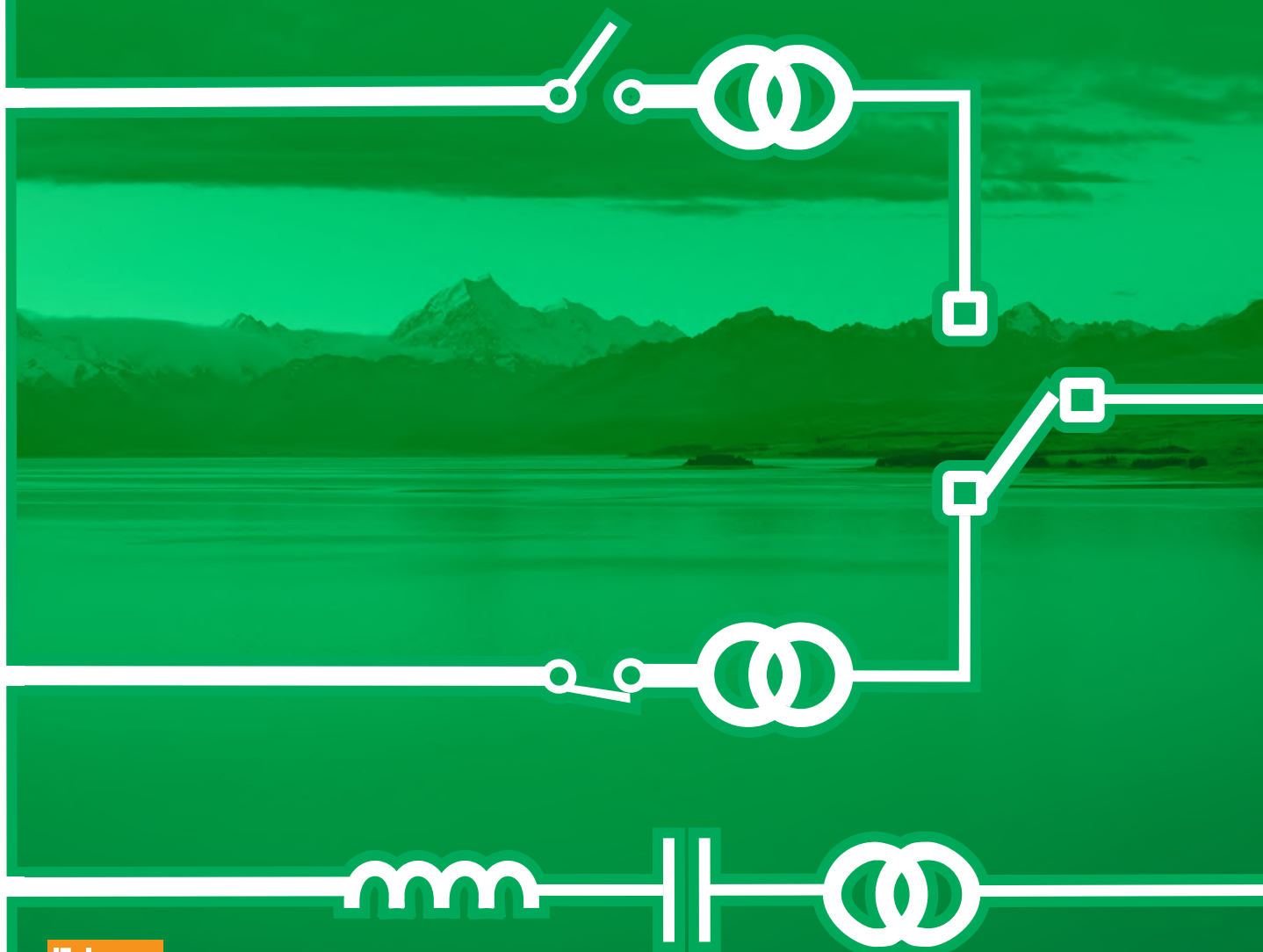




## ASSET MANAGEMENT PLAN

# 2017-2027



## ASSET MANAGEMENT PLAN

### ALPINE ENERGY LIMITED

---

Planning Period: 1 April 2017 to 31 March 2027

Disclosure date: 31 March 2017

---

P: 03 687 4300

F: 03 684 8261

[www.alpineenergy.co.nz](http://www.alpineenergy.co.nz)

---

### LIABILITY DISCLAIMER

Any information contained in this document is based on information available at the time of preparation. Numerous assumptions have been made to allow future resource requirements to be assessed. These assumptions may prove to be incorrect or inaccurate and, consequently, many of the future actions identified in this document may not occur.

Users of the information contained in this document do so at their own risk. Alpine Energy Limited will not be liable to compensate any person for loss, injury, or damage resulting from the use of the contents of this document.

If any person wishes to take any action on the basis of the content of this document, they should contact Alpine Energy Limited for advice and confirmation of all relevant details before acting.

## DIRECTORS' STATEMENT

The purpose of our 2017 to 2027 Asset Management Plan (AMP) is to provide insight and explanation of how we intend to provide electricity distribution services. We are committed to managing our distribution assets in a safe, reliable, and cost-effective manner that addresses required service levels and maintains a robust energy delivery system for our stakeholders.

The AMP has been published to meet our regulatory requirements for asset management under the Electricity Distribution Information Disclosure 2012.

Our distribution network is in a good condition. Assets built in the 1950s and 1960s are near the end of expected service life. However, asset condition and risk is used as a metric to determine when assets are replaced. In addition, assets that have served expected life and have become uneconomic will be retired and replaced with alternative products.

We continue our investment phase by identifying and committing funds for network developments. Developments are identified that best serve our consumers for the next 50 years i.e. the average life of an electricity distribution asset.

Our investment in the network is funded through our tariffs that are set in accordance with our pricing methodology. It is our intention to continue to keep tariffs within the price path set by the Commerce Commission and have a pricing methodology that is consistent with the Electricity Authority's pricing principles.

Capacity increases at grid exit points will be addressed through new investment agreements with Transpower, with a resulting price pass through to consumers as is the case now. Sole beneficiaries identified for additional capacity will have back-to-back agreements to minimise the risk of stranded assets.

We encourage consumers to comment on this document and the approach taken to maintain a cost-effective, safe, and reliable electricity supply to South Canterbury.

The Directors

Alpine Energy Limited

# DIRECTOR CERTIFICATION

## Certification for Asset Management Plan 2017–2027.

We, Stephen Richard Thompson and Alister John France, being directors of Alpine Energy Limited certify that, having made all reasonable enquiries, to the best of our knowledge—

- a) the Asset Management Plan 2017–2027 of Alpine Energy Limited prepared for the purposes of clause 2.6.1 and sub clauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) in all material respects complies with that determination
- b) the prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.



Stephen Richard Thompson

23 March 2017



Alister John France

23 March 2017

# Contents

<b>1. EXECUTIVE SUMMARY .....</b>	<b>11</b>
1.1 The purpose of the plan .....	11
1.2 Key objectives and assumptions .....	11
1.3 Period covered by the AMP .....	13
1.4 Asset management systems.....	13
1.5 Network and asset description .....	14
1.6 Service levels .....	15
1.7 Network development plans.....	15
1.8 Life cycle asset management .....	15
1.9 Risk management.....	16
1.9.1 Health and safety .....	16
1.9.2 Emergency response and contingency planning .....	16
1.9.3 Environment.....	17
1.10 Evaluation of performance .....	17
1.10.1 Expenditure forecast.....	17
<b>2. BUILDING BLOCKS OF THE ASSET MANAGEMENT PLAN .....</b>	<b>21</b>
2.1 Introduction.....	21
2.2 Purpose of the AMP .....	21
2.3 Mission statement.....	21
2.4 Development of strategic goals and objectives .....	22
2.4.1 Stakeholder engagement.....	22
2.5 Key planning documents .....	25
2.5.1 Statement of Corporate Intent .....	26
2.5.2 Asset management policy and strategy.....	27
2.5.3 Annual works plan .....	27
2.5.4 Safety Management System .....	27

2.6	Planning assumptions .....	28
2.7	Asset management systems and processes.....	28
2.7.1	Information technology for asset management.....	29
2.7.2	Operating processes and systems .....	29
2.7.3	Maintenance processes and system.....	29
2.7.4	Renewal processes and systems.....	30
2.7.5	Processes and systems for upgrades or extensions .....	30
2.7.6	Reliability enhancement processes and systems .....	30
2.7.7	Security of supply.....	30
2.7.8	Customer connection processes and systems.....	31
2.8	Accountabilities for asset management .....	31
2.8.1	Accountability at ownership level.....	32
2.8.2	Accountability at governance level.....	32
2.8.3	Accountability at executive level .....	33
2.8.4	Accountability at management level .....	33
2.8.5	Accountability of our contractors.....	34
2.8.6	Key reporting lines .....	35
<b>3.</b>	<b>NETWORK ASSETS.....</b>	<b>38</b>
3.1	Introduction.....	38
3.2	Our area of operations.....	38
3.2.1	Load growth on our network .....	40
3.2.2	Network configuration drivers.....	40
3.3	Network configuration .....	44
3.3.1	Historical constraints on our network .....	44
3.3.2	Transmission supply configuration .....	45
3.3.3	Assets by category .....	46
3.3.4	Sub-transmission and zone substation configuration .....	47
3.3.5	Major zone substation assets .....	49
3.3.6	Sub-transmission and distribution lines and cables .....	53
3.3.7	Distribution substations and transformers.....	64
3.3.8	Voltage regulators, capacitors, and rural switches .....	70

