Mossburn	KF	Longwood circuit breaker	Nulec
North Gore	KF	Nine Mile N circuit breaker	SEL
North Makarewa	D20M++	Nine Mile S circuit breaker	SEL
Ohai	D20 C	Parawa Reg	Form 5
Orawia	KF	Peters circuit breaker	SEL
Otatara	KF	Raymonds Gap	KF
Otautau	KF	River Road circuit breaker	Nulec
Riversdale	KF	Tapanui Reg	Nulec
Riverton	KF	Twinlaw Repeater	KF
Seaward Bush	D20ME	Waikawa circuit breaker	KF
South Gore	C68	Woodlands Reg	Mini
Te Anau	KF	Wyndham Ridges Reg	Nulec

- C68 = Siemens rack RTU, HDLC protocol over 300 baud modem.
- Mini = Siemens mini RTU, HDLC protocol over 1200 baud modem.
- D25 = Harris single rack RTU, DNP3.0 protocol over 9600 baud Modem.
- D20 M++, D20ME, D20 = Harris multiple rack RTU, DNP3.0 protocol over 9600 baud Modem.
- SEL = SEL 351 Protection Relay acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- Nulec = Nulec recloser controller acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- Form 5 = Cooper Recloser Controller acting as an Intelligent Electronic Device (IED), DNP3.0 protocol over 9600 baud Modem.
- KF = Kingfisher RTU, DNP3.0 protocol over 9600 baud Modem.

2.2.8.4 Other assets

(a) Mobile generation

None, but PowerNet owns a 275kW and 350kW diesel generators which are used for outage restoration, planned work and peak load lopping.

(b) Stand-by generators

None.

(c) Power factor correction

None.

(d) Mobile substations

One trailer mounted 3MVA 11kV regulator and circuit breaker with cable connections.

(e) Metering

Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

2.3 Age and condition of TPCL's assets by category

[Addresses handbook requirement 4.5.3(c)]

A general overview of all assets managed by PowerNet is provided in appendix B.

2.3.1 Bulk supply assets and embedded generation

The company owns the following assets within the GXP's:

Transformers

Voltage	Location	Quantity	Manufactured	Condition
33/66kV	North Makarewa	Two 30/40MVA	2000 (RL[19] = 43yrs)	Good.
33/11kV	Edendale	Two 6/12MVA	2002 (RL = 45yrs)	Good.

Circuit breakers

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	5	2007 (RL = 40yrs)	Good.
66kV	North Makarewa	4	2000 (RL = 33yrs)	Good.
33kV	North Makarewa	1	1971 (RL = 4yrs)	Average.
33kV	North Makarewa	1	1981 (RL = 14yrs)	Average.
33kV	North Makarewa	2	1983 (RL = 16yrs)	Average.
33kV	North Makarewa	2	1984 (RL = 17yrs)	Average.
33kV	Edendale	7	2002 (RL = 46yrs)	Good.
11kV	Edendale	5	1994 (RL = 27yrs)	Good.
11kV	Edendale	1	1995 (RL = 28yrs)	Good.
11kV	Edendale	1	1996 (RL = 29yrs)	Good.
11kV	Edendale	1	1998 (RL = 31yrs)	Good.
11kV	Edendale	2	1999 (RL = 32yrs)	Good.

Bus

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	1	2000 (RL = 33yrs)	Good.
33kV	Edendale	1	2002 (RL = 46yrs)	Good, Indoor switchboard.

Capacitor Banks

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	4	2007 (RL = 40yrs)	Good.

Neutral Earthing Resistor

Voltage	Location	Quantity	Manufactured	Condition
66kV	North Makarewa	1	2000 (RL = 33yrs)	Good.

Injection Plants

Voltage	Location	Quantity	Manufactured	Condition
66kV	Winton	1	1992 (RL = 0yrs)	Average, coupling cell and capacitors are outdoor.
33kV	Invercargill 1	1	1988 (RL = -4yrs)	Good, all gear is indoor.

[19] RL = Remaining Life based on ODV handbook standard life, as at 31 March 2012.

Voltage	Location	Quantity	Manufactured	Condition
33kV	Gore	1	1990 (RL = -2yrs)	Good, all gear is indoor.
33kV	Edendale	1	1988 (RL = -4yrs)	Good, all gear is indoor.
33kV	North Makarewa	1	1994 (RL = 2yrs)	Good, all gear is indoor.

There are a number of significant embedded generation plants (i.e. About 1MW or greater) but these are not owned by the company.

2.3.2 Subtransmission network

The chart below summarises the subtransmission lines constructed each year:

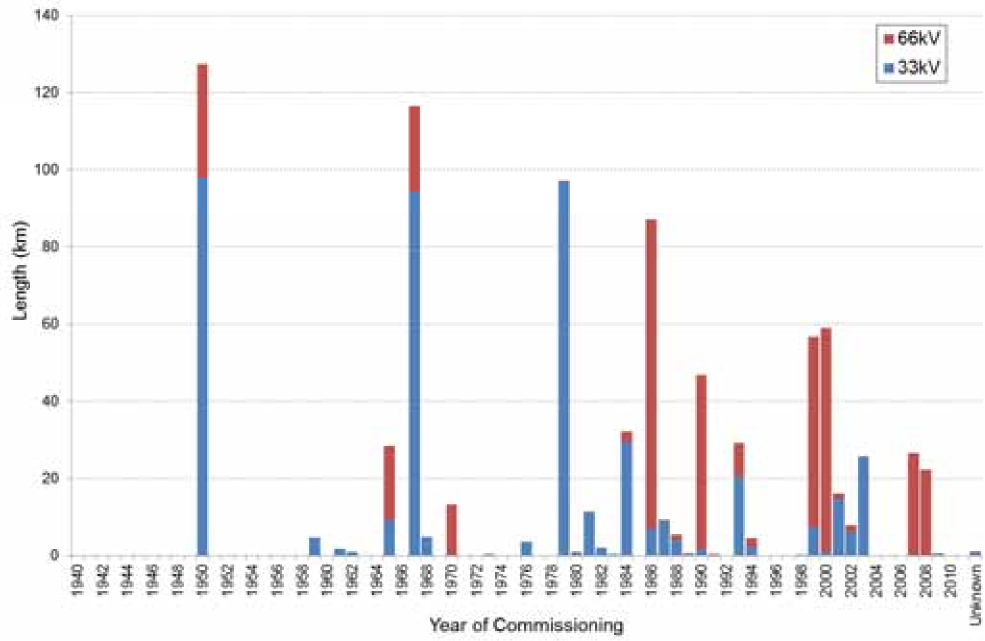


Figure 9 - Subtransmission line construction

The Monowai to Redcliff 66kV Line is over 45 years old but is still in operational condition. Determining the remaining life for multi-componented assets is difficult especially as sections are constructed to differing standards and materials. The chart below shows the remaining life based on poles on the subtransmission network:

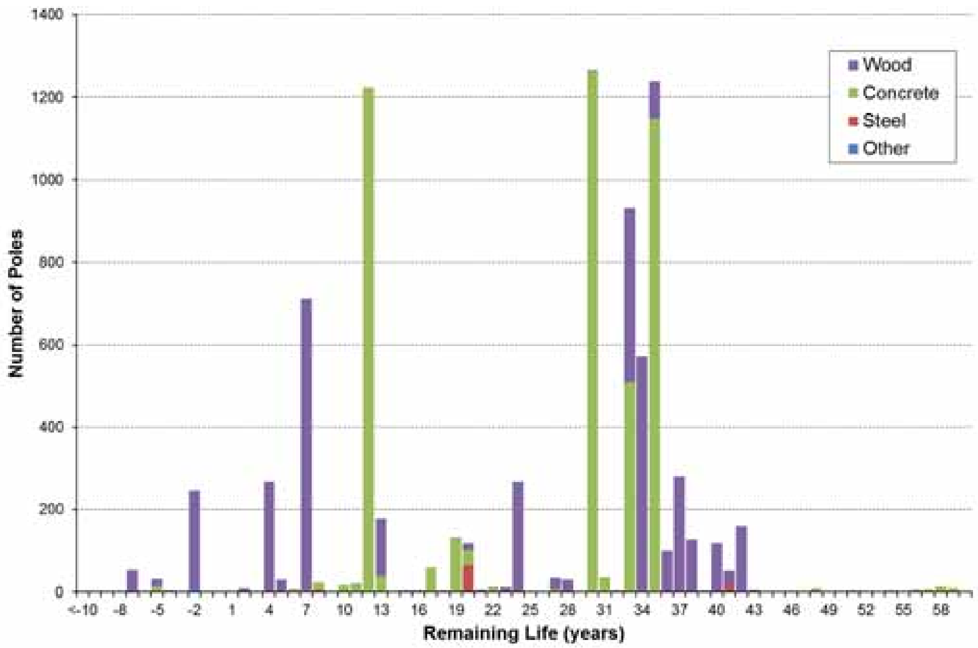


Figure 10 - Subtransmission Poles Type

In theory for wooden poles, all lines built prior to 1977 should be replaced before the end of 2022. Five yearly checks are made of all subtransmission lines with remedial repairs or renewal planned based on information obtained. Due to the criticality of this asset to supply reliability, complete circuits are renewed to modern standards verses piece-meal replacements.

This chart shows for concrete poles that a few lines segments with concrete poles will need to be renewed during the planning period.

Figure 11 Subtransmission Pole with 10 year or less of life remaining

The 33kV cables are recent additions to the network and these are in good condition.

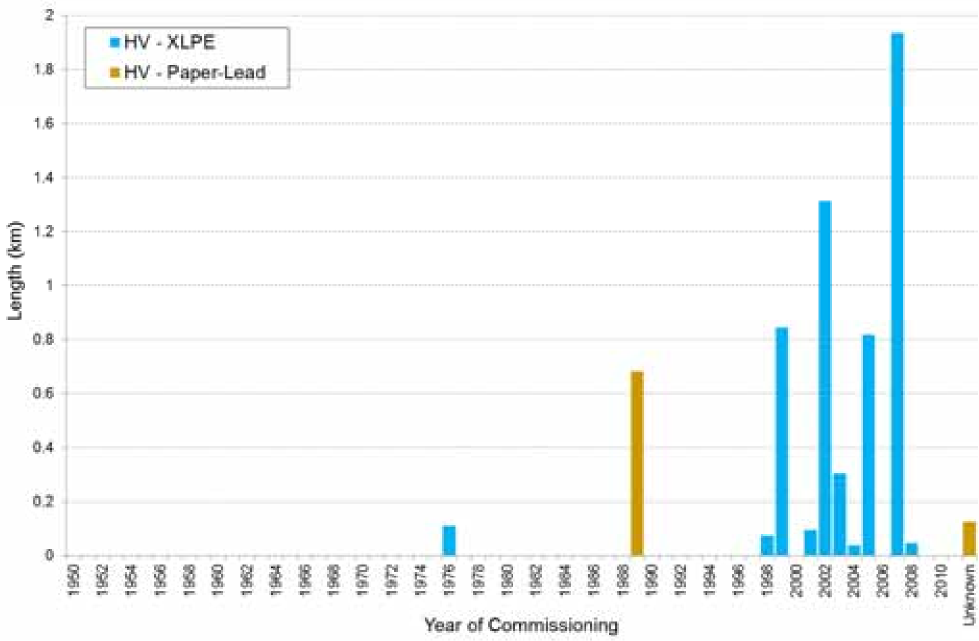


Figure 12 - Subtransmission Cables

2.3.3 Zone substations

2.3.3.1 HV Switchgear

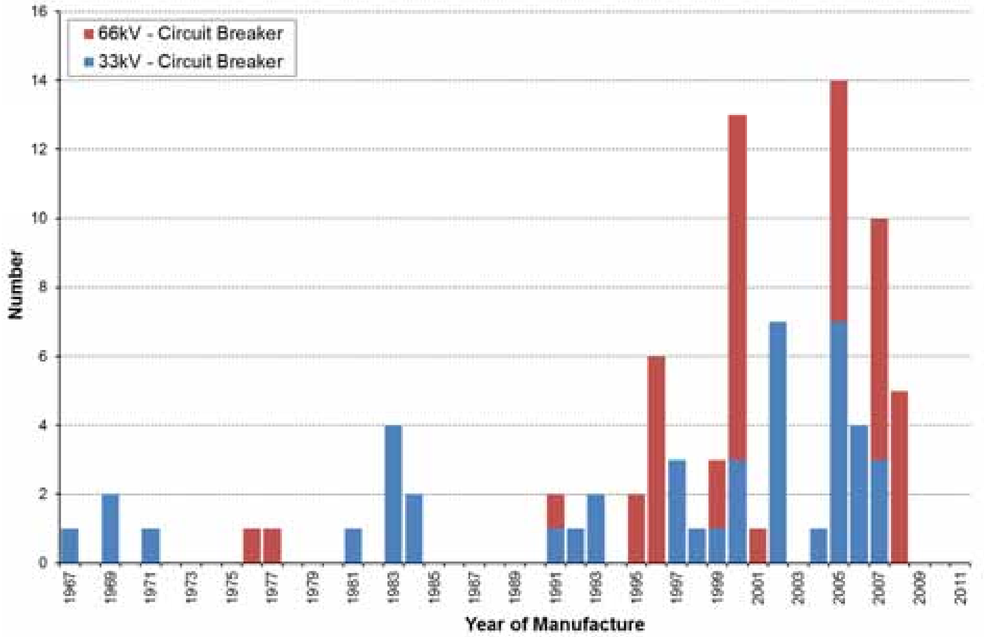


Figure 13 - High Voltage Switchgear

The age profile is shown for high voltage circuit breakers. Six CB's will exceed the standard life of 45 years over the next ten years. Condition is generally good.

2.3.3.2 Power Transformers

Age profile shows the present profile of ages for Power Transformers and Regulators.

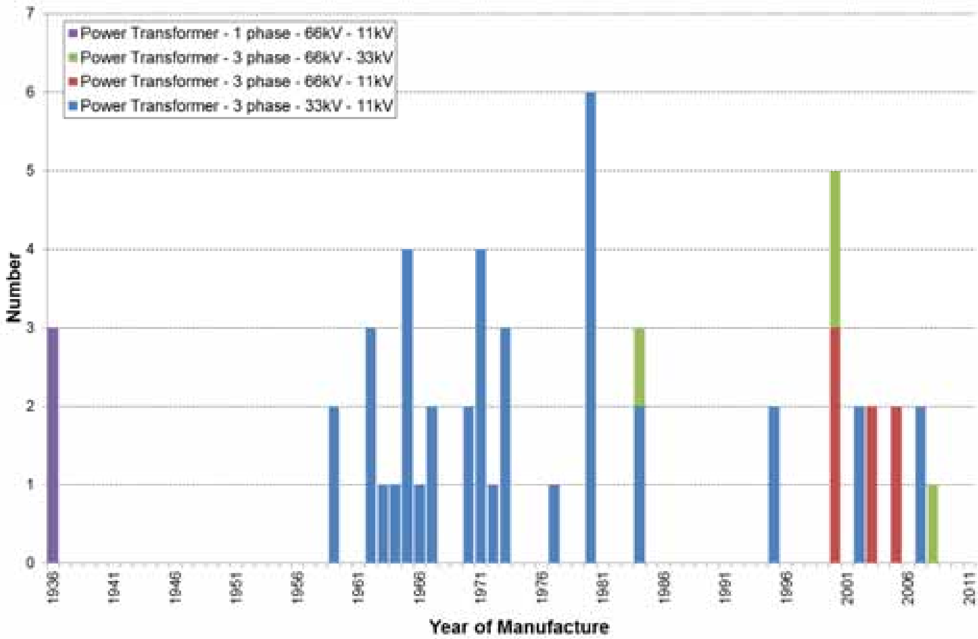


Figure 14 - Power Transformers

The old bank at Hillside is not showing signs of failure and no replacement is planned within the next ten years.

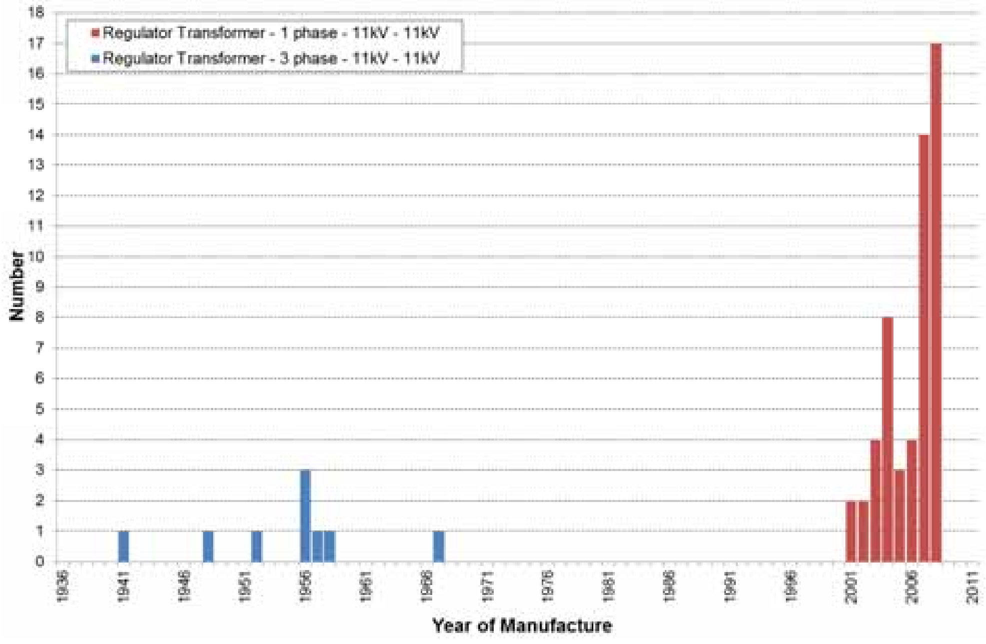


Figure 15 - Regulators

On-going renewal of old Regulators is planned with one unit replaced almost every year. This will result in no Regulators older than 21 years by 2022.

2.3.3.3 MV Switchgear

11kV circuit breakers in zone substations are either installed indoor or outdoor with the indoor units having an extra 5 years standard life. Therefore outdoor units older than 1982 and indoor older than 1977, should be refurbished or replaced by 2022.

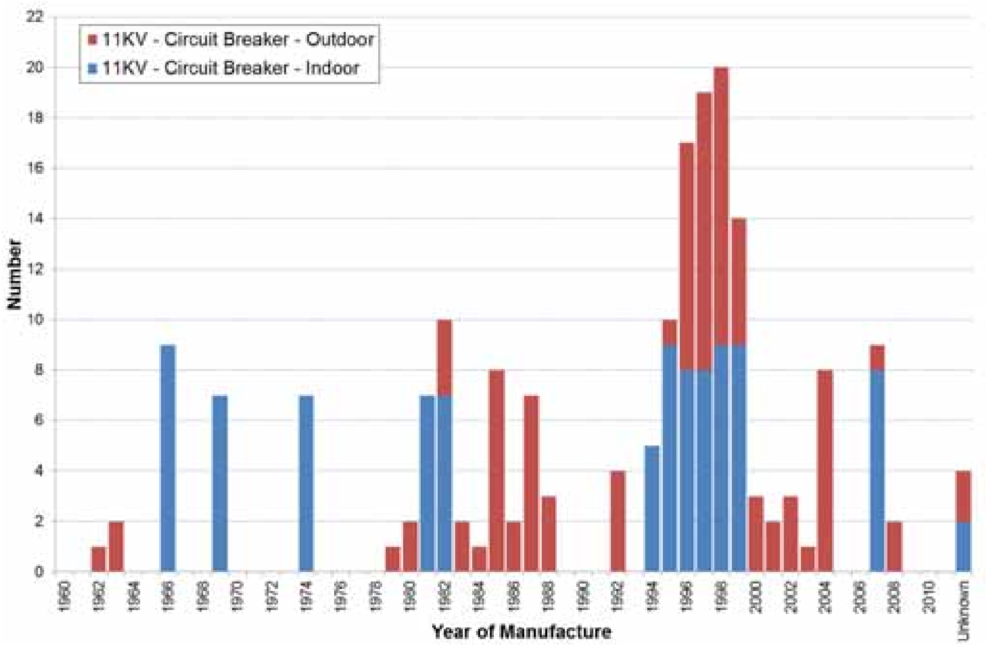


Figure 16 - Medium Voltage Switchgear

2.3.4 Distribution network

Medium voltage lines have an age profile as shown in Figure 17. In theory 7,316 wooden poles and 5,349 concrete poles should be renewed by 2022. Over the following ten year period the renewal values for concrete poled lines jumps to 30,922 and wooden drops to 1,026. This shows the 'wave of wire' that would require an average of over 2,000 poles per year to be renewed. Good pole lives proven by inspection and non-destructive testing (NDT) will hopefully allow 25% to remain in service for an additional ten years.

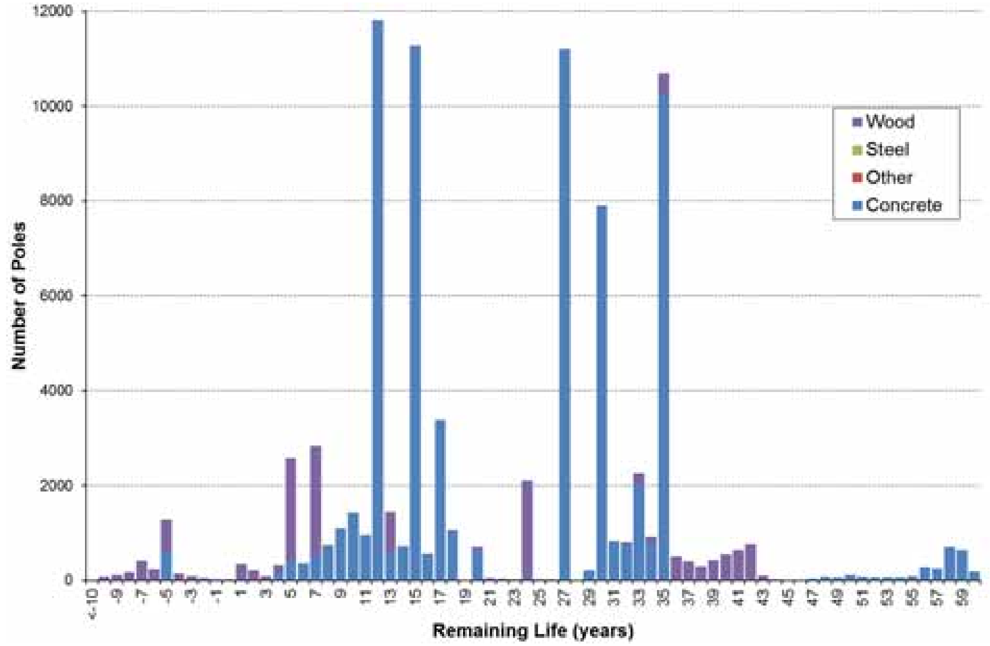


Figure 17 - Distribution Poles

To smooth this wave the company is proposing to increase the renewal for the next ten years from the average required of 750 poles (60km) per year, to 1,500 (120km) per year. The actual replacement rate will depend on available resources, the amount of new connections requiring upgrades, the five yearly inspection, NDT and fault incidences.

The figure 18 shows the location of distribution poles that 'in theory' should be replaced over the next ten years.

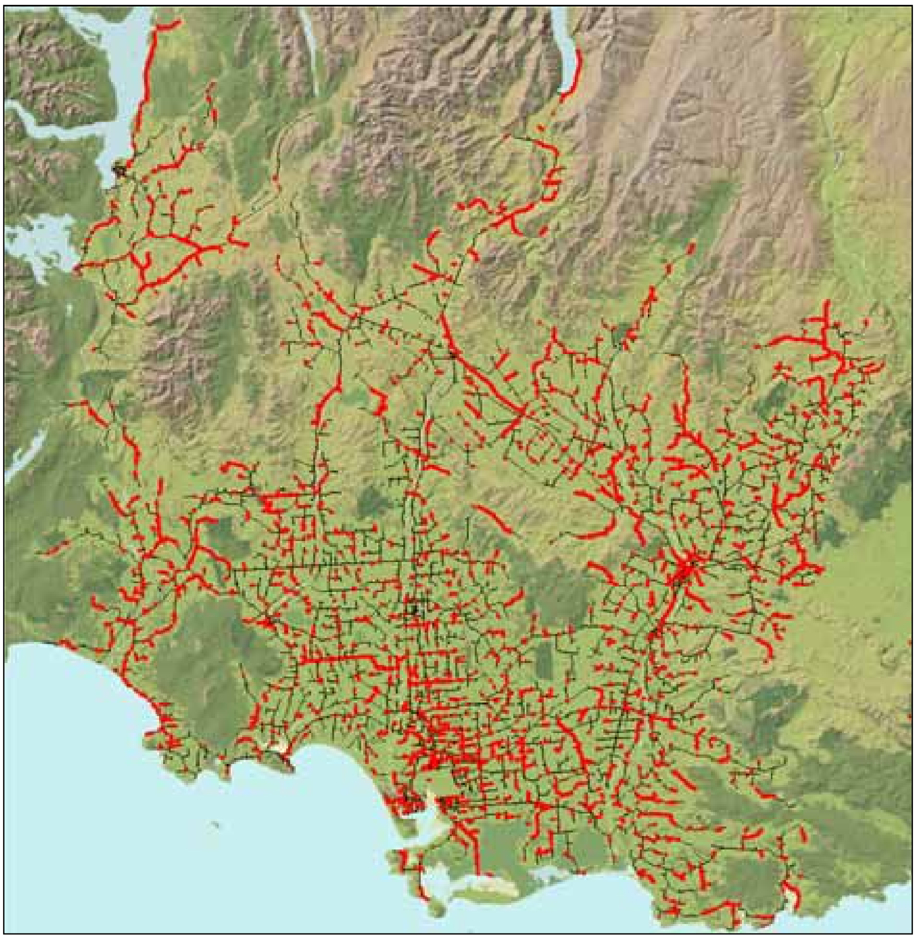


Figure 18 MV Poles with less than 10 year remaining life

The age profile of 11kV cables shows that very few cables will need renewal within the planning period.

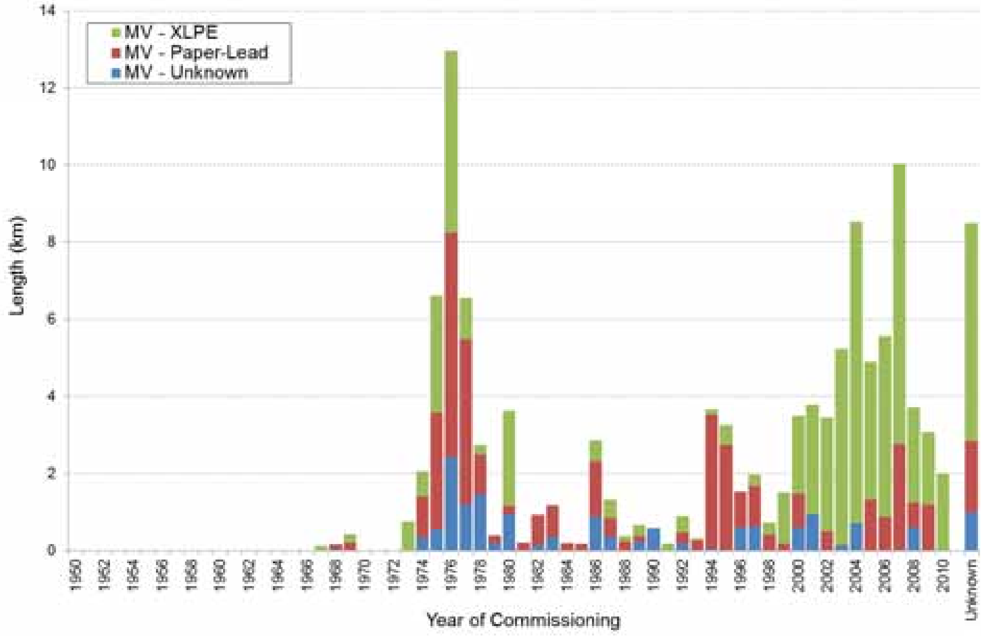


Figure 19 - Distribution Cables

2.3.5 Distribution substations

The age profile of distribution transformers is shown below. Condition of these varies generally due to proximity to the coast and if the unit has been heavily loaded.

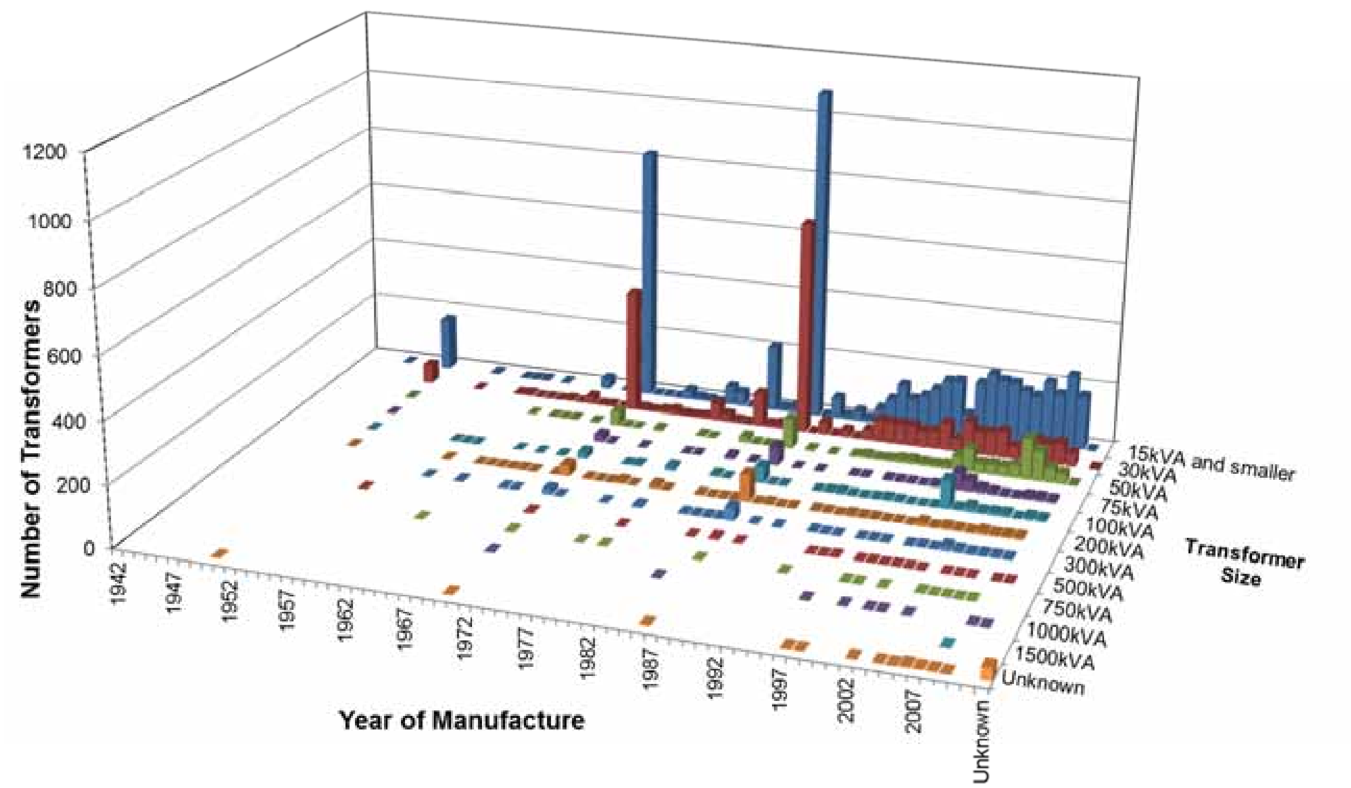


Figure 20 - Distribution Transformers

Three spikes occur at 1950, 1970 and 1986 where estimated ages have been used, as the actual manufacturing year was not able to be found.

2.3.6 LV network

The age profile of the 400 volt lines is displayed below. Conditions of these are average, with 1,710 poles due for renewal this planning period. The next planning period should renew 4,059 poles.

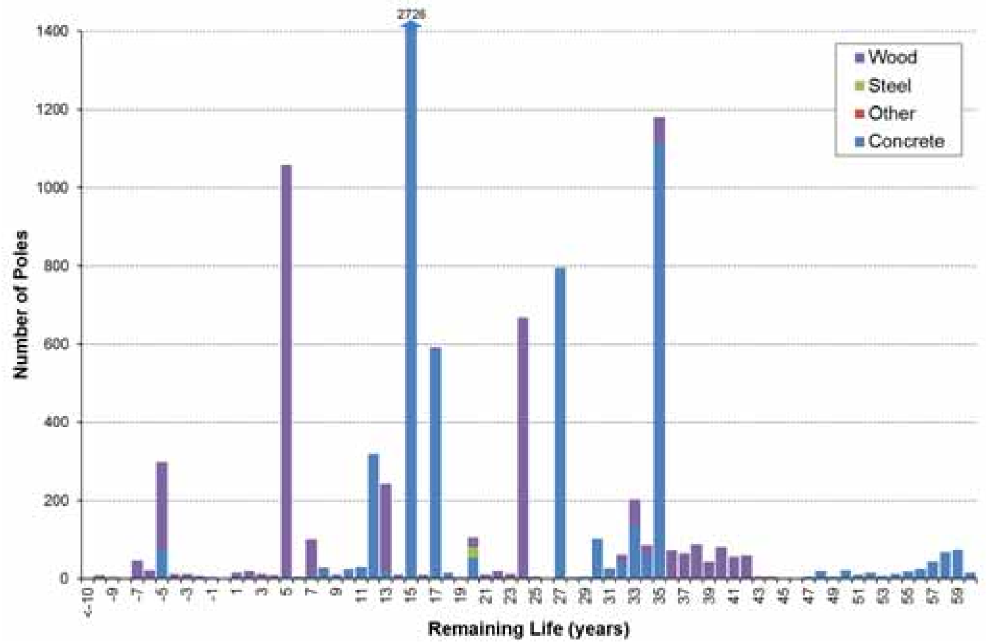


Figure 21 - Low Voltage Lines

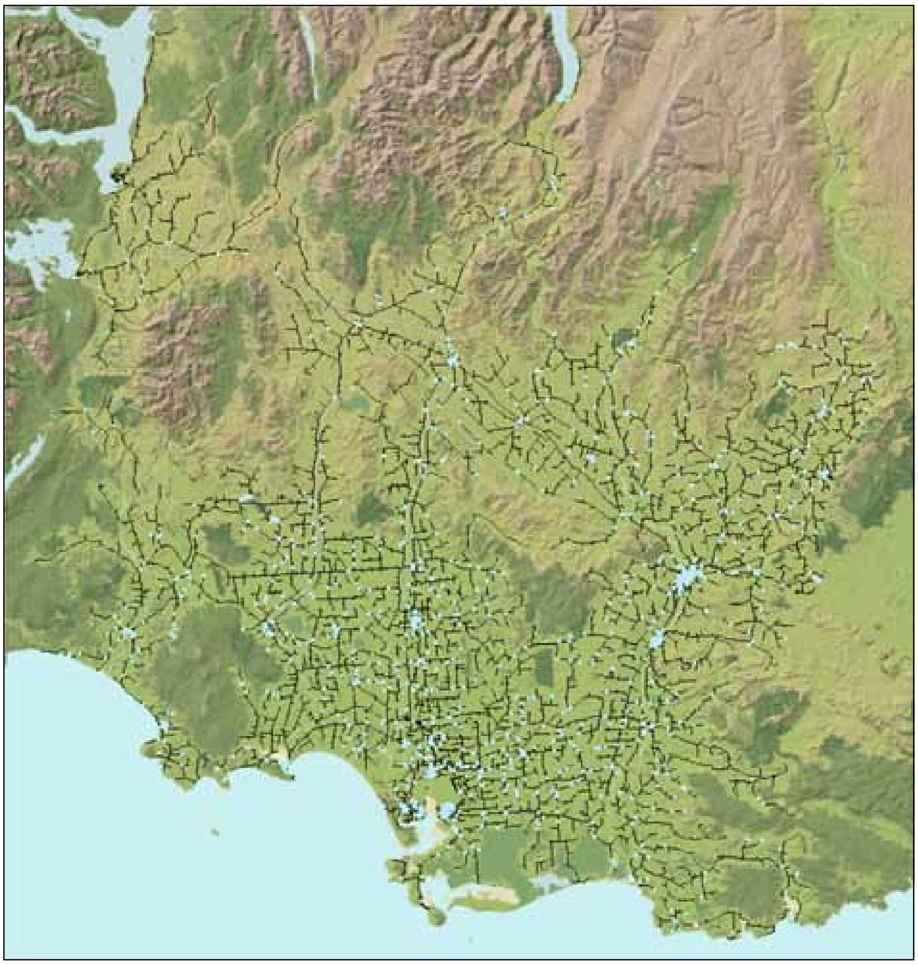


Figure 22 Low Voltage Poles with less than 10 years remaining life

The age profile for low voltage cables is displayed below. Over the planning period an estimated 73.4km could be renewed, if it is found that the standard ODV life applies to these cables. The following 10 year period could replacement of 24.0km.

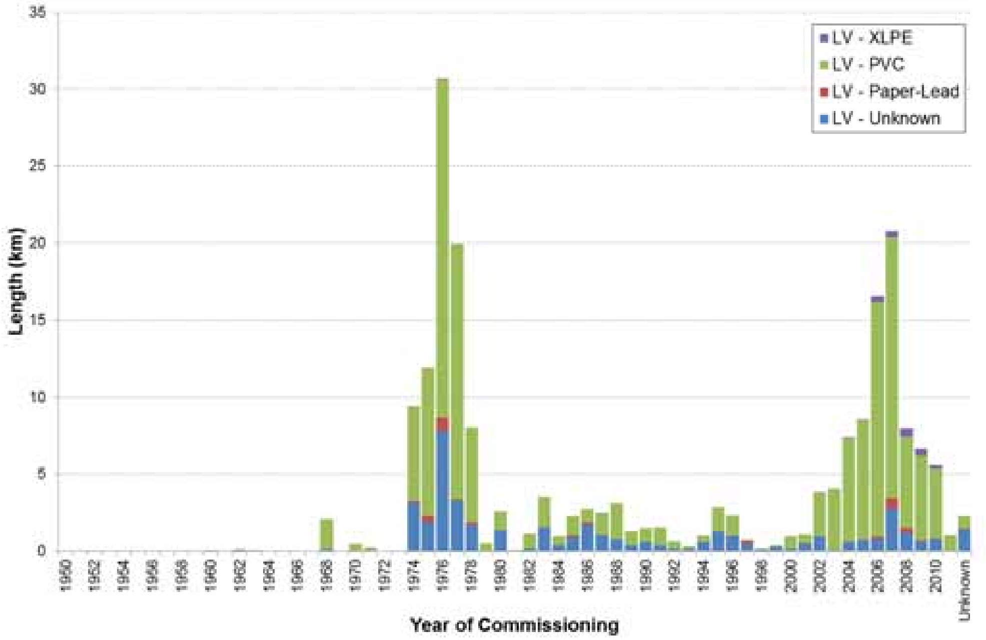


Figure 23 - Low Voltage Cables

2.3.7 Customer connection assets

No accurate age data exists for customer connection assets and generally these are renewed as they fail or are upgraded for increased customer requirements.

2.3.8 Load control assets

The installation of Load Control started with the injection plant at Invercargill in 1989 and finished at North Makarewa in 1994. Details are included with the GXP installed equipment. All 33kV plants are enclosed within buildings providing protection from the elements and therefore an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply units upgraded in 2005 after failures at other sites.

2.3.9 Protection and control

2.3.9.1 Key protection systems

The field circuit breakers are included with the 11kV zone substation circuit breakers, see section 2.3.3.3.

Switches

The air break switchgear has the following age profile. The condition of these is generally poor with a proportion of older units. Additional evidence of this is the number of faulty units found each month when they fail to operate.

Fuses

There are 10,000+ drop-out fuses on the network protecting transformers and laterals. No known age profile exists but these have a relatively low failure rate.

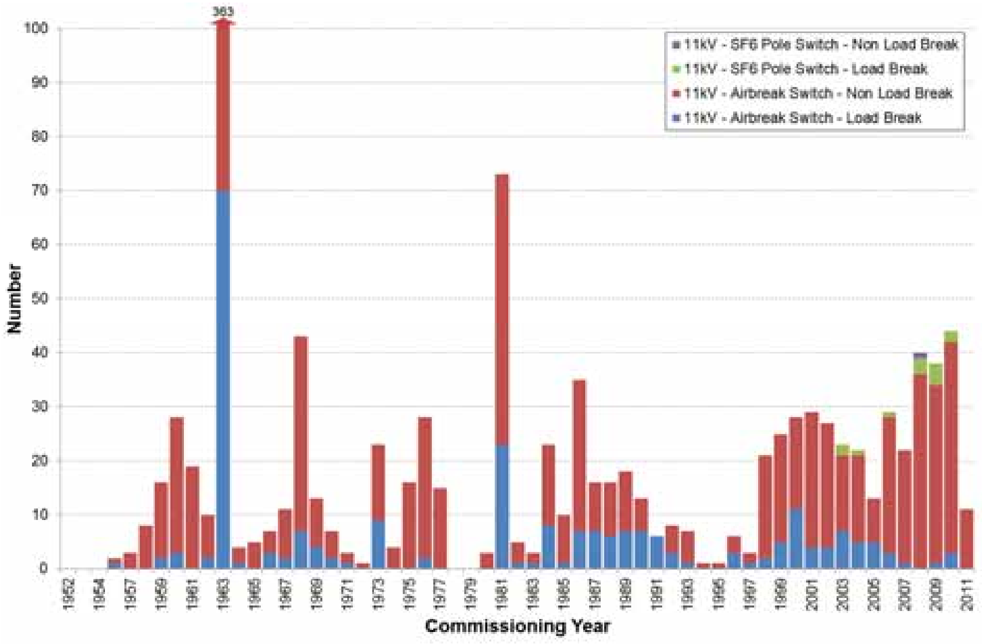


Figure 24 - Air Break Switches

2.3.9.2 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.

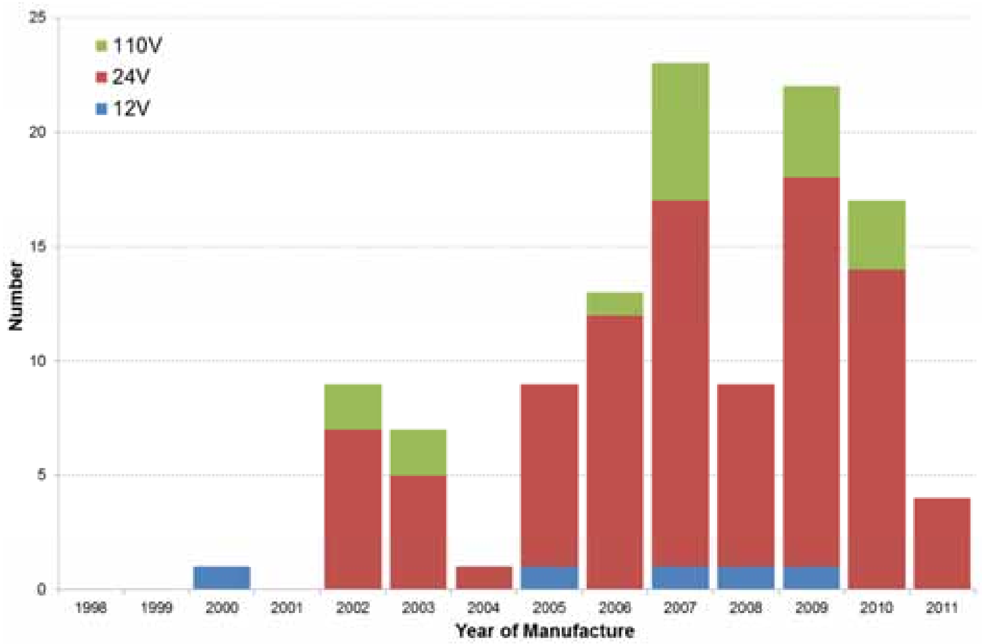


Figure 25 – Battery Banks

2.3.9.3 Tap changer controls

90 voltage regulating relays (VRR) are in service and most have been installed with the associated transformer. The condition of these is average with some recent problems. The recent significant jump in numbers due to installation single phase voltage regulators, which have a VRR per phase.