3.3.9	LV reticulation lines, cables, link, and distribution boxes.....	73
3.3.10	Protection, SCADA, and communication systems .....	74
3.3.11	Distributed generation.....	79
3.3.12	Outlook for existing asset configuration.....	84
3.4	Justifying assets.....	84
<b>4.</b>	<b>PERFORMANCE MEASURES .....</b>	<b>87</b>
4.1	Introduction.....	87
4.2	Why measure performance .....	87
4.3	Safety.....	87
4.3.1	Internal audits.....	87
4.3.2	External audits .....	88
4.4	Service standards .....	88
4.4.1	Measuring the impact of interruptions .....	88
4.4.2	Setting the reliability targets .....	89
4.4.3	Performance against the targets .....	90
4.4.4	Causes of unplanned interruptions .....	92
4.4.5	10-year reliability targets.....	93
4.4.6	Worst performing feeders .....	94
4.4.7	Energy delivered .....	95
4.5	Service levels .....	96
4.5.1	Consumer service level preferences.....	97
4.6	Financial performance.....	97
4.6.1	Line charge revenue.....	98
4.6.2	Actual versus forecast expenditure .....	98
4.7	Justifying service levels .....	101
<b>5.</b>	<b>NETWORK DEVELOPMENT PLANNING .....</b>	<b>102</b>
5.1	Introduction.....	102
5.1.1	Background .....	102
5.2	The strategic planning process.....	103
5.2.1	Situation analysis .....	103

5.2.2	Problem definition .....	109
5.2.3	Consideration of options .....	109
5.2.4	Implementation .....	111
5.2.5	Review .....	113
5.3	Demand forecasts on the network .....	113
5.3.1	Inclusion of step demand increases.....	115
5.3.2	Estimated demand at GXP level.....	116
5.3.3	Estimated demand at zone substation level.....	117
5.3.4	Effect of GXP forecasts on supply security .....	120
5.4	Effect of capacity constraints on planning.....	120
5.4.1	Non-electrical constraints.....	122
5.5	Criteria to consider when planning.....	123
5.5.1	Non-network options.....	123
5.5.2	Innovations to defer renewal .....	124
5.5.3	Demand side management.....	125
5.5.4	Options to meet security of supply.....	125
5.5.5	Issues arising from forecast demand.....	126
5.5.6	Estimated asset utilisation.....	126
5.5.7	Impact of climate change on planning.....	126
5.5.8	Equipment used in capital expenditure.....	127
5.6	Network development .....	128
5.6.1	Explanation of material variance in network Capex.....	129
5.7	Large non-network capital expenditure.....	131
5.7.1	Smart meters .....	131
5.7.2	Information technology .....	131
5.8	Capability to deliver .....	132
5.9	Continuous enhancement.....	133
5.9.1	Network Development Plan prioritisation process .....	133
<b>6.</b>	<b>LIFE CYCLE ASSET MANAGEMENT PLANNING.....</b>	<b>136</b>
6.1	Introduction.....	136

6.2	Maintenance planning .....	136
6.2.1	Linking strategic objectives to life cycle management .....	136
6.3	Understanding asset life cycles .....	137
6.3.1	Operating the assets .....	139
6.3.2	Maintaining the assets and systemic failure identification .....	142
6.4	Renewing assets .....	152
6.4.1	Refurbishment .....	152
6.4.2	Renewal triggers .....	153
6.5	Upsizing or augmenting assets.....	154
6.5.1	Network asset delivery .....	155
6.5.2	Building new assets.....	155
6.6	Enhancing reliability .....	155
6.7	Converting overhead to underground .....	156
6.8	Retiring assets .....	157
6.9	Routine and preventive maintenance programmes .....	157
6.9.1	Maintenance policies .....	157
6.9.2	Maintenance work plans .....	158
6.9.3	Defect identification process .....	161
6.9.4	Serious defect rectification process.....	162
6.9.5	Routine maintenance system .....	163
6.10	Maintenance plans for the next 12 months.....	165
6.10.1	Sub-transmission lines and cables .....	165
6.10.2	Zone substations.....	165
6.10.3	Distribution lines and cables.....	168
6.10.4	Distribution substations.....	171
6.10.5	LV lines and cables .....	173
6.10.6	SCADA, communications, and ripple plants .....	173
6.10.7	Vegetation management .....	174
6.11	Non-network asset maintenance and renewal .....	175
6.11.1	Motor vehicles .....	175

6.11.2	Office buildings .....	176
6.11.3	Information systems .....	176
6.11.4	Business equipment.....	176
6.12	Maintenance (Opex) budget projections .....	177
6.13	Replacement and Renewal budget projections .....	177
<b>7.</b>	<b>RISK MANAGEMENT.....</b>	<b>179</b>
7.1	Introduction.....	179
7.2	Safety Management System .....	180
7.2.1	Public Safety Management System .....	180
7.2.2	Health and Safety Management System .....	181
7.3	Emergency response and contingency planning .....	182
7.3.1	Business continuity planning .....	182
7.3.2	Emergency Preparedness Plan.....	182
7.3.3	Emergency communications.....	183
7.3.4	Participant Rolling Outage Plan .....	183
7.3.5	Specific contingency plans .....	184
7.3.6	Civil Defence Emergency management .....	184
7.4	Risk management planning for network assets.....	184
7.4.1	Risk identification.....	187
7.4.2	Risk analysis .....	188
7.4.3	High consequence low probability risks .....	192
7.4.4	Other network asset risks .....	196
7.4.5	Risk management strategies.....	197
7.4.6	Network resilience .....	199
<b>8.</b>	<b>ASSET MANAGEMENT MATURITY.....</b>	<b>200</b>
8.1	Introduction.....	200
8.2	Asset Management Framework.....	200
8.3	Asset Information Systems.....	201
8.3.1	Enterprise Asset Management System.....	202
8.3.2	Business Process mapping .....	202

8.3.3	Geospatial Information System .....	202
8.3.4	Supervisory Control and Data Acquisition system.....	202
8.3.5	Improving asset knowledge quality .....	203
8.4	Asset Management Maturity Assessment Tool .....	203
8.4.1	Changes to our AMMAT scores from last year .....	204
8.4.2	Continuous Improvement.....	205
<b>Appendix A</b>	<b>Capex workplan for 2017/18.....</b>	<b>218</b>
A.1	Clandeboyne zone substation no. 2 .....	218
A.2	Bells Pond upgrade.....	218
<b>Appendix B</b>	<b>Capex workplan for 2018 - 2021.....</b>	<b>222</b>
<b>Appendix C</b>	<b>Material projects for 2022 - 2027 .....</b>	<b>224</b>
<b>Appendix D</b>	<b>Schedule 14a .....</b>	<b>225</b>
<b>Appendix E</b>	<b>Standardisation and optimisation .....</b>	<b>226</b>
E.1	Sub-transmission lines .....	226
E.2	Sub-transmission cables.....	226
E.3	Zone substations .....	227
E.4	Distribution cables .....	227
E.5	Distribution substations—pole mounted .....	228
E.6	Distribution substations—ground and underground mounted.....	228
E.7	Low voltage reticulation.....	229
<b>Appendix F</b>	<b>Schedule 12c(ii) System Demand.....</b>	<b>231</b>
<b>Appendix G</b>	<b>GXP and major assets .....</b>	<b>232</b>
G.1	General.....	232
G.2	Albury GXP.....	235
G.3	BELL'S POND GRID EXIT POINT.....	243
G.4	STUDHOLME GRID EXIT POINT.....	251
G.5	TEKAPO GRID EXIT POINT.....	257
G.6	TEMUKA GRID EXIT POINT .....	267
G.7	TIMARU GRID EXIT POINT .....	278

G.8 TWIZEL GRID EXIT POINT.....291

# 1. EXECUTIVE SUMMARY

## 1.1 The purpose of the plan

Our AMP provides insight and explanation of how we intend to provide electricity distribution services by managing our distribution assets in a safe, reliable, and cost effective manner that addresses required service levels and maintains a robust energy delivery system to our stakeholders.

Our AMP also defines the major initiatives and projects that will meet stakeholder and consumer requirements for the planning period. Preparing the AMP in this format enables us to comply with mandatory disclosure requirements set out in *Attachment A—Asset Management Plans* of the Commerce Commission’s Electricity Distribution Information Disclosure Determination 2015 (consolidated in 2015), 24 March 2015 (ID Determination).

## 1.2 Key objectives and assumptions

Our asset management decision making processes are based on key asset management objectives and assumptions. These are described further below and throughout this document.

### 1.2.1.1 Meeting increasing demand

The demand for new connections during 2016 was down from the levels in 2015 mainly as a result of the lower milk pay-out from the dairy companies. At the time of writing this document, demand has shown a slight recovery on the back of some improvement in dairy pay-outs. Growth in demand includes: irrigation, industrial, commercial, and domestic subdivision connections and extensions. Although dairy conversions were down on 2014 and 2015, growth is still driven by irrigation development and more intensive farming.

We recognise the fact that the economy depends on a secure and reliable electricity supply. Investment in our network will ensure that necessary network capacity is available to support increasing demand.

### 1.2.1.2 Capital investment

We have reported network capital investment over 10 years based on projects with high priority and certainty due to capacity or security constraints, or replacing assets that are either at the end of their useful life, or present an unacceptable risk to the

company. Some projects will be conditional on third party decisions or developments such as consumer projects proceeding and resource consents being granted for irrigation schemes. Some of these could have a substantial impact on our budgets. The Capex spend on capital investment projects is summarised in Appendix A, Appendix B, and Appendix C respectively.

#### *1.2.1.3 Investment in transmission assets*

Some transmission projects may be required in order to provide satisfactory security and capacity at GXPs or transmission lines within the region. We are in constant discussions with Transpower with regards to constraints at some of our GXPs. In this regard, Transpower have also considered and proposed reconfiguration of the grid to address some of the constraints. This can have a significant impact on our planning process.

We will continue to deliver Transpower GXP capacity, grid support projects, and security requirements to current service levels. We pass through transmission costs to consumers through our tariffs.

#### *1.2.1.4 New technology*

We view distributed generation as an enabling technology for network support rather than network replacement. We assume no new technologies with the ability to entirely substitute for electricity network development will become available during the planning period. However, we do recognise the importance and the potential impact on our business and in this regard, and due to the size of our company, we are looking to align ourselves with others in the industry that are busy with or looking to do research, trials and experimentation with new technologies at a network level. We also own a relatively small battery energy storage installation connected to our network for experimentation purposes.

In developing and evaluating options for solutions to network capacity, reliability or security constraints, we consider new technologies. We also involve Infratec<sup>1</sup> when opportunities presents itself for the application of photovoltaic (PV), fossil fuel, wind generation and battery storage.

#### *1.2.1.5 NETcon*

We will continue to use NETcon Limited as our preferred contractor for the construction and maintenance services to the majority of our network through our

---

<sup>1</sup> Wholly owned subsidiary of NETcon Limited specialising in the application of new technologies.

Alliance Agreement. For specialised and when resources are constrained within the group, we will go to the market to obtain the most cost effective solution on behalf of the South Canterbury consumers. For minor new connections projects, our consumers can obtain the services of any network approved contractor.

#### *1.2.1.6 Compliance*

As a monopoly service provider we are subject to both economic and market regulation by the Commerce Commission and Electricity Authority respectively. During the planning period we will ensure compliance with relevant Acts and Regulations.

#### *1.2.1.7 Shareholder requirements*

During the planning period we will meet our shareholders' requirements by achieving the objectives set down in our mission statement.

#### *1.2.1.8 Year-on-year line charge increases*

Each year we set prices in a manner that ensures that we comply with the default price-quality path set by the Commerce Commission, while earning sufficient revenue to fund the continued enhancement of the reliability and security of our network.

Under the DPP Determination, our price increases are capped at CPI + 11% each year until 2020. We are mindful of the impact price increases have on households and businesses. And we are equally mindful of our obligation to balance cost increases against the need to provide a resilient network for our growing communities.

### **1.3 Period covered by the AMP**

This AMP covers the period 1 April 2017 to 31 March 2027 and was approved by our Board on 30 March 2017. The AMP was publicly disclosed by 31 March 2017 in accordance with the ID Determination.

### **1.4 Asset management systems**

The International Standards, ISO 55000:2014 and its companions, ISO 55001 and ISO 55002, were developed from the Publically Available Standard 55 (PAS 55) and are now internationally recognised standards for asset management.

An Asset Management System (AMS) is a subset of asset management and is defined as a set of interrelated or interacting elements of an organisation for coordinating activity to realise value from assets.

Our asset management policy and strategy is the formal expression of the intention and direction of our asset management. The objectives include strategic, tactical, and operational results to be achieved. Objectives are affected by uncertainty from potential events and the resulting risk of consequences.

We have embarked on a journey to implement an asset management framework (AMF) which will be an integral part of our AMS. This framework and the journey is detailed in Chapter 8-ASSET MANAGEMENT MATURITY. An elaboration of our AMS can be found throughout this document and includes descriptions of our strategies and policies, as well as discussions on our:

- asset databases
- system reliability
- condition assessment databases
- load flow analysis software
- maintenance records
- SCADA system
- contract management practices with external contractors
- Alliance Agreement with NETcon.

## 1.5 Network and asset description

We supply electricity to over 30,600 individual connection points throughout South Canterbury. Our area of supply covers approximately 10,000 km<sup>2</sup> and is located on the East Coast of the South Island, between the Rangitata and Waitaki Rivers, and inland to Mount Cook on the main divide as shown in Figure 3.1. Our asset base has a replacement value of over \$166 million.

Electricity is delivered to our network via seven GXPs and one embedded generator. The network delivered 818 GWh of energy and had a half hour average coincident maximum demand of 134.4 MW<sup>2</sup> in 2016. Energy consumption is up from the previous high of 806 GWh and a half hour average coincident maximum demand of 131.3 MW<sup>3</sup>.

---

<sup>2</sup> Recorded in January 2015.

<sup>3</sup> Recorded in February 2014.

## 1.6 Service levels

We set service levels in conjunction with the expectations of shareholders and consumers. Reliability levels are set by the Commerce Commission under the default price-quality path.

We ask consumers for their view of the price-quality trade-offs associated with levels of service and reliability, determined by the present network configuration through our consumer survey. The findings of the survey help us gain an understanding of the level of network performance and develop options to align to consumer reliability expectations.

Previous consumer engagement across both large and industrial, and mass market consumers revealed a high level of support for keeping line charges about the same in return for similar levels of supply reliability.

## 1.7 Network development plans

We identify asset enhancement and development projects through consumer requests and network studies. Guidelines published by the Ministry of Economic Development determine condition and performance grades used for calculating the economic life of an asset.

The large size of new loads, such as dairy factories, makes any projections of load difficult. 5 MW of new load can be supplied with less difficulty when located nearer to existing GXPs, or where a new GXP can be easily developed. However, electricity supply is only one of the factors considered when establishing large industrial loads, with priority given to transport corridors, land use restrictions, labour force, location of resource, etc.

Table 1.3 provides the capital expenditure (Capex) forecast for the next 10 years. Costs are GST exclusive and in constant (real) dollar terms.

## 1.8 Life cycle asset management

Various databases hold age information on existing assets which is used as a guide for setting inspection cycles to determine asset condition. Databases and existing plans record information on major maintenance, refurbishment, and replacement of assets. The collection of further data improves the confidence level of asset condition and performance assessment. We are currently transferring hard copy plans and records into GIS with the pole assets field captured via GPS. Data entry for new and modified plant is ongoing.

A replacement of our existing legacy databases is underway with the goal of improving the efficiency, reliability, and usability of our Asset Management System.

## 1.9 Risk management

A risk management study based on ISO 33000—Risk Management and the EEA Guidelines for Security of Supply in NZ Electricity Networks has been undertaken on a qualitative basis to review all major asset categories.

Our maintenance policies include routine and special inspections to manage asset condition and ensure regulatory compliance.

### 1.9.1 Health and safety

We uphold excellence in health and safety management. We are committed to taking all reasonably practicable steps to ensure the work we do is safe and to prevent any harm to people or property. In this regard we have been accredited to NZS 7901 by external accredited auditors.

Systems adopted in health and safety management are reviewed biannually. External contractors are required to disclose their health and safety management programmes, staff safety, and competency certification.

### 1.9.2 Emergency response and contingency planning

Development and review of emergency response and contingency planning is an integral part of:

- emergency response procedures, as covered in detail in our Emergency Preparedness Plan
- Electricity Authority approved Participant Rolling Outage Plan as required under the Electricity Governance (Security of Supply) Regulations 2008
- other contingency plans for electricity restoration (being developed in conjunction with the above).

We are a member of the Canterbury Lifelines Utility Group. The Group promotes utility resilience and is involved with the development and review of disaster recovery plans for civil defence emergencies as required under the Civil Defence Emergency Management Act 2002.

### 1.9.3 Environment

We are committed to acting in accordance with both the Resource Management Act 1991 and the Hazardous Substances and New Organisms Act 1996.

## 1.10 Evaluation of performance

We use the AMP to measure our asset management performance. Plans to maintain and improve the performance of our asset management are based on:

- improving condition based maintenance strategies
- adopting new and improved maintenance techniques and technologies
- refining the planning for new development projects to meet the need for renewal, upgrade, and extension of the network
- reviewing Asset Management System with a view to upgrading and/or replacing its existing components
- implementing the Commerce Commission AMP Review Report recommendations for achieving compliance.