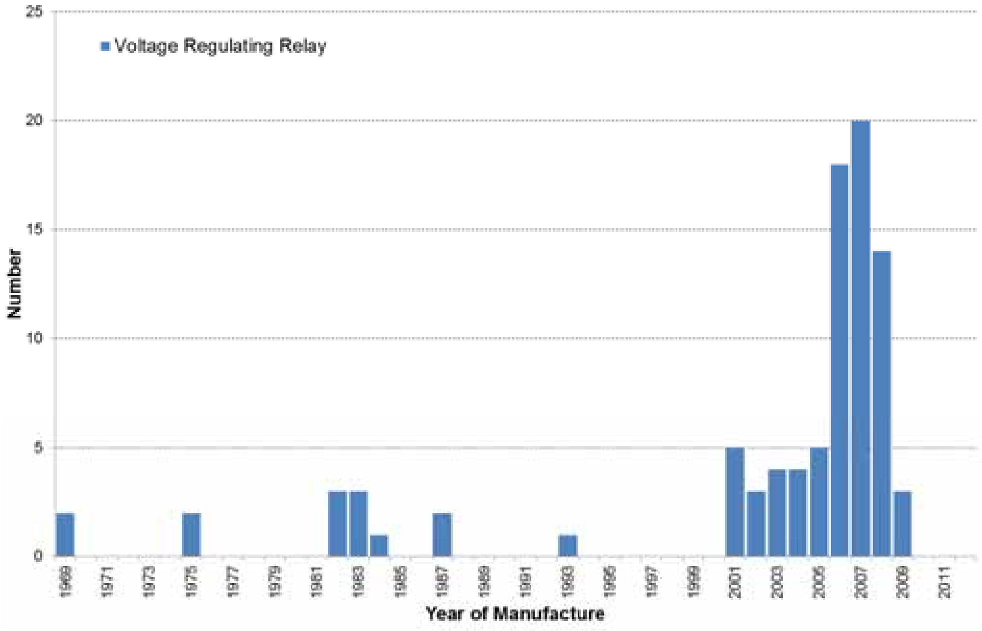


Figure 26 – Voltage Control Devices

2.3.10 SCADA and Communications

2.3.10.1 Master station

The initial system was commissioned in 1999 with a recent upgrade of the Server PC's in 2005. The software has been developed with the latest version being implemented with the new servers in 2005. Both operator stations now have LCD screens.

2.3.10.2 Communications links

Standard life is 15 years and condition of older units is good.

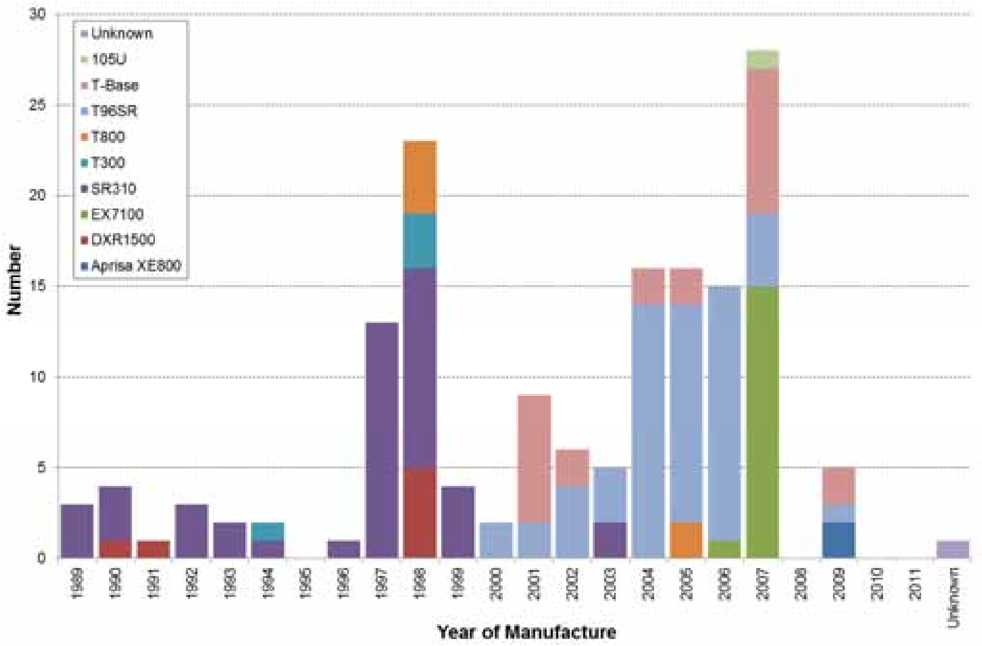


Figure 27 – Radios

2.3.10.3 Remote terminal units

Age profile of Remote Terminal Units (RTU) is shown in Figure 28. Standard age is 15 years and condition is average: with older Siemens units starting to become difficult to maintain.

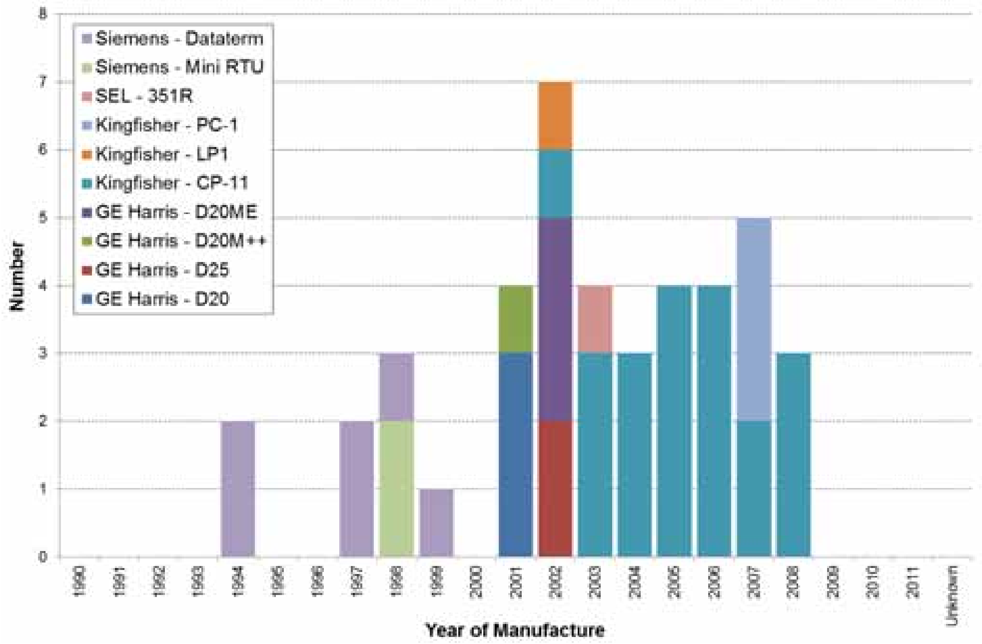


Figure 28 – Remote Terminal Units

2.3.11 Other assets

2.3.11.1 Mobile generation

None.

2.3.11.2 Stand-by generators

None.

2.3.11.3 Power factor correction

None.

2.3.11.4 Mobile substations

One mobile 3MVA 11kV Regulator, on a heavy trailer. Condition of this unit is average.

2.3.11.5 Metering

TPCL has 'Time Of Use' (TOU) meters on its Incoming Circuit Breakers to provide accurate loading information on each zone substation.

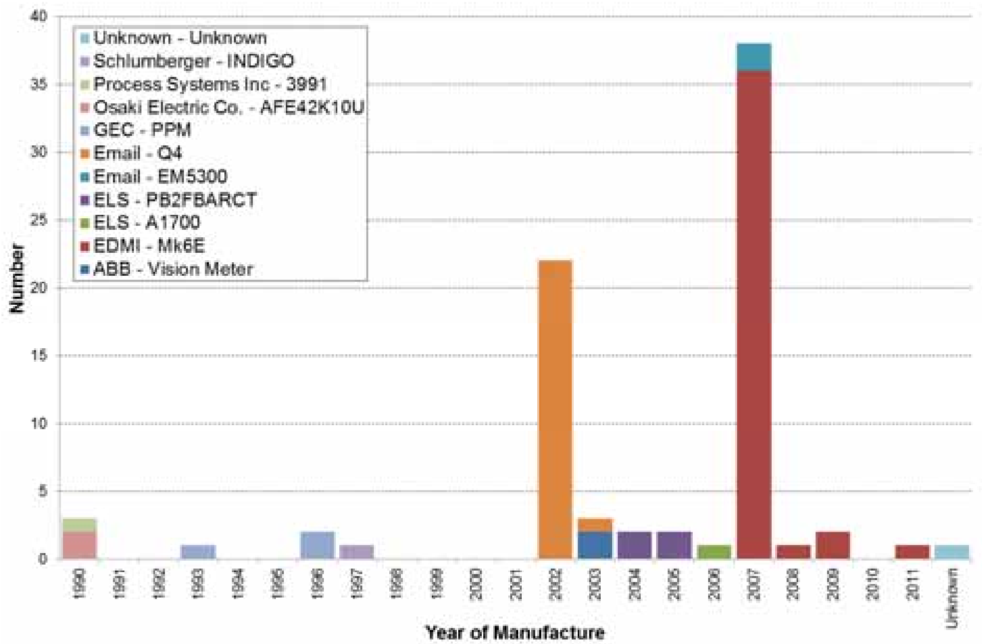


Figure 29 – TOU Meters

There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these meters is given in Figure 29.

2.3.12 Summary

TPCL's assets at the 2007 Directors valuation are summarised in Table 8.

Table 8 - Summary of assets by category (as at 2007 Director Valuation)

Asset description	Quantity	Unit	Average remaining life as a percent of ODV Standard Life	Condition summary[20]	Replacement Cost ($000)	Percent of RC
Ripple Injection	5	sites	15%	Good	2,085	0.4%
66kV line	356	km	64%	Good	34,959	7.0%
33kV line	459	km	49%	Good	29,755	5.9%
33kV cable	3	km	84%	Good	679	0.1%
Other zone substation assets		total	57%	Average	6,343	1.3%
HV switchgear	214	units	46%	Good	3,553	0.7%
MV switchgear	488	units	55%	Average	9,302	1.9%
Power transformers	51	units	49%	Average	20,741	4.1%
Isolating transformers	5	units	49%	Average	25	0.0%
Spares	68	units	58%	Average	1,486	0.3%
MV line	6,618	km	46%	Average	211,860	42.3%
MV cable	98	km	65%	Average	13,431	2.7%
MV regulators	20	units	27%	Average	1,814	0.4%
Distribution transformers	19,645	Units & sites	53%	Average	68,793	13.7%
Distribution switchgear	11,288	units	14%	Average	22,080	4.4%
LV lines	857	km	41%	Average	37,193	7.4%
LV cable	145	km	38%	Average	12,022	2.4%
LV switches, links etc.	2	units	63%	Average	7	0.0%
Street lighting circuits	188	km	45%	Average	3,289	0.7%
SCADA and system control	273	units	42%	Good	3,416	0.7%
Land and buildings	153	units	45%	Average	9,961	2.0%
Connection assets	32,064	units	45%	Average	7,668	1.5%
Total					**500,464**	

[20] 'Average' means the asset is close to remaining-life age profile, 'Good' is better and 'Poor' is worse. i.e. Good condition assets are expected to last longer than the standard life.

2.4 Justifying the assets

[Addresses the Handbook requirement 4.5.3(d)]

TPCL creates stakeholder service levels by carrying out a number of activities (described in section 5) on the assets, including the initial step of actually building assets such as lines and substations. Some of these assets need to deliver greater service levels than others e.g. TPCL's Waikiwi substation in north Invercargill has a higher capacity and security level than TPCL's Orawia substation in rural western Southland. Hence a greater level of investment will be required that will generally reflect the magnitude and nature of the demand.

Matching the level of investment in assets to the expected service levels requires the following issues to be considered:

- It requires understanding of how asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.
- It requires the asymmetric nature of under-investment and over-investment to be clearly understood i.e. over-investing creates service levels before they are needed but under-investing can lead to service interruptions (which typically cost about 10x to 100x, as much as over-investing as was discovered in Auckland in June 2006).
- It requires the discrete "sizes" of many classes of components to be recognised e.g. a 220kVA load will require a 300kVA transformer that is only 73% loaded. In some cases capacity can be staged through use of modular components.
- Recognition that TPCL's existing network has been built up over 80 years by a series of incremental investment decisions that were probably optimal at the time but when taken in aggregate at the present moment may well be sub-optimal.
- The need to accommodate future demand growth.

In theory an asset would be justified if the service level it creates is equal to the service level required. In a practical world of asymmetric risks, discrete component ratings, non-linear behaviour of materials and uncertain future growth rates, TPCL considers an asset to be justified if its resulting service level is not significantly greater than that required subject to allowing for demand growth and discrete component ratings.

A key practical measure of justification is the ratio of TPCL's optimised depreciated replacement cost (ODRC) to TPCL's depreciated replacement cost (DRC) which is 0.9916, with a ratio close to 1 indicating a high level of justification.

Assets that were optimised in the last ODV are listed in Table 9; together with a comment of changes since the 2004 ODV was completed.

Table 9 - Optimised Assets

Asset	Comment
Manapouri Substation	Retired from service.
Hillside to Manapouri 33kV line	Now operating at 11kV supplying south of Manapouri.
Waikaka to Pullar 33kV line	Disconnected, uneconomic to retire.
Pullar substation	All but civil works removed.
Underwood to Invercargill 33kV lines	Utilised to provide backup between North Makarewa and Invercargill GXP's.
North Makarewa to Invercargill 33kV (110kV)	Used as backup between GXP's.
Second 66kV Winton to Heddon Bush	Used as part of North Makarewa to Heddon Bush 66kV line.

Asset	Comment
Ohai substation	Extra 11kV circuit breakers are still in-service to provide quick change-over in event of power transformer failure.
Power transformer ratings.	Ratings are included in table 16, with Conical Hill transformers likely to be underutilised due to the closure of the Blue Mountain Lumber sawmill. Projected maximum demands are calculated in table 17.
Lines	ODV optimised 8.8km of heavy conductor to medium, 72.96km of medium to light and 52.97km of double circuit was optimised to single circuit.
Switchgear	68 ABS's were optimised and of these three have been retired off the network.

3. Proposed service levels

[Addresses handbook requirement 4.5.4]

This section describes how TPCL set its various service levels according to the following principles:

- What is most important to stakeholders (Section 1.6)
    - Safety
    - Viability
    - Price
    - Quality
    - Compliance
- How well is TPCL meeting those important objectives?
- What trade-offs exist between differing stakeholders? i.e.
    - Desire for ROI versus desire for low price with good reliability.
    - Safety at any cost?
    - Restoration ahead of compliance? (i.e. South Canterbury snow storm)

3.1 Creating service levels

TPCL creates a broad range of service levels for all stakeholders, ranging from capacity, continuity and restoration for connected customers (who pay for these service levels) to ground clearances, earthing, absence of interference, compliance with the District Plan and submitting regulatory disclosures (which are subsidised by connected customers), which are shown in Figure 30 below. This section describes those service levels in detail and how TPCL justifies the service levels delivered to its stakeholders.

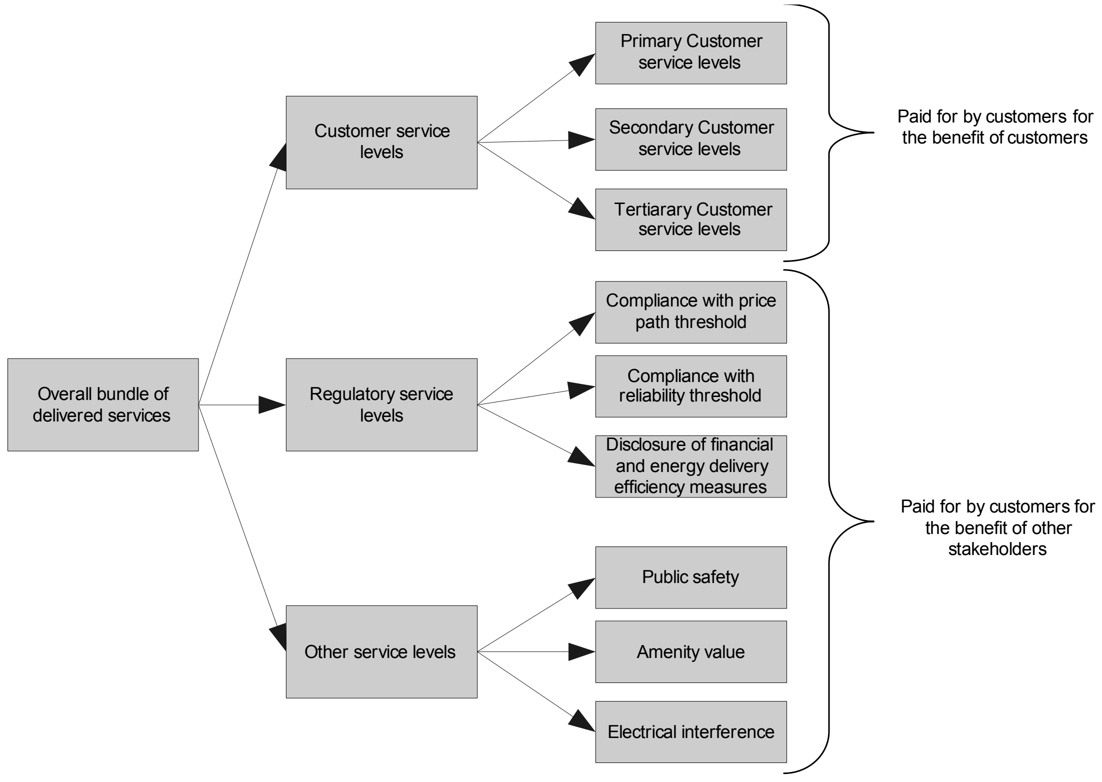


Figure 30 Types of service levels

3.2 Customer-oriented service levels

[Addresses handbook requirement 4.5.4(a)]

This section firstly describes the service levels TPCL expects to create for the customers, which are what they pay for and secondly the service levels TPCL expects to create for other key stakeholder groups which the customers are expected to subsidise.

Research indicates 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 has also become apparent from TPCL's research that there is an increasing value by customers placed on the absence of flicker, sags, surges and brown-outs. Other research however 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 and hence require capital expenditure solutions (as opposed to process solutions) to address which in itself raises the following three issues:

- Limited substitutability between service levels e.g. customers prefer TPCL to keep the power on rather than answer the phone quickly.
- Averaging effect i.e. all customers connected to an asset 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[21].

3.2.1 Primary service levels

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

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

TPCL's targets for these measures for the next ten years ending 31 March 2022 are set out in Table 10 below.

Table 10 - Primary Service Levels

	SAIDI			SAIFI		
Year End	**Class B**	**Class C**	**Total**	**Class B**	**Class C**	**Total**
Limit[22]			**184.10**			**3.68**
31/03/13	61.11	101.05	**162.16**	0.41	2.81	**3.22**
31/03/14	60.95	100.80	**161.75**	0.41	2.80	**3.21**
31/03/15	60.80	100.55	**161.35**	0.40	2.80	**3.20**
31/03/16	60.65	100.30	**160.95**	0.40	2.79	**3.19**
31/03/17	60.50	100.05	**160.55**	0.40	2.78	**3.18**
31/03/18	60.35	99.80	**160.15**	0.40	2.77	**3.17**
31/03/19	60.20	99.55	**159.75**	0.40	2.76	**3.16**
31/03/20	60.05	99.30	**159.35**	0.40	2.75	**3.15**
31/03/21	59.90	99.05	**158.95**	0.40	2.74	**3.14**
31/03/22	59.75	98.80	**158.55**	0.40	2.73	**3.13**

[21] This is the case with Invercargill and North Makarewa GXP's as they are more secure, due to the reliability required by the New Zealand Aluminium Smelter at Tiwai point.

[22] Limit calculated by the Commerce Commission Default Price-Quality Path methodology, with reference data from 1 April 2004 to 31 March 2009. The limit does not apply to TPCL as it is Consumer Owned, but is shown as the limit of acceptable reliability.

Note this target is based on normalising extreme events to the following daily boundary values: SAIDI 10.09, SAIFI 0.21 i.e. cannot get more than 10.09 customer-minutes of SAIDI occurring on a single day.

In practical terms this means TPCL's customers can broadly expect the reliability below:

General location	Expected reliability[23]
Parts of Invercargill not supplied by EIL.	One outage per year of about 30 minutes duration
Large towns	Two outages per year of about 45 minutes duration
Small towns.	Three outages per year of about 60 minutes duration
Village	Four outages per year of about 120 minutes duration
Anywhere else	Five outages per year of about 240 minutes duration

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.

3.2.2 Secondary service levels

Secondary service levels are the attributes of service that TPCL 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 TPCL could improve the shut-down notification process.
- They are heterogeneous in nature i.e. 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 after communication regarding:
  - Tree trimming
  - Connections
  - Faults.
- Time taken to respond to voltage complaints and time to remedy justified voltage complaints.
- Are customers given sufficient notice of planned shutdowns?

Table 11 below sets out the targets for these service levels for the next 3 years.

Table 11 - Secondary service levels

		Year Ending			
Attribute	**Measure**	**31/3/13**	**31/3/14**	**…**	**31/3/22**
Customer Satisfaction: Inquiries	Percentage satisfied with PowerNet staff. {CES: Q9(b)}[24]	>80%	>80%	…	>80%
Customer Satisfaction: New Connections	Phone: Friendliness and courtesy. {CSS: Q3(c)}[25]	>3.5[26]	>3.5	…	>3.5

[23] Except if directly connected to the faulty equipment….

[24] CES = Customer Engagement Survey of 200 customers, undertaken by phone annually.

[25] CSS = Customer Satisfaction Survey undertaken by sending questionnaire to customers with invoices.

[26] Where 1 = poor and 5 = excellent

		Year Ending			
Attribute	**Measure**	**31/3/13**	**31/3/14**	**…**	**31/3/22**
	Phone: Time taken to answer call. {CSS: Q3(a)}	>3.5	>3.5	…	>3.5
	Overall level of service. {CSS: Q5}	>3.5	>3.5	…	>3.5
	Work done to a standard which meet your expectations. {CSS: Q4(b)}	>3.5	>3.5	…	>3.5
Customer Satisfaction: Faults	Power restored in a reasonable amount of time. {CES: Q4(b)}	>60%	>60%	…	>60%
	Information supplied was satisfactory. {CES: Q8(b)}	>60%	>60%	…	>70%
	PowerNet first choice to contact for faults. {CES: Q6}	>30%	>35%	…	>50%
Voltage Complaints {Reported in Network report}	Number of customers who have made voltage complaints {NR}	<45	<45	…	<40
	Number of customers who have justified voltage complaints regarding power quality	<15	<15	…	<12
	Average days to complete investigation	<30	<30	…	<25
	Period taken to remedy justified complaints	<60	<60	…	<50
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>75%	>75%	…	>75%
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>75%	>75%	…	>75%
	Acceptance of maximum of three planned outages per year. {CES: Q1}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	>50%	>50%	…	>50%

{Where the information is collected / reported from.}

3.2.3 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 TPCL by statute and while they are for the public good, i.e. necessary for the proper functioning of a safe and orderly community, TPCL is expected to absorb the associated costs into its overall cost base.

3.2.3.1 Safety

Various legal requirements require TPCL's assets (and customers' 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 In Employment Act 1992.
- Electricity (Safety) Regulations 2010.
- Electricity (Hazards From Trees) Regulations 2003.
- Maintaining safe clearances from live conductors (NZECP34:2001).
- Power system earthing (NZECP35:1993).

3.2.3.2 Amenity value

There are a number of Acts and other requirements that limit where TPCL 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.

3.2.3.3 Industry performance

Various statutes and regulations require TPCL to compile and disclose prescribed information to specified standards. These include:

- Electricity Distribution (Information Disclosure) Requirements 2008 and subsequent amendments.
- Commerce Act (Electricity Distribution Thresholds) Notice 2004.

3.2.3.4 Electrical interference

Under certain operational conditions TPCL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of TPCL's own equipment or TPCL's customers' plant. The following two codes impose service levels on us.

- Harmonic levels (NZECP36:1993).
- SWER load limitation to 8A (NZECP41:1993).

3.3 Regulatory service levels

[Addresses handbook requirement 4.5.4(b)]

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

- Ensure a wide degree of 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.

TPCL is also required to disclose a range of internal performance and efficiency measures as required by the Electricity Distribution (Information Disclosure) Requirements 2008. The complete listing of these measures is included in TPCL's disclosure to 31 March 2011 with listing and analysis on the Commerce Commission website at http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

3.3.1 Financial efficiency measures

TPCL's projected financial efficiency measures are shown below. These measures are:

- Percentage of Operational Expenditure – [Operational Expenditure] / [Replacement cost of System Fixed Assets at year end]
- Indirect costs per ICP – [General Management, Administration and Overheads expenditure] / [Number of Connection Points (at year end)].
- All factors as defined in the Information Disclosure requirements.

Year ending	OPEX/RC %	Indirect costs/ICP
31/3/13	1.99%	$71.56
31/3/14	1.97%	$73.17
31/3/15	1.92%	$74.50
31/3/16	1.88%	$74.64
31/3/17	1.85%	$75.52
31/3/18	1.80%	$75.31

Year ending	OPEX/RC %	Indirect costs/ICP
31/3/19	1.79%	$75.10
31/3/20	1.77%	$74.88
31/3/21	1.75%	$74.67
31/3/22	1.74%	$74.46

3.3.2 Energy delivery efficiency measures

Projected energy efficiency measures are shown below. These measures are:

- Load factor – [kWh entering TPCL's network during the year] / [[max demand for the year] x [hours in the year]].
- Loss ratio – [kWh lost in TPCL's network during the year] / [kWh entering TPCL's network during the year].
- Capacity utilisation – [max demand for the year] / [installed transformer capacity[27]].

Slight improvements are targeted but changes in peak management requirements have impacted the load factor. It may take a number of years for the LSI peak to settle down to a predictable level.

Loss ratio has varied due to reliance on annum sales quantities from retailers. As retailers are not reading the customers meter at midnight on the 31 December, some estimation methodology is required.

Year ending	Loss ratio	Load factor	Capacity utilisation
31/3/13	8.00%	65%	30%
31/3/14	8.00%	65%	30%
31/3/15	8.00%	65%	30%
31/3/16	8.00%	65%	31%
31/3/17	8.00%	65%	31%
31/3/18	8.00%	65%	31%
31/3/19	8.00%	65%	31%
31/3/20	8.00%	65%	31%
31/3/21	8.00%	65%	31%
31/3/22	8.00%	65%	31%

3.4 Justifying the service levels

[Addresses handbook requirement 4.5.4(c)]

TPCL's service levels are justified in five main ways:

- Positive cost benefit within revenue capability.
- By what is achievable in the face of skilled labour and technical shortages.
- By the physical characteristics and configuration of TPCL's assets which are expensive to significantly alter but which can be altered if a customer or group of customers agrees to pay for the alteration.
- By a customer's specific request and agreement to pay for a particular service level.
- When an external agency imposes a service level on TPCL or in some cases an unrelated condition or restriction that manifests as a service level such as requirement to place all new lines underground or a requirement to increase clearances.

[27] Capacity utilisation now includes an estimate of the capacity of customer owned distribution transformers.

Customer surveys over the last three 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 TPCL does note the following issues:

- The service level called 'Safety' may need to increase as the requirements of the amended Electricity Act 1992 become operative.
- Food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets, and in particular interruptions to cooling and chilling are less acceptable. This requires TPCL's cold storage customers to have higher levels of continuity and restoration.
- Economic downturn may increase the instance of theft of materials and energy.

3.4.1 Basis for service level targets

Statistics for the last five years are listed below:

Measure	YE 31/3/07*	YE 31/3/08	YE 31/3/09	YE 31/3/10	YE 31/3/11
SAIDI	177.6	294.8	217.3	214.4	209.06
SAIFI	3.02	3.75	4.37	3.16	3.21
Load factor	70%	65%	64%	64%	63%
Loss ratio	7.4%	7.8%	8.0%	6.8%	6.8%
Capacity utilisation	33.5%	29.1%	29.7%	30.0%	29.5%
OPEX %		1.75%	1.95%	1.96%	1.84%
Indirect/ICP				$70.57	$67.50

(*To old Information Disclosure requirements.)

3.4.1.1 Reliability

Industry results for the last four years are shown in Figure 31 and 32 these show TPCL near the industry average but due to the low customer density and region covered the performance is considered good. This view is supported with the Customer survey result that 94.7% of people considered that faults were restored within a reasonable time.

We plan to normalise extreme events using the Commerce Commission DPP methodology. Target is calculated by averaging the normalised values, over the previous five years, and decreasing future years by 0.25% p.a. Main focus is to maintain similar reliability levels. These metrics are required to be reported for legislative monitoring.

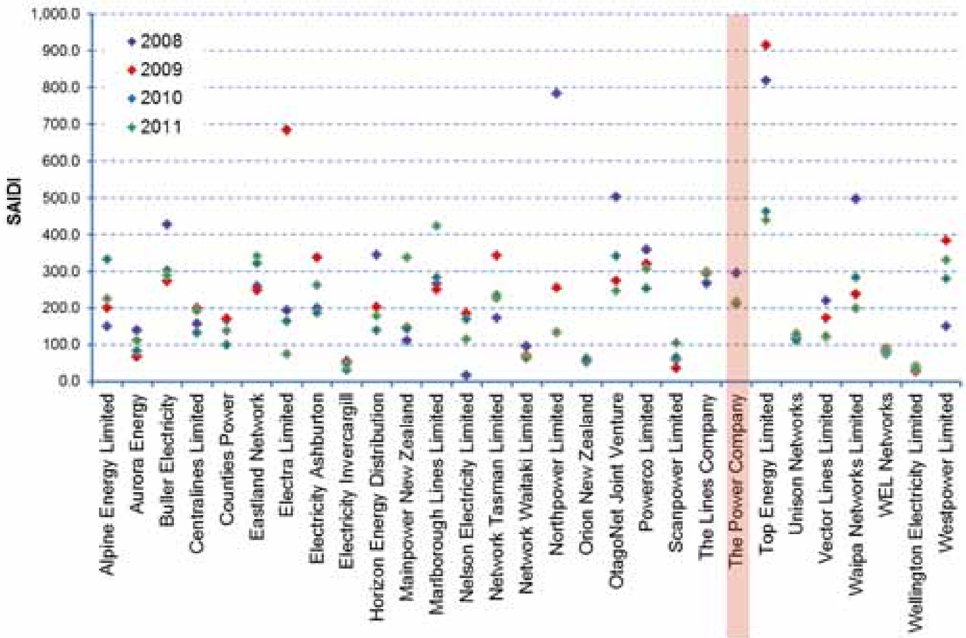


Figure 31 - Information disclosure data: SAIDI

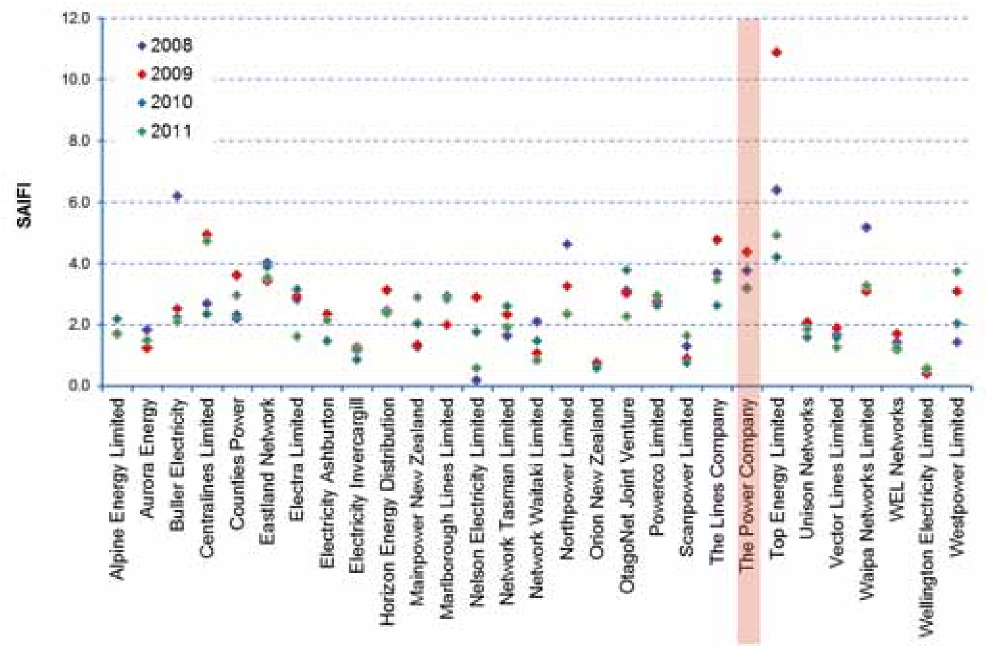


Figure 32 - Information disclosure data: SAIFI

3.4.1.2 Load Factor

LSI peak is due to New Zealand Aluminium Smelter (NZAS) and other network companies, with recent LSI peak occurring during winter due to demand in the cities and Dairy production beginning. This meant that peak load control was not required and results in a higher peak, as load control for peak reduction on each GXP was not needed.

TPCL's Load Factor is average with slight improvement due to transformer rationalisations planned. This metric is required to be reported for legislative monitoring.

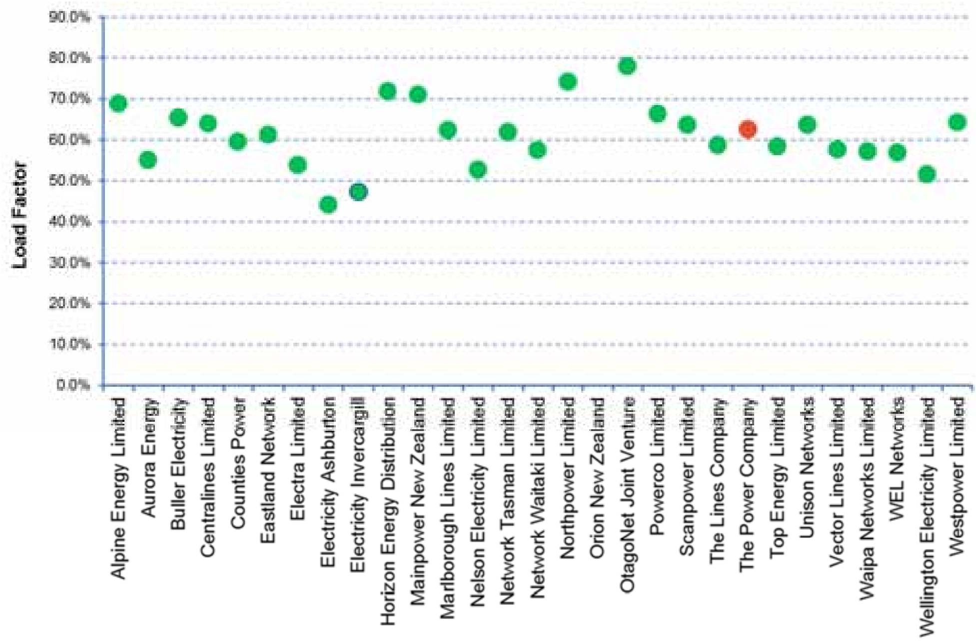


Figure 33 - Information disclosure 2011 data: Load Factor

3.4.1.3 Loss Ratio

Growth of Dairy Farms has increased loading on some feeders with the square-law impact on losses. i.e., a doubling of load would quadruple losses. Some minor reductions in losses due to poor voltage or current rating of equipment are remedied.

Comparison with others in the industry shows TPCL below similar rural companies, therefore no change in target planned. This metric is required to be reported for legislative monitoring.

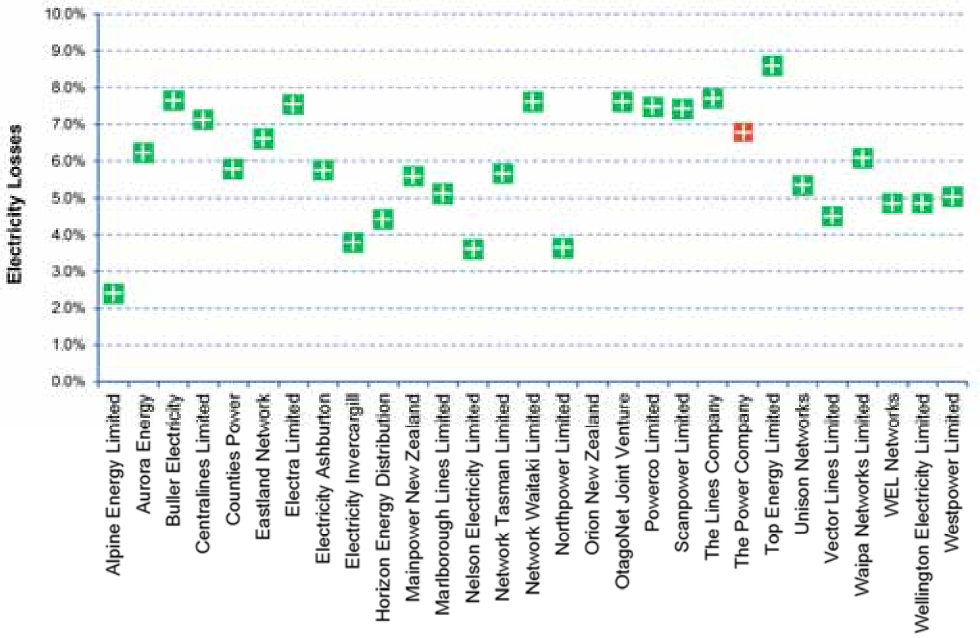


Figure 34 - Information disclosure 2011 data: Losses

3.4.1.4 Customer Survey

Target set at level felt to be desirable as a good corporate citizen, due to historic trend and likely impact of targeted improvements.

For example: More Public Relations with newsletter and fridge-magnet should increase PowerNet as first point of contact for faults.

3.4.1.5 Capacity Utilisation

Impact of Dairy boom is likely to impact with a large number of larger capacity transformers installed to supply new farms. The load profile on these is very peaky with no rationalisation[28] of transformers, as dairy sheds are normally distant from existing farm house. Only very minor improvement expected. Compared to other electricity lines businesses TPCL is average therefore no change in strategy is planned. This metric is required to be reported for legislative monitoring.

[28] Rationalisation is where one transformer is used to supply multiple customers, with peaks occurring at differing times a smaller installed capacity usually results. i.e. Dairy Shed transformer of 50kVA can normally supply the farm house, but due to distances usually requires its own 15kVA transformer.

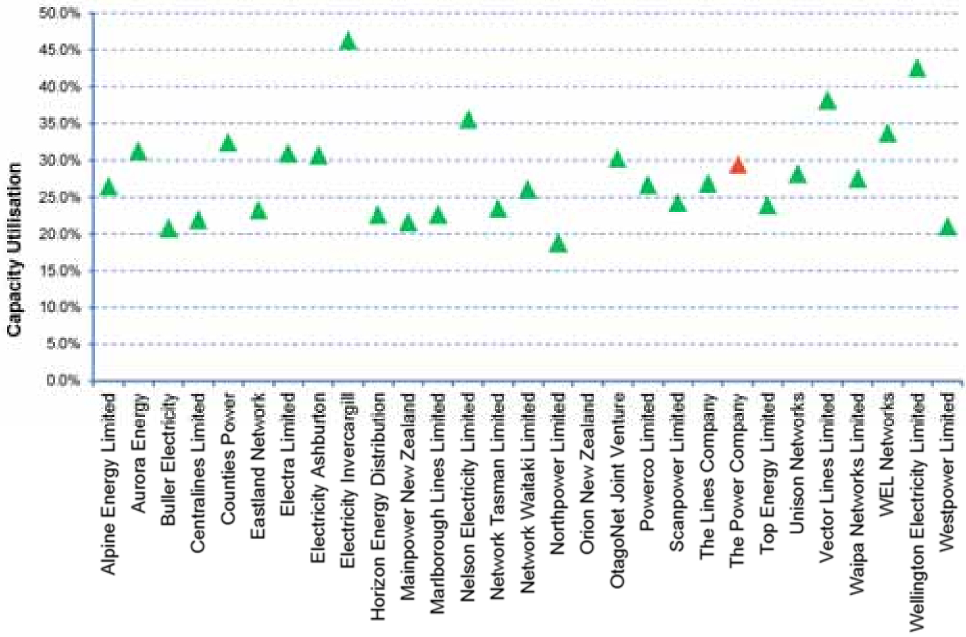


Figure 35 - Information disclosure 2011 data: Capacity Untilisation

3.4.1.6 Financial service levels

Due to TPCL having one of the lowest customer densities the financial service levels could be at the top end of New Zealand electricity lines businesses. Data from the 2011 Information Disclosure on Operational Expenditure Ratio (OPEX/RC) shows that TPCL is the second lowest as shown in Figure 36. The General management, administration and overheads cost (a.k.a. Indirect.) per connection is shown in Figure 37, with TPCL being the sixth lowest cost.

Based on the good ranking of TPCL in these measures the plan is to maintain these good results. The targets are set based on our projections, with budgeted costs, network growth and customer growth at 100 per year. Any higher growth or reduction in indirect costs will improve this efficiency measure.

These metrics are required to be reported for legislative monitoring.

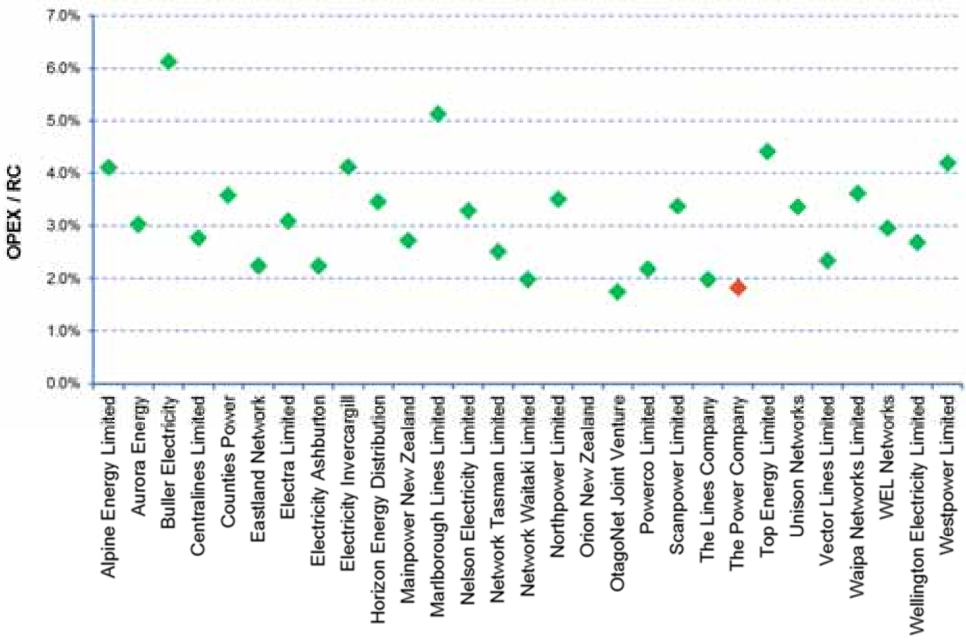


Figure 36 - Information disclosure 2011 data: OPEX/RC

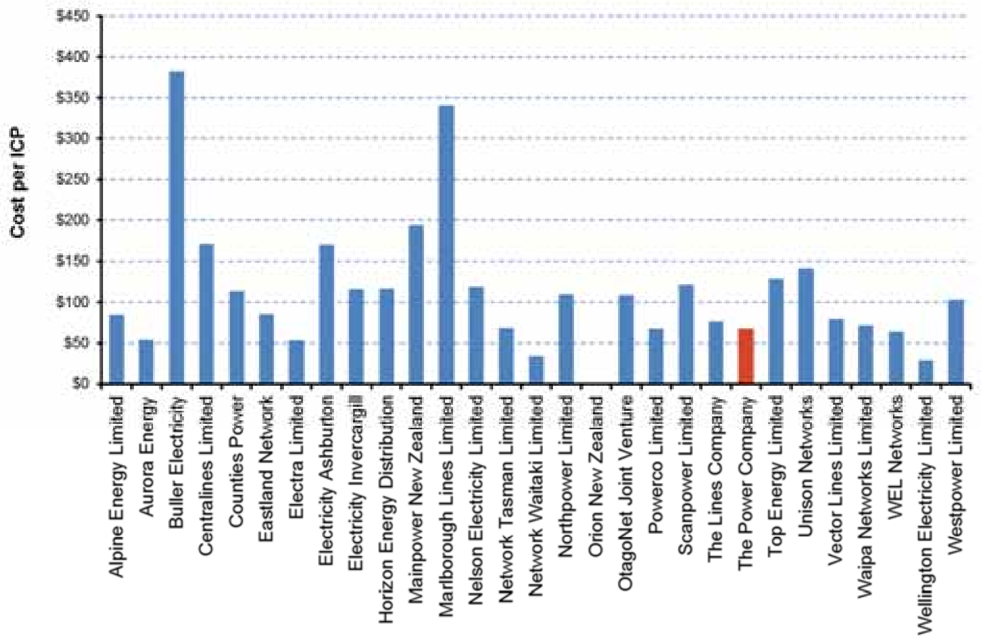


Figure 37 - Information disclosure 2011 data: General management, administration and overheads per Installation Connection Point

4. Development plans

Development plans are driven primarily by:

- Increasing customer demand, can be due to growth or generation
- Asset renewal requirements
- Statutory requirements to improve service levels (Security of supply, safety or environmental compliance.)
- Internally generated initiatives to improve service levels

At its most fundamental level, demand is created by individual customers drawing (or injecting) energy across their individual connections. The demand at each connection aggregates "up the network" to the distribution transformer, then to the distribution network, the zone substation, the subtransmission network to the GXP and ultimately through the grid to a power station.

4.1 Planning approach and criteria

[Addresses Handbook requirement 4.5.5(a)]

4.1.1 Planning unit

TPCL has adopted the 11kV feeder as TPCL's fundamental planning unit which typically represents one or perhaps two of the following combinations of customer connections:

- An aggregation of up to 1,000 urban domestic customer connections.
- An aggregation of up to 200 urban commercial customer connections.
- An aggregation of up to 30 urban light industrial customer connections.
- An aggregation of anywhere up to 500 rural domestic or farm customer connections.
- A single large industrial customer connection.
- Injection of generation.

Physically this planning unit will usually be based around the individual lines or cables emanating from a zone substation. For single load of more than 1MW (i.e., beyond what is considered incremental) TPCL's planning principles and methods still apply, but likely outcome is new assets at 11kV or higher.

4.1.2 Planning approaches

TPCL plans its assets in three different ways; strategically, tactically and operationally as shown in Table 12 below:

Table 12- Planning approaches

Attribute	Strategic	Tactical	Operational
Asset description	Assets within GXP. Subtransmission lines and cables. Major zone substation assets. Load control injection plant. Central SCADA and telemetry. Distribution configuration e.g. decision to upgrade to 22kV.	Minor zone substation assets. All individual distribution lines (11kV). All distribution line hardware. All on-network telemetry and SCADA components. All distribution transformers and associated switches. All HV customer connections.	All 400V lines and cables. All 400V customer connections. All customer metering and load control assets.
Number of customers supplied	Anywhere from 500 upwards.	Anywhere from one to about 500.	Anywhere from one to about 50.

Attribute	Strategic	Tactical	Operational
Impact on balance sheet and asset valuation	Individual impact is high. Aggregate impact is moderate.	Individual impact is moderate. Aggregate impact is significant.	Individual impact is low. Aggregate impact is moderate.
Degree of specificity in plans	Likely to be included in very specific terms, probably accompanied by an extensive narrative.	Likely to be included in specific terms and accompanied by a paragraph or two.	Likely to be included in broad terms, with maybe a sentence describing each inclusion.
Level of approval required	Approved in principle in annual business plan. Individual approval by Board and possibly shareholder.	Approved in principle in annual business plan. Individual approval by Chief Executive.	Approved in principle in annual business plan. Individual approval by Chief Engineer.
Characteristics of analysis	Tends to use one-off models and analyses involving a significant number of parameters and extensive sensitivity analysis.	Tends to use established models with some depth, a moderate range of parameters and possibly one or two sensitivity scenarios.	Tends to use established models based on a few significant parameters that can often be embodied in a "rule of thumb".

TPCL has developed the following "investment strategy matrix" shown in Figure 38, which broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

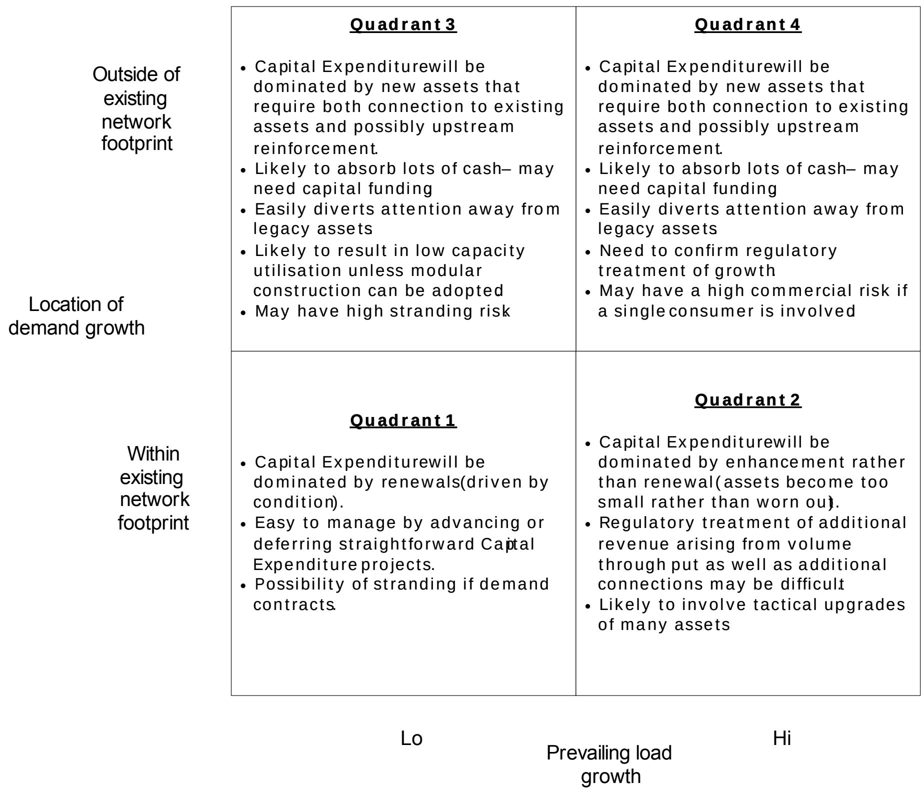


Figure 38 - Investment strategy matrix

Predominant capital expenditure (CAPEX) modes are:

- Large industrial loads such as a new factory, which involves firstly extension and then usually up-sizing, sit in Quadrant 4 which has desirable investment characteristics. This mode of investment does however carry the risk that if demand growth doesn't occur as planned, stranding can occur and the investment slips into Quadrant 3 which has less desirable investment characteristics.

- Dairy conversions involve extensions and then sometimes up-sizing but due to the lumpy nature of constructing line assets these may fall into Quadrant 3 which carries some risk of stranding or delayed recovery of investment.
- Declining cost of domestic heat pumps primarily requires urban up-sizing which fits mainly in Quadrant 2, which has reasonably desirable investment characteristics.
- Residential subdivisions around urban areas tend to have large up-front capital costs but recovery of costs through line charges often lags well behind. The size of the subdivision will dictate whether it falls in Quadrant 1 or 3, neither of which has particularly desirable investment characteristics. Hence some form of developer contribution is almost certain to be expected.

4.1.3 Trigger points for planning new capacity

As new capacity has valuation, balance sheet, depreciation and ROI implications for TPCL, endeavours will be made to meet demand by other less investment-intensive means. This discussion also links strongly to TPCL's discussion of asset life cycle in section 5.1.

The first step in meeting future demand is to determine if the projected demand will exceed any of TPCL's defined trigger points for asset location, capacity, reliability, security or voltage. These points are outlined for each asset class in Table 13.

If a trigger point is exceeded TPCL 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 in section 4.2 which also embodies an overall preference for avoiding new capital expenditure.

Table 13 - Summary of capacity "trigger points"

		Asset class		
Type	**Trigger**	**LV lines and cables**	**Distribution substations**	**Distribution lines and cables**
Extension	**Location**	Existing LV lines and cables don't reach the required location.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and substation.	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and substation.
Up-sizing	**Capacity**	Tends to manifest as fuse blowing when current exceeds circuit rating.	Where fitted, MDI reading exceeds 90% of nameplate rating.	Analysis calculates that the peak current exceeds the thermal rating of the circuit segment.
	Reliability	Not applicable. Normally a Maintenance or Operational trigger, as no requirement for up-sizing.		
	Security	Excursion beyond triggers specified in section 3.2.1.		
	Voltage	Voltage at customers' boundary consistently drops below 0.94pu.	Voltage at customers' boundary consistently drops below 0.94pu that cannot be remedied by LV up-sizing.	Voltage at MV terminals of transformer consistently drops below 10.45kV and cannot be compensated by local tap setting.
Renewal	**Condition**	Asset deteriorated to an unsafe condition. Third party requests work. Neighbouring assets being replaced.		

		Asset class		
Type	**Trigger**	**Zone substations**	**Subtransmission lines and cables**	**Network equipment within GXP**
Extension	**Location**	Load cannot be reasonably supplied by distribution configuration therefore requires new subtransmission lines or cables and zone substation.	Load cannot be reasonably supplied by distribution configuration therefore requires new subtransmission lines or cables and zone substation.	Load cannot be reasonably supplied by new or extended Subtransmission or substation therefore requires new GXP equipment.
Up-sizing	**Capacity**	Max demand consistently exceeds 100% of nameplate rating.	Analysis calculates that the peak current exceeds the thermal rating of the circuit segment.	Max demand consistently exceeds 80% of nameplate rating.
	Reliability	Not applicable. Normally a Maintenance or Operational trigger, as no requirement for up-sizing.		
	Security	Excursion beyond triggers specified in section 3.2.1.		
	Voltage	Voltage at MV terminals of transformer consistently drops below 10.45kV and cannot be compensated by OLTC.	Voltage at HV terminals of transformer consistently drops below 0.87pu and cannot be compensated by OLTC.	Not applicable.
Renewal	**Condition**	Asset deteriorated to an unsafe condition. Third party requests work.		

4.1.4 Quantifying new capacity

The two major issues surrounding constructing new capacity are:

- How much capacity to build? This comes back to the trade-off between cost and building in extra capacity for security and safety (risk-avoidance).
- When to build the new capacity? The obvious theoretical starting point for timing new capacity is to build just enough just in time, and then add a bit more over time.

However TPCL recognises the following practical issues:

- The need to avoid risks associated with over-loading and catastrophic failure.
- The need to limit investment to what can be recovered to Shareholder requirements.
- The standard size of many components (which makes investment lumpy).

The one-off costs of construction, consenting, traffic management, access to land and reinstatement of sealed surfaces (which make it preferable to install large lumps of capacity and not go back to the site).

Selection of the right capacity to build is based on the following:

- Overhead lines:
    - MV routes between zone substations, a minimum of Helium conductor.
    - Usually set by voltage drop limits and strength requirements.
    - MV laterals Chlorine conductor.
    - LV: allow 20% growth.
- Cables:
    - Allow 100% growth.
- Distribution transformers:
    - Individual customers, size to customer capacity.
    - Domestic customers based on following diversity:

Customers	Transformer Size
2	15kVA
6	30kVA
10	50kVA
20	100kVA
50	200kVA
80	300kVA
150	500kVA

- Line equipment:
  - Use standard ratings (e.g. ABS 400A, Recloser 400A).
- Power transformers:
  - Allow expected area growth over 20 years.
- Substation equipment:
  - Use standard ratings.
- Subtransmission lines:
  - Allow expected area growth over 20 years.

TPCL's guiding principle is therefore to minimise the level of investment ahead of demand, while minimising the costs associated with doing the work.

4.2 Prioritisation methodology

[Addresses handbook requirement 4.5.5(b)]

4.2.1 Options for meeting demand

Table 13 defines the trigger points at which the capacity of each class of assets needs to be increased. In a broad order of preference, actions to increase the capacity of individual assets within these classes can take the following forms:

- 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 TPCL. An example of where a do nothing option might be adopted is where the voltage at the far end of a remote rural feeder is unacceptably low for a short period at the height of the holiday season – the benefits of correcting such a constraint may be 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.
- Influence customers to alter their consumption patterns so that assets perform at levels below the 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. TPCL notes that the effectiveness of line tariffs in influencing customer behaviour is dampened by the retailers' practice of repackaging fixed and variable charges.
- Construct distributed generation so that an adjacent asset's performance is restored to a level below its trigger points. Distributed generation 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 is essentially a subset of the above approach but will generally involve less expenditure. This approach is more suited to larger classes of assets such as power transformers.

- 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.
- Install new assets with a greater capacity that will increase the assets trigger point to a level at which it is not exceeded. An example would be to replace a 200kVA distribution transformer with a 300kVA so that the capacity criterion is not exceeded.

In identifying solutions for meeting future demands for capacity, reliability, security and satisfactory voltage levels TPCL considers options that cover the above range of categories. The benefit-cost ratio of each option is considered including estimates of the benefits of public safety and environmental compliance and the option yielding the greatest benefit is adopted. TPCL uses the model in figure 39 to broadly guide adoption of various approaches:

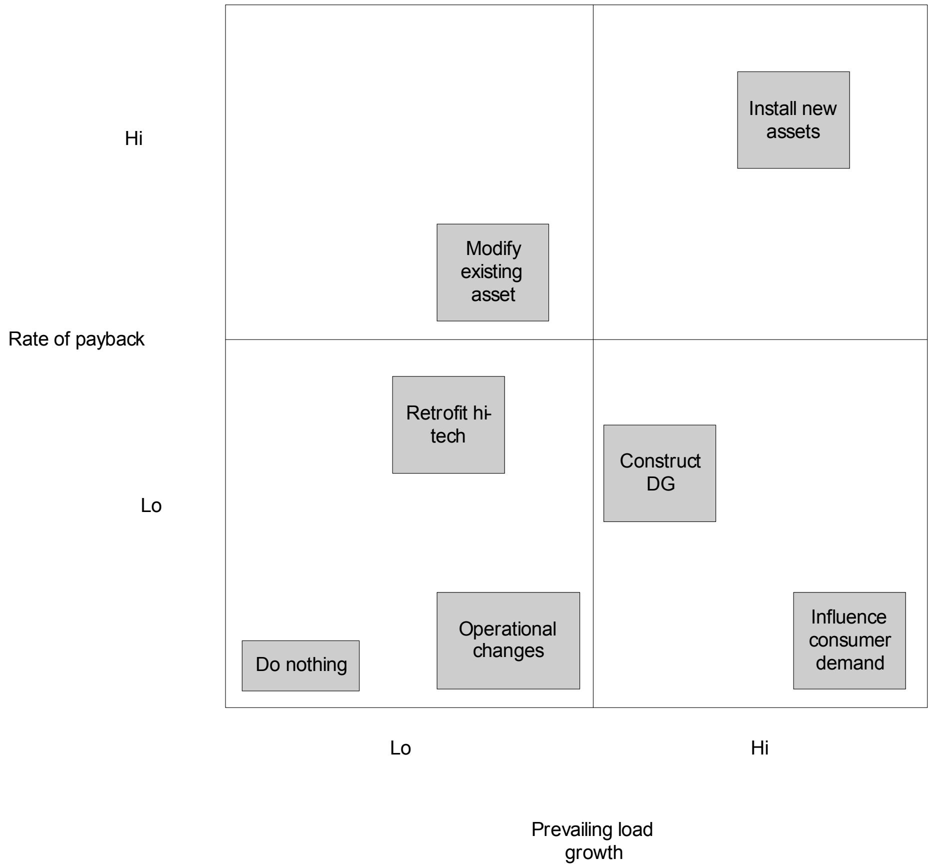


Figure 39 - Options for meeting demand

4.2.2 Meeting security requirements

A key component of security is the level of redundancy that enables supply to be restored independently of repairing or replacing a faulty component. Typical approaches to providing security to a zone substation include:

- Provision of an alternative substation-transmission circuit into the substation, preferably separated from the principal supply by a 66kV or 33kV switch.
- Provision to back-feed on the 11kV from adjacent substations where sufficient 11kV capacity and interconnection exists. This obviously requires those adjacent substations to be restricted to less than nominal rating.
- Use of local generation.
- Use of interruptible load (water heating, irrigation).

The most pressing issue with security is that it involves a level of investment beyond what is obviously required to meet demand and it can be easy to let demand growth erode this surplus capacity.

4.2.2.1 Prevailing security standards

The commonly adopted security standard in New Zealand is the EEA Guidelines which reflect the UK standard P2/5 that was developed by the Chief Engineers' Council in the late 1970's. P2/5 is a strictly deterministic standard i.e. it states that "this amount and nature of load will have this level of security" with no consideration of individual circumstances.

Deterministic standards are now beginning to give way to probabilistic standards in which the value of lost load and the failure rate of supply components is estimated to determine an upper limit of investment to avoid interruption.

4.2.2.2 Issues with deterministic standards

A key characteristic of deterministic standards such as P2/5 and the EEA Guidelines is that rigid adherence generally results in at least some degree of over investment. Accordingly the EEA Guidelines recommend that individual circumstances be considered.

4.2.2.3 Contribution of local generation to security

To be of any use from a security perspective, local generation would need to have 100% availability which is unlikely from a reliability perspective and even less likely from a primary energy perspective such as run-of-the-river hydro, wind or solar. For this reason, the emerging UK standard P2/6 provides for minimal contribution of such generation to security.

4.2.2.4 TPCL security standards

Table 14 below describes the security standards adopted by TPCL, whilst Table 15 lists the level of security at each zone substation, including any planned changes and justifies any shortfall. In setting target security levels the following guiding principles are used:

- Where a substation is for the predominant benefit of a single customer, their wish for security will over-ride prevailing industry guidelines.
- The preferred means of providing security to rural zone substations will be back-feeding on the 11kV subject to interconnection, line ratings and surplus capacity at adjacent substations.
- 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 14 - 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 in time to isolate and back-feed following the first contingent event.
A(ii)	Less than 1MW	All load restored in time to repair after the first contingent event.

Table 15 - Substation security levels

Substation	Target 2022	Actual Now	Remarks
Athol (New)	A(i)		
Awarua		A(i)	
Colyers Road (New Awarua)	AA		Depends if new load occurs.
Awarua Chip Mill	A(i)	A(i)	Major voltage dip during motor start will affect other customers if alternative supply route used.

Substation	Target 2022	Actual Now	Remarks
Bluff	AA	AAA	
Centre Bush		A(i)	
Centre Bush (66/11kV)	A(i)		Subtransmission upgraded from 33kV to 66kV.
Conical Hill	A(i)	AAA	Sawmill closed/moth-balled.
Dipton		A(i)	
Dipton (66/11kV)	A(i)		Subtransmission upgraded from 33kV to 66kV.
Edendale Fonterra	AAA	AAA	
Edendale	AA	AAA	Fonterra down-stream plant supplied off this substation.
Glenham	A(i)	A(i)	
Gorge Road	A(i)	A(i)	
Hedgehope (New)	A(i)		
Hillside	A(i)	A(i)	
Isla Bank (New)	A(i)		
Kelso	AA	A(i)	Depends if growth occurs.
Kennington		**A(ii)**	Need mobile regulator to restore full load. Second transformer to supply local area will improve backup capability.
Kennington (new)	AA		Needs alternate 33kV line to site.
Lumsden	A(i)	A(i)	Need mobile regulator to restore full load during peak load. Garston substation will improve by supplying part of this load.
Makarewa	AA	AAA	
Mataura		AA	Can switch over onto Edendale GXP.
Mataura (Upgraded)	AA		
Monowai	A(ii)	A(ii)	
Mossburn	A(i)	AA	Backup 33/11kV will go when line moved over to 66kV.
North Gore	AAA	AAA	Gore hospital supplied off this substation.
North Makarewa	AAA	AAA	Spare supply transformer at Mossburn.
Ohai	A(i)	A(i)	
Orawia	A(i)	A(i)	
Otatara	A(i)	A(i)	
Otautau	A(i)	A(i)	New Isla Bank will limit demand to under 5MVA.
Racecourse Rd (EIL)	A(i)	A(i)	
Riversdale		A(i)	Low voltage if supplied from Lumsden, but will be okay when Lumsden 66/33kV is completed.
Riversdale (upgraded)	AA		Tee-off 33kV line has no alternative.
Riverton	AA	AAA	Spare 66/11kV 5/7.5MVA transformer in service at this site.
Seaward Bush		AAA	Southland base hospital supplied off this substation.
Seaward Bush (Upgraded)	AAA		
South Gore	AAA	AAA	Supplies Gore CBD.
Te Anau	AAA	AAA	Main tourism centre.
Tokanui	A(i)	A(i)	
Underwood	AAA	AAA	
Waikaka	A(i)	A(i)	

Substation	Target 2022	Actual Now	Remarks
Waikiwi	AAA	AA	Need to switch-over to alternate 33kV if supplying 33kV faults.
White Hill (Wind)	A(ii)	A(ii)	
Winton	AA	AAA	New Hedgehope substation will limit demand to under 12MVA.

4.2.3 Choosing the best option to meet demand

Each of the possible approaches to meeting demand that are outlined in section 4.2.1 will contribute to strategic objectives in different ways. TPCL uses a number of decision tools to evaluate options depending on their cost:

Cost & nature of option	Decision tools	Organisational level of evaluation
Up to $50,000, commonly recurring, individual projects not tactically significant but collectively they do add up.	TPCL standard rules. Industry rules of thumb. Manufacturer's tables and recommendations. Simple spreadsheet model based on a few parameters.	GM Operations
Up to $500,000, individual projects of tactical significance.	Spreadsheet model to calculate NPV that might consider 1 or 2 variation scenarios.	Chief Engineer
Up to $2,500,000 occurs maybe once every few years, likely to be strategically significant.	Extensive spreadsheet model to calculate NPV, Payback that will probably consider several variation scenarios. Use of optimisation tools.	Chief Executive
Over $2,500,000 occurs maybe once in a decade, likely to be strategically significant.	Extensive spreadsheet model to calculate NPV, Payback that will probably consider several variation scenarios. Use of optimisation tools.	Board approval

4.2.4 Project prioritisation

Designer and planners use the 'decision tools' on projects to enable prioritisation and rationing of our resources. Large projects have differing alternatives scored and the tools grade each with factors/weightings determined by the Board. Consideration is also given to the Risk Profile of each option and this is also useful in selecting projects.

The Manager in each area prioritises the work based on their need to meet service standards. Level of budget is adjusted due to trends in service levels; therefore if service levels are steady, expenditure would remain the same. Some abnormal situations[29] do distort results and these are considered in setting targets and expenditure.

[29] Abnormal situations: Major storms, significant planned outages, dry year rationing, external party major equipment failures.

4.3 TPCL's demand forecast

[Addresses handbook requirement 4.5.5(c)]

4.3.1 TPCL's current demand

TPCL's Transpower maximum demand (MD) of 131.3 MW did not occur at the same time as the Lower South Island (LSI) peak at 1:30 pm on the 16 August 2011. The individual maximum demands and the LSI coincident demands are shown in Figure 40. Note that for the other generators no export of energy into the network occurred at these times. The maximum export to Transpower was 9.5 MW, i.e. Local generation supplied more than TPCL's demand for 101 hours during the year.

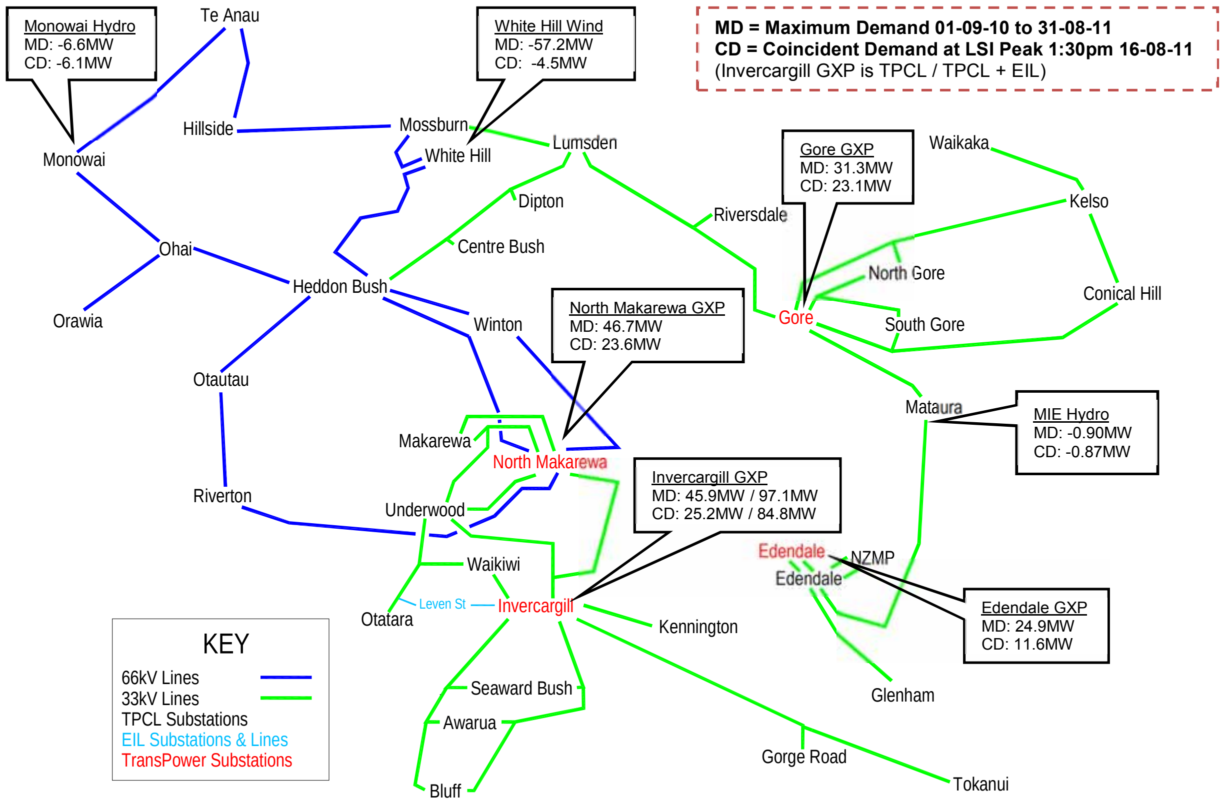


Figure 40 - GXP and Generation Demands

Each zone substation recorded the maximum demands as listed in Table 16. The 99.9 percentile demand is given to remove any short term load transfers and is more indicative of actual area maximum demand.

Table 16 substation demand

Zone substation	Installed Capacity (MVA)	2011 Maximum Demand (MVA)	99.9% 2011 (MVA)	99.9% 2010 (MVA)	99.9% 2009 (MVA)	99.9% 2008 (MVA)	99.9% 2007 (MVA)
Awarua (General)	5.0	3.81	3.72	3.50	3.15	1.51	1.45
Awarua (Chip Mill)	5.0	0.85	0.70	3.53	0.88	0.87	2.43
Bluff	24.0	4.72	4.46	4.66	4.60	4.48	4.67
Centre Bush	5.0	4.09	3.71	3.61	3.78	3.30	2.46
Conical Hill	10.0	2.09	1.14	2.47	3.06	3.13	4.03
Dipton	1.5	**1.68**	**1.59**	**1.60**	1.26	1.09	1.12
Edendale Fonterra	46.0	22.07	21.47	21.31	16.79	15.16	17.17
Edendale	24.0	6.76	6.44	6.41	6.49	6.46	6.00
Glenham	1.5	1.23	1.06	1.09	1.15	0.99	1.00
Gorge Road	3.0	2.07	1.87	1.81	1.73	1.85	1.63

Zone substation	Installed Capacity (MVA)	2011 Maximum Demand (MVA)	99.9% 2011 (MVA)	99.9% 2010 (MVA)	99.9% 2009 (MVA)	99.9% 2008 (MVA)	99.9% 2007 (MVA)
Heddon Bush	15.0	7.87	7.63	8.56	9.17	8.06	7.57
Hillside	2.3	0.72	0.62	0.63	0.72	0.69	0.56
Kelso	5.0	4.41	4.20	4.11	4.01	3.98	3.75
Kennington	5.0	4.63	4.26	4.27	4.48	3.88	4.01
Lumsden	5.0	3.55	3.44	3.52	3.34	2.94	2.65
Makarewa	24.0	5.58	5.11	5.32	5.45	4.99	4.65
Mataura	20.0	8.36	7.91	8.00	7.68	8.11	8.82
Monowai	[0.5[30]]	0.40	0.35	0.33	0.34	0.30	0.18
Mossburn	3.0	1.91	1.74	1.77	1.40	1.24	1.19
North Gore	30.0	13.26	9.13	7.88	7.61	8.16	8.15
North Makarewa (66kV)	90.0	**45.91**	44.90	43.60	42.05	43.73	29.81
Ohai	7.5	50.53	44.69	2.11	2.20	2.22	2.10
Orawia	7.5	2.57	2.33	2.74	2.54	2.67	2.43
Otatara	5.0	3.27	2.71	3.70	3.34	3.52	3.43
Otautau	7.5	3.97	3.80	4.01	4.72	4.49	4.06
Riversdale	5.0	4.78	4.43	4.30	4.26	3.70	3.56
Riverton	15.0	5.07	4.71	4.32	4.33	4.19	4.33
Seaward Bush	20.0	9.20	8.62	8.40	8.48	8.34	8.70
South Gore	24.0	8.91	8.11	8.00	7.69	7.76	10.57
Te Anau	24.0	5.91	5.44	5.21	5.37	5.15	5.38
Tokanui	1.5	1.11	1.05	0.97	0.96	1.02	0.99
Underwood	40.0	12.23	11.95	12.47	12.31	12.66	12.97
Waikaka	1.5	1.08	0.94	0.96	0.74	0.58	1.55
Waikiwi	24.0	**13.19**	**12.42**	11.55	10.93	10.81	10.65
Winton	24.0	11.54	11.04	10.52	10.67	10.08	10.47
White Hill (Wind)	[58.0[30]]	-57.23	-56.93	-56.88	-56.60	-57.15	
Monowai (Hydro)	[10.0[30]]	-6.96	-6.59	-6.63	-6.50	-5.25	

Dipton and Waikiwi substations peaked over the installed capacity. Projects are planned to upgrade Dipton and Waikiwi to remedy.

4.3.2 Drivers of future demand

Key drivers of demand growth (and contraction) are likely to include the issues depicted in Figure 41.

[30] Transformer(s) not owned by TPCL.

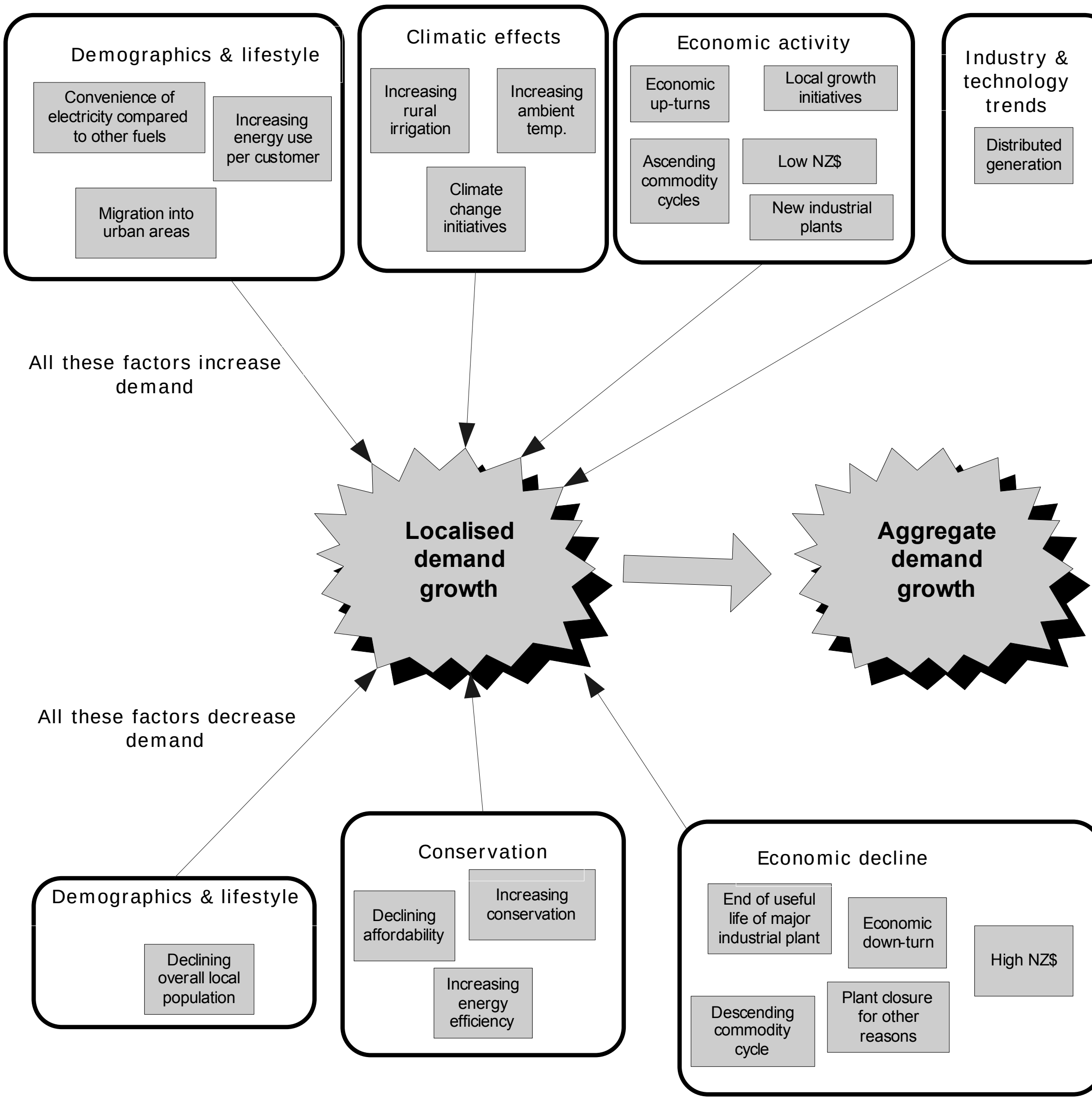


Figure 41 - Drivers of demand

At residential and light commercial feeder level, three or four of these issues may predominate and be predictable and manageable on a statistical basis; however experience is that large customers give little if any warning of increases or decreases in demand. The residential and light commercial demand projections can be aggregated into a reasonably reliable zone substation demand forecast but heavy industrial demand will always remain more unpredictable. TPCL's estimates of future demand are described in section 4.3.4 below.

Historically, TPCL has experienced an average annual demand growth of about 3.0% for the last 10 years. This growth has been distorted with Transpower's introduction of TPM[31] where individual ELB peaks have been replaced by a regional grouping. This has allowed TPCL to relax load control during the year due to the increased summer loading due to Dairying. Whilst the company expects this average rate not to continue and to influence the revenue aspects of TPCL's business, such as pricing, it must be acknowledged that actual demand growth at localised levels (which will influence costs) can vary anywhere

[31] Transmission Pricing Methodology: Allocation of Transpower costs are based on the share of the average of the top 100 peaks for all loads in the Lower South Island (LSI) region. See http://www.ea.govt.nz/industry/transmission/transmission-pricing/transmission-pricing-methodology/ for more details.

from negative to highly positive. The following sections examine in detail the predicted significant drivers of TPCL's network configuration over the next 10 to 15 years.

4.3.2.1 Construction of wind-farms

One large wind farm is presently under operation at White Hill. This is connected to the 66kV network and has taken most of the spare capacity on the lines between White Hill and North Makarewa when at full generation. Meridian has consents for six additional machines and desire network upgrades to allow installation of these additional units.

Other inquiries from numerous developers and land owners highlight the present interest in wind generation. Wind generation up to 2MW can be connected to some 11kV feeders. Above this level or, if a number are installed in an area, will require connection to the subtransmission network.

Distributed Generation (DG) of under 10kW is occurring at a slow rate on the network, and these are normally connected on existing installations, so no additional capacity is required. No other significant Wind Generation is planned to be connected over the next ten years.

Larger farms will need to connect to the Transpower Transmission network at 110kV or 220kV.

Timing	Injection Point	Expected injection	Required provision for injection
unknown	North Makarewa	12MW	Completion of Oteri Valley project to upgrade 33kV between Mossburn and Winton to 66kV.
unknown	All	< 0.01MW x 6 p.a.	Normally can connect onto existing equipment or connection onto MV network.

4.3.2.2 Milling of local forests

This could involve expansion of existing mills (Figure 38 Quadrant 2), or could involve new mills (Figure 38 Quadrant 2 or 4 depending on location). Key drivers of investment will include global timber prices, the eventual outcome of the Kyoto Protocol, the strength of the NZ dollar and any decisions to process locally as opposed to export.

No expected new mills in the next ten years, with the closure of the mill at Conical Hill and slow-down at Otautau.

4.3.2.3 Irrigation

Dry areas in northern Southland such as Athol, Riversdale and Mossburn have a reasonably predictable demand for irrigation which is already occurring. However there are wetter areas that may also install irrigation.

Project a 2% demand increase on substations in Northern Southland.

4.3.2.4 Dairy conversions

Data from Fonterra indicates that dairy conversions to date represent only about 5% of possible conversions based on land area, suggesting no end is in sight for concentrated 50kVA loads appearing throughout TPCL's entire network footprint. This will have the knock-on effect of another dairy factory or expansion of the existing Edendale plant which will mean about 7MW of additional load within the next 3 years.

Project a 1% demand increase in rural areas due to Dairy conversions, an on-going 1% pa growth at Fonterra Edendale and a 1.5MW step change at Awarua for the second stage of the Dairy Trust Plant, with an on-going 2.5% pa growth.

No allowance has been made for the Mataura Valley Milk plant at McNab, and should this occur would require a new zone substation and subtransmission line upgrades. Impact on Transpower is likely to be delayed until they undertake the second stage, as the present GXP load is mainly a winter profile.

4.3.2.5 Coal mining

The whole of Southland sits on at least 100 years of black and brown coal. The precise end use of this coal is not clear other than that the coal industry has undertaken not to supply the domestic market, so coal will not substitute for domestic electricity.

Solid Energy is planning a Briquette pilot plant in the Mataura area, with possible expansion to a full plant on success. No allowance in the projections but if it occurs would require a new substation next to the production site and upgrades of the Transpower network.

L&M are investigating Coal Seam Gas extraction with a pilot planned in the coming year at Ohai; with poor gas extraction last year delaying the project.

4.3.2.6 Oil exploration

Prospecting for petroleum reserves is currently occurring onshore with extensive offshore exploration planned for the next four years. Likely impact for TPCL is increased residential growth and new or expanded support industries.

Allowed for in the 1% pa general growth allowance.

4.3.2.7 Expanding tourism

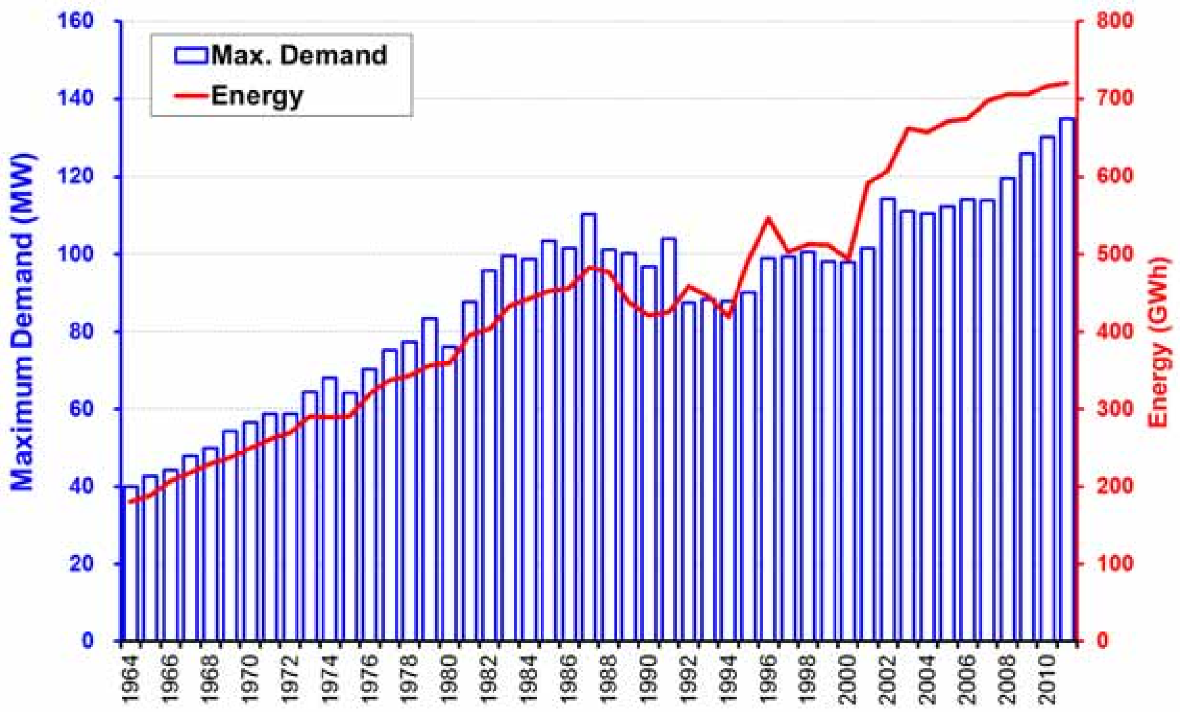
Continued interest in the Fiordland and Stewart Island World Heritage Parks, with the flow-on support infrastructure of hotels, restaurants, café etc.