### 1.10.1 Expenditure forecast

The following section shows our Opex and Capex for the next 10 years and includes discussion on uncertainty, variance analysis, and the use of nominal and/or real dollar terms. Our forecast for 2017–27 is provided in Table 1.3.

#### 1.10.1.1 Management of uncertainty

The statistics related to performance against target are taken from the last financial year (2015/16) summary details to compare actual vs target results over a 12 month period, in line with existing disclosure information.

There is uncertainty in any prediction and, accordingly, our AMP contains a certain level of uncertainty. The drivers of uncertainty in our industry include several large electrical loads driven by turbulent commodity markets, international economic volatility, public policy trends, and possible generation opportunities within our network demand profile.

At the same time, management and monitoring of asset condition provides us with knowledge that we can use to appropriately plan and maintain a safe and reliable network, servicing our consumer expectations into the future.

Table 1.1 lists the certainties we attach to the timeframes covered by the AMP.

**Table 1.1 AMP timeframe certainties**

Timeframe	Residential and commercial	Large industrial	Intending generators
Year 1	Very certain	Reasonably certain	Reasonable certainty
Years 2 and 3	Certain	Some certainty	Some certainty
Years 4 to 6	Reasonably certain	Little if any certainty	Little if any certainty
Years 7 to 10	Reasonably certain	Little if any certainty	Little if any certainty

### *1.10.1.2 Use of nominal and constant dollar values*

Both Capex and Opex values are expressed in constant dollar amounts (real dollars) unless otherwise specified. The values have been adjusted using an inflator of 2%<sup>4</sup> which approximates annual inflation for the next 10 years. Please note that Opex is decreasing in real terms for the first six years of the planning period. We have decided to introduce an efficiency factor equal to the approximate inflation rate. Opex is set to decrease in real terms by 2% p.a. which means that adjusting this amount by inflation each year leads to Opex values that remain static for the next 6 years (in nominal terms).

### *1.10.1.3 Forecast variance for 2015/16*

Table 1.2 shows the variance between forecast and actual expenditure for the 2015/16 financial year. Information required by Clause 2.6.5 and Attachment A of the Information Disclosure Determination 2012 are provided in detail in the Commerce Commission Schedule 11a and 11b. A copy of the Schedule in MS Excel format is available on our [website](#).

<sup>4</sup> From most recent Treasury forecasts.

Table 1.2 Variance between actual and forecast expenditure in 2015/16

<i>Variance between actual expenditure and previous year forecasts</i>	<i>Forecast ('(\$000) 2015/16</i>	<i>Actual ('(\$000) 2015/16</i>	<i>Variance As a %</i>
<b><i>Capital expenditure</i></b>			
Customer connection	2,850	8,031	+182%
System growth	1,660	3,079	+86%
Asset replacement and renewal	4,163	4,131	-1%
Asset relocations	495	108	-78%
Reliability, safety, and environment	1,310	3,250	+148%
Subtotal—capital expenditure on network assets	<b>10,478</b>	<b>18,600</b>	<b>+78%</b>
<b><i>Operating expenditure</i></b>			
Service interruptions and emergencies	1,450	1,528	+5%
Vegetation management	500	716	+43%
Routine and corrective maintenance and inspection	2,801	4,212	+50%
Asset replacement and renewal	598	190	-68%
Subtotal—operating expenditure on asset management	<b>5,348</b>	<b>6,646</b>	<b>+24%</b>
<b><i>Total direct expenditure on asset management</i></b>	<b>15,826</b>	<b>25,246</b>	<b>+60%</b>

Table 1.3 AMP forecast expenditure 2017 to 2027 (in \$'000)

Expenditure	Actual	Forecast										
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
<b>Capital expenditure</b>												
Customer connection	8,031	2,850	2,200	2,350	2,350	2,350	2,300	2,300	2,300	2,250	2,300	2,250
System growth	3,079	6,582	6,571	930	2,770	2,280	770	670	630	680	680	680
Asset replacement and renewal	4,131	7,141	5,857	10,352	5,872	6,622	5,782	5,720	9,160	5,660	5,660	5,660
Asset relocations	108	430	2,000	250	350	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Reliability, safety, and environment	3,250	1,570	1,578	1,120	825	870	870	870	870	870	870	870
<b>Subtotal—network Capex</b>	<b>18,600</b>	<b>18,573</b>	<b>18,206</b>	<b>15,002</b>	<b>12,167</b>	<b>13,122</b>	<b>10,722</b>	<b>10,560</b>	<b>13,960</b>	<b>10,460</b>	<b>10,510</b>	<b>10,460</b>
Capex on non-network assets	2,495	5,244	12,614	619	486	570	408	377	332	332	512	377
<b>Total Capex</b>	<b>21,095</b>	<b>23,817</b>	<b>30,820</b>	<b>15,621</b>	<b>12,653</b>	<b>13,692</b>	<b>11,130</b>	<b>10,937</b>	<b>14,292</b>	<b>10,792</b>	<b>11,022</b>	<b>10,837</b>
<b>Operational expenditure</b>												
Service interruptions and emergencies	1,528	1,383	1,344	1,317	1,291	1,266	1,241	1,217	1,217	1,217	1,217	1,217
Vegetation management	716	524	611	599	587	576	564	553	553	553	553	553
Routine and corrective maintenance	4,212	3,081	3,000	2,941	2,883	2,827	2,771	2,717	2,717	2,717	2,717	2,717
Asset replacement and renewal	190	360	289	283	278	272	267	262	262	262	262	262
<b>Subtotal—network Opex</b>	<b>6,646</b>	<b>5,348</b>	<b>5,243</b>	<b>5,140</b>	<b>5,039</b>	<b>4,941</b>	<b>4,844</b>	<b>4,749</b>	<b>4,749</b>	<b>4,749</b>	<b>4,749</b>	<b>4,749</b>
Opex on non-network assets	8,398	10,469	10,412	9,982	9,414	8,716	7,683	7,086	7,021	7,013	6,989	8,398
<b>Total Opex</b>	<b>13,746</b>	<b>15,712</b>	<b>15,552</b>	<b>15,021</b>	<b>14,355</b>	<b>13,560</b>	<b>12,432</b>	<b>11,835</b>	<b>11,770</b>	<b>11,762</b>	<b>11,737</b>	<b>13,746</b>
<b>Total expenditure on assets</b>	<b>34,841</b>	<b>39,529</b>	<b>46,372</b>	<b>30,642</b>	<b>27,008</b>	<b>27,252</b>	<b>23,562</b>	<b>22,772</b>	<b>26,062</b>	<b>22,554</b>	<b>22,759</b>	<b>24,583</b>

## 2. BUILDING BLOCKS OF THE ASSET MANAGEMENT PLAN

### 2.1 Introduction

This chapter provides details of the building blocks of our AMP by describing our:

- strategic goals and objectives, and how they are developed
- key planning documents
- asset management systems and processes
- accountabilities of asset management

### 2.2 Purpose of the AMP

The purpose of this AMP is to summarise our governance and management framework to ensure that we:

- set service levels and meet our stakeholder expectations and regulatory requirements,
- understand what levels of network capacity, reliability, and security of supply will be required now and into the future,
- have efficient and effective processes in place for managing all phases of the asset life cycle from the proposal phase to decommissioning in a consistent manner,
- identify risks to AEL and have proper processes in place to manage risks within acceptable levels,
- make appropriate provision for funding the asset life cycle activities
- make informed decisions using a systematic and structured framework at each level within the business,
- have good information on asset location, age, and condition, and
- comply with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 .

### 2.3 Mission statement

Our mission statement can be found in our *Statement of Corporate Intent* and is:

**“To ensure continuing commercial success by providing safe, reliable, and efficient energy delivery and infrastructure services.”**

We achieve our Mission Statement by:

- acknowledging safety as our first value and giving effect to that through our public safety management system, instilling a safety culture through training and familiarity with safety legislation, and adopting safety in design as a basic principle in the establishment of new infrastructure
- operating and maintaining our network infrastructure with view to minimise the impact of outages on our consumers and to perform within the regulatory quality standards
- providing good industry practice asset management services in order to ensure the best allocation of funds and investments that would result in maximum benefit to all stakeholders

## 2.4 Development of strategic goals and objectives

Our strategic goals and objectives are developed through communication with our stakeholders and are for:

- shareholders—to maximise the value of the company in the medium to long term,
- consumers—to provide safe, efficient, and reliable delivery of energy and services,
- Community—to promote energy efficiency and the effective utilisation of our network,
- staff—to be regarded as a fair and reasonable employer in our region and a company for whom staff are proud to work, and
- public and social responsibility—to be a law abiding responsible company.

### 2.4.1 Stakeholder engagement

Stakeholder engagement is an essential part of our decision making process.

Communicating our AMP to stakeholders and inviting their feedback is one way in which we engage.

Table 2.1 describes how we take account of our stakeholders interests.