We have allowed a 1.5% per annum increase in demand for the Te Anau Substation.

4.3.3 Load forecast trend

Analysis of historic demand and energy usage over the last 10 years gives demand growth of 3.0% and energy growth of 2.0%. The chart below shows the data since 1964 and the drop in demand in the early 1990's when load control was introduced.

The step in demand in the last four years is due to the Transmission Pricing Methodology impact.



4.3.4 Estimated zone substation demands

As outlined in detail in the remainder of section 4, TPCL's demand is expected to increase from that described in section 4.3.1 as follows:

- Standard natural growth of 1.0%, with some decline of small rural communities.

- Irrigation growth in Northern Southland of 2%.
- Tourism related growth in Te Anau of 1.5%.
- Continued Dairy conversions across pastoral Southland 1.0%, with related growth at Edendale Fonterra at 1%.
- Load Management shedding to control regional and local peaks is estimated at existing levels. The amount of this may decrease if price incentives are not passed on by retailers, or taken up by customers.

Experience strongly indicates that it would be rare to ever get more than a few months confirmation, sufficient to justify significant investment, of definite changes in an existing or a new major customer's demand. This is because most of these customers operate in fast-moving customer markets and often make capital investment decisions quickly themselves and they generally keep such decisions confidential until the latest possible moment. Probably the best that TPCL can do is to identify in advance where TPCL's network has sufficient surplus capacity to supply a large chunk of load but, as experience shows, industrial siting decisions rarely, if ever, consider the location of energy supply – they tend to be driven more by land-use restrictions, raw material supply and transport infrastructure.

Table 17 below identifies the rate of growth projected to zone substation level for a 10 year horizon, along with the provision expected to be made for future growth. Expanded data is included in Appendix C.

Table 17 Substation demand growth rates

Zone Substation	Proposed Annual Growth	Projected Maximum Demand 2012	2022	2022 Maximum Demand at 3 % pa[32]	Planned actions
Awarua	2.5%	3.9 MVA		**5.4 MVA**	▼ see below ▼
Colyers (New Awarua)	2.5%		8.0 MVA		New 2 x 6/12 MVA 33/11kV
Awarua Chip Mill	0.0%	0.9 MVA	0.9 MVA	1.2 MVA	Customer driven
Athol (New)	1.5%		0.9 MVA		New 1 x 3/5 MVA 66/11kV
Bluff	1.0%	4.8 MVA	5.3 MVA	6.6 MVA	
Centre Bush	2.0%	4.2 MVA		**5.8 MVA**	▼ see below ▼
Centre Bush (66/11kV)	2.0%		5.1 MVA		ex Ohai 5/7½ MVA 66/11kV
Conical Hill	0.5%	1.2 MVA	1.3 MVA	1.7 MVA	ex Mossburn & Dipton 2 x 1½MVA 33/11kV
Dipton	2.0%	**1.7 MVA**		**2.4 MVA**	▼ see below ▼
Dipton (66/11kV)	2.0%		2.1 MVA		New 1 x 3/5 MVA 66/11kV
Edendale Fonterra	0.5%	22.2 MVA	**27.5 MVA**	**30.7 MVA**	Customer driven
Edendale	2.0%	6.9 MVA	8.4 MVA	9.6 MVA	
Glenham	0.5%	1.2 MVA	1.3 MVA	**1.7 MVA**	None
Gorge Road	2.0%	2.1 MVA	2.6 MVA	2.9 MVA	
Heddon Bush	2.0%	6.3 MVA		8.8 MVA	Remove 33kV plant
Lumsden (New 66/33kV)	2.0%		3.7 MVA		Additional ex Heddon Bush 10/15 MVA 66/33kV
Hedgehope (New)	1.5%		2.3 MVA		New 1 x 3/5 MVA 66/11kV

[32] Average energy growth for the last 10 years, and given as a probable worst case load growth.

Zone Substation	Proposed Annual Growth	Projected Maximum Demand 2012	2022	2022 Maximum Demand at 3 % pa[32]	Planned actions
Hillside	2.0%	0.7 MVA	0.9 MVA	1.0 MVA	
Isla Bank (New)	1.5%		2.8 MVA		New 1 x 3/5 MVA 66/11kV
Kelso	2.0%	4.5 MVA	**5.5 MVA**	**6.2 MVA**	Additional ex Conical Hill 1 x 5MVA 33/11kV
Kennington	1.5%				▼ see below ▼
Kennington (New)	1.5%	5.7 MVA	6.6 MVA	7.9 MVA	New 2 x 6/12 MVA 33/11kV
Lumsden	3.0%	3.7 MVA	3.9 MVA	5.1 MVA	None
Makarewa	2.0%	5.7 MVA	6.9 MVA	7.9 MVA	
Mataura	1.0%	8.4 MVA		**11.7 MVA**	▼ see below ▼
Mataura (Upgraded)	1.0%		9.3 MVA		New 2 x 6/12 MVA 33/11kV
Monowai	1.0%	0.4 MVA	0.4 MVA	**0.6 MVA**	New 1 x 0.5 MVA 66/11kV
Mossburn	3.0%	2.0 MVA	2.6 MVA	2.2 MVA	
North Gore	1.5%	9.5 MVA	11.0 MVA	13.1 MVA	
North Makarewa	2.0%	46.8 MVA	**57.1 MVA**	**64.8 MVA**	▼ see below ▼
North Makarewa 33kV	2.0%	51.5 MVA	62.8 MVA	71.3 MVA	Request Transpower to add 220/66kV
Ohai	0.5%	2.6 MVA	2.7 MVA	3.6 MVA	New 1 x 3/5 MVA 66/11kV
Orawia	1.0%	3.3 MVA	3.6 MVA	4.6 MVA	
Otatara	2.0%	4.1 MVA	4.9 MVA	**5.6 MVA**	Monitor
Otautau	1.0%	4.3 MVA	3.5 MVA	6.0 MVA	None
Riversdale	3.0%	4.6 MVA		**6.4 MVA**	▼ see below ▼
Riversdale (Upgraded)	3.0%		6.2 MVA		ex Waikiwi 1 x 6/12 MVA 33/11kV
Riverton	2.0%	5.2 MVA	5.4 MVA	7.2 MVA	
Seaward Bush	1.0%	8.3 MVA		**11.5 MVA**	▼ see below ▼
Seaward Bush (Upgraded)	1.0%		8.5 MVA		New 2 x 6/12 MVA 33/11kV
South Gore	2.0%	9.1 MVA	11.1 MVA	12.6 MVA	None
Te Anau	2.0%	6.0 MVA	7.4 MVA	8.3 MVA	
Tokanui	0.5%	1.1 MVA	1.2 MVA	1.5 MVA	None
Underwood	0.5%	12.3 MVA	12.9 MVA	17.0 MVA	
Waikaka	2.0%	0.5 MVA	0.6 MVA	0.7 MVA	
Waikiwi	3.0%	12.1 MVA		**16.7 MVA**	▼ see below ▼
Waikiwi (Upgraded)	3.0%		16.2 MVA		New 2 x 11½/23 MVA 33/11kV
Winton	1.0%	11.7 MVA	10.1 MVA	**16.1 MVA**	Load transfer to Hedgehope and Makarewa
White Hill (Wind)	0.0%	-57.2 MVA	-69.9 MVA	-58.0 MVA	Customer driven
Monowai (Hydro)	0.0%	-7.0 MVA	-7.0 MVA	-7.8 MVA	Customer driven

The red highlighted values indicate when the initial trigger point for capacity is exceeded based on the present equipment and configuration.

4.3.4.1 Demand model assumptions

The impact of Distributed Generation (DG) has been ignored due to the estimated low connection rate of DG and the probability that only a small percentage of the capacity will be available during peaks, e.g. White Hill only contributed 4.5MW during the LSI peak (Figure 40).

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. Load shifting can also be done at the Retailer's request or during Dry-year rationing.

Increased monitoring of heavily load sites if data indicates capacity will be extended.

Annual preparation of this data will highlight sites that vary from the above model and the planned works adapted for each situation, with some upgrades delayed or brought forward.

4.3.5 Estimated demand aggregated to GXP level

Table 18 shows the aggregated effect of substation demand growth for a 10 year horizon at the four GXP's, Monowai and White Hill.

It is interesting to consider that any additional generation connected onto the North Makarewa GXP may be limited due to the network being fully loaded when White Hill and Monowai are at peak generation and the local area load is low.

Table 18 GXP demand growth

GXP	Rate of growth	2022 MD	Provision for growth
Edendale	1.97%	30.9MVA	Possible Transpower project to allow full 36.6/38.7 MVA (summer/winter) capacity with upgrades.
Gore	0.08%	31.6MVA	Load is under firm capacity of 36.6/37.9 MVA (summer/winter) and load control will be used to keep under this limit. Mataura is able to be transferred onto Edendale GXP during Dairy off-season. Any major new loads will require additional capacity at Transpower or an agreement to drop new load if Transpower loses one supply transformer.
Invercargill	2.16%	122.9MVA Incl. EIL 88.6MVA LM[33] = 34MVA	Two 120MVA banks, allows 20MVA of additional load. Presently limited to 104MVA. Possible Transpower project to allow full 144.8/151.3 MVA (summer/winter) capacity with small upgrades.
North Makarewa	2.12%	58.8MVA	As generation is likely to make this a normally exporting GXP. Possible Transpower project to allow full 76.1/79.4 MVA (summer/winter) capacity with 33kV cable upgrade.
Monowai	0%	- 7.1MVA	66kV lines able to export all expected generation.
White Hill	6 × 2MVA	- 70MVA	Needs additional 66kV lines.
Total	**1.68%**	**207.1MVA**	Including EIL

[33] LM = Load Management; an estimate of the controllable load on this GXP that could be off during system peaks.

4.3.6 Issues arising from estimated demand

The significant issues arising from the estimated demand in section 4.3.4 and Appendix C are:

- Short term trigger is reached at Dipton, Edendale Fonterra, Kennington, North Makarewa and Waikiwi.
- Medium term trigger is reached at Kelso, Kennington and Riversdale.
- Long term trigger may be reached at Lumsden, Otatara and Winton.

4.4 Where are TPCL's network constraints

TPCL's network includes the following constraints:

Constraint	Description	Intended remedy
Limited extra capacity.	Substations close to maximum capacity. (Dipton, Edendale Fonterra, Kelso, Kennington, Lumsden, North Makarewa, Otatara, Riversdale, Waikiwi, Winton)	Up-size as required. Review annually. Addition of new substations will transfer load off some heavily loaded substations.
Invercargill GXP.	104.0 MVA limitation in 'Other Equipment' ratings. Additional load likely.	Transpower project to upgrade 'Other Equipment' to allow 144.8/151.3MVA. Up-size when load control cannot keep load under this limit.
Gore GXP.	Close to firm capacity of 36.6 / 37.9 MVA (Summer/Winter) Additional load likely.	Up-size when load control cannot keep load under this limit.
North Makarewa GXP.	Firm capacity 62.3MVA, limited by 33kV cable and protection.	Transpower project to upgrade cables and protection to allow 76.1/79.4MVA. Up-size when load control cannot keep load under this limit.
Awarua substation.	Additional load likely.	Up-size transformers when customer request received.
Edendale Fonterra substation.	Additional load likely.	Up-size transformers when customer request received.
Subdivisions.	Possible large developments in Athol, Garston and Kingston.	Extend subtransmission to Athol and Kingston.
Environmental – Oil.	Expectation that no significant oil spills from substations.	Install oil bunding, blocking and separation systems.
Voltage at Riversdale and Centre Bush.	When the first 33kV line supplying northern Southland is out-of-service the voltage at the end substation is marginal.	Upgrade some lines to 66kV.
Export capability from White Hill.	Export of energy limited to 58MVA.	Upgrade 33kV lines to 66kV down the Oteri Valley, Mossburn to Winton.
11kV voltage low due to Dairy milking.	Conversion of farms to dairying may cause feeder voltage to drop below 0.94pu.	Install 11kV regulators to improve voltage. Install new substations if growth continues.
Undergrounding.	District / Regional Plan requirements on the location / position of lines.	Alternative routes. Undergrounding of lines.
Coastal marine.	Salt pollution reducing insulation effectiveness.	Over insulate lines. Use high pollution type equipment.
Coastal marine.	Increase corrosion.	Enclose substation equipment inside buildings. Increased renewals of outdoor equipment.

4.5 Policies for distributed generation

[Addresses handbook requirement 4.5.5(d)]

The value of distributed generation can contribute in the following ways:

- Reduction of peak demand at Transpower GXP's.
- 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.

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

The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings, with a guideline and application forms available on the web at http://www.powernet.co.nz/dg-guide.

4.5.1 Connection terms and conditions (commercial)

- Connection of up to 10kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10kW to an existing connection may incur additional costs to reflect network up-sizing.
- Distributed generation that requires a new connection to the network will be charged a standard connection fee as if it was a standard off-take customer.
- An application 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 TPCL's costs, such as transmission costs or deferred investment in the network, and, provided the distributed generation is of sufficient size 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.

4.5.2 Safety standards

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

4.5.3 Technical standards

- Metering capable of recording both imported and exported energy must be installed if the owner of the distributed generation wishes to share in any benefits accruing to TPCL. Such metering may need to be half-hourly.
- TPCL 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 TPCL's own prevailing standards.

4.6 Use of non-asset solutions

[Addresses handbook requirement 4.5.5(e)]

As discussed in section 4.2.1 the company routinely considers a range of non-asset solutions and indeed TPCL's preference is for solutions that avoid or defer new investment as part of the planning process for issues. Process is described in section 4.7.

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:

- The amount of Transpower charges by controlling the network load during the LSI peaks.
- The load on individual GXP's when they exceed the capacity of that GXP.
- The load on feeders during outage situations.
- Load shedding is used by some customers where they accept a drop of their load / generation instead of investing in additional network assets. i.e., White Hill wind farm will limit generation to under 20MW, if the 66kV line from White Hill to Heddon Bush is out.

Consideration is also given to local generation options. One situation is the supply to Kingston, which is presently a long radial fed from Lumsden. With growth this feeder is likely to cross the trigger level for reliability and require an alternate supply. Evaluation of options will consider the cost of 60km of new line verses the on-going cost of a diesel generator to provide this alternative.

If an Engineer considers that adoption of non-asset options may be sufficient to overcome a constraint, a business case would be prepared to get approval from the Chief Engineer or Chief Executive, to proceed.

The approval would be given if the likelihood of success is acceptable compared to the cost / benefit ratio.

Suggestions of non-asset options can come from other staff and external parties with these allocated to an Engineer to investigate.

4.7 Network development options

[Addresses handbook requirement 4.5.5(f)]

4.7.1 Identifying options

When faced with increased demand, reliability, security or safety requirements, TPCL considers the broad range of options described in Section 4.2.1. The range of options for each issue varies due to:

- Stakeholder interests

Section 1.6 lists stakeholder interests and the engineer considers these areas in planning and ranking an option.

- Size of the project

Different issues have differing resource requirements. The level of analysis and the breadth of options vary with size. A simple issue like connecting a new customer next to an existing low voltage pillar box would only have a single option analysed, whereas a new industrial plant would have multiple options considered.

- Creativity and knowledge of the Engineer

Breadth of options is also dependent on the Engineer undertaking the planning. Options are developed by the Engineer and critiqued by the Chief Engineer. Use of standard construction and existing designs mainly, but support for innovation.

- Resource

The other higher priority projects may limit the resources available for each option. This could be a limitation of finances (uneconomic), workforce (to plan, design, manage, build or operate), materials (unavailability or long lead-time of equipment) or legal (need Resource Consent or Easements.)

4.7.2 Identifying the best option

Once the best broad option has been identified using the principles embodied in figure 39. TPCL will use a range of analytical approaches to determine which option best meets TPCL's investment criteria. As set out in Section 4.2.3, TPCL uses increasingly detailed and comprehensive analytical methods for evaluating more expensive options.

- Simple Spreadsheet: Cost calculation with standardised economic benefit values.
- Risk analysis: More comprehensive and complexity for larger projects.
- Net Present Value (NPV) model: Time series model of future costs and benefits.
- Payback calculation: Financial calculation of the time estimated to recover cost of undertaking that option.
- Optimisation Tools: Multiple parameter models used to optimise stakeholder objectives.
- Customer consultation: If solution impacts on a customer and changes the service level provided, the customer must be consulted to obtain their support. i.e. disconnecting remote customers by replacing connection with a RAPS[34].

4.7.3 Implementing the best option

Having determined that a fixed asset (CAPEX) solution best meets TPCL's requirements and that TPCL's investment criteria will be met (and if they won't be met, ensuring that a customer contribution or some other form of subsidy will be forthcoming), a project will proceed through the following broad steps:

- Perform detail costing and re-run cost-benefit analysis if detail costs exceed those used for investment analysis.
- Address resource consent, land owner and any Transpower issues.
- Perform detailed design and prepare drawings, construction specifications and if necessary tender documents.
- Tender out or Assign construction.
- Close out and de-brief project after construction.
- Ensure that contractors pass all necessary information back to TPCL including as-builts and commissioning records.
- Ensure that learning experiences are examined, captured and embedded into PowerNet's culture.

4.8 Development programme

General individual estimates are only given as work is tendered and disclosure of estimates would negate the benefit of tendering.

4.8.1 Current projects

[Addresses handbook requirement 4.5.5(g)(i)]

Expected projects for year one (YE 31 March 2013) are as follows. These projects have a high certainty.

[34] RAPS = Remote Area Power System: A stand-alone energy network of alternative energy sources (Solar, Photovoltaic, Wind turbine, Micro-hydro, LPG, Diesel, etc…) so that a connection to the electricity network is not required.

4.8.1.1 Hedgehope Project (HP)

(a) **Description**

Continued construction of a new 66/11kV zone substation in the Hedgehope area with supply sourced from Winton. The 66kV line was completed during 2011/12 and work planned for the project is the construct a new zone substation with a single 66/11+11kV 5MVA transformer with three 11kV feeders. This will enable future upgrade of feeders to 22kV if required.

(b) **Issues**

Due mainly to dairy conversions the network in this area has been calculated to be at the limit of acceptable voltage and the installation of a second 11kV regulator downstream of Browns Regulator is considered not optimal. The projected peak load occurring at Winton is also nearing the firm capacity so a transfer of load is also desirable.

(c) **Options**

- New substation. [Selected option with advantages of improving reliability, reduce losses and allow future growth. Allows transfer of load off Winton substation.]
- Conversion to 22kV. [Higher cost and more difficult to schedule.]
- Additional 11kV regulators. [Increased losses and increased system impedance.]
- Up-sizing of components (Conductor, Transformer). [Limited future capability.]

(d) **Details**

Land has been purchased from a local Dairy Farmer for the site and Transit approval obtained for the site access.

Transfield Worley is designing the substation based on a port-a-com transportable building with equipment installed prior to transport to site.

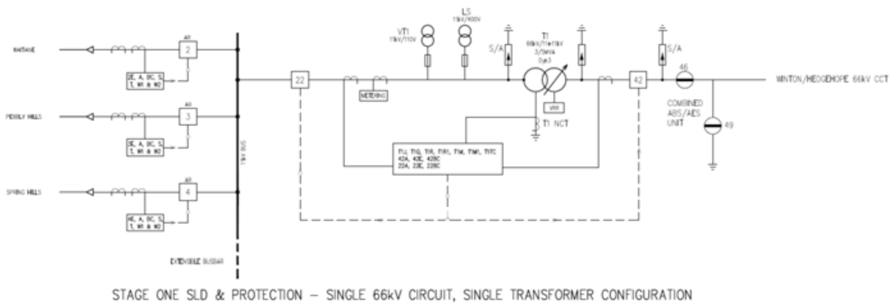


Figure 42 - Hedgehope Initial configuration

A new 66/11+11kV 5MVA power transformer from CGPT is being delivered in March 2012 with the11kV switchboard being supplied by Schneider United Kingdom. Protection is based on Schweitzer Engineering Laboratories (SEL) equipment and incorporate Arc-flash[35] detection.

Civil site works have been designed by CPG.

(e) **Cost and type**

$0.5M - $2.5M, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Migrate from a 33kV network to 66kV.

[35] Arc-flash is a methodology that uses fibre optic cables to monitor the light level inside a compartment of equipment. When an internal fault occurs the electric arc creates an intense flash of light which the equipment detects and together with a measurement of fault current triggers a very fast tripping. The fast tripping limits the energy discharged into the fault; this reduces the risk to personnel at the site and limits damage to the equipment.

4.8.1.2 Athol Project (AP)

(a) **Description**

Construction of a new 66/11kV zone substation in the Athol area with supply sourced from Mossburn.

Work planned for the project:

- Construct a new 50km 66kV line north out of Mossburn substation to Garston area. Sections of the route have been constructed to 33kV level with Fox conductor. It is proposed to reinsulate these sections and use the 33kV components to provide 11kV or 22kV distribution.
- Construct a new zone substation with a single 66/11+11kV 5/7.5MVA transformer with two 22kV feeders.
- Install an 11/22kV autotransformer at Five Rivers to allow backups.
- Convert main line from Five Rivers to Kingston and minor laterals to 22kV with all other laterals supplied by 22/11kV autotransformers.
- Installation of a 350kW diesel generator at Kingston to allow line construction, provide partial restoration to improved reliability, and save having to construct a second supply line in to the area.

Figure 43 - Athol area looking toward Parawa Regulator

(b) **Issues**

Irrigation and residential/commercial developments in this area has been calculated to be at the limit of acceptable voltage and the installation of a third and fourth 11kV regulator is considered not optimal. The connection of significant generation north of Kingston is not possible over the present 11kV or a 22kV network.

(c) **Options**

- New substation and 66kV or 33kV line. [66kV selected as the most economical solution with greater capability for future growth.]
- Conversion to 22kV. [Limited export capability of generation.]
- Additional 11kV regulators. [Increased losses and system impedance increase.]
- Up-sizing of components (Conductor, Transformer). [Limited future capacity.]

(d) **Details**

Land is being purchased from a local Dairy Farmer for the site and Transit approval obtained for the site access.

Mitton ElectroNet is designing the substation based on a port-a-com transportable building with equipment installed prior to transport to site. Protection to incorporate Arc-flash detection and enable remote monitoring and control from our central control centre.

(e) **Cost and type**

$2.5M - $5M 2012/13, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Strive to become an efficient and effective operation.

4.8.1.3 Oreti Valley Project (OVP)

(a) Description

The long term plan is to extend the 66kV network so it includes Centre Bush, Dipton and Mossburn substations. The southern connection is proposed at Winton to avoid all 66kV lines going through Heddon Bush substation.

The initial connection out of Winton substation is planned to be a new 66kV crossing the Oreti River to the west of the substation.

Over a number of years sections of the 33kV network will be upsized to 66kV but initially will operate at 33kV. At a date when load growth makes the 33kV unable to meet the service levels in the region, these sites can be upsized to 66/11kV transformers with the present 66/33kV transformer at Heddon Bush relocated to a new substation at Castlerock.

Work on this project may be accelerated in consultation with Meridian Energy to lower the losses occurring in transporting its generation output to the national grid.

Work planned includes:

- Add an additional 66kV bay off the Winton Substation to supply the new 66kV line up the Oreti Valley.
- New 66kV line out of Winton to the west across the Oreti River and north to Centre Bush substation.
- Upgrade Centre Bush with a new 66/11+11kV 5/7.5MVA transformer[36] and add one additional 11kV feeder to supply along the now free 33kV line back to Heddon Bush area. Feeder upgrading to 22kV will be possible.
- Incorporate dual protection on the lines to maintain less than 200mS clearance of faults, as required for the White Hill Wind Turbines.
- Reinsulate the 33kV lines from Centre Bush to Mossburn to 66kV.
- Upgrade Dipton by replacing the transformer with a new 66/11+11kV 3MVA unit and upgrade protection on the 66kV by having digital differential on the two sides of the substation but no 66kV Circuit Breakers.
- Construct a new 66kV substation at Castlerock at the point where the present two 33kV lines meet.
- Construct a step down at Lumsden utilising the 66/33kV 10/15MVA transformer and 33kV circuit breaker from Heddon Bush to supply the 33kV.
- The reinsulated 66kV line to connect into Mossburn substation by the spare 66kV bay.

Figure 44 - Winton 66kV Substation

(b) Issues

Load growth has made the existing back-ups to Riversdale, Lumsden, Dipton and Centre Bush marginal.

[36] 66/11+11kV transformer can be connected to provide 11kV or 22kV output by parallel or series connecting the two 11kV windings.

Losses occurring on the 66kV lines are significant when White Hill generation is high.

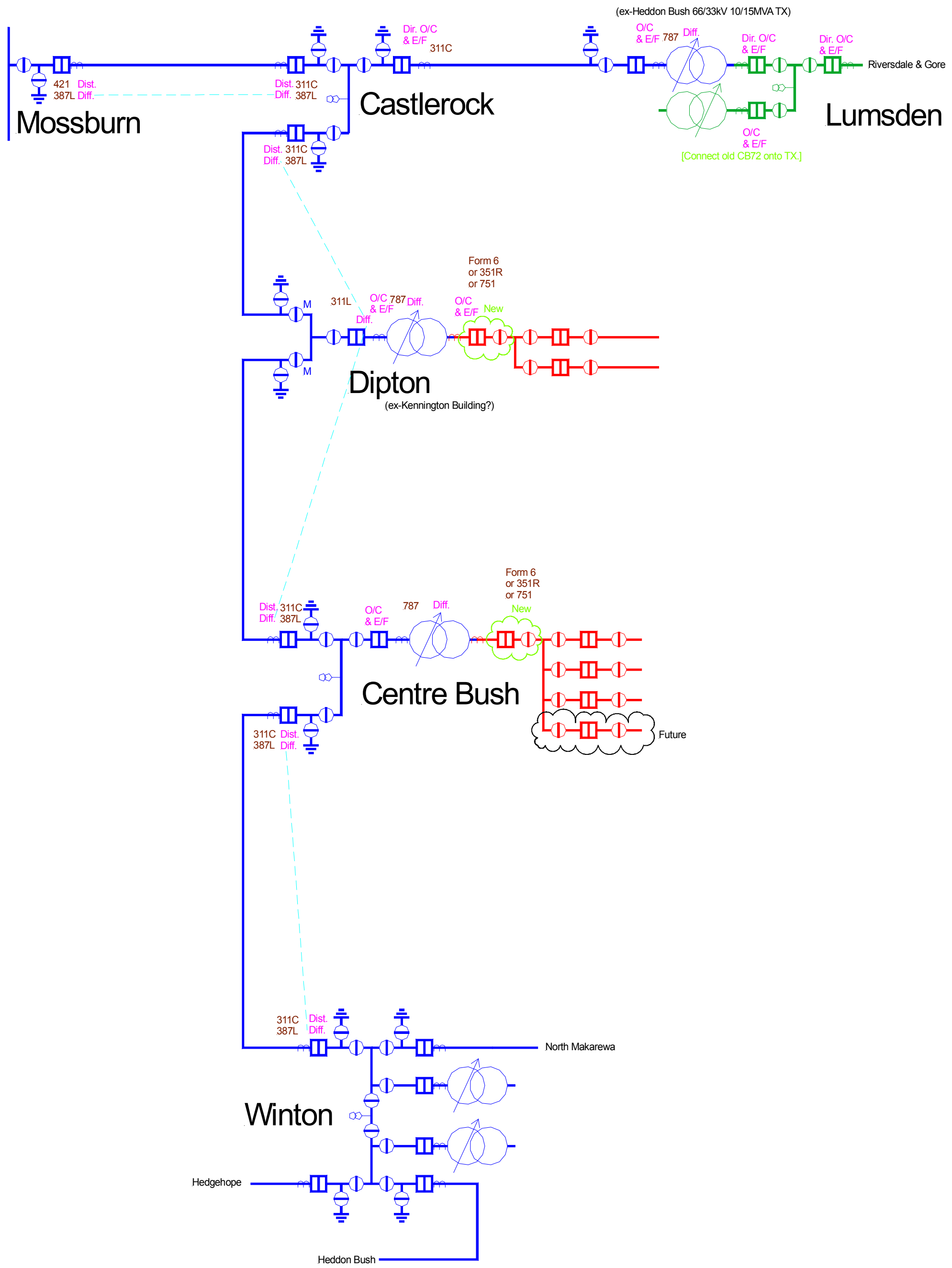
Desire by Meridian to increase generation at White Hill to the consented levels.

(c) **Options**

- Upgrade to 66kV from Mossburn to Winton. [Selected option that provides the greatest benefits.]
- Conversion to 110kV. [Too expensive.]
- 33kV regulators. [Increased losses and increase system impedance.]
- Up-sizing of components (Conductor, Transformer).[Limited future capacity.]

(d) **Details**

Planned outcome is shown in the diagram below:



(e) **Cost and type**

$0.5M - $2.5M p.a. 2012 to 2016, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Migrate from a 33kV network to 66kV.

4.8.1.4 Kennington upgrade

(a) **Description**

As an option to reduce the load at Waikiwi a project is proposed that will add additional feeders at Kennington substation. This allows the Fairweather Road regulator and circuit breaker to be decommissioned and these loads to be supplied from Kennington. The difficulty in supplying the industrial customers if the 33kV line fails could be improved by providing a second 33kV line connection into the substation.

Works planned include:

- Replacing the existing 5MVA 33/11kV transformer and adding a second with 6/12MVA 33/11kV transformers.
- Extending the 33kV bus to connect the new transformer.
- Addition of two new 11kV feeders off a new indoor switchboard.
- Provision of a second 33kV line teed off the Gorge Road 33kV line.

(b) **Issues**

Dairy farm conversions in the area have loaded neighbouring feeders so that at peak time voltage is below acceptable levels. Solutions to remedy would require two new 11kV Regulators and relocation of Fairweather Road regulator closer to Waikiwi Sub.

Waikiwi and Seaward Bush Substations are nearing their peak firm capacity.

Single 33kV line and limited 11kV backup to industrial customers.

(c) **Options**

- Add second power transformer and two new 11kV feeders at Kennington Substation. [Selected option as provides lower losses and increased growth potential.]
- Install two new 11kV Regulators and relocate Fairweather Road Regulator. [Limited future capability, increased losses and increase system impedance.]
- Upsize 11kV network to 22kV. [More expensive.]

(d) **Details**

Mitton ElectroNet is designing the substation based on a port-a-com transportable building with equipment installed prior to transport to site.

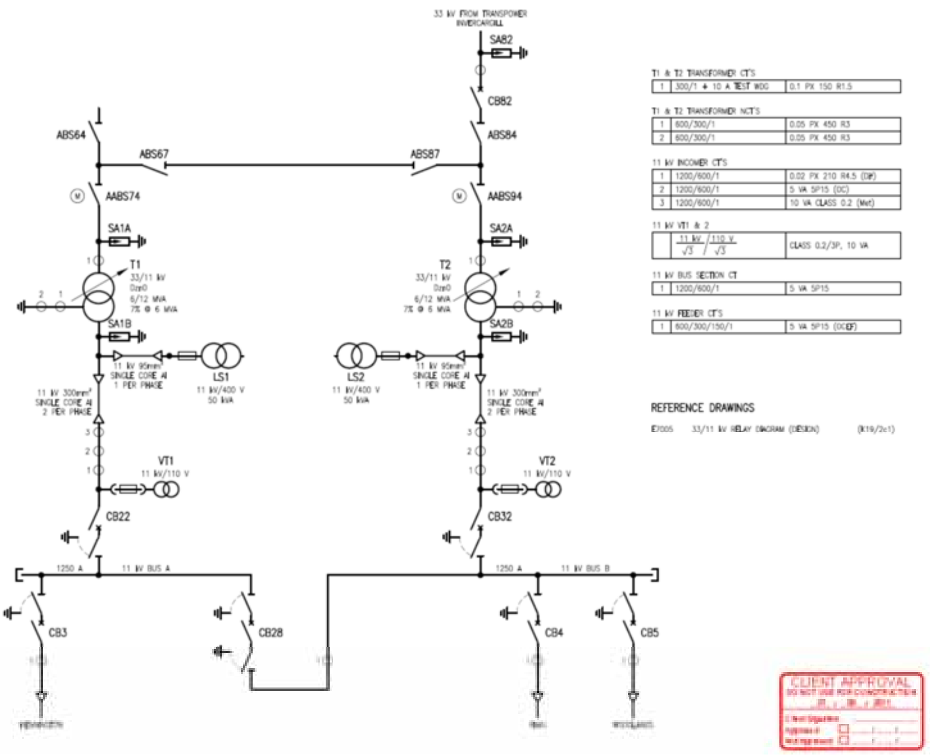


Figure 45 - Approved Single Line Diagram

New transformers have been ordered and delivered in January 2012; unfortunately one unit was damaged in transit and has been returned to CGPT for repair, this has delayed completion of the project.

Figure 46 – New CGPT 33/11kV 6/12MVA Transformer

Due to the closeness of the two transformers on the site we have added a fire wall on the new transformer to limit damage to the neighbouring unit should a fire occur.

(e) **Cost and type**

$0.25M - $0.5M, System Growth.

(f) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.1.5 Isla Bank Project (IBP)

(a) Description

Planning work for the construction of a new 66/11kV zone substation in the Isla Bank area with supply sourced from the 66kV line at Fairfax.

Work planned for the project:

- Construct a 66kV over 11kV line from Fairfax to Isla Bank.
- Construct a new zone substation with a single 66/11+11kV 5/7.5MVA transformer with three 11kV feeders.

Figure 47 - Isla Bank area - looking towards the village

(b) Issues

Due to dairy conversions the network in this area has been calculated to be at the limit of acceptable voltage and the installation of additional 11kV regulators is considered not optimal. The projected peak load occurring at Otautau is also nearing the firm capacity so a transfer of load is also desirable.

(c) Options

- New substation on the 66kV network. [Selected option as provides the most benefits.]
- Conversion to 22kV. [More expensive.]
- 11kV regulators. [Increased losses.]
- Demand-side management (Tariff? Dairying loads…)[Limited capability from farmers.]

(d) Details

Consultants are designing the substation based on a port-a-com transportable building with equipment installed prior to transport to site similar to Kennington solution.

Design of the 66kV line from Fairfax will be done and major equipment ordered for delivery in 2013/14.

Final construction details will be defined when designs are completed.

(e) Cost and type

$0.5 - $2.5M 2013/14, $0.5 - $2.5M 2014/15, System Growth.

(f) Goal / Strategy

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.1.6 Waikiwi Project

(a) Description

Initial planning work and major equipment procurement for the upgrade of the Waikiwi substation.

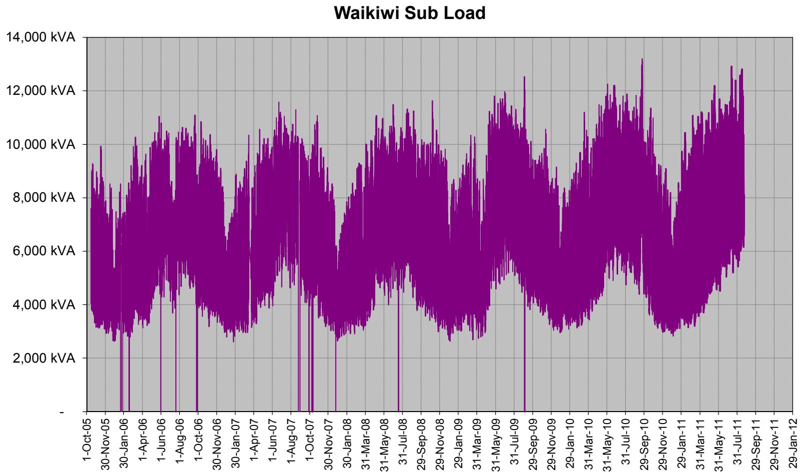
Figure 48 – Aerial view of Waikiwi Substation

(b) Issues

Load growth has reached the capacity trigger point of 12MW.

Site has been in-built with residences now on three side of the site.

Noise levels on boundary exceed District Plan requirements.



(c) Options

- Upgrade 33/11kV transformers. [Selected option as provides the most benefits.]
- Conversion to 66kV. [More expensive.]
- Transfer loads to other substations. [Some planned to go to Kennington.]
- Move equipment indoor to reduce noise level. [Most likely only option to achieve noise level requirements.]

(d) Details

Consultants are designing the substation upgrade based on indoor transformer rooms with external radiators.

Final construction details will be defined when the design is completed.

(e) Cost and type

< $0.25M 2012/13, $0.5 - $2.5M 2013/14, System Growth.

(f) Goal / Strategy

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.1.7 Seismic remedial work

(a) **Description**

After the earthquakes in Christchurch a review of substations is planned and some strengthening works will be undertaken.

(b) **Issues**

Liquefaction and high horizontal forces damaged equipment in Christchurch, beyond what was expected.

(c) **Options**

- Strengthen
- Replace
- Spares

(d) **Details**

CPG will review each site and highlight any equipment that is likely to be damaged due to current learning's on earthquakes.

This budget is to undertake upgrade works after the review.

(e) **Cost and type**

Under $0.5M p.a. 2012 to 2015, Reliability, Safety.

(f) **Goal / Strategy**

Undertake safety and environmental improvements.

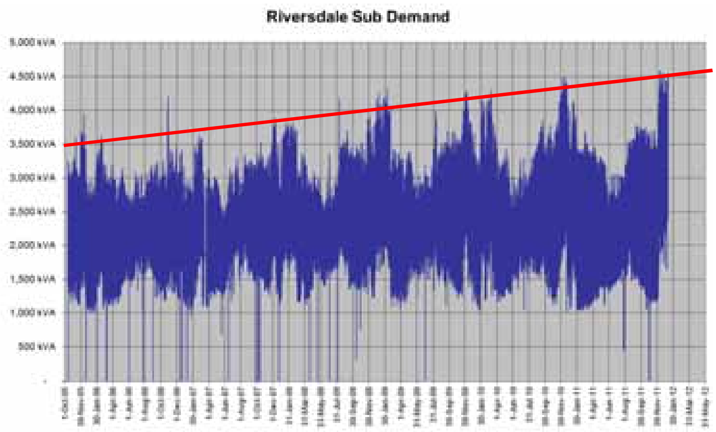
4.8.1.8 Riversdale Transformer

(a) Description

Add extra capacity at Riversdale.

Figure 49 - Present Riversdale substation

(b) Issues



Nearing capacity trigger.

Risk with a single power transformer on-site.

Limitation of 11kV to supply new irrigation in the area.

Reliability issue with 11/22kV autotransformers. (Energising forces stress the coils, and impedance requires downstream regulation.)

(c) Options

- Replace 33/11kV 5MVA power transformer with a 6/12MVA unit. [Selected option as least cost but needs backup option of mobile sub or generator to be developed.]
- Add a second 33/11kV power transformer on-site. [Limited space.]
- Add a 33/11+11kV power transformer on-site. [Existing unit has remaining life.]
- Transfer some load to new substation, Balfour and/or Mandeville. [Higher cost as would require a fully new site.]

(d) Details

Design work will begin to detail the installation of a 33/11kV 6/12MVA transformer that is planned to be removed from Waikiwi in 2013/14.

(e) Cost and type

< $0.25M 2013 to 2015, Growth.

(f) Goal / Strategy

Strive to become an efficient and effective operation.

4.8.1.9 Monowai Transformer

(a) Description

Add a 66/11+11kV, 1.0MVA power transformer at Monowai power station to supply local area.

(b) Issues

Pioneer Generation Limited (PGL) wishes to remove 6.6/11kV transformers and separate generation and TPCL plant.

Single 6.6kV supply from PGL generator bus to the local feeders.

Reliability issue with 6.6/11kV transformers when trippings occur on network and cause overvoltage that stresses the transformer windings.

Old structure is at a low height and a safety risk.

Figure 50 - Monowai Structure (6.6kV and 11kV equipment close to fence.)

(c) Options

- Replace 6.6/11kV ½MVA power transformer with a 66/11kV 1.0MVA unit.
- Add a second 6.6kV feeder to local area. [Limited room for expansion.]
- Add a connection point for a temporary generator to be quickly installed.
- Supply local 11kV network from neighbouring substations. [Large gap, single phase lines and need for Voltage regulators make this more expensive and less reliable.]

(d) Details

Design work will detail the installation of a new 66/11kV 1.0MVA transformer supplied from a new 66kV Circuit breaker (CB). The 11kV will be supplied by a new 11kV CB and the old low level equipment removed.

Provision will be made to allow quick installation of a temporary generator to supply the area during maintenance and major equipment failures.

(e) Cost and type

$0.5 - $2.5M 2012/13, Growth.

(f) Goal / Strategy

Strive to become an efficient and effective operation.

4.8.1.10 Mobile Substation

(a) **Description**

With multiple single transformer substations and reducing back-up capability from neighbouring substations the option of building a mobile substation is planned for investigation.

(b) **Issues**

Single transformer substations with little or no periods where backup from neighbouring substations can be used.

Significant periods to move spare transformers into sites where the transformer has failed.

Differing vector angles between the 66kV, 33kV, 22kV and 11kV.

(c) **Options**

- Mobile Substation(s).
- Mobile Generator(s).
- Add second transformer to single transformer substations.
- Add extra substations to restore backup capability.

(d) **Details**

Investigation stage only to develop the best solution for TPCL.

Cost for following year is assuming that a mobile substation business case is approved.

(e) **Cost and type**

Under $0.5 2012/13, $0.5 - $2.5M 2013/14 Reliability.

(f) **Goal / Strategy**

Strive to become an efficient and effective operation.

4.8.2 Current routine projects

Expected routine projects for year one (YE 31 March 2013) are as follows.

4.8.2.1 Quality Remedies

(a) **Description**

Projects to remedy poor power quality.

Voltage is measured (or calculated to vary) outside of regulatory limits.

(b) **Alternatives**

Each of the below options / situations are considered and an appropriate solution implemented.

- Installation of 11kV regulators.
- Up-sizing of components (Conductor, Transformer).
- Demand side management. (Planning an Irrigation ripple control channel.)
- Power factor improvements. (Ensuring customer loads are operating effectively.)
- Harmonic filtering / blocking. (Ensuring customers are not injecting harmonics.)
- Motor starter faults / settings remedied. (Ensuring customer equipment is working and configured appropriately.)

Cost is budgeted at under $0.5M pa on-going, System Growth.

(c) **Goal / Strategy**

Achieve 100% regulatory compliance. Migrate from a 33kV subtransmission network to 66kV.

4.8.2.2 New connections

(a) **Description**

Allowance for new connections to the network. Each specific solution will depend on location and customer requirements.

Some subdivision developments are occurring but we receive little or no prior notification of these. Request to Developers and Regional Authorities provided only minor subdivisions occurring, or no firm commitments. An estimated allowance based on past experience and projected development has been included in the plan.

An allowance has been made to connect Distributed Generation to the network as the proposed regulations have this as a TPCL's cost.

(b) **Alternatives**

Vary due to customer type and location.

Cost is budgeted at $2.5M - $5M pa on-going, Customer Connection.

(c) **Goal / Strategy**

Undertake new investments, which are 'core business', acceptable return for risk involved.

4.8.2.3 Earth upgrades

(a) **Description**

Regular testing of earths across the network is still locating sites with earths that are not sufficient. This programme is to upgrade these to an acceptable level and ensure that missing or stolen components are replaced.

Resistance to earth and earthing systems on equipment needs to be sufficient to maintain a safe environment for staff and the public.

(b) **Alternatives**

- Upgrade and/or extension of electrodes in the ground.
- Limit earth fault current.
- Isolate equipment for contact.
- Separate HV / MV and LV / MEN earths.

Cost is budgeted at $0.25M - $0.5M p.a. Safety.

(c) **Goal / Strategy**

Undertake safety and environmental improvements. Achieve 100% regulatory compliance.

4.8.2.4 Reliability projects

(a) **Description**

Small projects to minimise reliability issues.

Low reliability can lead to pockets of poor quality; while overall figures look okay some individuals may be bearing the brunt of outages.

(b) **Options**

- Upgrade and/or extension.
- Replacement with new.
- Undergrounding.
- Change in configuration, i.e. Change from Open wire MV to Spacer cable.
- Sectionalise the network to lessen the number of customers affected.
- Remote control devices to speed isolation and restoration.

Cost budgeted at under $0.5M p.a. Reliability.

(c) **Goal / Strategy**

Improve reliability by sectionalising poor performing feeders. Expand remote controllability. Replace critical assets near to their technical life.

4.8.2.5 Line Relocation

(a) **Description**

Works to move lines around trees or for roadway realignments.

Needed to achieve clearances between lines and trees, due to high tree value to community or individuals.

(b) **Alternatives**

- Move line to other side of road.
- Underground line next to the trees.
- Insulate the line next to the trees.
- Remove or trim the trees.
- Move line to a long-side new alignment.

Cost budgeted at under $0.5M pa, Relocation.

(c) **Goal / Strategy**

Undertake safety and environmental improvements. Achieve 100% regulatory compliance.

4.8.3 Planned projects

[Addresses handbook requirement 4.5.5(g)(ii)]

Expected projects for year two to five (YE 31 March 2014 to 2017) are as follows. These projects have some certainty.

Note some projects are planned to start in year one and continue over following years, these are not repeated in following sections.

4.8.3.1 Awarua Project

(a) **Description**

The Invercargill City Council has purchased an area of land southeast of the present substation for industrial zoning, but has yet to attract any customers.

It is proposed to begin planning and design to build a new substation to supply most existing industrial customers and have provision for expansion. The new site will be developed and incorporate indoor 33kV and 11kV switchgear and space for up to three 11.5/23MVA transformers, giving a firm capacity of 46MVA. Note that if load did grow an additional 33kV heavy line could be added from Invercargill.

First stage will purchase the two 33/11kV transformers and store these until customer demand requires the extra capacity.

Design work will be done for the substation as lead time for any new customer is likely to be short.

The existing site would be retained to continue supply to the South Wood Exports 1500kVA chipper motor.

(b) **Issues**

The present substation is not close to the likely load centre, is limited in expansion and is a very damp site.

Short timeframe for new industrial customers wanting supply.

Marine / Coastal location, with high salt pollution.

(c) **Options**

- New substation on the 33kV network. [Selected as provides the greatest benefits.]
- Expansion of the present site. [Limited space and prone to liquefaction.]
- Upsize of the old 33/11kV 5MVA transformer. [Would not provide reliability level desired.]

(d) **Cost and type**

Under $0.5M 2012/13, $2.5M - $5M 2014 to 2016, System Growth.

(e) **Goal / Strategy**

Achieve 100% regulatory compliance. Provide its customers with above average levels of service.

4.8.3.2 Distribution Automation

(a) **Description**

Additional remote control and monitoring will be added to Air Break Switches (ABS) to enable faulty sections to be quickly isolated and power restored to unaffected sections.

(b) **Issues**

Time required for field staff to travel to ABS's to operate them.

(c) **Options**

- Retrofit actuator to existing ABS's with a separate RTU.
- Replace with remotely controllable ABS's.

Communications to each site needed for both options.

(d) **Detail**

Installation of remote control and monitoring on distant switches.

Investigation of distribution automation (DA) systems, and self-healing network systems.

(e) **Cost and type**

Under $0.5M pa 2013 to 2020, Reliability / Safety.

(f) **Goal / Strategy**

Expand remote controllability of the distribution network.

4.8.3.3 Gore to Mataura upsize

(a) **Description**

Reconductor of the 33kV line between Gore GXP and Mataura substation.

(b) **Issues**

High losses due to medium conductor size.

(c) **Options**

- Reconductor to larger conductor. [Lowest cost option.]
- Upgrade to a higher voltage. [Expensive.]
- Construct a parallel 33kV line. [Expensive and difficult to get a new line route.]

(d) **Cost and type**

$0.5 - $2.5M 2015/16, Growth.

(e) **Goal / Strategy**

Strive to become an efficient and effective operation.

4.8.3.4 Gore Supply Transformers and Injection Plant upgrade

(a) **Description**

Upgrade the ripple injection plant due to network growth and Transpower changing the network impedance by adding a 220/110kV interconnection.

Transpower is likely to upgrade the 110/33kV supply transformers and may have some impact on TPCL's assets around Gore GXP.

(b) **Issues**

Existing plant overloaded.

Network electrical parameters changing.

(c) **Options**

- Replace with a higher rated plant. [Likely option as services provided are likely to continue into the near future.]
- Change to another methodology. (Radio)
- Stop providing this service. [Could be provided by Smart Meters if bulk replacement occurs.]

(d) **Details**

Final solution not defined with investigation of alternatives still to occur.

Estimate is assuming that the Injection Plant is upgraded.

(e) **Cost and type**

$0.5 - $2.5M 2014/15, Growth.

(f) **Goal / Strategy**

Strive to become an efficient and effective operation.

4.8.3.5 Township Undergrounding

(a) **Description**

Underground conversion of the 11kV and 400V lines in the townships. Mostly driven and funded by the local community.

(b) **Issues**

The aesthetics of the lines is poor.

District plan requirement that all new lines are underground.

(c) **Options**

- Underground the 11kV and 400V lines.
- Reroute lines away from the township.

(d) **Cost and type**

Under $0.5M pa 2014 to 2020, Safety, Environmental, Underground Conversion.

(e) **Goal / Strategy**

Undertake safety and environmental improvements.

4.8.3.6 Mataura Transformer Upgrade

(a) **Description**

Replacement of the two 33/11kV, 10MVA power transformers at Mataura substation.

(b) **Issues**

Possible load growth may exceed the firm capacity of the substation.

Age of the two power transformers is nearing expected life with mechanical components likely to start to become unreliable.

Limited space at Mataura substation.

(c) **Options**

- Replace the two power transformers with 33/11kV, 6/12MVA units. [Limited extra capacity.]
- Replace the two power transformers with 33/11kV, 11½/23MVA units. [Planned option that will provide good future capacity.]
- Major refurbishment of the two units with fitting of pumps, fans, and monitoring to enable the units to operate at 12MVA or higher. [Limited life of paper in existing units that would be consumed quicker if ran at higher temperatures.]

(d) **Detail**

Replace the two transformers with 33/11kV 11½/23MVA units.

Redo the transformer pads to provide fire protection or blocking between the units.

Change 11kV to cable connection to provide better clearances.

(e) **Cost and type**

$0.5 - $2.5M pa 2015/16, Growth.

(f) **Goal / Strategy**

Replace critical assets near to their technical end-of-life.

4.8.3.7 Edendale Supply Transformers and Injection Plant Upgrade

(a) **Description**

Load growth at Fonterra is likely to require an upgrade at Edendale but will be driven by Fonterra.

Should an upgrade occur, the Edendale Injection Plant may need to be upgraded.

(b) **Issues**

Possible load growth may exceed the firm capacity of the substation.

(c) **Options**

- Replace the two power transformers with 33/11kV, 18/36MVA units. [Limited capacity of 33kV Cables and 11kV equipment.]
- Add third 33/11kV, 11½/23MVA power transformer. [Planned option that will provide good future capacity and allows a separate site to be used to get diversity.]
- Supersede the Ripple Injection system with Smart Meters. [Is a possibility and should have an idea if occurring by this year.]

(d) **Detail**

Add third 33/11kV 11½/23MVA transformer on Fonterra site, supplied by a new 33kV cable.

Upgrade the Ripple Injection plant to provide sufficient injection to provide reliable operation of existing ripple receivers.

(e) **Cost and type**

$0.5 - $2.5M pa 2016/17, Growth.

(f) **Goal / Strategy**

Provide its customers with above average levels of service.

4.8.4 Considered projects

[Addresses handbook requirement 4.5.5(g)(iii)]

Expected projects for year six to ten (YE 31 March 2018 to 2022) are as follows. These projects have little if any certainty.

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

4.8.4.1 North Makarewa Supply Transformers and Injection Plant Upgrade

Load growth is likely to require an upgrade at North Makarewa. The suggested upgrade would add one or two 220/66kV supply transformers.

Should an upgrade occur, the Injection Plant may need to be upgraded.

4.8.5 Contingent projects

The following projects are contingent on uncertain events. These have been excluded from TPCL's spend plans until they become certain.

4.8.5.1 Mataura Valley Milk

Possible additional Milk Powder plant at the old saleyards site in McNab. Will require a new substation and reinforcement of the 33kV network.

4.8.5.2 Additional Milk Processing

Possible additional Milk Processing plants at existing or new sites.

4.8.5.3 Solid Energy Briquette Plant

Possible production of Lignite Briquettes in the Mataura area. Depending on the location, may require a new substation and subtransmission lines to supply or a step increase in capacity at an existing substation.

4.8.5.4 Third 33kV Line to Awarua

If major industries develop plants at Awarua that require extra capacity or reliability a third 33kV Heavy line may be built from Invercargill.

4.8.5.5 Coal to Liquid Plants

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

4.8.5.6 Mines

Possible mineral extraction with power required to operate the mine and/or process the material. Possible resources include coal, lignite, silicon, gold, platinum…

4.8.5.7 Oil Refineries

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

4.8.6 Proposed network configuration

The 2021 proposed network configuration is shown in figure 51.

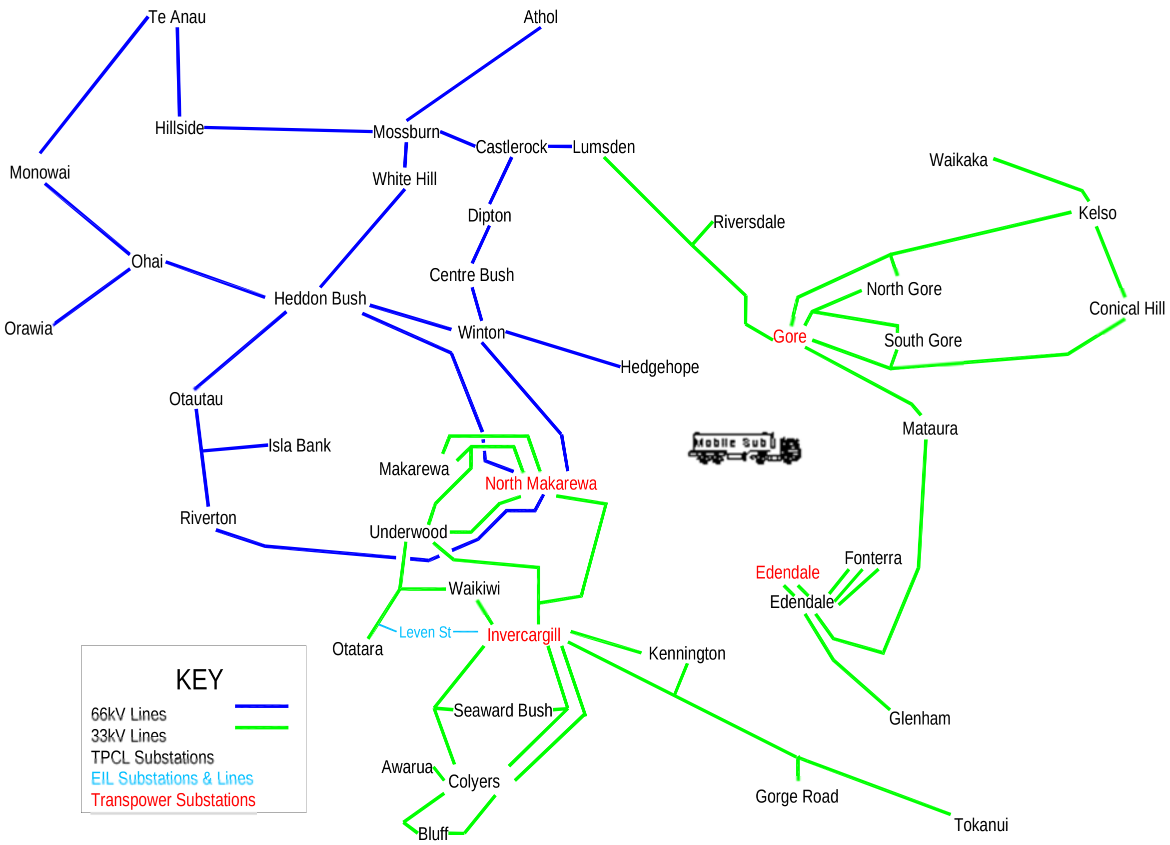


Figure 51 2022 proposed network configuration

4.8.7 Capital Budget

[Addresses handbook requirement 4.5.9(a)]

The estimated capital budget for TPCL is given below in Figure 52. Note the actual cost of some projects are not shown so as not to compromise the contractors' estimating and tendering processes.

CAPEX: System Growth	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Supply Quality Upgrades	230,000	230,000	230,000	230,000	230,000	230,000	230,000	230,000	230,000	230,000
New Hedgehope Substation	[redacted]	-	-	-	-	-	-	-	-	-
New Athol Substation	[redacted]	-	-	-	-	-	-	-	-	-
New 66/22kV line Mossburn to Athol	[redacted]	-	-	-	-	-	-	-	-	-
New Isla Bank Substation	[redacted]	[redacted]	-	-	-	-	-	-	-	-
New Fairfax to Isla Bank 66kV Line	[redacted]	[redacted]	-	-	-	-	-	-	-	-
Awarua 2 Substation	[redacted]	-	[redacted]	[redacted]	-	-	-	-	-	-
Waikiwi Substation Upgrade	[redacted]	[redacted]	-	-	-	-	-	-	-	-
Kennington Sub Feeders and 2nd TX	[redacted]	-	-	-	-	-	-	-	-	-
Monowai 66/11KV TX	[redacted]	-	-	-	-	-	-	-	-	-
OVP-Design	[redacted]	-	-	-	-	-	-	-	-	-
OVP-Winton to Centre Bush	[redacted]	[redacted]	-	-	-	-	-	-	-	-
OVP-Centre Bush to Mossburn	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-
OVP-New Castlerock 66/33kV Sub	-	-	-	[redacted]	[redacted]	-	-	-	-	-
OVP-Dipton Sub Upgrade	-	-	[redacted]	[redacted]	-	-	-	-	-	-
OVP-Centre Bush Sub Upgrade	-	[redacted]	[redacted]	-	-	-	-	-	-	-
OVP-Lumsden Sub Upgrade	-	-	[redacted]	[redacted]	-	-	-	-	-	-
Riversdale Sub Upgrade	[redacted]	[redacted]	-	-	-	-	-	-	-	-
Distribution Automation	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TPNZ Gore 110/33kV TX Upgrade	-	-	[redacted]	-	-	-	-	-	-	-
Gore Injection Plant Upgrade	-	-	[redacted]	-	-	-	-	-	-	-
Gore to Mataura Reconductor	-	-	-	[redacted]	-	-	-	-	-	-
Mataura Transformer Upgrade	-	-	-	-	[redacted]	-	-	-	-	-
TPNZ Edendale 110/33kV TX Upgrade	-	-	-	-	[redacted]	-	-	-	-	-
Edendale Injection Plant Upgrade	-	-	-	-	[redacted]	-	-	-	-	-
Edendale Substation Upgrade	-	-	-	-	[redacted]	-	-	-	-	-
New 33kV to Awarua	-	-	-	-	-	-	[redacted]	-	-	-
TPNZ North Makarewa 220/66kV TX	-	-	-	-	-	-	-	-	[redacted]	[redacted]
Unspecified Projects	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9,180,450	**5,870,290**	**5,787,720**	**5,593,140**	**4,719,600**	**3,680,000**	**3,680,000**	**3,680,000**	**3,680,000**	**3,680,000**

CAPEX: Customer Connection	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Customer Connections	2,530,000	2,530,000	2,530,000	2,530,000	2,530,000	2,530,000	2,530,000	2,530,000	2,530,000	2,530,000
Distributed Generation Connection	17,250	17,250	17,250	17,250	17,250	17,250	17,250	17,250	17,250	17,250
New Subdivisions	575,000	345,000	575,000	345,000	345,000	575,000	345,000	345,000	575,000	575,000
	3,122,250	**2,892,250**	**3,122,250**	**2,892,250**	**2,892,250**	**3,122,250**	**2,892,250**	**2,892,250**	**3,122,250**	**3,122,250**

CAPEX: Replacement and Renewal	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
General Distribution Replacement-PSL	627,147	632,500	632,500	632,500	632,500	862,500	862,500	862,500	862,500	862,500
General Distribution Replacement-OPSL	328,943	333,500	333,500	333,500	333,500	333,500	333,500	333,500	333,500	333,500
General Technical Replacement	116,898	212,750	212,750	212,750	212,750	212,750	212,750	212,750	212,750	212,750
Transformer Replacement - PSL	966,000	966,000	966,000	966,000	966,000	966,000	966,000	966,000	966,000	966,000
Transformer Replacement - OPSL	483,000	483,000	483,000	483,000	483,000	483,000	483,000	483,000	483,000	483,000
11 kV Line Replacement - PSL	1,840,000	2,300,000	2,645,000	2,645,000	2,645,000	2,645,000	2,645,000	2,645,000	2,645,000	2,645,000
11 kV Line Replacement - OPSL	918,850	1,150,000	1,380,000	1,380,000	1,380,000	1,380,000	1,380,000	1,380,000	1,380,000	1,380,000
Subtransmission Lines Replacement - PSL	-	57,500	57,500	57,500	57,500	57,500	57,500	57,500	57,500	57,500
Subtransmission Lines Replacement - OPSL	690,000	57,500	57,500	57,500	57,500	57,500	57,500	57,500	57,500	57,500
Zone Substation Minor Replacement	130,732	69,000	69,000	69,000	69,000	69,000	69,000	69,000	69,000	69,000
RTU Replacements	-	172,500	172,500	172,500	172,500	172,500	172,500	172,500	172,500	172,500
Regulators Replacements	-	161,000	-	161,000	-	161,000	-	161,000	-	-
Relay Replacements	-	-	28,750	28,750	28,750	28,750	28,750	28,750	28,750	28,750
Communications Replacements	-	230,000	230,000	-	-	-	-	-	-	-
Kelso RTU, Oil, CB's replacement	[redacted]	-	-	-	-	-	-	-	-	-
South Gore switchboard replacement	[redacted]	-	-	-	-	-	-	-	-	-
Underwood Switchboard replacement	[redacted]	-	-	-	-	-	-	-	-	-
Riversdale to Lumsden 33kV Replacement	-	-	[redacted]	[redacted]	-	-	-	-	-	-
Winton switchboard replacement	[redacted]	[redacted]	-	-	-	-	-	-	-	-
Riverton Switchboard Replacement	[redacted]	[redacted]	-	-	-	-	-	-	-	-
Seaward Bush Transformer replacement	-	-	-	-	-	[redacted]	-	-	-	-
Counsel Rd Nth - Winton 66kV Replacement	-	-	[redacted]	-	-	-	-	-	-	-
Invercargill Injection Plant Replacement	-	-	-	[redacted]	-	-	-	-	-	-
Counsel Rd Sth - Ingill 33kV Replacement	-	-	-	[redacted]	-	-	-	-	-	-
Gore to Riversdale 33kV Line Replacement	-	-	-	[redacted]	[redacted]	-	-	-	-	-
North Makarewa Inj Plant Replacement	-	-	-	-	[redacted]	-	-	-	-	-
Hillside to Te Anau 66kV Replacement	-	-	-	-	[redacted]	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	7,912,819	**7,636,000**	**9,913,000**	**10,447,750**	**9,499,000**	**9,154,000**	**8,993,000**	**9,154,000**	**8,993,000**	**8,993,000**

CAPEX: Reliability, Safety, Environment	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Earth Upgrades	549,145	517,500	460,000	345,000	230,000	115,000	115,000	115,000	115,000	115,000
NER Installation at Substations	-	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-
Field Reclosers	-	[redacted]	-	[redacted]	-	[redacted]	-	[redacted]	-	[redacted]
Township Undergrounding	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mobile Substation	[redacted]	[redacted]	-	-	-	-	-	-	-	-
Seismic Remedial Work	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
Network Improvement Projects	198,605	115,000	115,000	115,000	115,000	115,000	115,000	115,000	115,000	115,000
	862,750	**2,806,000**	**1,265,000**	**1,138,500**	**977,500**	**563,500**	**517,500**	**563,500**	**517,500**	**563,500**

CAPEX: Asset Relocation	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Line Relocations	86,250	86,250	86,250	86,250	86,250	86,250	86,250	86,250	86,250	86,250
	86,250	**86,250**	**86,250**	**86,250**	**86,250**	**86,250**	**86,250**	**86,250**	**86,250**	**86,250**

CAPEX Grand Total	**21,164,518**	**19,290,790**	**20,174,220**	**20,157,890**	**18,174,600**	**16,606,000**	**16,169,000**	**16,376,000**	**16,399,000**	**16,445,000**

Figure 52 - Capital Budget

5. Managing the assets' lifecycle

All physical assets have a lifecycle. This section describes how TPCL manages assets over their entire lifecycle from "commissioning" to "retirement".

5.1 Lifecycle of the assets

The lifecycle of TPCL's existing assets is outlined in Figure 53 below:

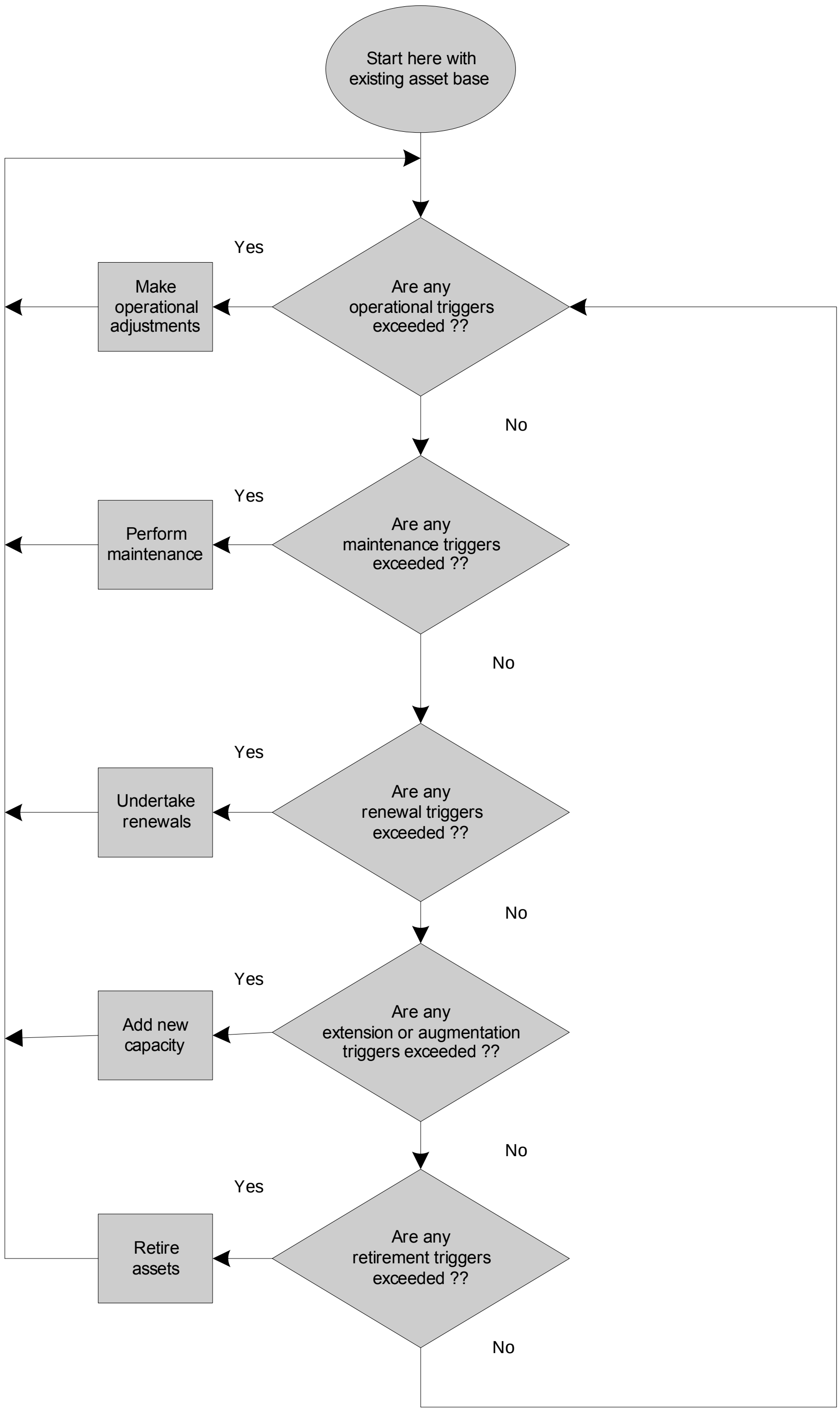


Figure 53 - Asset lifecycle

Table 19 below provides some definitions for key lifecycle activities:

Table 19 – Definition of key lifecycle activities

Activity	Detailed definition
Operations	Involves altering the operating parameters of an asset such as closing a switch or altering a voltage setting. Doesn't involve any physical change to the asset, simply a change to the asset's configuration that it was designed for. In the case of electrical assets it will often involve doing nothing and just letting the electricity flow.
Maintenance	Involves replacing consumable components like the seals in a pump, the oil in a transformer or the contacts in a circuit breaker. Generally these components will be designed to wear out many times over the asset's design lifecycle and continued operation of the asset will require such replacement. There may be a significant asymmetry associated with consumables such as lubricants in that replacing a lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the asset's life.
Renewal	Generally involves replacing a non-consumable item like the housing of a pump with a replacement item of identical functionality (usually capacity). Such replacement is generally regarded as a significant mile-stone in the life of the asset and may significantly extend the life of the asset (a bit like "Grandpa's axe"). Renewal tends to dominate the Capital expenditure in low growth areas (Quadrant 1 of Figure 38) because assets will generally wear out before they become too small. The most typical criteria for renewal will be when the capitalised costs of operation and maintenance exceed the cost of renewal. A key issue with renewal is technological advances that generally make it impossible to replace assets such as SCADA with equivalent functionality.
Up-sizing	Generally involves replacing a non-consumable item like a conductor, busbar or transformer with a similar item of greater capacity but which does not increase the network footprint i.e. restricted to Quadrants 1 and 2 in Figure 38.
Extensions	Involves building a new asset where none previously existed because a location trigger in Table 13 has been exceeded e.g. building several spans of line to connect a new factory to an existing line. This activity falls within Quadrants 3 and 4 of Figure 38. Notwithstanding any surplus capacity in upstream assets, extensions will ultimately require up-sizing of upstream assets.
Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement will be when an asset is no longer required, creates an unacceptable risk exposure or when its costs exceed its revenue.

5.2 Operating TPCL's assets

As outlined in Table 19 operations predominantly involves doing nothing and simply letting the electricity flow from the GXP's to customers' 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). As outlined in Figure 53 the first efforts to relieve excursions beyond trigger points are operational activities with typical activities listed in Table 20.

Table 20 Typical responses to operational triggers

Asset class	Trigger event	Response to event	Approach
GXP	Voltage is too high or low on 33kV or 11kV.	Automatic operation of tap changer.	Reactive

	Demand exceeds allocated Transpower limit.	Activate ripple injection plant to switch off load control relays.	Reactive
		Move Zone Substations between GXP's to relieve load from highly loaded GXP.	Reactive
	Transition from day to night.	Activate ripple injection plant to switch street lights on or off.	Proactive
	On-set of off-peak tariff periods.	Activate ripple injection plant to switch controlled loads on or off.	Proactive
Zone substation transformers	Voltage is too high or low on 11kV.	Automatic operation of tap changer.	Reactive
	Demand exceeds rating.	Move tie points to relieve load from zone sub.	Reactive
Distribution reclosers	Fault current exceeds threshold.	Automatic operation of recloser.	Reactive
Distribution ABS's	Component current rating exceeded.	Open & close ABS's to shift load.	Proactive or reactive
	Fault has occurred.	Open & close ABS's to restore supply.	Reactive
Distribution transformers	Voltage is too high or low on LV.	Manually raise or lower tap where fitted.	Reactive
	Fuses keep blowing.	Shift load to other transformers by cutting and reconnecting LV jumpers.	Reactive
LV distribution	Voltage is too low at customers' board.	Supply from closer transformer if possibly by cutting and reconnecting LV jumpers.	Reactive

Table 21 outlines the key operational triggers for each class of TPCL's assets. Note that whilst temperature triggers will usually follow demand triggers, they may not always e.g. an overhead conductor joint might get hot because it is loose or rusty rather than overloaded.

Table 21 - Operational triggers

Asset category	Voltage trigger	Demand trigger	Temperature trigger
LV lines and cables	Voltage routinely drops too low to maintain at least 0.94pu at customers switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at customers switchboards.	Customers' pole or pillar fuse blows repeatedly.	Infra-red survey reveals hot joint.
Distribution substations	Voltage routinely drops too low to maintain at least 0.94pu at customers switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at customers switchboards.	Load routinely exceeds rating where MDI's are fitted. LV fuse blows repeatedly. Short term loading exceeds guidelines in IEC 354.	Infra-red survey reveals hot connections.
Distribution lines and cables		Alarm from SCADA that current has exceeded a set point.	Infra-red survey reveals hot joint.

Asset category	Voltage trigger	Demand trigger	Temperature trigger
Zone substations	Voltage drops below level at which OLTC can automatically raise or lower taps.	Load exceeds guidelines in IEC 354.	Top oil temperature exceeds manufacturers' recommendations. Core hot-spot temperature exceeds manufacturers' recommendations.
Subtransmission lines and cables	Alarm from SCADA that voltage is outside of allowable set points.	Alarm from SCADA that current is over allowable set point.	Infra-red survey reveals hot joint.
TPCL equipment within GXP	Alarm from SCADA that voltage is outside of allowable set points.	Alarm from SCADA that current is over allowable set point.	Infra-red survey reveals hot joint.

5.3 Maintaining TPCL's assets

[Addresses handbook requirement 4.5.6(a)]

As described in Table 19 maintenance is primarily about replacing consumable components. 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 wearing of pump seals. Continued operation of such components will eventually lead to failure as indicated in Figure 54 below. Failure of such components is usually based on physical characteristics and 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 54 is not simply labelled "time".

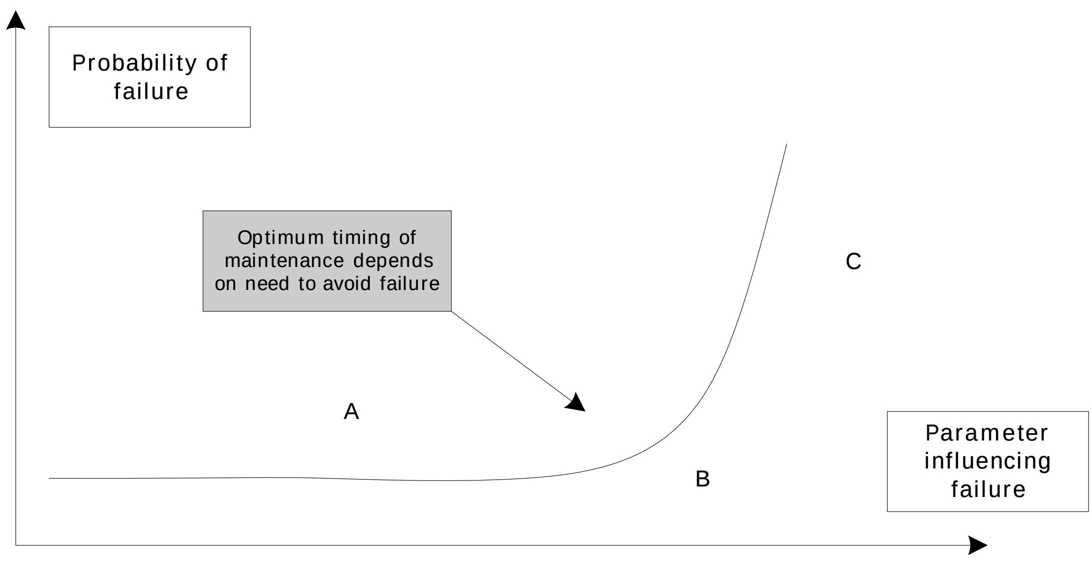


Figure 54 - Component failure

Exactly when maintenance is performed will be determined by the need to avoid failure. For instance the need to avoid failure of a 10kVA transformer supplying a single customer is low; hence it might be operated out to point C in Figure 54 whilst a 66/11kV substation transformer may only be operated to point B due to a higher need to avoid failure. In the extreme case of, say, a transformer supplying a critical process plant or facility, it would be desirable to avoid even the slightest probability of failure hence the supply transformer may only be operated to point A. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the asset's lifecycle along with the cost of discarding unused component life.

Like all TPCL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoiding supply interruption. The practical effect of this is that assets supplying large customers or numbers of customers will be extensively condition monitored to avoid supply interruption whilst assets supplying only a few customers such as a 10kVA transformer will more than likely be run to breakdown. The maintenance strategy map in Figure 55 broadly identifies the maintenance strategy adopted for various ratios of costs and benefits.

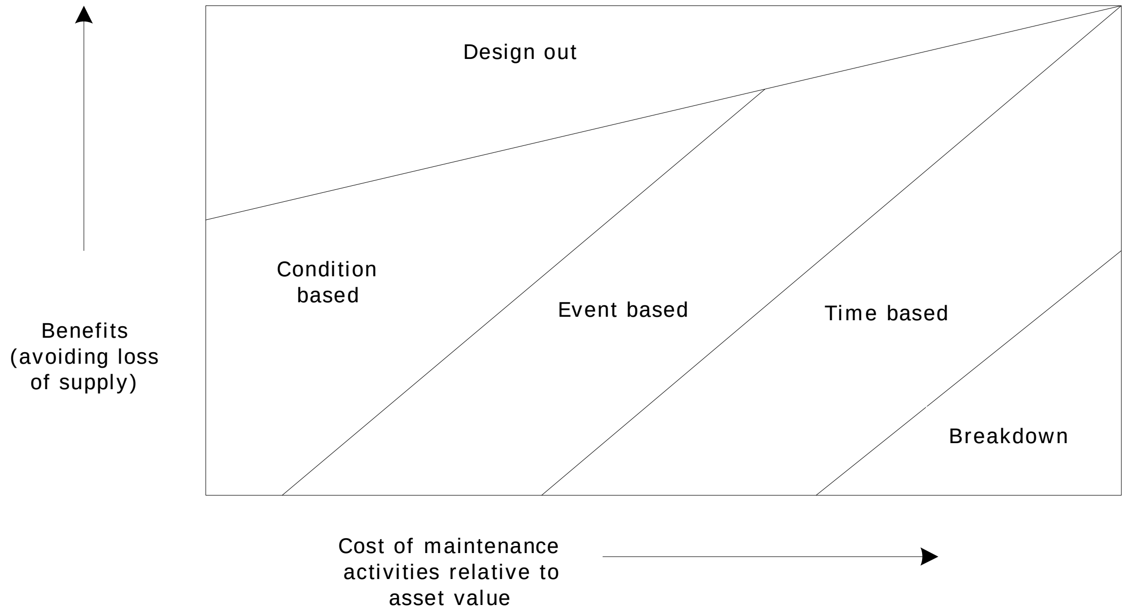


Figure 55 - Maintenance strategy map

This map indicates that where the benefits are low (principally there is little need to avoid loss of supply) and the costs of maintenance are relatively high, an asset should be run to breakdown. 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 DGA[37] for transformer oil).

Component condition is the key trigger for maintenance; however the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 22 describes the maintenance triggers adopted:

Table 22 - Maintenance triggers

Asset category	Components	Maintenance trigger
LV lines and cables • Five yearly inspection • Ten yearly scan of wooden poles	Poles, arms, stays and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Pins, insulators and binders	• Obviously loose pins. • Visibly chipped or broken insulators. • Visibly loose binder.
	Conductor	• Visibly splaying or broken conductor.

[37] DGA = Dissolved Gas Analysis, where the type and quantity of gas dissolved in the oil is measured. This usually gives an early indication of failure.

Asset category	Components	Maintenance trigger
Distribution substations • Five yearly inspection • Six monthly for sites >150kVA	Poles, arms and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Enclosures	• Visible rust. • Cracked or broken masonry.
	Transformer	• Excessive oil acidity (500kVA or greater). • Visible signs of oil leaks. • Excessive moisture in breather. • Visibly chipped or broken bushings.
	Switches and fuses	• Visible rust. • Oil colour. • Visible signs of oil leak.
Distribution lines and cables • Five yearly inspection • Ten yearly scan of wooden poles	Poles, arms, stays and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Pins, insulators and binders	• Loose tie wire. • Chipped or cracked insulator.
	Conductor	• Loose or pitted strands. • Visible rust.
	Ground-mounted switches	• Visible rust. • Oil colour. • Visible signs of oil leak.
	Regulators	• Visible rust. • Oil colour. • Visible signs of oil leak. • Excessive moisture in breather. • High Dissolved Gas Analysis results.
Zone substations • Monthly checks	Fences and enclosures	• Weeds. • Visible rust. • Gaps in fence.
	Buildings	• Flaking paint. • Timber rot. • Cracked or broken masonry.
	Bus work and conductors	• Hot spot detected by Infrared detector. • Corrosion of metal or fittings.
	33kV switchgear	• Visible rust. • Operational count exceeded. • Low oil breakdown.
	Transformer	• Visible rust. • High Dissolved Gas Analysis results (Annual test). • Low oil breakdown. • High oil acidity.
	11kV switchgear	• Visible rust. • Operational count exceeded. • Low oil breakdown.
	Instrumentation/protection • Electromechanical three yearly • Electronic five yearly	• Maintenance period exceeded. • Possible mal-operation of device.
	Batteries • Six monthly test	• Discharge test or Impedance test.
Substation-transmission lines and cables • Five yearly inspection • Ten yearly scan of wooden poles	Poles, arms, stays and bolts	• Evidence of dry-rot. • Loose bolts, moving stays. • Displaced arms.
	Pins, insulators and binders	• Loose tie wire. • Chipped or cracked insulator.
	Conductor	• Loose or pitted strands. • Visible rust.
	Cable • Annual check	• High Partial discharge detected. • Sheath insulation short. • Oil pressure declining.
Our equipment within GXP • Monthly check	Injection plant	• Alarm from failure ripple generation. • Period exceed for checks.

Typical maintenance policy responses to these trigger points are described in Table 23.

Table 23 Typical responses to maintenance triggers

Asset class	Trigger point	Response to trigger	Approach
Subtransmission lines	Loose or displaced components	Tighten or replace	Condition as revealed by annual inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by annual inspection or ten yearly scan
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by annual inspection
GXP and zone substation transformers	Oil acidity	Filter oil	Condition as revealed by annual test
	Excessive moisture in breather	Filter oil	Condition as revealed by monthly inspection
	Weighted number of through faults	Filter oil, possibly de-tank and refurbish	Event driven
	General condition of external components	Repair or replace as required	Condition as revealed by monthly inspection
Distribution lines	Loose or displaced components	Tighten or replace	Condition as revealed by five yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by five yearly inspection or ten yearly scan
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by five yearly inspection
Distribution reclosers	Weighted number of light and heavy faults	Repair or replace contacts, filter oil if applicable	Event driven
Distribution ABS's	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by five yearly inspection
	Seized or tight	Lubricate or replace components as required	Breakdown
Distribution transformers	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by five yearly inspection
	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by five yearly inspection
	Oil acidity	Filter oil	Remove from service for full overhaul every 15 years
	Excessive moisture in breather where fitted	Filter oil	Condition as revealed by three yearly inspection
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by five yearly inspection
	Chipped or broken bushings	Replace	Breakdown or condition as revealed by five yearly inspection
LV lines	Loose or displaced components	Tighten or replace	Breakdown unless revealed by five yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Five yearly inspection or ten yearly scan

Asset class	Trigger point	Response to trigger	Approach
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by five yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by five yearly inspection

The frequency and nature of the response to each of the above triggers are embodied in TPCL's policies and work plans.

5.3.1.1 Systemic faults

Analysis of incidents over the last year has been done, with the resulting map shown in Figure 59. From this analysis no additional concerns have been highlighted.

Examples of past investigations and outcomes:

- 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
- Snow loading leading to cascade failure of pre-stressed poles: Installation of stayed poles to limit extent of cascade.

5.3.2 Inspection, monitoring and routine maintenance

[Addresses handbook requirement 4.5.6(b)]

Each maintenance trigger has a related inspection period listed in Table 22. i.e. Zone substations are checked each month.

Monitoring of assets includes the following areas:

- Protection relay testing / checks.
- Earthing checks.
- DGA of transformer oil.
- Partial discharge and Infrared survey of substations and major distribution equipment.
- Injection plant tuning checks.
- Supply quality checks.
- Line surveys and testing.

The on-going maintenance of assets is also covered by this budget. Items covered include:

- Lubrication of ABS's.
- Cleaning of air insulated switchgear.
- Battery replacements.
- Rust repairs and painting.
- TCOL and CB service.
- Minor customer connections.

Two extra tasks are planned for the coming year:

- Spares checks: What do we have and what is its condition?
- Seismic checks: Will our substations continue to operate after likely earthquakes?

OPEX on this is budgeted at $2.7 to $2.8 million per annum.

5.3.3 Fault restoration and repairs

Fault and emergency maintenance provides for the provision of staff, plant and resources to be ready for faults and/or emergencies. This resource attends and makes the area safe, then may isolate the faulty section so other customers are restored or undertake quick repairs to restore supply to all customers.

OPEX on this is budgeted at $2.4 million per annum.

5.3.4 Tree trimming

Electricity (Hazards from Trees) Regulations 2003, put the requirement on TPCL to undertake the first trim of trees free, and this budget is the on-going actioning of this. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation.

OPEX on this is budgeted at $1.2 million for 2012/13 and reducing after this.

5.4 TPCL's maintenance policies

[Addresses handbook requirement 4.5.6(c)]

TPCL's maintenance policies are embodied in the PowerNet standards PNM-99, PNM-105 and PNM-97 which broadly follow manufacturers' recommendations but tend to be modified by industry experience.

5.5 Renewing TPCL's assets

[Addresses handbook requirement 4.5.6(d) and (e)]

Work is classified as renewal if there is no change (and such change would usually be an increase) in functionality i.e. the output of any asset doesn't change. TPCL's key criterion for renewing an asset is when the capitalised operations and maintenance costs exceed the renewal cost and this can occur in a number of ways:

- Operating costs become excessive e.g. addition of inputs to a SCADA system requires an increasing level of manning.
- Maintenance costs begin to accelerate away e.g. a transformer needs more frequent oil changes as the seals and gaskets perish.
- Supply interruptions due to component failure become excessive; what constitutes "excessive" will be a matter of judgment which will include the number and nature of customers affected.
- Renewal costs decline, particular where costs of new technologies for assets like SCADA decrease by several fold.

Table 24 below lists TPCL's renewal triggers for key asset classes.