**Table 2.1 Identification and management of stakeholder expectations**

Stakeholder	Identification and management of expectations	Key interests
Shareholders: Lines Trust South Canterbury and district councils	Through approval and/or amendment of the Statement of Corporate Intent (SCI). We have regular meetings between directors and the trustees.	<ul style="list-style-type: none"> <li>• Health and safety</li> <li>• Financial return</li> <li>• Service quality</li> <li>• Good governance</li> </ul>

Stakeholder	Identification and management of expectations	Key interests
Retailers	Regular meetings and consultations with retailers.	<ul style="list-style-type: none"> <li>• Line charges</li> <li>• Quality of supply</li> <li>• Low transaction costs</li> <li>• Compliance</li> </ul>
Electricity consumers	Most communications are done through retailers as consumers are contracted to retailers rather than us. We engage with industry groups through representatives on an informal basis.	<ul style="list-style-type: none"> <li>• Health and safety</li> <li>• Line charges</li> <li>• Quality of supply</li> <li>• Compliance</li> </ul>
Employees and contractors	Regular staff briefings and contractor meetings. Normal course of business interactions.	<ul style="list-style-type: none"> <li>• Health and safety</li> <li>• Training and development</li> <li>• Compliance</li> <li>• Service quality</li> </ul>
Public, iwi, and landowners	Informal talks, media presentations/information disseminations, and local advertising and sponsorship.	<ul style="list-style-type: none"> <li>• Health and safety</li> <li>• Respect for cultural and environmental issues</li> <li>• Land access</li> </ul>
Regulators: Commerce Commission and Electricity Authority	We receive regular bulletins from the regulators. We submit on the various consultation papers and participate through industry working groups.	<ul style="list-style-type: none"> <li>• Regulated return</li> <li>• Pricing methodologies</li> <li>• Quality of supply</li> <li>• Compliance</li> </ul>
Local councils	Regular meetings to discuss planning. Formally as necessary to discuss common issues (assets on council land or CDEM Group).	<ul style="list-style-type: none"> <li>• Environmental compliance</li> <li>• District and regional plans</li> <li>• Health and safety</li> </ul>
Transpower	Meet and discuss development needs and opportunities as these arise. Participate in industry working groups	<ul style="list-style-type: none"> <li>• Health and safety</li> <li>• GXP loads</li> <li>• Quality of supply</li> <li>• Compliance</li> </ul>
Embedded generators	We receive information from our embedded generators. We submit on consultation papers and provide feedback through industry working groups.	<ul style="list-style-type: none"> <li>• Health and safety</li> <li>• Financial return</li> <li>• Price</li> <li>• Quality of supply</li> <li>• Compliance</li> </ul>

#### 2.4.1.1 Accommodating common stakeholder interest

Table 2.2 describes how we accommodate common stakeholder interests.

**Table 2.2 Accommodating stakeholder interests**

Interest	Description	How we accommodate interests
Safety	Staff, contractors and the public at large must be able to move around and work on our network safely.	We will keep the public at large safe by ensuring so far as is reasonably practicable, 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. Underground assets are recorded on plans and maps and issued to contractors through the "BeforeUDig" process to ensure assets are not compromised or results in a safety hazard. We will so far as is reasonably practicable, ensure the safety of our staff and contractors by providing all necessary equipment, asset information, continuously improving safe work practices, and ensuring that workers are stood down in unsafe conditions.
Viability	Viability is necessary to ensure that stakeholders have sufficient reason to keep investing.	We will accommodate our stakeholders' needs for long-term viability by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return.
Price	Price is a key means signalling underlying costs. Getting prices wrong has economic implications for both us and our stakeholders.	Failure to recover sufficient revenue to fund reliable assets will negatively impact consumers' activities. Under the Electricity Authority's pricing principles prices are expected to be cost reflective. However, our price increases are capped by the default price-quality path administered by the Commerce Commission. Substantial new investment may require us to apply to the Commerce Commission for a customised price-quality path if the default price-quality path is unable to balance security, capacity, reliability, and return on investment.
Supply quality	Continuity, restoration, and maintaining voltage is essential to maintaining quality of supply to our consumers.	We will accommodate our stakeholders' needs for supply quality by focusing resources on quality, continuity, and restoration. We will endeavour to comply with the quality standards under the default price-quality path during each regulatory year.
Compliance	We must comply with many statutory requirements ranging from safety to the annual disclosure of information.	We will comply with our regulatory obligations. Where we suspect non-compliance we will document and report the causes to the applicable regulatory body and implement appropriate corrective action.

Interest	Description	How we accommodate interests
Efficient operation	Operating the business and managing costs efficiently.	We are always looking to improve our asset management systems to make our operations more efficient.

#### 2.4.1.2 *Managing conflicting interests*

Conflicting stakeholder interests are managed by taking account of the hierarchy of priorities:

- 1) Risk reduction
  - a) health and safety
  - b) Environmental
  - c) Compliance
  - d) Financial impact
  - e) Reputation
- 2) Security of Supply
- 3) Reliability of supply
  - a) SAIDI reduction
  - b) SAIFI reduction
- 4) Project Implementation
  - a) SAIDI (Planned)
  - b) Cost
  - c) Ease of implementation

## 2.5 Key planning documents

Our key planning documents set out the actions needed to achieve our strategic goals and objectives and include the:

- Statement of Corporate Intent
- Asset Management Policy
- Asset Management Strategy (in draft)
- Life Cycle Strategies and Fleet Strategies (to be developed)
- Risk Management Policy
- Network Development Plan (over 10 years)
- Works Plan (annually)
- Safety Management System and related documents.

Figure 2.1 shows the interaction of our key processes, entities and planning documents and how they combine to achieve our strategic goals and objectives.

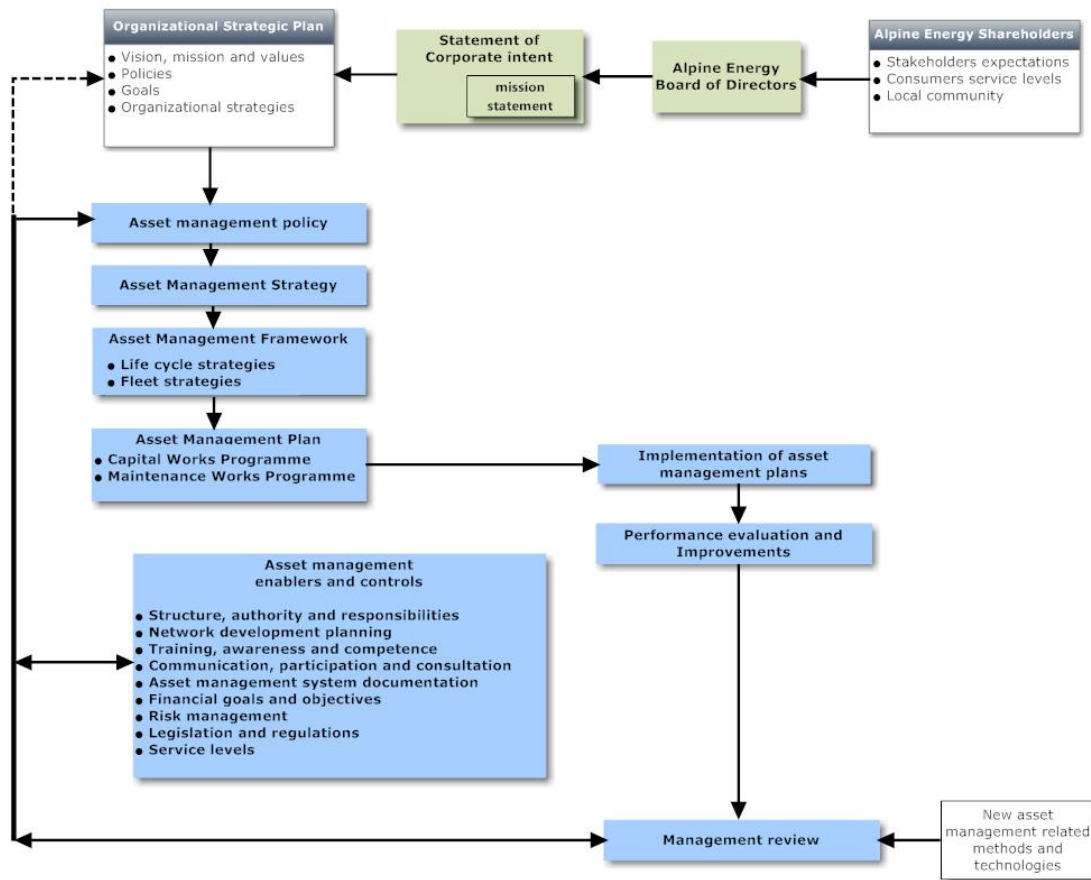


Figure 2.1 AEL asset management system

### 2.5.1 Statement of Corporate Intent

Our Statement of Corporate Intent (SCI) sets out our strategy for delivering our goals and objectives for the next three years (i.e. April 2017 to March 2020) by:

- stating our mission, vision, values, goals and objectives
- detailing the nature and scope of activities that we will be undertaking
- detailing the agreed proprietorship ratio
- committing to have accounting policies that support compliances
- setting financial and operational performance targets
- summarising our dividend distribution policy
- specifying the information to be provided to shareholders
- outlining procedures for the acquisition of interests in other companies or organisations
- disclosing transaction details.

## 2.5.2 Asset management policy and strategy

Our asset management policy aims to align our asset management activities as a service-orientated company to our corporate objectives. The policy also guides the development of specific asset management objectives and strategies. Our policy comprises the following main points:

- safety
- legislative and regulatory compliance
- reliable and efficient electricity supply
- risk management in service delivery
- justified and prudent investment
- appropriate structure and skills mix
- community engagement

Our Asset Management Strategy defines our strategic objectives as directed by our asset management policy, for managing the electricity distribution network assets that supplies the South Canterbury region consumers. Our main objectives are:

- safety in all aspects of asset management
- achieving our service level targets
- effective and efficient expenditure/investment in and on assets
- support community in enabling economic development
- secure and develop our staff to achieve our objectives

## 2.5.3 Annual works plan

Our annual works plan ensures that our activities and projects are prioritised and aligned with our goals and objectives. It reflects on existing projects and adjusts for recent commercial and operational issues, while contributing to long term planning. The projects in the annual works plan are described in this AMP and a list can be found in Appendix A.

## 2.5.4 Safety Management System

We have *Health and Safety Always* as our first value. This includes a Safety Management System (SMS). Having a SMS is also a regulatory requirement which incorporates the *Health and Safety Management System* and the *Public Safety Management System*. It is further described in Chapter 7-RISK MANAGEMENT.

### 2.5.5 Document control, audit and review processes

We control documents described above through several documented processes. These are a combination of Business Process Maps (BPM), ICT systems and committees (including term of References for these committees).

The BPMs are all documented on InfoWorld, our Intranet site, for staff to consult as required. Version control is managed through an ITC system called Industryprint Process Modeller. BPM owners will go through a set process for updating BPMs, including consultation with stakeholders affected by the BPM.

Technical standards are controlled using our AEL documentation database and BPM. Each standard has an owner and stakeholders are tracked through a RASCI<sup>5</sup> responsibility matrix. All current standards in pdf format are available from the documentation database by all staff and selected contractors.

Policies are managed and controlled by the *Policy Steering Committee* and approved by our CEO. The committee members are made up from members of our Executives. All current policies are available to staff from InfoWorld.

The *Health and Safety Committee* together with the *General Manager - Safety and Risk*, control and manage all health and safety documents. Refer to Section 7.2 for more information. All health and safety document are available through our InfoWorld, Health and Safety Portal. This includes Flash reports, safety notices, minutes, reports, policies, references and manuals.

## 2.6 Planning assumptions

Our planning takes into account feedback from all our stakeholders but is also based on assumptions and takes account of uncertainty around the social, economic, and political environment in which we operate. Our assumptions are listed in Section 5.2.1.4-Planning assumptions and impact of uncertainty.

## 2.7 Asset management systems and processes

Our asset management systems (AMS) and processes are methods that we use to manage asset data and information to achieve our strategic goals and objectives.

The present state of our AMS and processes is described below. Further details on our asset life cycle management can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

---

<sup>5</sup> Responsible, Accountable, Support, Consult and Inform,

### 2.7.1 Information technology for asset management

ICT systems specific to asset management are described in Table 2.3 below.

**Table 2.3 Information technology systems and databases**

System	Tasks/data provided	Linkages
GIS	Network asset data and location of all network assets. Network connectivity for electrical tracing and data manipulation.	Links to AMS and ICP database. The ICP database updates address information in GIS.
AMS	AMS database including serial numbers, maintenance data, current ratings, voltage levels, etc.	Links to GIS
ICP database	Metering asset database. Consumer connection point information.	Links to GIS
SCADA	Real time and historic substation data and control.	Stand alone
Nimbus	Accounting and financial asset register	Stand alone

### 2.7.2 Operating processes and systems

To ensure safety to personnel, contractors, public, and plant, our operating systems and processes are based on good industry practices. The Electricity Engineers' Association (EEA) *Safety Manual—Electricity Industry (SM-EI)* and various other EEA published guides guide our internal operating procedures. Workshops with other Electricity Distribution Businesses (EDB) are held regularly to share knowledge and experiences on safe working practices, network control, and operating procedures.

### 2.7.3 Maintenance processes and system

Our maintenance processes are based on good industry practices and manufacturer specifications and maintenance requirements. Generally, asset condition is assessed on age and physical condition. The assessment determines whether an asset is replaced, refurbished, maintained, or deemed to be in good condition and left until the next scheduled inspection or maintenance.

Our present maintenance processes and systems are a combination of manual and paper-based systems (e.g. maintenance and test cards, test reports, and spread sheet schedules) and ICT systems such as Nimbus (accounting and workflow), AMS database, and Geospatial Information System (GIS). Routine maintenance is undertaken by our maintenance contractor or the maintenance contractor's user, holds, and maintains detailed maintenance schedules for our substations, and plant.

Project based maintenance, such as major refurbishment and renewal work, is managed as projects within the context of our overall Works Plan for the year.

### 2.7.4 Renewal processes and systems

When the condition assessment indicates that an existing asset is at end of life, the item is scheduled for renewal. As assets age or exhibit deterioration at different rates, a decision often needs to be made in regard to replacing an entire series or individual assets on successive visits. The economics of each approach is evaluated on a case-by-case basis.

Overhead lines are routinely inspected as detailed in section 6.10.3.4 and the remaining strength of the support poles are assessed to determine end of life. Substation and plant inspections are undertaken either by the maintenance contractor as part of the routine maintenance programme or as part of a once –off condition assessment inspection by a technical expert. The information from these inspections is collated, reviewed, assessed, and used to inform our asset management decisions.

### 2.7.5 Processes and systems for upgrades or extensions

Generic load growth will reduce existing spare capacity. Our forecasting and network modelling tools indicate when feeders are likely to require capital investment to bring the feeder back to compliance with our Security of Supply standard.

Network modelling software programs, such as ETAP<sup>6</sup>, are a valuable forecasting tool in simulation when a feeder will become capacity constraint and subsequent investment to upgrade will be required. For further information, please see Section 5.2—The strategic planning process

### 2.7.6 Reliability enhancement processes and systems

We review faults on our network and investigate the causes to determine how interruptions can be reduced or avoided. Our reliability is measured using the system average incident duration index (SAIDI) and system average incident frequency index (SAIFI) in accordance with the Commerce Commission’s Information Disclosure determination 2012. Refer to Chapter 4-PERFORMANCE MEASURES for more detail.

### 2.7.7 Security of supply

Security of supply is our ability to supply the load on our network to set standards and is aligned to the EEA Guideline *Security of Supply Standards* (EEA Standards Guide) as good

---

<sup>6</sup> ETAP provides electrical power system modelling, design, analysis, optimization, control, operation, and automation software more information can be found on ETAP’s website at <http://etap.com/>

industry practice. As well using the EEA Guide, we take our network conditions into account when evaluating any non-compliance with our Security of Supply Policy<sup>7</sup>.

In setting our security of supply policy, we allow for:

- local geography,
- demography,
- type of load (residential, industrial, medical dependency),
- contractor and technical resource availability (time to switch or repair),
- asset type, and
- consumer requirements.

With these factors applied, different security of supply levels result compared to those contained in the EEA guide.

A non-compliance with our Security of Supply Policy triggers an engineering investigation to remedy the non-compliance.