Table 24 – Renewal triggers

Asset category	Components	Renewal trigger
LV lines and cables	Poles	• Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Done with pole renewal.
	Conductor	• Excessive failures. • Multiple joints in a segment.
Distribution substations	Poles	• Failure due to pole test. • Failure due to external force.
	Enclosures	• Uneconomic to maintain.
	Transformer	• Excessive rust. • Old technology, pre-1970 core. • Not economical to maintain.
	Switches and fuses	• Not economical to maintain.
Distribution lines and cables	Poles	• Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Done with pole renewal.
	Conductor	• Excessive failures. • Multiple joints in a segment.
	Ground-mounted switches	• Not economical to maintain. • No source of spare parts. • If not able to be remote controlled.

Asset category	Components	Renewal trigger
	Regulators	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
Zone substations	Fences and enclosures	• Not economical to maintain.
	Buildings	• Not economical to maintain.
	Bus work and conductors	• Not economical to maintain.
	33kV switchgear	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Transformer	• Not economical to maintain. • No spare parts. • Greater than 1.2 Standard Life and maintenance required.
	11kV switchgear	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Bus work and conductors	• Not economical to maintain.
	Instrumentation/Protection	• Not economical to maintain. • No spare parts. • Greater than Standard Life and maintenance required.
	Batteries	• Prior to manufacturers' stated life. • On failure of testing.
Subtransmission lines and cables	Poles	• Not economical to maintain. • Fails pole test. • Failure due to external force.
	Pins, insulators and binders	• Not economical to maintain.
	Conductor	• Not economical to maintain. • Excessive joints in a segment
	Cables	• Not economical to maintain.
Our equipment within GXP		• Not economical to maintain.

Broad polices for renewing all classes of assets are:

- When an asset is likely to create an operational or public safety hazard.
- When the capitalised operations and maintenance costs exceed the likely renewal costs.
- When continued maintenance is unlikely to result in the required service levels.
-

5.5.1 Current Renewal projects

[Addresses handbook requirement 4.5.6(d)(i)]

Renewal projects planned to year end 31 March 2013.

5.5.1.1 General replacement

This covers the on-going operation of the network and covers the following items / areas:

- Red tagged pole replacement
- Increasing road crossing height
- Minor distribution renewals and upgrades.

Cost: $0.8M - $1.0M per annum, CAPEX Renewals.

5.5.1.2 Transformer replacement

On-going renewals of distribution transformers. Most are identified during distribution inspections with projects grouping like work in an area.

Some removed units are refurbished.

Cost: $1.3M per annum, CAPEX Renewals.

5.5.1.3 Line replacement

Work discovered during previous years inspections are combined by feeders into projects. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's. Distribution transformers are covered by the previous item.

Cost: $2.4M - $3.5M per annum, CAPEX Renewals.

5.5.1.4 Subtransmission Line replacement

Work discovered during previous years inspections are combined by circuits into projects. Allows for renewal of equipment and minor upgrades.

Under $0.6M per annum, CAPEX Renewals.

5.5.1.5 Zone Substation replacement

Work discovered during previous years inspections are combined by sites into projects. Allows for renewal of equipment and minor upgrades.

Cost: Under $0.3M per annum, CAPEX Renewals.

5.5.1.6 Kelso Substation Renewal

A combined project at Kelso that will undertake renewal of the GPT RTU and the Brush PMR circuit breakers. Oil interception system and earthquake reinforcement of the site equipment will be undertaken under this project. The main works are scheduled for 2012/13, with design work occurred in 2011/12.

Cost: Under $0.5M 2012/13, CAPEX Renewals.

5.5.1.7 Switchboard Renewals

The 11kV switchboards at South Gore (2012/13), Underwood (2012/13), Winton (2012/13) and Riverton (2013/14) reach the standard ODV life of 45 years. Due to the impact that failure of these would do to service levels and the strategy of "Replace critical assets near to their technical end-of-life" these units are programmed for renewal / replacement.

Options considered included:

- Retrofit existing circuit breaker trucks with modern units.
    - Does not renew other fittings on switchboard, e.g. bus supports, metalwork, current transformers, bushings, cable terminations.
    - Very little interruption to implement.
    - Lower cost.
- Replace the board with modern 11kV switchboard.
    - Renews all parts of switchboard with modern protection and control.
    - Requires substantial outage of the switchboard.
    - Higher cost.
- Do nothing and wait until switchboard fails.
    - May not be able to repair when fails.
    - Failure could destroy or damage whole switchboard.
- Mass install individual generation so no need for network.
    - Not economic as no reticulated fuel. (H_2, LPG, CNG)

The selected solution is to replace the whole switchboard with modern units.

Initial design and planning work is programmed for the year prior to installation.

Cost: $0.5M - $1.5M per site, CAPEX Renewals.

5.5.1.8 Distribution refurbishment

A budget to allow refurbishment works that doesn't impact on the valuation of the distribution asset. This covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

Cost: $0.6M per annum, OPEX Renewals.

5.5.1.9 Subtransmission refurbishment

A budget to allow refurbishment works that doesn't impact on the valuation of the subtransmission assets. This covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

Cost: $0.14M per annum, OPEX Renewals.

5.5.1.10 Substation refurbishment

A budget to allow refurbishment works that doesn't impact on the valuation of the substation assets. This covers items like power transformer, earth sticks, safety equipment, buildings, battery systems etc.

Cost: $0.3M per annum, OPEX Renewals.

5.5.1.11 Transformer refurbishment

A budget to allow refurbishment works that doesn't impact on the valuation of the distribution assets.

Cost: Under $0.1M per annum, OPEX Renewals.

5.5.2 Planned renewal projects

[Addresses handbook requirement 4.5.6(d)(ii)]

Project planned for year two to five, YE 2014 to YE 2018.

5.5.2.1 SCADA RTU replacements

This project will replace an average of two sites each year. Beginning with the GPT RTU's then the Harris RTU's. Some substation projects will include the RTU replacement and costs included. i.e. Kelso and switchboard replacement projects.

This was chosen as the present units are becoming unreliable and full remote operation is required to meet the service levels. Rate of renewal could be increased if unreliability reaches unacceptable levels.

Cost: Under $0.25M per annum from 2013/14, CAPEX Renewals.

5.5.2.2 Communications replacements

This project will replace an average of four links each year. Beginning with the EX7100 units that are having reliability issues. Rate of renewal could be increased if unreliability reaches unacceptable levels.

Cost: Under $0.25M per annum from 2013/14, CAPEX Renewals.

5.5.2.3 Regulators replacements

Age and condition based assessment of regulators highlights that certain units need replacement. This programme allows for approximately one site to be renewed every two years.

Cost: Under $0.25M bi-annually from 2013/14, CAPEX Renewals.

5.5.2.4 Relays replacements

On-going testing and fault investigation sometimes highlight protection and control relays that are not performing as desired; this programme allows renewal of these with modern protection and control relays. (Includes Voltage Regulating Relays)

Some replacements will occur with other replacement projects, i.e. Kelso and replacement switchboard projects.

Cost: Under $0.5M per annum from 2014/15, CAPEX Renewals.

5.5.2.5 Riversdale to Lumsden 33kV replacement

The 33kV line from Riversdale to Lumsden will reach its Standard Life in 2010 and limitations exist in transporting power though this line. Consideration was given to upgrading this line to 66kV but the need for this capacity is not expected until after 2016. Initial works will consider the condition of each pole and replace if the expected life is less than five years or the strength of the pole is not sufficient for upsizing to neon conductor. Neon AAAC[38] is selected to match the capacity of the Wolf ACSR[39] Riversdale to Gore 33kV section of this route.

Cost: $0.5 - $2.5M 2014 - 2016, CAPEX renewal.

5.5.2.6 North Makarewa to Winton replacement

The line is nearing its Standard Life and renewal is expected during 2014/15. Line was purchased from Transpower and full refurbishment or renewal of all components is desired to maintain service levels in Western and Northern Southland.

Cost: $0.5 - $2.5M 2014/15, CAPEX renewal.

5.5.2.7 Invercargill Injection Plant replacement

The injection plant at Invercargill will exceed its standard life and will likely begin to perform poorly, so replacement of the equipment is planned during 2015/16.

Cost: $0.5 - $2.5M 2015/16, CAPEX renewal.

5.5.2.8 North Makarewa to Invercargill renewal

The line is nearing its Standard Life and renewal is expected during 2015/16.

Cost: $0.5 - $2.5M 2015/16, CAPEX renewal.

5.5.2.9 Gore to Riversdale renewal

The 33kV line is nearing its Standard Life and renewal is expected during 2015 to 2017.

Cost: $0.5 - $2.5M 2015/16, $0.5 - $2.5M 2016/17, CAPEX renewal.

5.5.2.10 North Makarewa Injection Plant replacement

The injection plant at North Makarewa will exceed its standard life and will likely begin to perform poorly, so replacement of the equipment is planned during 2016/17.

Cost: $0.5 - $2.5M 2016/17, CAPEX renewal.

5.5.2.11 Hillside to Te Anau renewal

The 66kV line is nearing its Standard Life and renewal is expected during 2016/17.

Cost: $0.5 - $2.5M 2016/17, CAPEX renewal.

5.5.3 Future renewal projects

[Addresses handbook requirement 4.5.6(d)(iii)]

Projects planned for year five to ten, YE 2018 to YE 2022.

5.5.3.1 Seaward Bush Transformer

The two 33/11kV 10MVA power transformers at Seaward Bush are nearing their 'end-of-life' and additional refurbishments are not considered desirable due to insulation degradation, corrosion of main tank, corrosion of radiators and TCOL[40] mechanism wear. Due to the impact that failure of these would do to service levels and the strategy of "Replace critical assets near to their technical end-of-life", these units are programmed for replacement. The old units are planned to be retained until newer spares are obtained.

Cost: $0.5M - $2.5M 2017/18, CAPEX renewal.

[38] AAAC = All Aluminium Alloy Conductor

[39] ACSR = Aluminium Conductor Steel Reinforced.

[40] TCOL = Tap Change On-Load

5.5.4 Renewal/replacement budget

CAPEX renewals are budgeted in the capital budget, see section 4.8.7.

5.6 Up-sizing or extending TPCL's assets

If any of the capacity triggers in Table 13 are exceeded consideration is given to either up-sizing or extending TPCL's network. These two modes of investment are however, quite different as described in Table 25 below.

Table 25 - Distinguishing between up-sizing and extension

Characteristic	Up-sizing	Extension
Location	Within or close to existing network footprint (within a span or so).	Outside of existing network footprint (more than a couple of spans).
Load	Can involve supply to a new connection within the network footprint or increasing the capacity to an existing connection.	Almost always involves supply to a new connection.
Upstream reinforcement	Generally forms the focus of up-sizing.	May not be required unless upstream capacity is constrained.
Visible presence	Generally invisible.	Obviously visible.
Quadrant in Figure 38	Either 1 or 2 depending on rate of growth.	Either 3 or 4 depending on rate of growth.
Necessity	Possible to avoid if sufficient surplus capacity exists. Possible to avoid or defer using tactical approaches described in section 4.2.1.	Generally can't be avoided – a physical connection is required.
Impact on revenue	Difficult to attribute revenue from increased connection number or capacity to augmented components.	Generally results in direct contribution to revenue from the new connection at the end of the extension.
Impact on costs	Cost and timing can vary and be staged.	Likely to be significant and over a short time.
Impact on ODV	Could be anywhere from minimal to high.	Could be significant depending on length of extension and any consequent up-sizing required.
Impact on profit	Could be anywhere from minimal to high.	Could be minimal depending on level of customer contribution.
Means of cost recovery	Most likely to be spread across all customers as part of on-going line charges.	Could be recovered from customers connected to that extension by way of capital contribution.
Nature of work carried out	Replacement of components with greater capacity items.	Construction of new assets.

Despite the different nature of up-sizing and extension work, similar design and build principles are used as described in sections 5.6.1 and 5.6.2.

5.6.1 Designing new assets

TPCL uses a range of technical and engineering standards to achieve an optimal mix of the following outcomes:

- Meet likely demand growth for a reasonable time horizon including such issues as modularity and scalability.
- Minimise over-investment.
- Minimise risk of long-term stranding.
- Minimise corporate risk exposure commensurate with other goals.

- Maximise operational flexibility.
- Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with sensible environmental and public safety requirements.

Given the fairly simple nature of TPCL's network standardised designs are adopted for all asset classes with minor site-specific alterations. These designs, however, will embody the wisdom and experience of current standards, industry guidelines and manufacturers recommendations.

5.6.2 Building new assets

TPCL uses external contractors to augment or extend assets. As part of the building and commissioning process TPCL's information records will be "as-built" and all testing documented.

5.7 Enhancing reliability

Although enhancing reliability does not neatly fit into the life-cycle model, TPCL believes that enhancing reliability is strategically significant enough in reshaping the business platform to merit inclusion in the AMP. As described in Section 3.2.1 customers prefer to receive about the same reliability in return for paying about the same line charges, so it is acknowledged that there is no mandate to go improving reliability just because it can be improved, even if TPCL doesn't need to increase line charges to do it. However there are many factors that will lead to a decline in reliability over time:

- Tree re-growth.
- Declining asset condition (especially in coastal marine areas).
- Extensions to the network that increase its exposure to trees and weather.
- Increased customer numbers that increase the lost customer-minutes for a given fault.
- Installation of customer requested asset alterations that can reduce reliability (e.g. needing to lock out reclosers on feeders that have embedded generation).

TPCL believes it is necessary to offset these impacts in order to maintain reliability; hence a reliability enhancement program using an approach that embodies the following steps has been developed:

- Identifying the customer-minutes lost for each asset by cause.
- Identifying the scope and likely cost of reducing those lost customer-minutes.
- Estimating the likely reduction in lost customer-minutes if the work scope was to be implemented.
- Calculating the cost per customer-minute of each enhancement opportunity.
- Prioritising the enhancement opportunities from lowest cost to highest. TPCL expects the incremental cost of regaining lost customer-minutes will accelerate away at some point which will set an obvious limit to implementing opportunities.

5.8 Converting overhead to underground

Conversion of overhead lines to underground cable is also an activity that doesn't fit neatly within the asset life-cycle because it tends to be driven more by the need to beautify areas rather than for asset-related reasons (which doesn't really fit the renewal or up-sizing triggers). As such, conversion tends to rely on other utilities cost sharing or local communities funding the work.

5.9 Retiring of TPCL's assets

Retiring assets generally involves doing most or all of the following activities:

- De-energising the asset.
- Physically disconnecting it from other live assets.
- Curtailing the assets revenue stream.
- Removing it from the ODV.

- Either physical removal of the asset from location or abandoning in-situ (typically for underground cables).
- Disposal of the asset in an acceptable manner particularly if it contains SF_6, oil, lead or asbestos.

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.
- Where better options exist to create similar outcomes (e.g. replacing lubricated bearings with high-impact nylon bushes) and there are no suitable opportunities for re-deployment.
- Where an asset has been augmented and no suitable opportunities exist for re-deployment.

5.10 TPCL's Maintenance Budget

[Addresses handbook requirement 4.5.9(a)]

Estimated expenditure on maintaining the assets are given below. Target is maintaining the ratio of maintenance under 2% of the total network replacement cost. This budget covers both Operation and Maintenance areas.

OPEX: Routine and Preventative Maintenance	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Routine Dist Insp Check & Mtce - PSL	152,000	152,000	152,000	152,000	152,000	152,000	152,000	152,000	152,000	152,000
Routine Dist Insp Check & Mtce - OPSL	163,458	163,458	163,458	163,458	163,458	163,458	163,458	163,458	163,458	163,458
Minor Work Dist Insp Check & Mtce - PSL	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Minor Work Dist Insp Check & Mtce - OPSL	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000
Condition and Data Assessment	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
Pole Scanning - OPSL	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
Distribution Earthing Maintenance	337,000	337,000	337,000	337,000	337,000	337,000	337,000	337,000	337,000	337,000
Routine Tech Insp Check and Mtce - TSL	370,255	370,255	370,255	370,255	370,255	370,255	370,255	370,255	370,255	370,255
Routine Tech Insp Check and Mtce - PSL	61,800	61,800	61,800	61,800	61,800	61,800	61,800	61,800	61,800	61,800
Minor Work Tech Insp Check & Mtce - TSL	566,500	566,500	566,500	566,500	566,500	566,500	566,500	566,500	566,500	566,500
Minor Work Tech Insp Check & Mtce - PSL	103,000	103,000	103,000	103,000	103,000	103,000	103,000	103,000	103,000	103,000
Infrared Survey	0	0	0	0	0	0	0	0	0	0
Partial Discharge Survey	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Supply Quality Checks	30,900	30,900	30,900	30,900	30,900	30,900	30,900	30,900	30,900	30,900
Spares Checks and Minor Maintenance	30,591	30,591	30,591	30,591	30,591	30,591	30,591	30,591	30,591	30,591
Seismic Checks	60,000	60,000	-	-	-	-	-	-	-	-
Vegetation Control	1,255,000	1,000,000	800,000	600,000	400,000	200,000	200,000	200,000	200,000	200,000
Connections Minor Works	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000
	4,057,504	3,802,504	3,542,504	3,342,504	3,142,504	2,942,504	2,942,504	2,942,504	2,942,504	2,942,504
OPEX: Refurbishment and Renewal Maintenance	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
General Dist Refurbishment - PSL	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
General Dist Refurbishment - OPSL	212,866	212,866	212,866	212,866	212,866	212,866	212,866	212,866	212,866	212,866
Subtransmission Refurbishment - PSL	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
Subtransmission Refurbishment - OPSL	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Zone Substation Refurbishment	30,900	30,900	30,900	30,900	30,900	30,900	30,900	30,900	30,900	30,900
Transformer Refurbishment	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500
SCADA and Comms Refurbishment	-	-	-	-	-	-	-	-	-	-
	785,266	785,266	785,266	785,266	785,266	785,266	785,266	785,266	785,266	785,266
OPEX: Fault and Emergency Maintenance	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Incident Response Dist - PSL	1,463,700	1,463,700	1,463,700	1,463,700	1,463,700	1,463,700	1,463,700	1,463,700	1,463,700	1,463,700
Incident Response Dist - OPSL	430,500	430,500	430,500	430,500	430,500	430,500	430,500	430,500	430,500	430,500
Incident Additional Time Dist - PSL	61,800	61,800	61,800	61,800	61,800	61,800	61,800	61,800	61,800	61,800
Incident Additional Time Dist - OPSL	29,870	29,870	29,870	29,870	29,870	29,870	29,870	29,870	29,870	29,870
Incident Response Technical - TSL	112,270	112,270	112,270	112,270	112,270	112,270	112,270	112,270	112,270	112,270
Incident Response Technical - PSL	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196
Incident Additional Time Technical - TSL	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000
Incident Additional Time Technical - PSL	63,860	63,860	63,860	63,860	63,860	63,860	63,860	63,860	63,860	63,860
	2,373,196	2,373,196	2,373,196	2,373,196	2,373,196	2,373,196	2,373,196	2,373,196	2,373,196	2,373,196
Operational Expenditure Total	7,215,966	6,960,966	6,700,966	6,500,966	6,300,966	6,100,966	6,100,966	6,100,966	6,100,966	6,100,966
System Management and Operations	2,475,398	2,620,193	2,654,685	2,726,049	2,780,570	2,780,570	2,780,570	2,780,570	2,780,570	2,780,570
AMP OPEX Total	9,691,364	9,581,159	9,355,651	9,227,015	9,081,536	8,881,536	8,881,536	8,881,536	8,881,536	8,881,536

6. Risk management

[Addresses handbook requirement 4.5.7(a)]

The business is exposed to a wide range of risks. This section examines TPCL's risk exposures, describes what it has done and will do about these exposures and what it will do when disaster strikes.

Risk management is used to bring risk within acceptable levels.

6.1 Risk methods

The risk management process as it applies to the electricity network business is intended to assess exposure and prioritise mitigating actions.

The risk on the network is analysed at the high level, reviewing major network components and systems to see if possible events could lead to undesirable situations.

6.1.1 Guiding principles

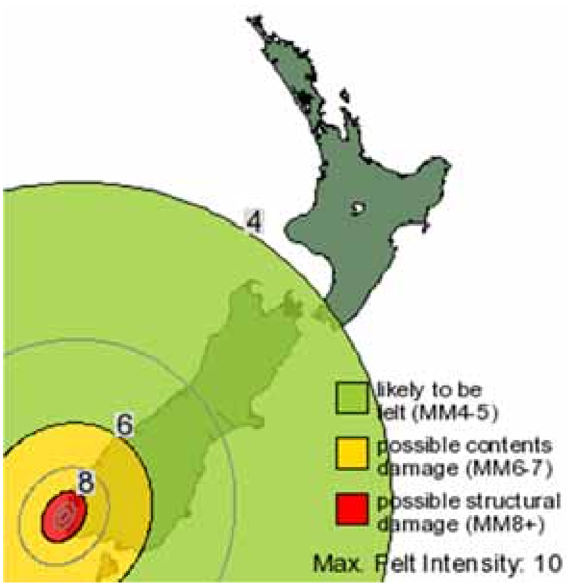
TPCL's behaviour and decision making is guided by the following principles:

- 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.
- Risks will be removed, mitigated, or lessened, depending on the economics.

6.1.2 Risk categories

Risks are classified against the following categories:

- Weather
    - Wind – strong winds that cause either 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 the 1984 floods has caused Regional Council to install flood protection works, but still need to consider if similar water levels do occur again.
- Physical
    - Earthquake – no recent history of major damage. Large events may occur and impact the network. The 15 July 2009 7.8 Richter scale quake 100 km south-west of Te Anau, caused no damage to the network. (*Ref. number 3124785/G*)
    - Liquefaction – post Christchurch 22 February 2011 6.3 quake, 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.
    - Terrorism – malicious damage to equipment can interrupt supply.



  - 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.
- Human
  - 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.
  - Car versus pole – damage to the driver/passengers and the network could be significant.
  - Vandalism – range varies from malicious damage to 'tagging' of buildings or equipment.
- Corporate
  - 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 TPCL'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.

6.2 Risk tactics

The following tactics are used to manage risk under the following broad categories:

- Operate a 24hr Control centre.
- Provide redundancy of supply to large customer groups.
- Remove assets from risk zone.
- Involvement with the local Civil Defence.

6.3 Risk details

[Addresses handbook requirement 4.5.7(b)]

6.3.1 Weather

Event	Likelihood	Consequence	Responses
Wind	Medium	Low	Impact is reduced by undergrounding of lines. Network design standard specifies level for design. If damage occurs on lines this is remedied by repairing the failed equipment.
Snow	Low	Low	Impact is reduced by undergrounding of lines. If damage occurs on lines this is remedied by repairing the failed equipment. If access is limited then external plant is hired to clear access or substitute.
Flood	Very Low	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.

6.3.2 Physical

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Extremely Low	Major	Disaster recovery event. Need to determine actual likely level of survivability of existing assets.

Earthquake (6 to 7)	Very Low	Low to High	Specify so buildings and equipment will survive. Review existing buildings and equipment and reinforce if necessary.
Liquefaction	Very Low	Low to Medium	Specify buildings and equipment foundations to minimise impact.
Fire	Very Low	High	Supply customers from neighbouring substations. Maintain fire alarms in buildings.
Terrorism	Very Low	High	Ensure security of restricted sites. Use alternative routes and equipment to restore supply, similar to equipment failures below.

6.3.3 Equipment Failures

As the impact of this 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.

Event	Likelihood	Consequence	Responses
33kV & 66kV Lines and Cables	Low	Low	Regular inspections and maintain contacts with experienced faults contractors. Provide alternative supply by ringed subtransmission or through the distribution network. All new works to Southern Power Contractors Line Design Standard.
Power Transformer	Very Low	Low to medium	Dual power transformers sites can be removed from service due to fault or maintenance. Continue to undertake annual DGA to allow early detection of failures. Relocate spare power transformer to site while damage unit is repaired or replaced.
11kV Switchboard	Low	Medium	Annual testing including PD[41] and IR[42]. 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	Medium	Low	Regular inspections and maintain contacts with experienced faults contractors. Provide alternative supply by meshed distribution network.
Oil Spill	Very Low	Medium	Oil spill kits located at a few substations for the faults contractor to use in event of an oil leak or spill. Most zone substations have oil bunding and regular checks that the separator system is functioning correctly.
Security measures	Very Low	Medium	Monthly checks of each restricted site. Remote monitoring of access doors by SCADA.
Batteries	Low	Medium	Continue monthly check and six monthly testing.

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

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

Event	Likelihood	Consequence	Responses
Circuit breaker Protection	Very low	Medium	Continue regular operational checks. Mal-operations investigated.
Circuit Breakers	Very low	Low	Backup provided by incomer circuit breaker. Continue regular maintenance and testing.
SCADA RTU	Low	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 Masterstation	Very low	Low	Continue to operate as a Dual Redundant configuration, with two operator stations. This requires both Servers to fail before service is lost. Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.
Load Control	Low	Medium	Provide backup to and from EIL Invercargill 2 Ripple Injection Plant for Invercargill, Winton backs up North Makarewa and Gore and Edendale backup each other. Manually operate plant with test set if SCADA controller fails.

6.3.4 Human

Event	Likelihood	Consequence	Responses
Pandemic	Low	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.
Car versus pole	Low	Low	Have resource to bypass and repair.
Vandalism	Medium	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.

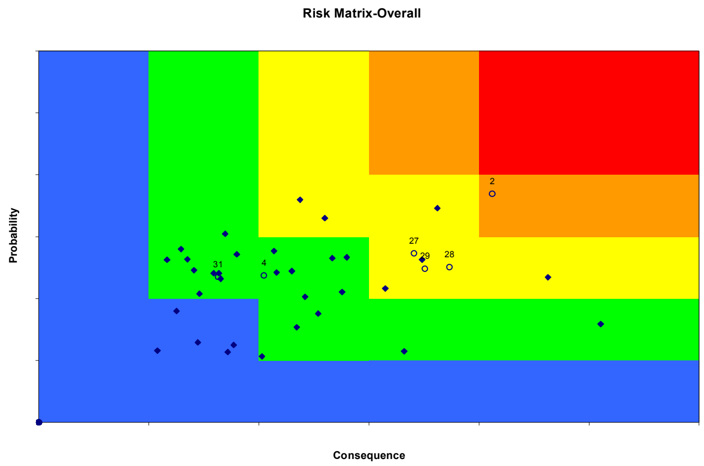
6.3.5 Corporate

Event	Likelihood	Consequence	Responses
Investment	Low	Low	Very little new investment occurring, new larger contracts require Shareholder Guarantee before supply is provided.
Loss of Revenue	Very Low	High	Continue to have Use of System Agreements with retailers. New large investments for individual customers to have a guarantee.
Management Contract	Extremely low	High	Maintain a contract with PowerNet. Ensure PowerNet has and operates to a Business Continuity Plan.

Regulatory	Extremely low	High	Continue to contract PowerNet to meet regulatory requirements. Ensure PowerNet has and operates to a Business Continuity Plan.
Resource	Low	High	Continue to enhance Alliance contractor relationship with present contractors. Provide a long term commitment and support, for the contractor to be sufficiently resourced to achieve the contract service levels on the network.

6.3.6 Projects

Current year major projects are evaluated by the decision tools. Part of the analysis is a risk assessment of the project.



The two axes relate to the probability of failure, the higher up the "Y" axis the more certainty that this may occur and the "X" axis representing the consequence or impact of failure from minimal to catastrophic.

The coloured regions group the common risk levels with the blue representing very minor risks through to the red zone representing an unacceptable extreme risk.

This shows the risk analysis of the selected projects. The unselected projects are shown as unfilled points with these generally relating to the other options for major projects.

6.4 Contingency plans

TPCL has the following contingency plans through its management company PowerNet:

6.4.1 PowerNet Business Continuity Plan

PowerNet must be able to continue in the event of any serious business interruption. Events causing interruption can range from malicious acts through damaging events, to a major natural disaster such as an earthquake.

The principle objectives of the Business Continuity Plan are to:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- 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.

6.4.2 PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause staff to be unable to function in their job.

The plan aims to manage the impact of an influenza pandemic on PowerNet's staff, the business and services through two main strategies:

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

6.4.3 Network Operating Plans

As contingency for major outages on the TPCL network PowerNet holds network operating plans for safe and efficient restoration of services where possible. For example, an operating order detailing operational steps required to restore supply after loss of a zone substation.

6.5 Insurance

TPCL 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
- Marine Cargo.

Contractors working on the network are asked to hold Liability Insurance.

7. Funding the business

Everything discussed in TPCL's AMP so far has been (indirectly) about costs. This section discusses how TPCL's business is funded.

7.1 Business model

TPCL's business model is based around the right-hand side of Figure 56.

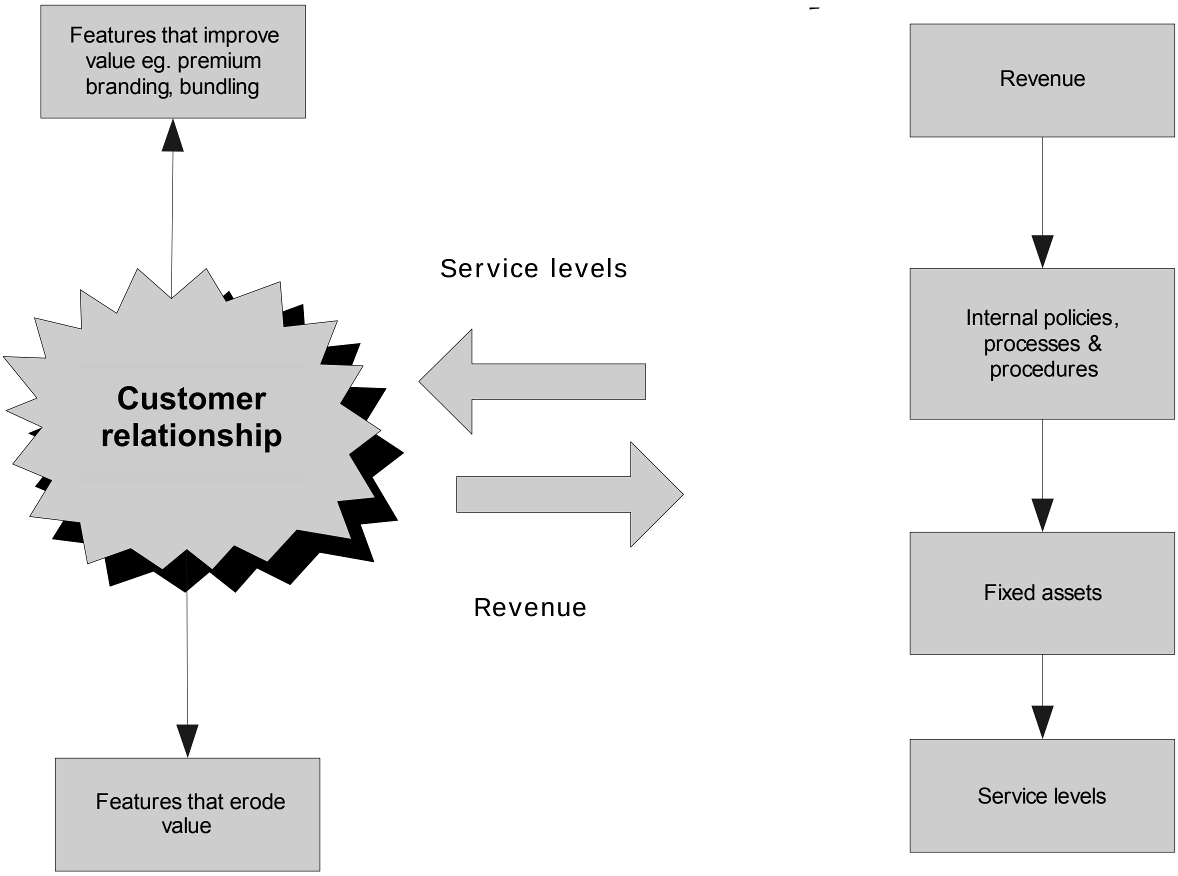


Figure 56 - Customer interface model

This model clearly shows that the company receives cash from TPCL's customers (via the retailers who operate on TPCL's network) and then, through a wide range of internal processes, policies and plans, the company converts that cash into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and voltage stability that customers want.

7.2 Revenue

TPCL's money comes primarily from the retailers who pay TPCL for conveying energy over TPCL's lines or by customer contributions for the uneconomic part of works. In regard to funding new assets (i.e. beyond the immediate financial year) TPCL 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 TPCL to avoid new capital on its ODV and its balance sheet.

7.3 Expenditure

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

7.4 Changes in the value of assets

Given the preferences expressed by TPCL's customers for the following price-quality trade-offs in the 'Customer engagement telephone survey' undertaken by Gary Nicol Associates in January - February 2011 (2010 score):

- 9% (11%) of rural customers are willing to pay $10 more each month for improved reliability.
- 9% (6%) or rural customers don't know or are unsure of price-quality trade-offs.
- 12% (12%) of urban customers are willing to pay $10 more each month for improved reliability.
- 6% (4%) of urban customers don't know or are unsure of price-quality trade-offs.

This presents TPCL with the dilemma of responding to customers wishes for lower supply quality in the face of a "no material decline in SAIDI requirement". Factors that will influence TPCL's asset value are shown in Table 26 below:

Table 26– Factors influencing TPCL's asset value

Factors that increase TPCL's asset value	Factors that decrease TPCL's asset value
Addition of new assets to the network. Need to confirm exactly when asset value can be added to valuation base under ODV rules.	Removal of assets from the network. Need to confirm when asset value can be removed from valuation base under ODV rules.
Renewal of existing assets. Note definition of renewal as being restoration of original functionality – no increase in service potential beyond original functionality.	On-going depreciation of assets.
Increase of standard component values implicit in the ODV methodology.	Reduction of standard component values implicit in the ODV methodology.

At a practical level TPCL'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.

7.5 Depreciating the assets

As outlined in section 7.4 above, the accounting treatment of depreciation doesn't strictly model the decline in service potential of an asset - sure it probably does 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. Processes and systems

[Addresses handbook requirement 4.5.2(f)]

The core of TPCL's asset management activities lie with the detailed processes and systems that reflect TPCL's thinking, manifest in TPCL's policies, strategies and processes and ultimately shape the nature and configuration of TPCL's fixed assets. The hierarchy of data model shown in Figure 57 describes the typical sorts of information residing within TPCL's business (including in TPCL's employees' brains).

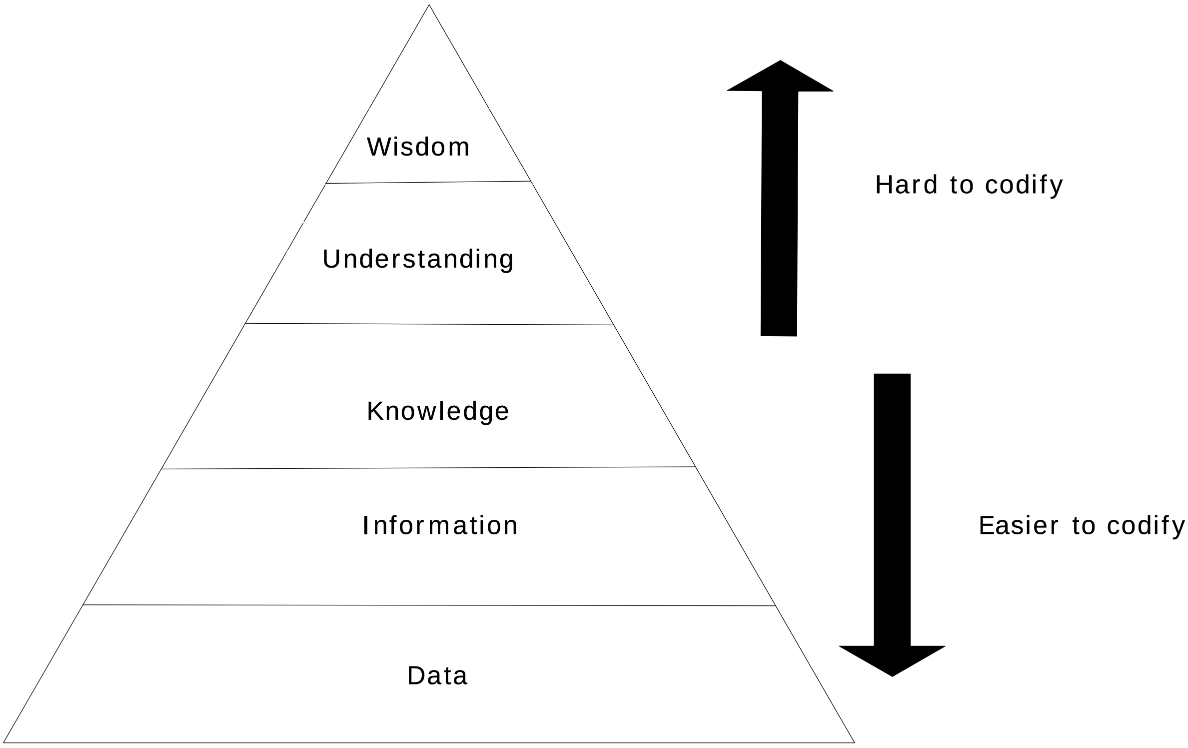


Figure 57 - Hierarchy of data

The bottom two layers of the hierarchy tend to relate strongly to TPCL's asset and operational data which reside in the GIS and SCADA respectively and the summaries of this data that form one part of TPCL's decision making.

The third 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 tend to be very broad and often quite fuzzy. It is at this level that key organisational strategies and processes reside at. As indicated in Figure 57 it is generally hard to codify these things, hence correct application is heavily dependent on skilled people.

8.1 Asset knowledge

[Addresses handbook requirement 4.4.6]

TPCL knows a great deal about almost all of the assets – their location, what they are made of, generally how old they are and how well they can perform.

TPCL's asset data resides in three key locations:

- Asset description, location, age and condition information of line, cables and field devices resides in the Geographical Information System (GIS).
- Asset descriptions, details, age and condition information of serial numbered components resides in Asset Management System (AMS).
- Asset operational data such as loadings, voltages, temperatures and switch positions reside in the Supervisory Control and Data Acquisition (SCADA).

An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history.

Table 27 Knowledge Accuracy

System	Parameter	Completeness	Notes
GIS	Description	Excellent	Some delays between job completion and updating into the GIS
GIS	Location	Excellent	
GIS	Age	Poor	Pole ages not available for 63%
GIS	Condition	Poor	No recent information
WASP	Description	Okay	Some delays between job completion and updating into WASP
WASP	Details	Okay	
WASP	Age	Okay	Missing age on old components
WASP	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Okay	A few sites monitored

8.2 Improving the quality of the data

[Addresses handbook requirement 4.4.6(c)]

8.2.1 GIS data improvement

TPCL'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. We are considering options to get ages measured, for the un-dated poles, but no economic methodology has been found.

About 20% of the network (by length) each year is condition assessed to update asset condition data (noting that that asset condition is continually varying), and any discovered details are updated.

Key process improvements will include more timely as-builts with PowerNet staff GPS-ing[43] poles and use of scan-able forms for data input (Teleform system).

8.2.2 AMS data improvement

Data for the AMS is collected by the Network Movement Notice 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.

8.3 Use of the data

All data will be used for either making decisions within TPCL's own business or assisting external entities to make decisions. This data is almost always aggregated into information (the second level of the pyramid) in order to make decisions e.g. a decision to replace a zone substation transformer will be based on an aggregation of loading data.

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

8.4 Decision making

The decision making process also 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 source, roles and interaction of each component of the hierarchy are shown below in Figure 58.

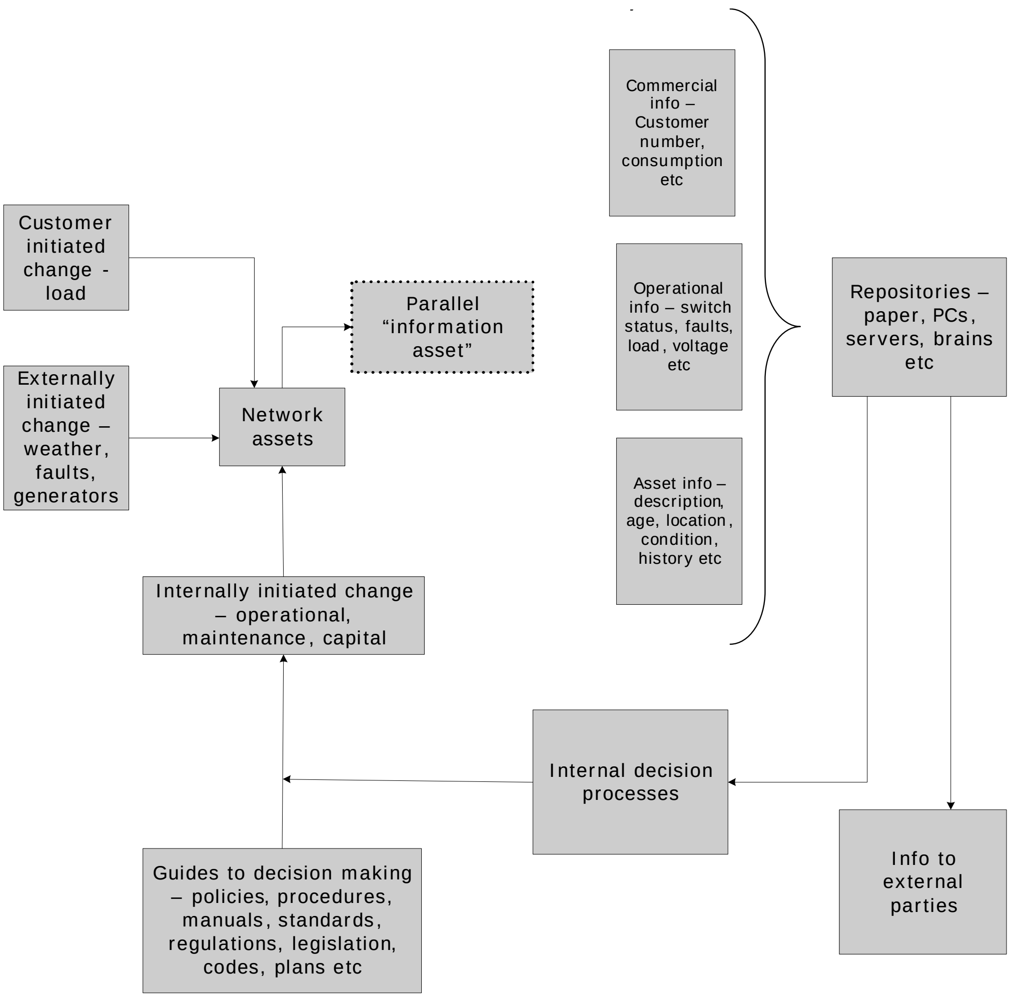


Figure 58 - Key information systems and processes

8.5 Key processes and systems

TPCL's key processes and systems are based around the key lifecycle activities defined in Figure 53, based around the AS/NZS9001:2001 Quality System and are described in the following sections. These processes are not intended to be bureaucratic or burdensome, but are rather intended to guide TPCL'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.

8.5.1 Operating processes and systems

Commissioning Network Equipment	PNM-61
Network Equipment Movements	PNM-63

Planned Outages	PNM-65
Network Faults, Defects and Supply Complaints	PNM-67
Major Network Disruptions	PNM-69
Use of Operating Orders (O/O)	PNM-71
Control of Tags	PNM-73
Access to substations and Switchyards	PNM-75
Operational Requirements for Confined Space Entry	PNM-76
Operating Authorisations	PNM-77
Radio Telephone Communications	PNM-79
Operational Requirements for Live Line Work	PNM-81
Control of SCADA Computers	PNM-83
Machinery Near Electrical Works	PNM-85
Customer Fault Calls/Retail Matters	PNM-87
Site Safety Management Audits	PNM-88
Meter/Ripple Receiver Control	PNM-121

8.5.2 Maintenance processes and systems

Control of Network Spares	PNM-97
Transformer Maintenance	PNM-99
Maintenance Planning	PNM-105

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

8.5.3 Renewal processes and systems

Network Development	PNM-113
Design and Development	PNM-114

8.5.4 Up-sizing or extension processes and systems

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

8.5.5 Retirement processes and systems

Disconnected And/Or Discontinued Supplies	PNM-125

8.5.6 Performance measuring processes and systems

[Addresses handbook requirement 4.5.2(f)(iii)]

8.5.6.1 Faults

All faults are entered into the 'Faults' database and reported monthly to the board, together with details of all the planned outages.

8.5.6.2 Financial

Monthly reports out of the Finance One (F1) financial system provide measurement of revenues and expenses for the TPCL line business unit. Project costs are managed in PowerNet with project managers managing costs through the WASP system. Interfaces between F1 and WASP track estimates and costs against assets.

8.5.6.3 Customer

Customer statistics are monitored by a Customer Database system developed by ACE computers. This interfaces with the National Registry to provide and obtain updates on customer connections and movements. Customer consumption is monitored by another ACE Computers system 'BILL'. BILL receives monthly details from retailers and links this to the customer database.

8.5.6.4 Service levels

Customers that have had work done are sent a survey form at the end of the job. Results are monitored and any comments given are reviewed and responded to.

8.5.7 Other business processes

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

Setting Up the Contract	PNM-10
Tender Evaluation	PNM-15
Contract Formation	PNM-20
Construction Approval	PNM-25
Materials Management	PNM-30
Contract Control	PNM-35
Contract Close Out	PNM-40
Customer Satisfaction	PNM-50
Internal Quality Audits	PNM-55
External Contracting	PNM-60
Drawing Control	PNM-89
Network Operational Diagram/GIS Control	PNM-91
Control of Operating and Maintenance Manuals	PNM-93
Control of External Standards	PNM-95
Control of Power Quality Recorders	PNM-103
Quality Plans	PNM-107
Health and Safety	PNM-109
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

8.6 Asset management tools

[Addresses handbook requirement 4.5.2(f)(i) and (ii)]

A variety of tools and procedures are utilised by PowerNet to best manage the assets of the various networks. GIS and AMS software packages are used to store and evaluate assets data. Quality system procedures are in place to highlight and focus on various management techniques. The outputs of these systems produce 1 year and 10 year AMP's, together with data for on-going day to day planning and control.

8.6.1 GIS

An Intergraph based Geographic Information System is utilised to store and map data on individual components of distributed networks. This focuses primarily on cables, conductors, poles, transformers, switches, fuses and similar items. Large composite items such as substations are managed by more traditional techniques such as drawings and individual test reports.

Equipment capacity, age and condition are listed by segment. The data is used to provide base maps of existing equipment, for extensions to the network, for maintenance scheduling and similar functions.

8.6.2 AMS

Our present Asset Management System is WASP (Works, Assets, Scheduling, Purchasing) which provides work scheduling and asset management tool. It is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling.

Most day to day operations are managed using WASP. Maintenance regimes, field inspections and customers produce tasks and/or estimates that are sometimes grouped and a 'work packs' issued from WASP.

8.6.3 Faults Database

All outages are logged into a database, with is used to provide regulatory information and statistics on network's performance. Reports from this system are used to highlight poorly performing feeders. These are then analysed to determine if it is a maintenance issue or if reliability may be enhanced by other methods. An analysis of one year's fault data is shown in Figure 59; and indicates no areas of concern.

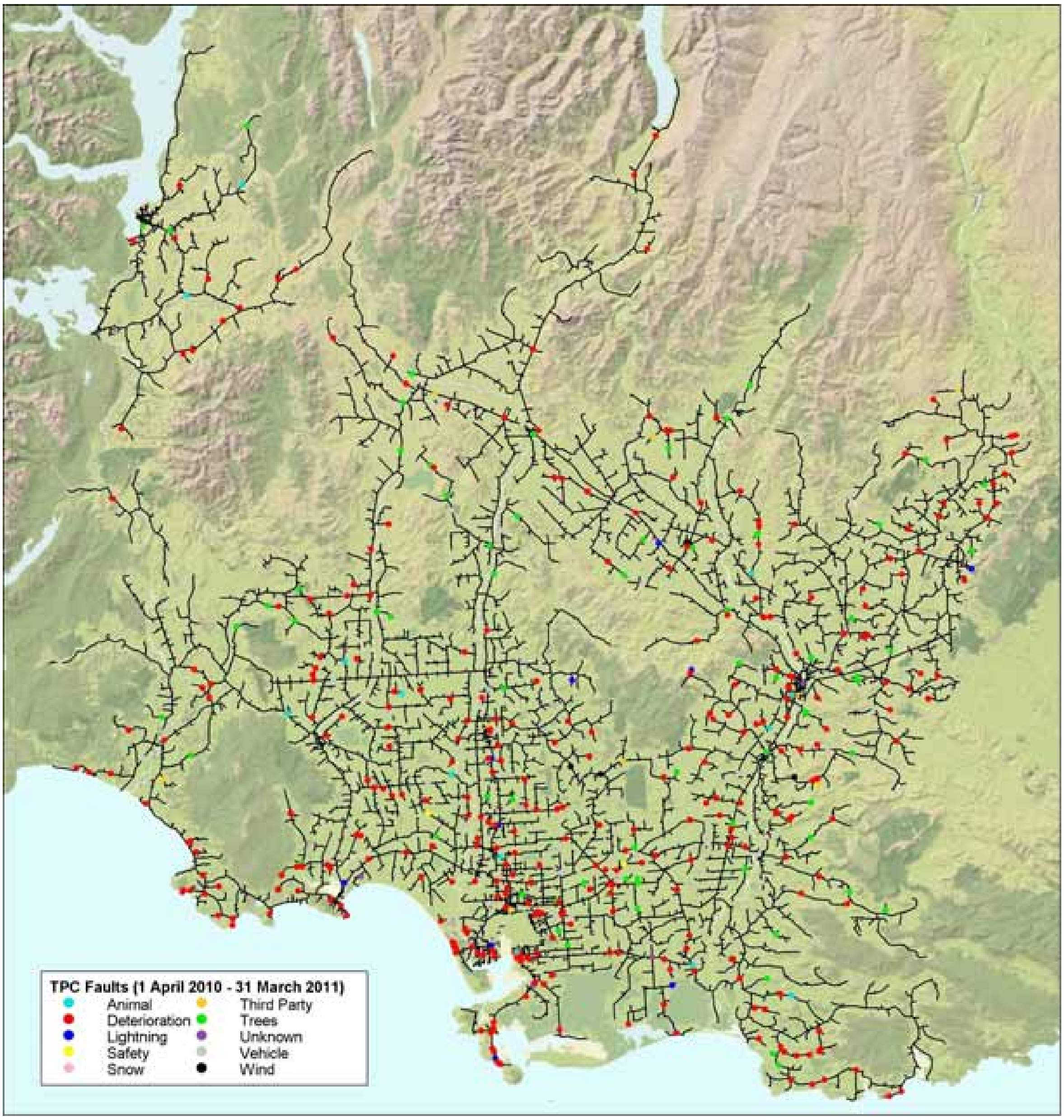


Figure 59 Faults 1 April 2010 to 31 March 2011

8.6.4 PNM-105 Maintenance Planning

The quality system procedure PNM-105 drives maintenance planning. It is the procedure used to drive this document to completion. Flowchart from this quality system document is shown in Figure 60.

Relevant inputs into the plan include:

- WASP Records
- Surveys (field, CDM)
- Analysis of faults database
- GIS database
- System network loading data
- Major customers
- Growth (domestic, commercial, industrial) in geographic areas
- Legislation
- Cyclic maintenance on major plant items
- Current AMP.

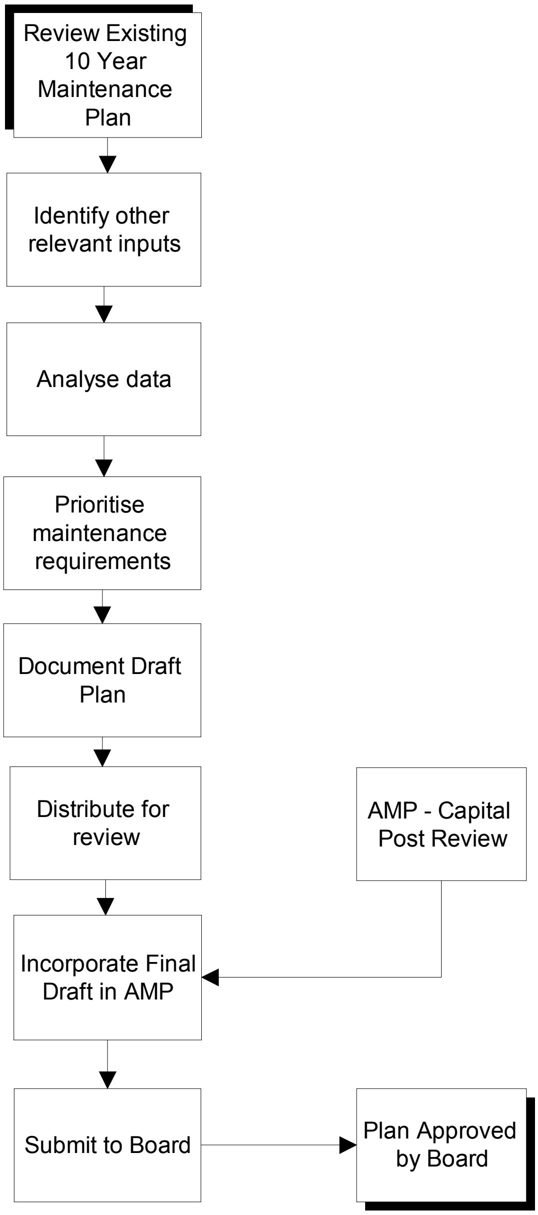


Figure 60 PNM-105 Maintenance Planning Flowchart

9. Performance and improvement

This section firstly evaluates TPCL's performance over the 2010/11 year and secondly identifies areas where TPCL believes it could improve its business.

9.1 Outcomes against plans

[Addresses handbook requirement 4.5.8(a)]

9.1.1 Capital

	Actual for Current Financial Year ($000)	Previous forecast for Current Financial Year ($000)	% Variance
Customer Connection	3,335	4,677	-28.7%
System Growth	2,234	6,227	-64.1%
Reliability, Safety and Environment	354	274	29.2%
Asset Replacement and Renewal	6,013	7,101	-15.3%
Asset Relocations	86	105	-18.1%
Capital Expenditure	**12,022**	**18,384**	**-34.6%**

9.1.1.1 Customer Connection

Less activity than forecast due to the economic downturn.

9.1.1.2 System Growth

Due to planning, design and procurement delays some large projects delayed. Seismic strengthening planning also caused delays.

9.1.1.3 Reliability, Safety and Environment

One project under budgeted.

9.1.1.4 Asset Replacement and Renewal

Design delays.

9.1.1.5 Asset Relocations

Reactive work; fewer projects than anticipated.

9.1.2 Maintenance

	Actual for Current Financial Year ($000)	Previous forecast for Current Financial Year ($000)	% Variance
Routine and Preventative Maintenance	3,150	2,344	34.4%
Refurbishment and Renewal Maintenance	718	960	-25.2%
Fault and Emergency Maintenance	2,274	2,410	-5.6%
Operational Expenditure	6,142	5,714	7.5%

9.1.2.1 Routine and Preventative Maintenance

Extra costs for September storm and no reduction in Tree Trimming cost as Tree Owners disputing first trim and declaring 'no-interest'.

9.1.2.2 Refurbishment and Renewal Maintenance

Additional cost due to September storm.

9.2 Performance against targets

[Addresses handbook requirement 4.5.8(b)]

9.2.1 Primary service levels

The chart below displays the target versus actual reliability performance on the network.

	20010/11 AMP Target	12 Month Actual
SAIFI	3.24	3.21
SAIDI	162.08	**209.06**

For the 2010/11 year the network has performed poorly, with SAIDI exceeded by 46.98 customer-minutes due to September storm.

The Frequency of faults (SAIFI) was under target.

9.2.2 Secondary service levels

Results for 2010/11 are shown below:

Attribute	Measure	Target	Feb11
Customer Satisfaction: Inquiries	Percentage satisfied with PowerNet staff. {CES: Q9(b)}[44]	>80%	78%
Customer Satisfaction: New Connections	Phone: Friendliness and courtesy. {CSS: Q3(c)}[45]	>3.5[46]	4.9
	Phone: Time taken to answer call. {CSS: Q3(a)}	>3.5	4.8
	Overall level of service. {CSS: Q5}	>3.5	4.5
	Work done to a standard which meet your expectations. {CSS: Q4(b)}	>3.5	4.6
Customer Satisfaction: Faults	Power restored in a reasonable amount of time. {CES: Q4(b)}	>60%	72%
	Information supplied was satisfactory. {CES: Q8(b)}	>60%	92%
	PowerNet first choice to contact for faults. {CES: Q6}	>25%	**17%**
Voltage Complaints {Reported in Network report}	Number of customers who have made voltage complaints {NR}	<45	30
	Number of customers who have justified voltage complaints regarding power quality	<15	**16**
	Average days to complete investigation	<30	13
	Period taken to remedy justified complaints	<60	40
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>75%	91%

[44] CES = February – March 2009 Customer Engagement Survey of 200 customers, undertaken by phone annually.

[45] CSS = Customer Satisfaction Survey undertaken by sending questionnaire to customers with invoices.

[46] Where 1 = poor and 5 = excellent

Attribute	Measure	Target	Feb11
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>75%	87%
	Acceptance of maximum of three planned outages per year. {CES: Q1}	>50%	99%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	>50%	91%

Result for 'Customer Satisfaction: Inquiries' had nine respondents, with two unsatisfied.

PowerNet as first contact for faults has reduced likely due to Retailer switching campaigns that has increased their profile.

High justified voltage complaints are due to the extra load that dairy farm conversions have put on the network, and neighbouring customers seeing a decline in quality.

9.2.3 Other service levels

9.2.3.1 Efficiency

Measure	2010/11 AMP Target	Actual
Load factor	64%	63%
Loss ratio	8.0%	6.8%
Capacity utilisation	30%	29.5%

Load factor impacted with change to TPM relaxing individual GXP peaks caused system peak to increase.

The utilisation just missed the target.

9.2.3.2 Financial

Measure	2010/11 AMP Target	Actual	Comment
Direct costs	$933.34	**$983.05**	Cost per km of line
Indirect costs	$67.88	$67.50	Cost per customer

Overspend on OPEX pushed Direct Cost measure over target.

Indirect was close to target.

9.3 Improvement Areas and Strategies

[Addresses handbook requirement 4.5.8(c)]

The following areas are highlighted as gaps in performance that could be improved, and the strategies proposed to achieve improvements.

TPCL plans to improve its AMP in the future not simply by writing a better document but by improving the asset management processes, systems and activities that it uses / undertakes.

9.3.1 Capital Works

Gaps:

Completion of the planned projects and initiatives.

Discussion:

Planned work has not been completed that can lead to delays in future projects.

Strategies:

We plan to create a long term relationship with contractors so they can build their resources and personnel. This will allow more work to be completed and ensure a resource for future years.

We will increase our Project Management team and management, and structure them with clear areas of responsibility.

We will continue to forward plan projects so that resource requirements are better defined and works can be effectively scheduled.

We will bring design and planning back 'in-house' to improve timing on projects and provide better control on implementation.

9.3.2 Reliability

Gaps:

Decline in reliability level.

Discussion:

Better targets could be set that take into account forecast work.

Refocus on renewal is likely to lead to a restoration in reliability and a catch-up the condition of the network.

Strategies:

We will create a long term relationship with contractors so they can build their resources and personnel, so that the restoration of supply is done effectively.

We will continue to regularly inspect the network and action critical items as they are identified.

We will increase number of remotely controlled devices to speed isolation of faulty sections and restoration of supply to healthy sections.

9.3.3 Voltage Complaints:

Gaps:

High number of justified voltage complaints.

Discussion:

The boom of extra load in rural areas is stretching the network with voltage complaints an indicator of this.

Strategies:

We will increase modelling of the network to analyse all new medium loads (≥50kVA) and review existing model for problem areas.

9.3.4 Surveys

Gaps:

Low level of respondents to Customer Engagement Surveys.

Discussion:

Those to be contacted are randomly selected and changing of this process could negate the survey quality.

Strategies:

Monitor results and consider alternative random selection criteria.

9.3.5 Efficiency

Gaps:

Low transformer capacity utilisation.

Reduce loss to improve efficiency.

Discussion:

Network growth occurs at an unknown rate and equipment is chosen to meet expectations or customer requests. Unfortunately the customer requests for capacity can require a larger unit because of standard sizes. Eg. Customer requests 350kVA so a 500kVA transformer is installed, as a 300kVA is too small.

Actual monitoring of loadings or maximum demands of equipment is done to ensure that equipment can safety supply the load, or if expectations have not been met.

Some loads have a very poor load factor but still require an appropriate sized transformer. E.g. Fire pumps at a factory may need 300kVA to operate but will hopefully never use any energy.

A new requirement has transformers not owned by TPCL included in this parameter and we may need to encourage the owners of these to rationalise the rating of their transformers.

Overloaded and highly loaded equipment normally has higher then optimal losses.

Strategies:

We will check as new transformers are added to the network, with a rationalisation of capacities. Underutilised units will be relocated to match loads. Overloaded transformers will also be rationalised and this has a negative impact on this indicator.

We will review the demand of customers that own their own transformers and contact them if we believe that there is a concern.

Analysis of highly loaded lines and cables has highlighted sections that have high losses, up-sizing of these to larger conductor or a higher voltage will improve the loss ratio of the network. The level of losses normally doesn't initiate the change but is used when selecting sizes when work is done on the equipment.

A. Appendix - Customer Engagement Survey

PowerNet Consumer Engagement Telephone Survey: TPCL

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?		

A1: Do you know who PowerNet is?	Yes	**1**	*Go to A2*
	No	**2**	*Go to A3*
A2: 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 X**	
	Sensitive to the environment	**1 2 3 4 5 X**	
	Supporting the community	**1 2 3 4 5 X**	
	Safety conscious	**1 2 3 4 5 X**	
Go to D1	Efficient	**1 2 3 4 5 X**	

A3: PowerNet maintains the local electricity lines and substations that supply power to your premises.

D1: Do you live in a mainly rural or urban area?	Urban	**5**	
	Rural	**6**	
D2: Are you a commercial or residential customer?	Commercial	**1**	
	Residential	**2**	
Question 1: PowerNet is proposing a maximum of one planned interruption to your power supply, on average, every year in order to carry out maintenance or upgrade work on its electricity network. Do you consider this number of planned interruptions to be reasonable?	Yes	**1**	*Go to Q 2*
	No	**2**	*Go to Q 1(a)*
	Don't know/unsure	**3**	*Go to Q 2*
Question 1(a): How many years between planned interruptions do you consider to be more reasonable?	2 years	**1**	
	3 years	**2**	
	4 years	**3**	
Question 2: PowerNet expects 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 3
	No	**2**	Go to Q 2(a)
	Don't know/unsure	**3**	Go to Q 3
Question 2(a): What length of time would you consider to be more reasonable? *(Specify hours)*	30 min	**1**	
	1 hour	**2**	
	$1^1/_2$ hours	**3**	

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

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

Question 3 (b): What additional information would you have liked?

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

Question 3(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 3(e): Do you have a preferred day and time(s) for a planned interruptions?	Yes	**1**	*Go to Q 3(f)*
	No	**2**	*Go to Q 4*

Question 3 (f): What is your preferred day and time(s)?

Question 4: Have you had an unexpected interruption to your power supply during the last 6 months?	Yes	**1**	*Go to Q 4(a)*
	No	**2**	*Go to Q 5*
	Unable to recall	**3**	*Go to Q 5*

Question 4(a): Thinking about the most recent unexpected interruption to your electricity supply, how long did it take for your supply to be restored? *(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 4(b): Do you consider your electricity supply was restored within a reasonable amount of time?	Yes	**1**	*Go to Q 5*
	No	**2**	*Go to Q 4(c)*
	Unable to recall	**3**	*Go to Q 5*

Question 4(c): What do you consider would have been a more reasonable amount of time?	30 minutes	**1**	$1^1/_2$ hours	**4**

(Specify hours/days) *(Do not prompt)* ***Go to Q5(a)***	45 minutes **2**	2 hours **5**
	1 hour **3**	Other **6**

Question 5: 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 5(a): PowerNet is reviewing the level of service provided to its customers and options include increasing spending. Presently there is an average of three interruptions each year. If this was reduced to two interruptions per year 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 6: Who would you contact 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**
	Other	**6**

Question 7: Have you made such a call within the last 6 months?	Yes	**1**	*Go to Q 8*
	No	**2**	*Go to Q 8(d)*
	Unable to recall	**3**	*Go to Q 8(d)*

Question 8: Were you satisfied that the system worked in getting you enough information about the supply interruption?	Yes	**1**	*Go to Q 8(b)*
	No	**2**	*Go to Q 8(a)*
	Don't know/unsure	**3**	*Go to Q 8(b)*

Question 8 (a): What, if anything, do you feel could be done to improve this system?

Question 8 (b): Were you satisfied with the information that you received?	Yes	**1**	*Go to Q 8(d)*
	No	**2**	*Go to Q 8(c)*
	Don't know/unsure	**3**	*Go to Q 8(d)*

Question 8 (c): What, if anything, do you feel could be done to improve this information or the way in which it is delivered?

Question 8 (d): 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**	
	Other	**3**	
Question 8(e): Are you aware of PowerNet's 0800 faults number?	Yes **1**	No **2**	
Question 9: Have you contacted PowerNet regarding any other issues relating to your electricity supply during the last 6 months?	Yes	**1**	*Go to Q 9(a)*
	No	**2**	*Go to Q 9(e)*
	Unable to recall	**3**	*Go to Q 9(e)*
Question 9(a): What did your enquiry relate to? *(Do not prompt)*	Voltage complaints	**1**	
	Safety disconnections	**2**	
	New or altered supply	**3**	
	Trees near lines	**4**	
	Other	**5**	
Question 9 (b): Were you satisfied with the performance of the PowerNet staff member(s) who handled your enquiry?	Yes	**1**	*Go to Q 9(d)*
	No	**2**	*Go to Q 9(c)*
	Don't know/unsure	**3**	*Go to Q 9(e)*
Question 9 (c): Specifically what were you dissatisfied with?			
Question 9 (d): Was there anything that PowerNet did well?			
Question 9 (e): What if anything do you feel could be done to improve the service provided by PowerNet staff?			

This concludes our survey - Thank you for your time

B. Appendix - Description of TPCL's assets

This appendix extends the descriptions of TPCL's assets.

B.1 Subtransmission

The natural split of this group is into overhead tower circuits, overhead pole line circuits and cable circuits. Any particular circuit from A to B may be a mixture of these forms. Overhead lines may be multi circuit or be common with lower voltage circuits. Maintenance planning differences are more a function of circuit form than circuit voltage.

Subtransmission includes all circuits "upstream" of a zone substation. Effectively these circuits bring electricity to whole communities of interest and are therefore more critical than distribution circuits. The arrangement of these circuits is very much dependent on geography and history. The required reliability varies according to the security available with the associated network configuration. Supply security and reliability are defined in the Network Design Standard

TPCL's subtransmission is largely ringed or parallel fed with few common mode failure points. Consequently the inherent circuit reliability of TPCL's network can be relaxed while still providing overall supply reliability.

Figure 61 The Power Company Limited Area

B.1.1 Tower circuits

B.1.1.1 Description and capacity

Generally these are limited to critical areas or such locations as river crossings. Individual drawings, profiles and route plans are kept for these lines that provide invaluable information for maintenance and development purposes.

Tower lines tend to be dual circuit. Conductor is Wolf ACSR. Sagging is based on 75°C giving a current rating of 500A. Generally the lines are rated for voltage drop and loss considerations, such that the load is well below the 500A limit. The tower circuits are well utilised. Voltage drop and losses are quite significant. In some operating conditions the voltage drop increases to the allowable maximum.

Most towers are located on the 66kV circuit between Mossburn and Hillside, Northern Southland. These towers were constructed for 110kV use, but are only insulated to 66kV.

B.1.1.2 Condition, age and performance

Most towers were installed around 1983 to New Zealand Electricity (NZE) 110kV standard. Strain insulators are 110kV ceramic type. Other insulation is 66kV glass disk suspension format. Generally the condition of the tower circuits remains very good. Unfortunately the performance of the main Winton to Hillside 66kV circuit has generally been poor. Fault causes have largely been classified as lightning and trees. Maintenance to date has primarily focused on improving reliability to design levels.

B.1.1.3 Monitoring and procedures

Deterioration of the tower circuits is very slow. All towers are of galvanised steel lattice construction mounted on concrete cage foundations. Maintenance programming has been limited to intermittent field surveys by experienced personnel.

Dominant failure modes are corrosion and insulator cracking. Galvanising thickness provides a suitable indicator for anticorrosion protection and can readily be measured by non-destructive testing (NDT) techniques. Cracked insulators are typically located by visual inspection. Monitoring consists of:

- Visual inspection at 5 yearly intervals. This includes checks of foundation condition, location of any rust, faulty hardware and insulator condition.
- Galvanising thickness is inspected on a 10 year cycle.
- Fault data is used for abnormal problems.

B.1.1.4 Maintenance plan

A program to install vibration dampers on conductor has been implemented.

Bird deterrent fixtures are being installed in specific areas where birds are causing faults.

Very little routine maintenance is required.

B.1.1.5 Renewal plan

There are no plans for renewal of towers or associated conductor in the next 10 years.

B.1.1.6 Retirement plan

There are no plans for any retirement of tower circuit assets.

B.1.2 Pole line circuits

B.1.2.1 Description and capacity

Pole lines form the majority of subtransmission circuits within rural Southland and Otago. These consist of unregulated 33kV or 66kV circuits of a capacity specifically chosen for

the anticipated load. The dominant design parameters are voltage drop and losses with current loading generally always being well below capacity. Voltage drop is a problem due to small conductor and long circuit lengths. On a voltage and loss basis most circuits operate between 80% and 150% of optimum level.

Most subtransmission line circuits are routed cross-country to minimise cost and length. More recent circuits tend to be constructed along road reserve due to land access issues. Poles are a mixture of concrete, hardwood and softwood, chosen by the relative costs at the time of construction. Rural lines are typically sagged to a maximum operating temperature of 75°C to maximize capacity and minimise cost.

Some of the circuits have substantial design drawings and route plans, a reflection of their importance. The poles and conductors are listed within the GIS system in the same fashion as lower voltage circuits.

B.1.2.2 Condition, age and performance

Little of the original subtransmission network remains. Upgrading, rebuilding and piecewise maintenance has largely replaced circuits originally installed between 1928 and 1950.

The age profile of transmission circuits is shown in Figure 9. Since most transmission circuits are of overhead line construction this graph gives a good indication of overall circuit age. Note however that many circuits have poles and other hardware replaced when and were needed. Consequently the age of circuits is difficult to precisely state.

The subtransmission pole age distribution is provided in Figure 10 for wood and concrete. This data is contained within the GIS database. Again the data should be treated carefully. The data generally refers to installation date. Many poles may be second hand when installed, although generally of good quality.

The 33kV subtransmission fault rate was 3.49 faults/100km/per annum and the 66kV was 0.52 faults/100km/per annum. Since overhead lines form the majority of subtransmission, these figures effectively relate to pole lines. These rates provide suitable overall system performance as measured by SAIDI etc.

B.1.2.3 Monitoring and procedures

Dominant failure modes are pole and crossarm deterioration, tree contact, conductor corrosion, ties/clamps, joints and insulator cracking.

Visual inspection is conducted annually to locate obvious problems. These are rectified dependent on the urgency.

Defect inspection is conducted at 5 yearly intervals on a rolling basis. This includes checks of foundation, pole integrity, crossarm condition, faulty hardware and insulator condition. Part of the inspection includes the diagnostic techniques of scanning and thermal imaging and a ten yearly x-ray of wooden poles. This inspection is the prime driver for maintenance planning.

Fault data is used for abnormal problems. Protection relay data (distance to fault) is used where available to help locate faults and subsequently identify fault cause. Detailed analysis of outages and their cause using root cause analysis (RCA) identifies target areas for maintenance programs.

B.1.2.4 Maintenance plan

Repair of items identified from inspections or analysis.

B.1.2.5 Renewal plan

See the capital works plan for details of subtransmission circuit renewal.

B.1.2.6 Retirement plan

There are no plans for any retirement of any circuit assets.

B.1.3 Cable circuits

B.1.3.1 Description and capacity

Subtransmission cables are limited to special locations in rural areas. Cable circuits are listed in Figure 12.

Subtransmission cables are a mixture of types, sizes and configurations, largely determined by age and network.

The present standard generally consists of aluminium conductor, XLPE insulation, single cores and copper screens.

Generally the smallest cable size used is $120mm^2$, a size suitable for typical fault levels. Selected thermal backfill is used where required.

B.1.3.2 Condition, age and performance

The installation date of the cable circuits is shown in Figure 12. Generally there are no known problems associated with the cables. The cable sizes match the associated lines and substations to which they connect, so are well utilised.

B.1.3.3 Monitoring and procedures

Dominant failure modes for cables are joint or termination faults, sheath damage, overheating and external mechanical damage. Generally the cables are very stable and require little attention.

On line partial discharge testing is conducted on a five year basis to check for insulation integrity. Time domain spectrometry and screen insulation resistance tests are conducted when cables are available unenergised and at installation. These tests indicate significant discontinuities or sheath failure that may require further investigation or corrective action. Five yearly thermal inspections of terminations are conducted to check for excessive heating or overload. Fibre cable has been installed on recent circuits to allow for real time temperature profiles to be undertaken should the need arise.

B.1.3.4 Maintenance plan

There are no plans for any significant cable maintenance other than monitoring.

B.1.3.5 Renewal plan

There are no plans for any renewal of subtransmission cables.

B.1.3.6 Retirement plan

There are no plans for any retirement of cables.

B.2 Zone substations

B.2.1 Substations general

B.2.1.1 Description and capacity

There are 33 zone (district) substations in the network. These are listed in section 2.2.3.

These stations vary considerably from installations with indoor switchgear and transformers to small roadside stations with no buildings.

The prime general functions of the stations are to house the transformers, switchgear and associated control.

B.2.1.2 Monitoring and procedures

The stations consist of buildings, fences, yards and similar exposed items similar to other industrial sites. Monitoring consists of monthly checks to identify obvious problems such as broken windows, weeds, and damaged security fencing. Routine maintenance such as spraying is conducted in conjunction with monitoring.

Yearly inspections are undertaken for forward planning, at which time such activities as painting, spouting, rusting problems are identified. The standard required is as would be expected for domestic or industrial building.

Station batteries have resistance checked yearly and are replaced before the manufacturer's recommendation useful life on assumption that failure rates increase significant at this age.

Electromechanical protection relays are tested on a 5 yearly basis due to general drift and wear of the mechanical bearings etc. They are also being replaced with electronic relays in conjunction with circuit breaker renewal. The preferred relays are the Schweitzer Engineering Laboratories range chosen on a reliability, flexibility and functional basis. Electronic relays are checked on a eight yearly cycle.

SCADA is generally maintained on a repair basis due to the random basis of failure. The original GPT Remote Terminal Units (RTU) are being replaced because of the high overall failure rate and non-availability of parts.

Outdoor structures are checked as part of the monthly inspections. Yearly visual inspections are undertaken to assess overall condition and list any action required. Yearly ultrasonic and thermal imaging tests are done to identify failed insulation or high contact resistance.

B.2.1.3 Maintenance and renewal plans

Maintenance is of a routine nature with no significant activity expected. There are no plans to replace any existing sites. The Centre Bush Building is planned to be replaced during the period.

B.2.2 Transformers

B.2.2.1 Description and capacity

These vary significantly in both size and detail. Transformers within the network consist of two 11.5/23MVA 33/11kV Yyn0 three phase units complete with on load tap changers (OLTC).

The remainder of the TPCL transformers vary from 10/20MVA ONAN/OFAF capacity down to 1.5MVA, all with OLTC.

The zone substation transformers have two main purposes. Firstly they are required to "transform" the higher subtransmission voltages to more usable distribution voltage. And secondly they are required to regulate the highly variable higher voltages to a more stable voltage at distribution levels.

Several issues should be noted. The rating is obviously important. The transformers must be suitable to withstand the load imposed upon them. This is generally stated as the ONAN (Oil Natural, Air Natural) level at which losses are optimised and no special cooling is required. To allow for maintenance or faults transformers are often installed in pairs. Typically they share the load and operate within their economic ONAN level. Should one transformer not be in service then the remaining transformer can carry the total load. Fans and pumps are needed to dissipate heat and the life may be reduced. The rating at this level is called OFAF and may be twice the ONAN rating. Transformers are often relocated to optimise use as load varies at the various sites. Consequently the transformers are well utilised.

Phasing of the transformers is important to allow paralleling of the network. Most of the transformers therefore have Dyn3 vector for 66/33kV or 66/11kV, Yyn0 or Dzn0 for 33/22kV or 33/11kV.

On Load Tap Changers provide a less expensive regulation method than separate regulators.

The high cost of the larger transformers has driven the installation of comprehensive protection systems for the transformers.

The TPCL transformers are less utilised generally because of transformer availability and historic lack of dual rated transformers.

B.2.2.2 Monitoring and procedures

Most transformer deterioration is assumed to be time based, with the exception that tap changing equipment wears proportionately to the number of operations. Monthly visual inspection is undertaken to check for obvious problems such as oil leaks. Yearly inspections are done to check fan control operation, paint condition and obtain oil samples for Dissolved Gas Analysis (DGA) testing.

Routine transformer maintenance is done on a 5 yearly basis. This covers protection relay operation, insulation levels and instrumentation checks.

Tap Changer maintenance is done on a time and/or operation basis as per manufacturers' recommendations.

DGA results are checked for trend changes and against industry standard absolute levels. Action is taken as recommended by the testing agency. Insulation trend is used to trigger further more specific action.

Transformers are sometimes moved as part of utilisation planning.

B.2.2.3 Maintenance plan

There are no plans for any significant transformer maintenance. All work consists of routine inspection and maintenance.

B.2.2.4 Renewal plan

The Mataura and Seaward Bush transformers are to be replaced due to age and capacity limits.

B.2.2.5 Retirement plan

The Mataura and Seaward Bush transformers will be evaluated for major refurbishment but are likely to be sold as scrap or retained as-is for emergency use.

B.2.3 Switchgear

B.2.3.1 Description and capacity

Four general group types of switchgear are in use in the network:

- The majority of 33kV and 66kV circuit breakers are outdoor units mounted on stands in conjunction with associated current transformers. Many types and ratings are in use. This equipment is purchased on a case-by-case basis, generally on a lowest price tender basis. Minimum oil, vacuum and SF_6 units are in use. Ratings vary from 200A to 2000A, although load is typically in the range of 20A to 630A. Most operating mechanisms are dc motor wound spring to allow operation de-energised. There are a number of "recloser: type units in service although these are limited in number because of the directional limits of solenoid closing.
- 33kV ABB Unisafe switchgear has been installed at Edendale and Waikiwi. These were installed on a price and limited space basis.
- 50% of 11kV circuit breakers are Reyrolle indoor panels of various vintages.
- 50% of 11kV circuit breakers consist of pole mounted outdoor units with integral current transformers. Many of these are solenoid operated reclosers.


2000A 66kV SF6
Outdoor CB & CT
- Heddon Bush

Note that current transformers are generally assumed to form part of the switchgear, but outdoor isolators etc. are lumped in with the general structure.

The dominant circuit breaker rating is 630A continuous and 12kA or 13kA fault break capacity. Few circuit breakers are loaded over 200A due to the nature of the networks.

The main purpose of a circuit breaker is to allow switching of high energy circuits and more specifically to switch open (i.e. break) faulted circuits automatically by the use of associated protection devices. A few circuit breakers at the source ends of lines would be adequate to protect the lines from a safety point of view.

Unfortunately faults are bound to occur on lines no matter how well maintained the lines are. If a large length of line were protected by a very limited number of circuit breakers then the reliability at any particular installation would be completely unacceptable. To achieve reasonable reliability on the network TPCL have adopted a guideline such that no more than 40km of line is connected between circuit breakers for circuits near the coast. This figure increases to 100km inland where fault density is less. The large length of lowly loaded line circuits in the Otago and Southland hinterland has resulted in a large number of lightly loaded field circuit breakers being installed. These are included together with substation circuit breakers as a single logical grouping.

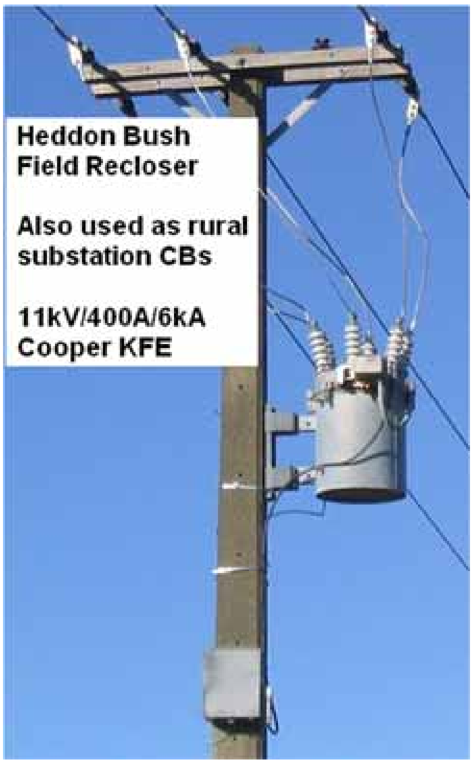
Based on load capacity the circuit breakers are very much underutilized. Based on the more important safety and reliability parameters there is no doubt that more circuit breakers should be installed in specific areas.

B.2.3.2 Monitoring and procedures

Circuit breakers are assumed to deteriorate in a time based fashion with regard to general corrosion and mechanical faults. Experienced has indicated that circuit breakers with oil based arc quenching require significant maintenance following relatively few fault clearing operations. Literature and manufacturer recommendations suggest that vacuum and SF_6 devices have longer maintenance cycles and generally provide service levels based on fault breaking current.

PowerNet does not have significant data on current breaking levels for individual switching operations. Consequently routine maintenance is carried out at two yearly intervals for oil base circuit breakers and five years for vacuum and SF6. Some circuit breakers are maintained following a specific number of operations.

Routine substation inspections are used to check for corrosion, external damage and the like.



Maintenance is specific to the requirements. Outdoor units may require sand blasting and painting as determined from inspections. Time based maintenance generally covers correct operation, timing tests, insulation levels and determination of contact life, contacts or vacuum bottles are replaced as per the manufacturers' recommendations.

B.2.3.3 Maintenance plan

There are no plans for any significant circuit breaker maintenance. All work consists of routine inspection and maintenance.

B.2.3.4 Renewal plan

Kelso 11kV feeder circuit breakers are being replaced. The existing outdoor SF6 units have become unreliable and parts are not readily available.

B.2.3.5 Retirement plan

Oil and SF_6 gas are reclaimed. Useful spare parts are retained. The contractor scraps the remainder.

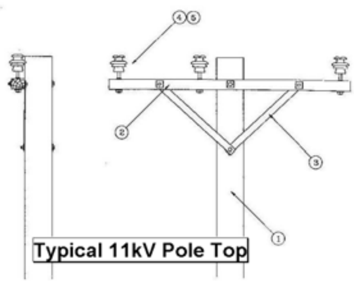
B.3 Distribution circuits

B.3.1 Overhead lines

B.3.1.1 Description and capacity

Overhead lines form the backbone of the rural networks. These form the basis of getting the centralised bulk generation to the multitude of individual customers. The lines account for the largest proportion of rural network costs and interference to customer supply.

Most lines are rated at 11kV phase to phase. This is the most common voltage utilised for distribution within New Zealand and has been the standard used in Southland and most of Otago since the inception of reticulated electrical supply. A few circuits have been built at 22kV. This voltage has four times the capacity of 11kV and greatly reduces voltage drop and losses. There is generally a 15% cost penalty in using this voltage over 11kV, so implementation is limited. There are a few other



voltages used specifically in conjunction with Single Wire Earth Return (SWER).

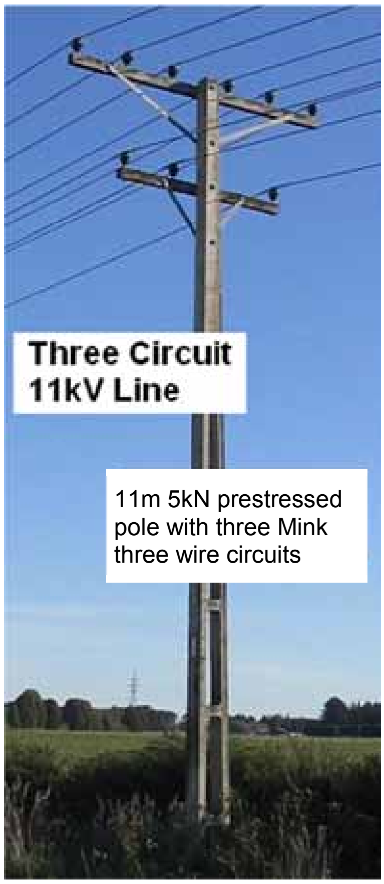
The majority of feeder lines are three wire three phase with all connections phase to phase. A significant of the Southland lines reduces to two wire single phase circuits. SWER is used a little bit within remote parts of the Southland system.

SWER system consists of one phase wire and the earth as a return path. Voltages to earth vary, typically being 6.35kV, 6.6kV and 11kV. Special transformer systems are generally required to create the SWER voltage. The main advantage of SWER is that the number of poles and length of conductor can be significantly reduced from the standard 11kV requirements. Cost is significantly reduced at the expense of very limited capacity.

A typical concrete pole is 11m long with a transverse top load capacity of 5kN. A typical softwood pole is 11m 9kN symmetric top load capacity. 12m, 6kN and 12kN poles are also relatively common. Common conductors previously used are relative small such as: Squirrel, Dog, Mink, Dog and Cockroach. The present AAAC standard allows for five conductors for most situations:

Conductor Name	Current Rating	Resistance
Chlorine	150A	0.86Ω/km
Helium	250A	0.38Ω/km
Iodine	350A	0.24Ω/km
Neon	500A	0.12Ω/km
Oxygen	700A	0.09Ω/km

B.3.1.2 Condition, age and performance



Bulk electrical distribution within Otago and Southland generally commenced around 1930. Lines are up to 70 years old. Most construction was undertaken in the 1930's, 1950's and 1960's. The 1970's and 1980's expansions were generally to transmit larger levels of energy into the existing reticulated areas. Present construction levels are very low.

Consequently there is quite a range of material and construction types. Hardwood poles gave way firstly to concrete, then largely softwood and now returning to concrete. Copper conductor was very common. This was generally replaced by AAC and ACSR conductor (All Aluminium Conductor and Aluminium Conductor Steel Reinforced) based on a lesser cost. The present standard is AAAC1120 (All Aluminium Alloy Conductor) based on price and resistance to corrosion. Maintenance requirements vary by material.