### 2.7.8 Customer connection processes and systems

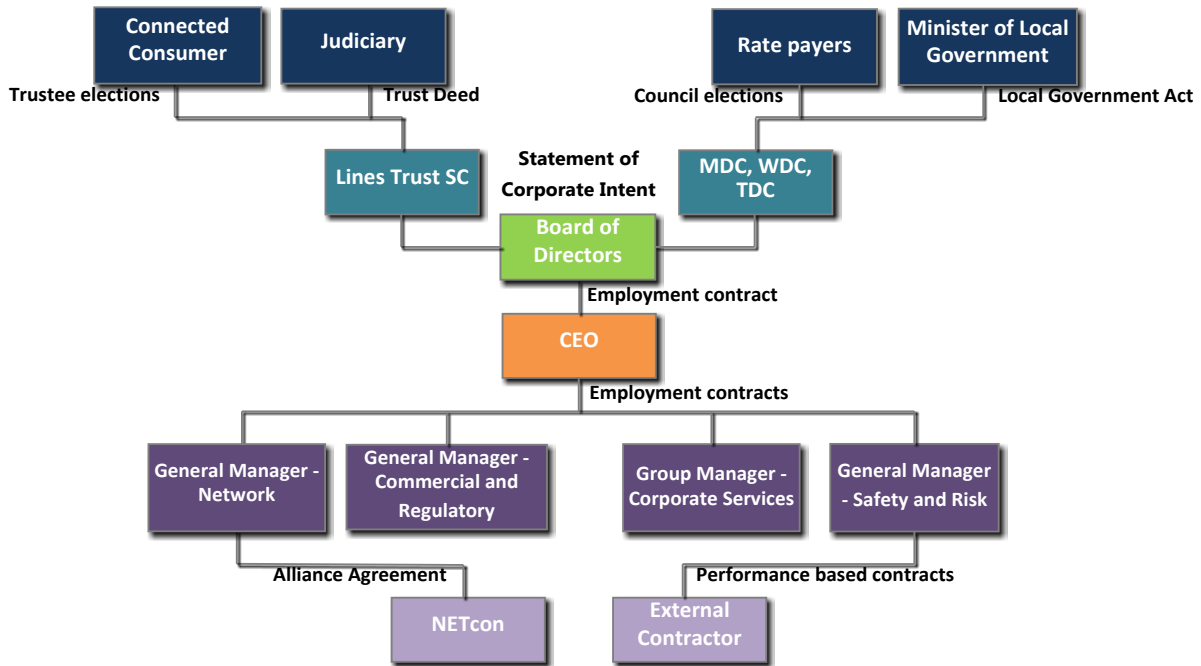
Consumer applications for new connections to our network are processed through a standard system, with contractor quotations used to determine connection price. This process is documented in our Business Process Maps (BPM).

## 2.8 Accountabilities for asset management

Figure 2.2 below shows our asset management accountabilities and mechanisms.

---

<sup>7</sup> We currently use the EEA Guide for Security of Supply 2013



**Figure 2.2 Accountabilities and mechanisms for asset management**

### 2.8.1 Accountability at ownership level

We are 100% owned by the South Canterbury community—the community we serve. Our shareholders are:

- Timaru District Council (TDC)—47.5% shareholding
- Lines Trust South Canterbury—40% shareholding
- Waimate District Council (WDC)—7.54% shareholding
- Mackenzie District Council (MDC)—4.96% shareholding.

### 2.8.2 Accountability at governance level

Our directors are accountable to our shareholders through our SCI. We presently have five directors who are appointed as follows:

- two directors appointed by the Lines Trust South Canterbury
- two directors appointed by the TDC
- one director appointed jointly by the MDC and WDC.

Our directors are responsible for certifying the AMP. In this regard they also approve the Opex and Capex budgets for the next financial year, while noting, but not approving the forecast expenditure for the remainder of the planning period. They receive a monthly board report including but not limited to the following details:

- health and safety
- asset management
- financial performance to budgets for the relevant month and year to date
- quality standards

### 2.8.3 Accountability at executive level

Our Chief Executive Officer is accountable to the directors through an employment contract that sets out the leadership of the organisation and key business performance indicators to meet SCI goals and objectives.

### 2.8.4 Accountability at management level

Accountability for asset management lies with our *General Manager—Network*.

To better align with ISO 55000, we have restructured our Network Department. The new structure is designed to support company strategy and goals, the asset management framework (AMF), legislative and regulatory compliance, our Alliance Charter, workload diversity, quantity, and compliance.

We aim to achieve our goals through the development of a comprehensive AMF; documentation, controls, and review; systems and information management; communication and participation; and structure, capability, and authority.

In order to implement the new structure, the following positions have been created in the Network Department.

*Network Delivery Manager*—is accountable for leading our design and project management team in planning and completing all major designs and project manage the delivery of the annual works plan according to good industry practice and our standards; and for achieving cost effective and safe solutions to network development and refurbishment opportunities.

*Customer Service Manager*—is accountable for leading the new connections team to:

- manage new connections and extensions and distributed generation applications,
- minor designs, project and contract management related to these connections, and
- ensure all metering obligations are met in accordance with the Electricity Industry Participation Code 2010.

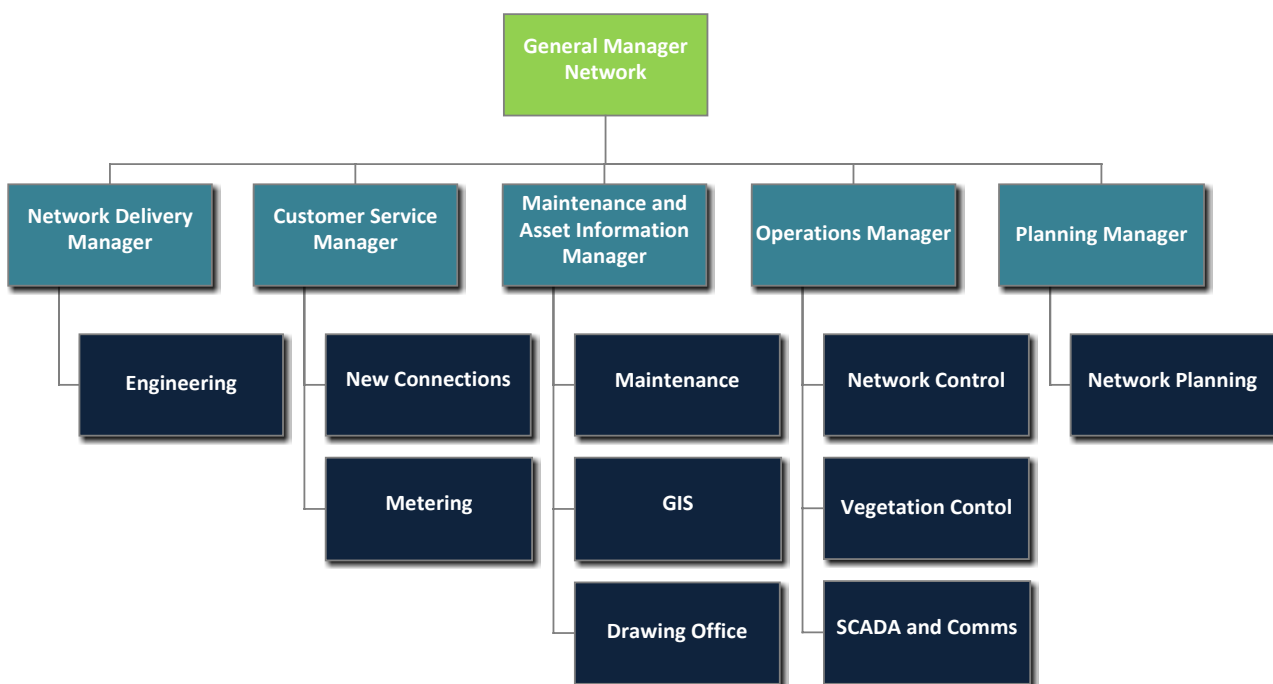
*Maintenance and Asset Information Manager*—is accountable for leading our asset and plant maintenance team, and the implementation, operation, and management of our asset information systems; and for leading the maintenance, GIS, and CAD teams to achieve company goals and objectives.

*Operations Manager*—is accountable for ensuring the safe and reliable operation of the network and for the planning, control, and execution of all work, emergency, construction and maintenance, on the network, including vegetation management.

*Planning Manager*—is accountable for short and long term planning (strategic) of the network and associated deliverables.

Through close team collaboration between the teams managed by the above managers, we balance budgets and coordinate maintenance, renewal, and operation of the asset portfolio as directed under the framework of the AMP and business target strategies.

Figure 2.3 shows our accountabilities at network level.



**Figure 2.3** Accountabilities for asset management at network level

## 2.8.5 Accountability of our contractors

### 2.8.5.1 Contractor accountability

All contractors are obliged to comply with our policies and standards, including:

- Health and Safety Requirements for Network Contractors
- Drugs and Alcohol
- Personal Protective Equipment
- Risk Management
- Network Authorisation and Competency

NETcon is accountable through the Alliance Agreement as our preferred contractor for capital projects and maintenance services on our network. NETcon has approximately 100 staff who provide a scalable resource for us during adverse weather events, large projects, and assist us in our obligations under the mutual agreements we have with other EDBs.

Contractors other than NETcon are accountable through individual performance based contracts.

#### *2.8.5.2 Service contract negotiations*

We use NETcon for the majority of the network's operations, maintenance, renewal, and upgrade work, subject to the Alliance Agreement.

Project work required for extensions, renewals, and upgrades to the network is subject to quotations before jobs are awarded. New connection work is subject to competitive quotes from other contractors, as are some large network projects.

Specialist tasks are undertaken by external contractors who quote to a scope or specification on a competitive basis. For example, some engineering design, civil design, construction associated with new zone substations, major line construction, certain types of communications systems work, and specialist inspection and training services.

#### *2.8.6 Key reporting lines*

The Board of Directors governs our business. The Board has delegated overall responsibility for the management of our assets to the CEO.

Our Board receives a monthly report from management outlining our performance against key indicators, including:

- health and safety
- financial
- operational (corporate)
- corporate
- regulatory
- progress on the annual work plan for maintenance
- capital expenditure activities
- SAIDI and SAIFI

Board meetings are typically held every two months.

The budget detail and review of the AMP is driven by the network managers.