Poles are the critical and most expensive component of line support. Most construction in the 1930's utilised hardwood poles because of availability and strength. Hardwood poles cannot be effectively treated and are therefore prone to rot. Rot is worst in the biologically active ground area. Rot is often not visible, such that many poles that appeared healthy were in fact very prone to failure. Typical life expectance of hardwood poles varies from 30 years to 70 years. Around 20% of poles are hardwood. Structurally the poles are very good, but cost and life expectancy limit hardwood pole usefulness.

Concrete poles became prevalent in the 1950's. The strength of these poles is very limited and failure from abnormal overload such as snow loading can be a problem. They do not suffer from significant deterioration so maintenance requirements tend to be limited.

More recently softwood poles have been introduced based on cost and strength. These are treated timber with a minimum life expectancy of 50 years. Long term durability has yet to be confirmed.

New concrete poles became the standard from 2008. The new design provides improved strength and expected long life.

Cross arms are generally hardwood and suffer from significant deterioration. Life expectancy varies, but since they are not in contact with the ground a minimum life of 20 years is expected. Recent crossarms have the top surface painted to extend their life to 30 years. A few lines have been constructed in armless format, but generally this form does not have acceptable mid span clearance. For most distribution lines hardwood crossarms remain the preferred form.

Conductor life is limited by vibration (excessive tension) and corrosion. Copper conductor is robust, but very expensive. ACSR conductor is prone to corrosion especially in coastal areas. All Aluminium Alloy Conductor has been chosen as a standard conductor that is expected to limit maintenance requirements of line conductor.

The age profile of poles is shown in Figure 17.

B.3.1.3 Monitoring and procedures

Overhead distribution lines are the dominant feature of rural networks. With poles numbering over 100,000 and conductor length over 1,000,000m the largest proportion of capital is tied up in these assets. Consequently cost effective procedures have been introduced to optimise the balance between cost, safety and reliability. The PowerNet inspection and maintenance regime is aimed at the identification and rectification of defects which have the potential to cause outages or which threaten safety. The following specific procedures are extracted from the Lines Services Contracts Scope of Works.

Strategies

Focus should be on:

- Higher priority will be given to those 33/66kV and 11kV circuits that have a greater potential to adversely affect SAIDI figures.
- Factors adversely affecting SAIFI and the number of faults per kilometre of line to allow subsequent appropriate targeting of maintenance using RCM strategies on areas that significantly impact reliability indices.
- Issues affecting public safety and the safety of employees working on the network using CDM strategies.
- Meeting legislative requirements for test and inspection criteria.

Inspection regime

General

The Scope of Work generally describes the requirements for inspections of the subtransmission and distribution networks using visual and diagnostic techniques (i.e. x-ray scanning, thermal imaging) and includes:

Inspections of all the equipment listed, including 5 yearly circuit inspections, 6 monthly transformer inspections/MDI recording and earth testing and ten yearly scanning of wooden pole by x-ray. Upgrading of earths is not included in the scope but may be added at a later date.

Annual inspections of certain circuits selected due to their low reliability and/or high importance.

The contractor will include in its response its proposed methodology in implementing the required strategies and any enhancements that may be beneficial. PowerNet and the Contractor(s) will jointly review the inspection regime and the annual program to ensure best practice is being employed.

Methodology

The PowerNet inspection and maintenance regime is aimed at the identification and rectification of defects which have the potential to cause outages or which threaten safety.

The SAIFI and SAIDI performance of each 11kV feeder and 33/66kV circuit will be analysed quarterly and classified as being either Level 1, 2 or 3. Those in Level 1 will be passed to a team consisting of PowerNet and Contractor's staff for a detailed root cause analysis and to establish an inspection and maintenance strategy. Those in Level 2 will be discussed by the team to reach an agreed maintenance strategy and will then be closely monitored by PowerNet System Control.

Level 1 represents the worst performance.

The table below provides an indication of the inspection and maintenance regime.

- Defect Inspection

This is a detailed route and equipment inspection, generally conducted from ground level and includes an ultra-sound inspection. For the five yearly inspection cycle 20% of the feeders/circuits in the contract area are inspected every year, as part of the cycle and included as part of the lump sum cost.

- Targeted Inspections

Selected feeders/circuits, including those in Level 1 and those supplying important CBD and industrial areas, may require more frequent inspections. The frequency of these inspections will be decided on a reliability basis and completed as a reimbursable cost. Use of a helicopter may be approved in some rural situations.

- Annual Inspections

These are rapid patrol generally achieved by a drive-by, although CBD cable routes may require a walk-by to identify any recent works that may affect cable performance. The object is to identify any obvious defects that may impact network reliability in the short term (2 years). For example: leaning/damaged poles; unbalanced/excessive sags; leaning insulators; loose ties and/or hardware; excavations near poles; clearances from ground, buildings, trees; damaged crossarms, lightning arrestors, insulators; ground mounted equipment: cable protection and terminations; and similar items. Included as part of the lump sum cost.

- Thermal Inspections

Generally carried out at times of peak load on the network in order to identify hot connections. A thermal inspection of connections on CBD, industrial and urban feeders may be required within 3 days of a heavy fault near a substation. Unit rates per kilometre of overhead line and per site for ground mounted equipment are to be provided. Inspections are to be grouped for efficiency and an estimate of costs prepared prior to commencement.

- Ultra-Sound Inspections

To be carried out in conjunction with Defect Inspections and Thermal Inspections.

- Wood pole tests

PowerNet owns a 'X-Ray' scanner equipment that will be made available to the Contractor(s) for the purpose of testing wood (hardwood and softwood) poles. The use of this equipment will be subject to a lease agreement between the Contractor(s) and PowerNet. The Contractor(s) must have at least 2 staff trained in the use of the equipment.
The criteria for selecting poles to be tested are wood poles over ten years old that have not been tested in the previous ten years, or any pole the Contractor(s) believe to be in danger of imminent failure.

A unit rate per test is to be provided on the basis of a specific agreed number of poles.

- Pole Top Inspections

This inspection is to identify any defects in the pole head, crossarm, insulators, tie wire and associated hardware, connections and terminations, as required. A unit rate per kilometre of overhead line is to be provided. Inspections are to be grouped for efficiency and a cost estimate prepared prior to commencement."

	Level 1	Level 2	Level 3
CBD and Major Industrial	Thermal inspection on fault route < 7 day response and correction of urgent defects < 3 month correction of non-urgent defects No loss of 11kV supply	All incidents Level 1	Annual thermal inspection at peak loads, including link boxes Annual cable route inspection 5 yearly defect inspection < 6 month correction of non-urgent defects No loss of 11kV supply
Industrial	Thermal, ultra sound and defect inspection < 1 month response and correction of urgent defects live line < 3 month correction of non-urgent defects No loss of 11kV supply	All incidents Level 1	Annual thermal inspection at peak loads 5 yearly defect inspection, live line pole top inspection and ten yearly pole test < 6 month correction of non-urgent defects
Urban	Thermal, x-ray and defect inspection < 1 month response and correction of urgent defects live line < 3 month correction of non-urgent defects	Thermal inspection following heavy fault Defect inspection Defect correction live line. < 6 month correction of non-urgent defects	Annual Inspection 5 yearly thermal and defect inspection and ten yearly pole test 10 year live line pole top inspection 12 month correction of non-urgent defects
Rural	Defect inspection < 2 month response and correction of urgent defects live line < 6 month correction of non-urgent defects	Defect inspection < 2 month response and correction of urgent defects live line < 6 month correction of non-urgent defects	Annual Inspection 5 yearly defect inspection and ten yearly pole test 12 month correction of non-urgent defects

B.3.1.4 Maintenance plan

A significant volume of maintenance is planned, too numerous to detail within this document.

B.3.1.5 Renewal plan

Few lines are replaced in entirety solely based on maintenance requirements. Most lines are like the proverbial axe that was two hundred years old. It had its head replaced twice and the handle replaced ten times. In theory it was 200 years old. In practice it was much less. Lines, in common with most network equipment, consist of many components of varying age. Complete renewal is usually triggered by capacity upgrade requirements or similar. Significant capital works are listed elsewhere.

B.3.1.6 Retirement plan

Since no lines are being replaced under maintenance, there are no lines that require retirement. However a significant amount of material does become redundant. This typically has little value and is not suitable for reuse, since it is component level material that has deteriorated beyond use.

B.3.2 Distribution cables

B.3.2.1 Description and capacity

Most cables in TPCL network tend to be 1 or 3 core aluminium conductor, XLPE insulated, medium duty copper screen and HDPE sheath. This is the present cable standard used in all of the PowerNet networks. Because of the very short circuit lengths generally associated with cable supply, voltage drop is seldom a problem. So design limits tend to be that of the cable current rating. XLPE cables operate acceptably at significantly higher temperatures to paper insulated cables. Therefore the current rating is higher with XLPE giving a more economic cable form.

The standard sizes and typical ratings of cables are listed below.

Cable type	Current Rating	Resistance
1 x 3C 35mm^2 Al XLPE	135A	0.868Ω/km
1 x 3C 95mm^2 Al XLPE	240A	0.320Ω/km
1 x 3C 185mm^2 Al XLPE	320A	0.164Ω/km
3 x 1C 300mm^2 Al XLPE	420A	0.100Ω/km

Rating is very much affected by the thermal parameters of the surrounding media. Most distribution cables are direct buried to limit temperature rise associated with ducts. Backfill material is almost always the removed material, so no control is available over thermal resistivity. Most backfill tested appears to have similar characteristics to the standard quoted figures.

Lightning protection (surge divertors) is fitted where cables terminate to overhead lines. Over-voltage stress due to lightning is a dominant cause of cable failure.

B.3.2.2 Condition, age and performance

The southern networks basically utilised overhead distribution until 1958 when the Invercargill network started to install 11kV cable. A significant amount of urban development in the TPCL network utilised 11kV cable in the 1970's. The age profile is shown in Figure 19.

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

B.3.2.3 Monitoring and procedures

Little monitoring is conducted on cables. Most processed involving cable is involved with loading and circuit arrangement. Failure analysis is the prime tool utilised to identify possible maintenance or remedial action.

B.3.2.4 Maintenance plan

Several types of cable termination have been identified as a common cause of failure. The breakout arrangements on these terminations are being replaced.

B.3.2.5 Renewal plan

There are no plans to replace existing cables.

B.3.2.6 Retirement plan

No cables have been identified for retirement.

B.3.3 Distribution switchgear

B.3.3.1 Description and capacity

Distribution switchgear used in the Southern region can be classified into four forms. The most common switch is in fact a fuse that can be used to switch, isolate and protect equipment. Around 30,000 HV fuses are in service in sets of 1, 2 or 3. The most common fuse is the drop out fuse rated up to 100A. These are the preferred type because of fault rating and clearly visible break point. A number of glass fuses and sand filled porcelain are still in use, but are generally replaced during significant maintenance work. Fuses are fitted at transformers, on HV service mains and quite a number of lateral circuits.

The majority of true switches, generally in rural areas, are pole mounted air break switches (ABS). There are approximately 1500 switches in service. They are generally rated 200A continuous capacity or 400A. Most are in fact more correctly called isolators because their load breaking capacity is in the range of 10A to 20A. 10% of these switches have load break heads that allow the switch to break rated load. A few enclosed units are being trailed.

Approximately 200 outdoor ring main unit switches are in service with most being manufactured by ABB (SDAF series). These are often associated with transformers and located on the road berm.

There are a significant number of indoor polymer construction switches such as Krone and Magnefix. These are mounted within the few LV substation buildings, or more generally within transformer kiosk enclosures.

B.3.3.2 Monitoring and procedures

Experience has shown that the ABB and indoor Ring Main Units require little maintenance. Routine visual inspections are conducted in conjunction with line surveys. The dominant maintenance requirement is protective painting of outdoor equipment.

Outdoor air break switches are also visually assessed. Major switchgear is periodically inspected with Infrared thermal cameras, which are the main method of identifying joint or contact heating problems. Unfortunately, for the majority of switchgear, failure during operation is the first indication of a maintenance requirement.

B.3.3.3 Maintenance plan

There are no plans for any specific switchgear maintenance. All work consists of routine inspection and maintenance.

B.3.3.4 Renewal plan

General renewal as part of works identified in five yearly inspections.

B.3.3.5 Retirement plan

Most switchgear removed from service is overhauled and made available for reuse. The contractor scraps the remainder.

B.3.4 Distribution transformers

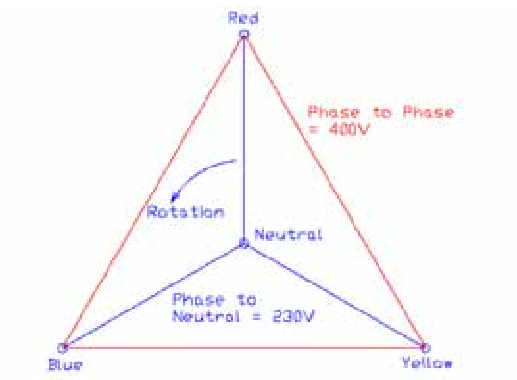
B.3.4.1 Description and capacity

The concept of electrical transformers was central to the development of the present integrated electricity systems found throughout the world. Previous centralised generation systems were extremely inhibited due to the limits imposed by low voltage direct current utilisation. Transformers provide a relatively economic means to convert voltage and allow distribution of electricity over large areas. Distribution transformers are the present devices used to convert distribution level voltages to reticulation level voltages directly usable by customers.

The majority of rural transformers supply one or two customers in close proximity. Since many rural properties are spaced kilometres apart there are a great number of customers with their own individual transformer. The most common rural transformer size is 10kVA to 30kVA. Urban customers tend to have section frontages of 20m, meaning they are in close proximity. The most economic electrical supply arrangement tends to have around 50 domestic customers connected to a single transformer. Consequently the most common urban transformer ratings are 200kVA to 300kVA.

The primary side voltage ratings must match the distribution voltages. Consequently most distribution transformers have a primary rating of 6.6kV, 11kV or 22kV phase to phase. A few connect directly to 33kV subtransmission and are therefore rated at 33kV. There are a few single wire earth return (SWER) transformers in the systems. These are generally rated at 6.35kV, 6.6kV or 11kV phase to ground.

The secondary side voltage must be suitable for typical reticulation voltages. The secondary rating is almost always 240V phase to neutral which is equivalent to 415V phase to phase. An important point to note is that the standard New Zealand nominal LV voltage is 230V, yet 240V transformers are used. 230V is the nominal voltage with an allowable deviation of ±6%. As load is applied to a transformer the voltage always drops. Transformers are rated at the upper limit of the allowable voltage range. As load increases the voltage falls through the nominal system voltage towards the minimum allowable limit. This fine distinction has created problems, even with experts.



Another item of significance that is best explained in terms of transformers is that of polyphase systems. Polyphase systems generally utilise three phases, usually being the most economic form. Two important differences exist between single phase (or direct current) and three phase systems. The three phase system has two voltage levels available. 230V is the voltage between any one of the tree phases and the common neutral point. But 400V is the voltage between any pair of the three phases. The standard vector arrangement of distribution transformers is Dyn11. It is difficult to connect some transformers in a standard fashion. Consequently the actual 400V system vector varies.

The other significant advantage of three phase supply is that the system has a sense of rotation. Motors will rotate in a direction defined by their electrical connection. Originally many rural properties utilised motors, so three phase supply was prevalent. Typical domestic requirements are met by single phase supply. Groups of urban customers are most economically supplied by connecting single phase customers to three phase transformers.

Consequently there are a great variety of transformer configurations and ratings. This has significant implications for stocking levels and renewal availability. Most transformers are purchased with off load tap change (OLTC) systems to allow adjustment of voltage. The dynamic nature of voltage variation and correct specification generally means that the tap setting must remain on neutral, so OLTC is in fact not particularly practical or useful.

There are four general forms of transformers. Most rural transformers in the range of 15kVA to 50kVA are pole hanger mounted. These have brackets that allow easy installation of the transformer hear the pole top, giving a very economic installation. Some large outdoor transformers are still in service, mounted on heavy specially made pole structures. This arrangement is rather messy. Most of these units are replaced or rearranged to some form of ground mount system.

A third form of transformer is the kiosk unit. These are freestanding ground mount transformers that have cubicles included to enclose associated switches and terminations. These are the most common form of urban transformer. A similar form is a cable entry transformer that has no cubicles for switchgear. Cables are terminated in small termination boxes.

None of the above forms require additional housing. There are a limited number of open bushing transformers houses in specially built structures. These are commonly called distribution substations. The cost and land requirements mean these are quite rare within the southern systems.

Transformers are one of the few network assets that can be readily and uniquely tracked as individual items. Most other named items are formed of combinations of minor parts that are replaced as needed. Consequently the age of lines, for example, is in reality not really definable. With transformers, however, at least the nameplate has a manufacture date. The tank and cores may have been replaced, but a date can still be associated with each transformer. Transformers are fairly robust devices. It is economic to overhaul many units for reuse on the system. Consequently there are quite a number of old units still in use as shown in the age profile graph in Figure 20.

Care is required in interpretation of transformer age. In many cases the age refers to the site installation date. The age in that case will in reality be that of the transformer site including miscellaneous equipment associated with transformation. The actual transformer may be older still.

Transformers have for many years been purchased on a total cost economic basis. This includes capitalization of losses. Losses now form part of the MIPS legislation that specifies maximum allowable equipment losses. Generally there is little difference between old and new transformers

B.3.4.2 Monitoring and procedures

As equipment failure is not a major cause of outages most maintenance is based on inspections. Age of assets is deemed to have greater impact on maintenance requirements and inspection strategies are adjusted to allow for this. Small rural transformers are inspected together with line circuits on a 5 year basis. Urban transformers and large rural transformers are inspected on a six monthly basis and Maximum Demand Indicators are read where fitted.

The typical maintenance requirement is for tank and bushing repair or refurbishment. This can usually be determined from the visually inspection. A 5 year cycle of inspection is well within typical deterioration rates. Catastrophic failure is very random in nature and no economic means are available to determine risk of failure. The six monthly inspections are largely to check for overload and problems with miscellaneous equipment such as fuse heating.

Transformers are replaced on site with new or refurbished transformers. Removed transformers are individually assessed for repair or retirement.

B.3.4.3 Maintenance plan

There are no plans for any large scale maintenance of transformers. All work consists of routine inspection and maintenance.

B.3.4.4 Renewal plan

A number of transformers are being replaced as part of renewal programs, or due to load requirements. These changes are part of the capital plans.

B.3.4.5 Retirement plan

Oil is removed from scrapped transformers and the remainder of the transform sold as scrap metal. Bushings are sometimes kept where these may prove useful to replace damaged insulation. High loss and nonstandard transformers removed from service are invariably scrapped.

Typical LV ABC Reticulation mounted on common HV Pole

B.4 Reticulation

B.4.1 Overhead lines

B.4.1.1 Description and capacity

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

Underground reticulation became dominant in the 1960's especially in urban areas, but overhead reticulation has remained in some areas until this day. The main change in overhead construction has been the use of aerial bundled conductor (ABC) since around 1990. This eliminated the need for crossarms, uses covered conductor and is generally a more reliable and aesthetically pleasing overhead format.

Typical LV Overhead Reticulation arrangement

The dominant bare wire conductor sizes range from 14mm^2 (7/16 Cu) to 40mm^2 (19/16Cu). ABC uses aluminium conductor of 35mm^2, 50mm^2 and 95mm^2 area. Some bare aluminium conductor was used prior to the introduction of ABC.

Many LV reticulation circuits are attached to 11kV poles.

B.4.1.2 Condition, age and performance

Most overhead reticulation is relatively old, because little of this construction is used now days. Age profiles are provided in Figure 21.

LV systems are more tolerant of ambient conditions than HV systems due to the much lower voltage stress imposed.

B.4.1.3 Maintenance plan

There are no plans for any large scale maintenance. All work consists of routine inspection and maintenance. LV overhead reticulation is managed on a similar basis to the HV distribution, although with a lesser priority.

B.4.1.4 Renewal plan

Renewals are done as reticulation is checked as part of the on-going inspections.

B.4.1.5 Retirement plan

See overhead distribution.

B.4.2 Reticulation cables

B.4.2.1 Description and capacity

The majority of reticulation is now undertaken using cable circuits. Cable is generally aluminium conductor with a copper neutral screen. Standard sizes are 95mm^2, 185mm^2 with a small amount of 300mm^2 as the maximum size. The dominant selection criterion is to limit voltage drop. Typically cables are loaded to 30% of their current capacity.

The combination of aluminium cable and copper based switchgear requires rigid adherence to proper termination procedures, generally utilising bimetal compression joints.

B.4.2.2 Condition, age and performance

Few problems are experienced with underground cable. Most faults are due to joints and external mechanical damage. The cable network is relatively young as shown in Figure 23.

B.4.2.3 Monitoring and procedures

Little monitoring is conducted on cables. Most processed involving cable is involved with loading and circuit arrangement. Failure analysis is the prime tool utilised to identify possible maintenance or remedial action.

B.4.2.4 Maintenance plan

Minor works only.

B.4.2.5 Renewal plan

No renewal is planned for.

B.4.2.6 Retirement plan

No cables have been identified for retirement.

B.4.3 Service mains

B.4.3.1 Description and capacity

Service mains are generally the responsibility of individual customers with the demarcation point at the local pillar box. But a large proportion of rural service mains are MV. MV circuits are generally not a specialty of customers or their electricians. Consequently ownership of most MV service mains now resides with the associated network.

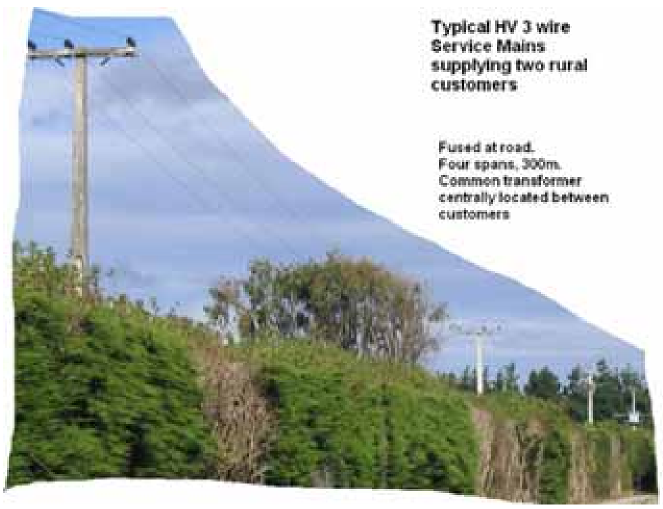
Typical MV service mains will be of 2 or 3 wire squirrel conductor, possibly 2 to 5 spans long. In many cases there will be drop out fuses protecting both the line and the transformer.

B.4.3.2 Condition, age and performance

Not a lot of information is available on service mains due to past ownership changes.

B.4.3.3 Monitoring and procedures

A 5 yearly inspection regime is in place, as required for safety and forward planning. Similar methods are used as with the distribution circuits. This inspection is limited to circuits identified as owned by the various networks.



B.4.3.4 Maintenance, renewal and retirement

Little maintenance is planned. Retirement is at the whim of the individual customers.

B.5 Earthing

B.5.1.1 Description and capacity

Earthing is a very importance safety system that is often overlooked. Earthing costs are significant. Earthing comes in two general forms. In urban areas with close proximity between transformers the prime format is to ensure interconnection of earth systems to create a large equipotential grid. In rural areas the main purpose is to create a connection to earth that has a reasonable resistance and will ensure that protection will operate to clear any fault.

Urban design targets limiting EPR to 650V and ensuring Touch Voltages are acceptable. $70mm^2$ earth conductor is used to allow for the relatively large fault currents.

Rural design attempts to achieve a 10Ω earth resistance. $25mm^2$ conductor is used, suitable for the lower fault currents.

B.5.1.2 Condition, age and performance

The age profile of earth system is similar to that of transformers. Unfortunately earth systems, by definition, are in close proximity to the ground. Corrosion is an on-going problem.

B.5.1.3 Monitoring and procedures

A 5 yearly inspection regime is in place. Generally a site is inspected, tested and maintained as a single process. Sites are chosen from the GIS system based on last inspection.

B.6 Ripple control

B.6.1.1 Description and capacity

"Ripple Control" controls a large proportion of demand side load directly or indirectly. This is a form of communications that has the highest probability of reaching all electrical sites. Ripple control is a very slow speed communication signal superimposed on the network. Where 50Hz power flows, so does the ripple signal.

Modern systems utilise 216⅔Hz as the carrier signal. Older systems used 500Hz to 1000Hz, which had problems due to electrical resonance. The signals propagate similar to telephone signals. Communications theory is required to understand and analyse the operation of ripple control.

Ripple systems consist of three basic sections. Firstly the load must be monitored such that appropriate control actions can be undertaken. This is done with separate SCADA equipment.

Secondly a signal must be injected onto the 50Hz network. This is done with Injection Plants. And finally the signal must be detected by a Receiver that undertakes control at the individual installations. A common receiver is shown in the section Metering below. It is similar to a radio receiver that receives its signal not from an antenna, but from the mains wiring. One, two or three relays control equipment such as hot water heating, night store heaters and meters. The maintenance and control of receivers is intricately tied to meters.

The central part of ripple control that is discussed here is injection plant. They all consist of a generator and a coupling cell. The generator was traditionally a motor/generator set. Modern generators use electronic components to convert 50Hz firstly to direct current and secondly to the required frequency. A typical rating is 100kVA at around 200V.

The coupling cells vary. Those in use in the PowerNet networks consist of: (a) LV side inductor/capacitor tuning, (b) coupling transformer and (c) EHV capacitors. These operate well under a large range of network configurations.

Many traditional systems injected onto the 11kV busbar of each zone substation. This required a lot of injection plants. The systems within PowerNet all inject at or near to

Transpower Grid Exit Points. The signal propagates quite satisfactorily down to the zone substations on to individual LV installations.

Injection plants are located at the sites below.

- Edendale 33kV 125kVA (a backup coupling connects to the 11kV)
- Gore 33kV 125kVA
- Invercargill 1 33kV 125kVA
- Invercargill 2 (EIL) 33kV 125kVA (Designed to operate in parallel with plant 1)
- North Makarewa 33kV 125kVA
- Winton 66kV 125kVA

The typical signal level is 2%. The system works adequately at injection levels down to 1.4%.

Ripple control has been instrumental in increasing load factor from around 45% to the present 65%. Effectively between 70MW of load is controlled by ripple control.

B.6.1.2 Monitoring and procedures

Most of the plants are located indoors and utilise electronic components. There is little that can deteriorate. Inspection is limited to locating obvious signs of failure. Spare parts or duplicate systems are available as backup in the case of faults. Most work involves tuning and signal level investigation that is largely influence by the network, not the injection plant.

B.6.1.3 Maintenance, renewal and retirement

No maintenance is planned other than routine inspection.

Renewal of plants is envisaged in the later part of the ten years, due to electronics failures and Transpower network upgrades.

B.7 Trees

B.7.1.1 Description and capacity

The networks do not own trees. However they are the single most common cause of faults on the network. Consequently a lot of effort is spent on tree control and maintenance.

B.7.1.2 Monitoring and procedures

Trees and similar vegetation are listed within the GIS system. Procedures are in place for proper monitoring within the bounds of recent legislation.

A significant amount of tree trimming is being undertaken at the expense of the networks. Once trees have been confirmed as being within specified clearances from the lines, the responsibility is placed on the tree owner for future maintenance. At that stage procedures will change to a monitoring and policing role.

C. Appendix - Expanded Data Tables

Table 28 Existing Substations Growth Projection

Zone Substation	2012[47]	2017	2022	2027	2032	2042	2052
Awarua	3.9	4.4	5.0	**5.6**	**6.4**	**8.2**	**10.5**
Awarua Chip Mill	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Bluff	4.8	5.0	5.3	5.5	5.8	6.4	7.1
Centre Bush	4.2	4.6	**5.1**	**5.6**	**6.2**	**7.6**	**9.2**
Conical Hill	1.2	1.2	1.3	1.3	1.3	1.4	1.5
Dipton	**1.7**	**1.9**	**2.1**	**2.3**	**2.6**	**3.1**	**3.8**
Edendale Fonterra	22.2	22.7	**23.3**	**23.9**	**24.5**	**25.8**	**27.1**
Edendale	6.9	7.6	8.4	9.3	10.3	**12.5**	**15.2**
Glenham	1.2	1.3	1.3	1.3	1.4	1.4	**1.5**
Gorge Road	2.1	2.3	2.6	2.8	**3.1**	**3.8**	**4.7**
Heddon Bush	6.3	7.0	7.7	8.5	9.4	11.5	14.0
Hillside	0.7	0.8	0.9	1.0	1.1	1.3	1.6
Kelso	4.5	5.0	**5.5**	**6.1**	**6.7**	**8.2**	**9.9**
Kennington	4.7	**5.1**	**5.5**	**5.9**	**6.3**	**7.3**	**8.5**
Lumsden	3.7	4.2	4.9	**5.7**	**6.6**	**8.9**	**11.9**
Makarewa	5.7	6.3	6.9	7.7	8.5	10.3	**12.6**
Mataura	8.4	8.9	9.3	9.8	**10.3**	**11.4**	**12.6**
Monowai	0.4	0.4	0.4	0.5	0.5	**0.5**	**0.6**
Mossburn	2.0	2.3	2.6	**3.1**	**3.6**	**4.8**	**6.4**
North Gore	9.5	10.2	11.0	11.8	12.7	14.8	**17.2**
North Makarewa	**46.8**	**51.7**	**57.1**	**63.0**	**69.6**	**84.8**	**103.4**
North Makarewa 33kV	51.5	56.9	**62.8**	**69.4**	**76.6**	**93.4**	**113.8**
Ohai	2.6	2.6	2.7	2.8	2.9	3.0	3.2
Orawia	3.3	3.5	3.6	3.8	4.0	4.4	4.9
Otatara	4.1	4.5	4.9	**5.5**	**6.0**	**7.3**	**9.0**
Otautau	4.3	4.5	4.8	**5.0**	**5.3**	**5.8**	**6.4**
Riversdale	4.6	**5.4**	**6.2**	**7.2**	**8.4**	**11.3**	**15.1**
Riverton	5.2	5.7	6.3	7.0	**7.7**	**9.4**	**11.4**
Seaward Bush	8.3	8.7	9.2	9.6	**10.1**	**11.2**	**12.4**
South Gore	9.1	10.0	11.1	**12.2**	**13.5**	**16.5**	**20.1**
Te Anau	6.0	6.7	7.4	8.1	9.0	10.9	**13.3**
Tokanui	1.1	1.1	1.2	1.2	1.2	1.3	1.4
Underwood	12.3	12.6	12.9	13.2	13.6	14.3	15.0
Waikaka	0.5	0.6	0.6	0.7	0.8	0.9	1.1
Waikiwi	**12.1**	**14.0**	**16.2**	**18.8**	**21.8**	**29.3**	**39.4**
Winton	11.7	**12.2**	**12.9**	**13.5**	**14.2**	**15.7**	**17.3**
White Hill (Wind)	-57.2	-57.2	-57.2	-57.2	-57.2	-57.2	-57.2
Monowai (Hydro)	-7.0	-7.0	-7.0	-7.0	-7.0	-7.0	-7.0

[47] Years are Year End, i.e., 2012 is from 1 April 2011 to 31 March 2012

Table 29 Substation Demands with Proposed Developments 2013 – 2017

Zone Substation	2013 Changes	2013 Demand	2014 Changes	2014 Demand	2015 Changes	2015 Demand	2016 Changes	2016 Demand	2017 Changes	2017 Demand
Awarua	0.0	4.0	0.0	4.1	-4.2					
Colyers (New Awarua)					6.7	6.7	0.0	6.9	0.0	7.0
Awarua Chip Mill	0.0	0.9	0.0	0.9	0.0	0.9	0.0	0.9	0.0	0.9
Athol (New)			0.8	0.8	0.0	0.8	0.0	0.8	0.0	0.8
Bluff	0.0	4.8	0.0	4.9	0.0	4.9	0.0	5.0	0.0	5.0
Centre Bush	0.0	4.3	-4.3	0.0						
Centre Bush (66/11kV)			4.3	4.3	0.0	4.4	0.0	4.5	0.0	4.6
Conical Hill	0.0	1.2	0.0	1.2	0.0	1.2	0.0	1.2	0.0	1.2
Dipton	0.0	**1.8**	0.0	**1.8**	-1.8	0.0				
Dipton (66/11kV)					1.8	1.8	0.0	1.9	0.0	1.9
Edendale Fonterra	0.0	22.3	0.0	22.4	4.0	**26.5**	0.0	**26.6**	0.0	**26.8**
Edendale	0.0	7.0	0.0	7.2	0.0	7.3	0.0	7.5	0.0	7.6
Glenham	0.0	1.2	0.0	1.2	0.0	1.3	0.0	1.3	0.0	1.3
Gorge Road	0.0	2.2	0.0	2.2	0.0	2.2	0.0	2.3	0.0	2.3
Heddon Bush	0.0	6.5	0.0	6.6	-6.7	0.0				
Lumsden (New 66/33kV)					3.2	3.2	5.2	8.5	0.0	8.6
Hedgehope (New)	2.0	2.0	0.0	2.0	0.0	2.1	0.0	2.1	0.0	2.1
Hillside	0.0	0.7	0.0	0.8	0.0	0.8	0.0	0.8	0.0	0.8
Isla Bank (New)					2.5	2.5	0.0	2.5	0.0	2.6
Kelso	0.0	4.6	0.0	4.7	0.0	4.8	0.0	4.9	0.0	5.0
Kelso (upgraded)										
Kennington	-5.8									
Kennington (New)	5.8	5.8	0.0	5.9	0.0	6.0	0.0	6.1	0.0	6.1
Lumsden	0.0	3.8	-0.8	3.1	0.0	3.2	0.0	3.3	0.0	3.4
Makarewa	0.0	5.8	0.0	5.9	0.0	6.0	0.0	6.2	0.0	6.3
Mataura	0.0	8.5	0.0	8.6	0.0	8.7	0.0	8.8	-8.9	0.0
Mataura (Upgraded)									8.9	8.9
Monowai	0.0	0.4	0.0	0.4	0.0	0.4	0.0	0.4	0.0	0.4
Mossburn	0.0	2.0	0.0	2.1	0.0	2.1	0.0	2.2	0.0	2.3
North Gore	0.0	9.6	0.0	9.7	0.0	9.9	0.0	10.0	0.0	10.2
North Makarewa	0.0	**47.8**	0.0	**48.7**	0.0	**49.7**	0.0	**50.7**	0.0	**51.7**
North Makarewa 33kV	0.0	52.6	0.0	53.6	0.0	54.7	0.0	55.8	0.0	56.9
Ohai	0.0	2.6	0.0	2.6	0.0	2.6	0.0	2.6	0.0	2.6
Orawia	0.0	3.3	0.0	3.4	0.0	3.4	0.0	3.4	0.0	3.5
Otatara	0.0	4.1	0.0	4.2	0.0	4.3	0.0	4.4	0.0	4.5
Otautau	0.0	4.4	0.0	4.4	-1.2	3.3	0.0	3.3	0.0	3.3
Riversdale	0.0	4.8	-4.9	0.0						
Riversdale (Upgraded)			4.9	4.9	0.0	5.1	0.0	5.2	0.0	5.4
Riverton	0.0	5.3	0.0	5.4	-0.8	4.7	0.0	4.8	0.0	4.9
Seaward Bush	0.0	8.4	0.0	8.5	-0.5	8.0	0.0	8.1	0.0	8.2
Seaward Bush (Upgraded)										
South Gore	0.0	9.3	0.0	9.5	0.0	9.6	0.0	9.8	0.0	10.0
Te Anau	0.0	6.2	0.0	6.3	0.0	6.4	0.0	6.5	0.0	6.7
Tokanui	0.0	1.1	0.0	1.1	0.0	1.1	0.0	1.1	0.0	1.1
Underwood	0.0	12.3	0.0	12.4	0.0	12.5	0.0	12.5	0.0	12.6
Waikaka	0.0	0.5	0.0	0.5	0.0	0.5	0.0	0.5	0.0	0.6
Waikiwi	0.0	**12.5**	-12.8							
Waikiwi (Upgraded)			12.8	12.8	0.0	13.2	0.0	13.6	0.0	14.0
Winton	-2.0	9.8	0.0	9.9	-0.5	9.5	0.0	9.6	0.0	9.7
White Hill (Wind)	0.0	-57.2	0.0	-57.2	0.0	-57.2	-12.7	-69.9	0.0	-69.9
Monowai (Hydro)	0.0	-7.0	0.0	-7.0	0.0	-7.0	0.0	-7.0	0.0	-7.0

Table 30 Substation Demands with Proposed Developments 2018 – 2022

Zone Substation	2018 Changes	2018 Demand	2019 Changes	2019 Demand	2020 Changes	2020 Demand	2021 Changes	2021 Demand	2022 Changes	2022 Demand
Awarua										
Colyers (New Awarua)	0.0	7.2	0.0	7.4	0.0	7.6	0.0	7.8	0.0	8.0
Awarua Chip Mill	0.0	0.9	0.0	0.9	0.0	0.9	0.0	0.9	0.0	0.9
Athol (New)	0.0	0.8	0.0	0.9	0.0	0.9	0.0	0.9	0.0	0.9
Bluff	0.0	5.1	0.0	5.1	0.0	5.2	0.0	5.2	0.0	5.3
Centre Bush										
Centre Bush (66/11kV)	0.0	4.7	0.0	4.8	0.0	4.9	0.0	5.0	0.0	5.1
Conical Hill	0.0	1.2	0.0	1.2	0.0	1.2	0.0	1.3	0.0	1.3
Dipton										
Dipton (66/11kV)	0.0	1.9	0.0	2.0	0.0	2.0	0.0	2.1	0.0	2.1
Edendale Fonterra	0.0	**26.9**	0.0	**27.1**	0.0	**27.2**	0.0	**27.3**	0.0	**27.5**
Edendale	0.0	7.8	0.0	7.9	0.0	8.1	0.0	8.2	0.0	8.4
Glenham	0.0	1.3	0.0	1.3	0.0	1.3	0.0	1.3	0.0	1.3
Gorge Road	0.0	2.4	0.0	2.4	0.0	2.5	0.0	2.5	0.0	2.6
Heddon Bush										
Lumsden (New 66/33kV)	0.0	8.8	0.0	9.0	0.0	9.2	0.0	9.3	0.0	9.5
Hedgehope (New)	0.0	2.2	0.0	2.2	0.0	2.2	0.0	2.3	0.0	2.3
Hillside	0.0	0.8	0.0	0.8	0.0	0.9	0.0	0.9	0.0	0.9
Isla Bank (New)	0.0	2.6	0.0	2.7	0.0	2.7	0.0	2.7	0.0	2.8
Kelso	-5.1									
Kelso (upgraded)	5.1	5.1	0.0	5.2	0.0	5.3	0.0	5.4	0.0	5.5
Kennington										
Kennington (New)	0.0	6.2	0.0	6.3	0.0	6.4	0.0	6.5	0.0	6.6
Lumsden	0.0	3.5	0.0	3.6	0.0	3.7	0.0	3.8	0.0	3.9
Makarewa	0.0	6.4	0.0	6.5	0.0	6.7	0.0	6.8	0.0	6.9
Mataura										
Mataura (Upgraded)	0.0	9.0	0.0	9.0	0.0	9.1	0.0	9.2	0.0	9.3
Monowai	0.0	0.4	0.0	0.4	0.0	0.4	0.0	0.4	0.0	0.4
Mossburn	0.0	2.3	0.0	2.4	0.0	2.5	0.0	2.6	0.0	2.6
North Gore	0.0	10.3	0.0	10.5	0.0	10.7	0.0	10.8	0.0	11.0
North Makarewa	0.0	**52.7**	0.0	**53.8**	0.0	**54.9**	0.0	**56.0**	0.0	**57.1**
North Makarewa 33kV	0.0	58.0	0.0	59.2	0.0	60.4	0.0	61.6	0.0	62.8
Ohai	0.0	2.7	0.0	2.7	0.0	2.7	0.0	2.7	0.0	2.7
Orawia	0.0	3.5	0.0	3.5	0.0	3.6	0.0	3.6	0.0	3.6
Otatara	0.0	4.6	0.0	4.7	0.0	4.7	0.0	4.8	0.0	4.9
Otautau	0.0	3.4	0.0	3.4	0.0	3.4	0.0	3.5	0.0	3.5
Riversdale										
Riversdale (Upgraded)	0.0	5.5	0.0	5.7	0.0	5.9	0.0	6.1	0.0	6.2
Riverton	0.0	5.0	0.0	5.1	0.0	5.2	0.0	5.3	0.0	5.4
Seaward Bush	-8.2									
Seaward Bush (Upgraded)	8.2	8.2	0.0	8.3	0.0	8.4	0.0	8.5	0.0	8.5
South Gore	0.0	10.2	0.0	10.4	0.0	10.6	0.0	10.9	0.0	11.1
Te Anau	0.0	6.8	0.0	6.9	0.0	7.1	0.0	7.2	0.0	7.4
Tokanui	0.0	1.1	0.0	1.2	0.0	1.2	0.0	1.2	0.0	1.2
Underwood	0.0	12.7	0.0	12.7	0.0	12.8	0.0	12.9	0.0	12.9
Waikaka	0.0	0.6	0.0	0.6	0.0	0.6	0.0	0.6	0.0	0.6
Waikiwi									0.0	0.0
Waikiwi (Upgraded)	0.0	14.4	0.0	14.9	0.0	15.3	0.0	15.8	0.0	16.2
Winton	0.0	9.8	0.0	9.8	0.0	9.9	0.0	10.0	0.0	10.1
White Hill (Wind)	0.0	-69.9	0.0	-69.9	0.0	-69.9	0.0	-69.9	0.0	-69.9
Monowai (Hydro)	0.0	-7.0	0.0	-7.0	0.0	-7.0	0.0	-7.0	0.0	-7.0

D. Appendix - Assumptions

When developing this plan we have made the following assumptions:

- No major developments in the region, unless specifically listed.
    - Developers don't always let TPCL know of their plans with large projects kept confidential until the last minute.
- Transpower will upgrade the 110kV network by reinforcing Gore.
- Growth trends will be similar to historic trends.
    - No step changes considered as none are certain.
    - Historic shows actual outcomes over a long period.
- No change in present regulation.
    - Any changes likely to add additional costs.
- Distributed generation will develop slowly with little impact until after ten years.
    - Based on current connections onto the network.
- The standard life of assets is based on the ODV asset life, with actual replacement done on a condition basis.
    - Some areas greatly exceed standard lives (Inland North Otago) and others fail to reach standard lives (Coastal).
- Population for sizing of equipment is based on the high projection.
    - Sizing of equipment step changes are minor with labour cost being a large proportion of works.
- No decline in meat and wool markets.
    - So no closures of the meat processing plants.
- Increase in dairy markets.
    - Growth in dairy farm conversions being similar to recent years.
- Recovery in the timber market.
    - Some additional production occurring at Brightwood, Otautau.
- No major development in coal extraction and/or processing.
    - Any new mine or process could add or subtract load and require new network to be built.
- No major development in mineral extraction and/or processing.
    - Any new mine or process could add or subtract load and require new network to be built.
- Material and Labour costs only increasing by CPI.
    - Any abnormal price movements are difficult to predict and not allowed for in estimates.

10. Approval by Board of Directors

Form 2 – Certificate for Asset Management Plans

We, Alan Bertram Harper and, Maryann Louise Macpherson being Directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge, the attached asset management plan of The Power Company Limited prepared for the purposes of requirement 7(1) of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008 complies with those Requirements.

A B Harper

M L Macpherson

28 March 2012