Projects are approved by the Board of Directors through the AMP and Capital Expenditure approval process.

### 2.8.6.1 *Network Department*

The Network Department consists of five teams:

- Network Delivery
- Customer Service
- Maintenance & Asset Information
- Operations
- Planning

#### ***Network Delivery***

The Network Delivery team is responsible for the design, procurement, installing, and commissioning new capital plant assets, as determined by the Planning team and Customer Service team, to meet the requirements of our growing network.

#### ***Customer Service***

The Customer Service team is responsible for processing all new connection and distributed generation applications, as well as technical and administrative metering functions. The team also looks after some retailer service requests such as disconnects, reconnects, site visits, etc. Since we are in the process of moving out of the metering equipment provider space, this workload is reducing.

#### ***Maintenance and Asset Information***

The Asset Maintenance and Information team is responsible for the maintenance of existing electrical assets on our network. The team's responsibility extends to the collection and management of asset condition data. They are also the custodians of all asset data and information systems.

#### ***Operations***

The Operations team is responsible for the real time operational management of the network assets. They also provide tactical planning, operating, and management of fault response services to ensure high levels of consumer service are maintained. The team is also responsible for switching, ensuring that all work on the network is done safely and with as few and shortest supply interruptions as possible.

#### ***Planning***

The Planning Team is responsible for the strategic planning of the electricity network required to meet security of supply requirements, growth, and other changing needs of our network through detailed load forecasting and network configuration studies.

### *2.8.6.2 Corporate Services Department*

The Corporate Services Department manages the financial, human resource, accounting, and ICT system functions.

### *2.8.6.3 Commercial and Regulatory Department*

The Commercial and Regulatory Department ensures that we are aware of our regulatory obligations in accordance with various legislation and regulations under which we operate. The department is responsible for billing and registry functions, and provides commercial support.

### *2.8.6.4 Safety and Risk Department*

The Safety and Risk Department ensures our compliance with: health and safety legislation, industry regulations, staff and contractor training, as well as civil defence, lifeline utility and related matters. The Department ensures that all contractors working on our network are authorised to access the network. The Department champions our health and safety culture through the promotion of good practice and continuous improvement of safety on the network.

## 3. NETWORK ASSETS

### 3.1 Introduction

Chapter 3 describes the geographical area covered by our network and the various types of loads supplied. In addition the configuration of the network is explained and the various types and quantities of assets detailed. The different voltage levels, age profiles and condition of various types of assets are also described as well as the current and forecast loading of different parts of the network.

### 3.2 Our area of operations

Our network stretches over 10,000 km<sup>2</sup>, bounded between the Rangitata River in the north and the Waitaki River in the south.



To the west, our supply extends to the southern divide as far as Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 3.1<sup>8</sup>. The three district councils—MDC, TDC, and WDC—provide infrastructure assets across the area.

The 2013 population statistics for the three council districts are listed in Table 3.1.

<sup>8</sup> The Hakateramea and high country bounding on Aviemore and Benmore lakes are part of Network Waitaki Limited (NWL).

**Table 3.1 Population growth (source: Statistics NZ)**

District\census	1996	2006	2013 census	Growth: 1996-2013	Annual growth
Timaru	42,633	42,870	43,932	3.05%	0.18%
Mackenzie	4,077	3,804	4,158	1.98%	0.12%
Waimate	7,620	7,206	7,536	-1.1%	-0.06%
Total	54,330	53,880	55,626	2.4%	0.14%

The average annual growth in population is small and occurs mostly in urban areas. Most of the load growth on our network comes from the irrigation requirements of dairy farming.

### ***Timaru***

The majority of our 31,936 consumers live in the Timaru area on the east coast, with about 13,500 living in or near Timaru City. Timaru is the hub of South Canterbury, connecting the road networks west, north, and south. The city serves a CBD, a main residential population, and a range of industries and commercial businesses including two meat processing plants; a container, timber, and bulk cement port; a brewery; wool scour; and food processing plants. The majority of load growth in the city comes from industrial development in the Washdyke area.

The second largest population group lives at Temuka, 20 km north of Timaru. Temuka is surrounded by plains used for dairy and cropping farming. Our largest customer, Fonterra (30 MW instantaneous demand), operates a milk processing factory at Clandeboye and continues to stimulate growth in the local economy. The areas north of Temuka, up to the Rangitata River, continue to experience development in cropping and dairying with supporting irrigation.

### ***Mackenzie***

The MacKenzie area is situated 40 km west of Timaru and extends to the main divide. The Mackenzie is an alpine area, requiring assets to be designed for snow and wind loading. The MacKenzie District Council (MDC) is headquartered in Fairlie and administers the Albury, Tekapo, Twizel, and Mt Cook townships. Fairlie is a farming support town, while Tekapo and Mt Cook are tourist and holiday home destinations with growing subdivision and hotel accommodation developments. While Twizel is a tourist pass through, it also has a diverse service industry for engineering, building, agriculture, and salmon farming while also the Mackenzie headquarters for Meridian Energy.

Near Twizel, Meridian Energy has generation assets at Lake Ohau, Lake Ruataniwha, and Lake Benmore. Genesis Energy has generation assets at Lake Tekapo and Lake Pukaki. Growth is occurring in the Tekapo and Twizel areas, with plans for further irrigation

development in the Mackenzie Basin, and a new retail development in the Tekapo Township planned for 2017 onwards.

### **Waimate**

The Waimate area is administered by the WDC and is the southernmost area of South Canterbury. Sizeable irrigation development has occurred here, serving to stabilise the population of the Waimate township. A new irrigation scheme, Waihao Downs Stage 1, was completed last year. Another irrigation scheme, Hunter Downs Water, is planned for the area between Studholme and St Andrews. The Oceania Dairy Limited factory is also a substantial employer in the region and expansion of this factory is currently underway.

#### **3.2.1 Load growth on our network**

The total energy consumed in 2015/16 was 810 GWh. Annually, energy consumed varies from year to year depending on wet or dry irrigation seasons, and severe or mild winters.

The coincident peak demand (CPD) is presently 134 MW<sup>9</sup>. Growth in CPD has been approximately 3.35% per year over the last 18 years.

#### **3.2.2 Network configuration drivers**

Economic activity in our area of operation, particularly activity in the primary industry sector, strongly influences the configuration of our network. In addition our performance targets and service delivery dictates decisions on network configuration and any anticipated changes.

There has been significant growth in dairy farming and processing, bringing an increased demand from irrigation purposes, along with the need to supply Oceania Dairy Limited (ODL) dairy factory near Glenavy and the Fonterra dairy plants at Studholme and Clendeboye. Other large industrial consumers, such as the Alliance Smithfield and Silver Fern meat processing plants, impact on network configuration and augmentation. Overall, the viability of arable farming and the availability of water have a significant impact on the local economy and subsequently also on the design and configuration of our network.

The port operations at PrimePort Timaru<sup>10</sup> continue to be an important part of the region's economy. The recent change in ownership of the port continues the resurgence in local container operations. In addition, Holcim started its operations at PrimePort Timaru (a partner of the Port of Tauranga) for the movement of its bulk cement in December 2015

---

<sup>9</sup> As reported in our 2016 information disclosures

<sup>10</sup> More information about PrimePort Timaru can be found at [www.primeport.co.nz](http://www.primeport.co.nz).

and is now running at full load having added a combined load of up to 3 MW to the supply from Grasmere Street and North Street substations.

### 3.2.2.1 Peak loading

Irrigation load is the main cause of summer peak loading at all the GXPs except TIM, TKA, and TWZ although the increase in irrigation demand is tempered by local environmental restrictions on water use and nitrogen application.

Winter peak loading occurs mainly at TIM and TKA GXPs although other areas, like Fairlie and Geraldine, also have significant demand for load during the winter months.

Winter load demand may rise due to more regulation around air quality and particulate matter, restricting the use of fires for heating and placing greater demand on the network to service other forms of heating, such as heat pumps and other conventional electricity heating.

### 3.2.2.2 Large consumers

We consider large consumers that have a significant impact on network operations or asset management priorities to be consumers that we have a direct contractual agreement with. Our top five consumers, based on demand, are described in Table 3.2.

**Table 3.2 Our directly contracted customers**

Fonterra Co-Operative Group Limited	
Location	Clandeboye 1 and Clandeboye 2, Milford
Dedicated assets	CD1 - One underground 33 kV cable circuit from TMK GXP, plus one overhead 33 kV line circuit from TMK GXP, 33/11 kV zone substation, including 2x 20 MVA OLTC transformers and 15 cubicle 11 kV switchboard, plus many 11/0.4 kV distribution substations with transformers and RMUs. CD2 - One underground 33 kV cable circuit from TMK GXP, plus one overhead 33 kV line circuit from TMK GXP, 33/11 kV zone substation, including 2 x 25 MVA OLTC transformers and 12 cubicle 11 kV switchboard, plus many 11/0.4 kV distribution substations with transformers and RMUs.
Impact on the network	Significant, dictating AMD at TMK GXP, having taken up all capacity at the GXP during the peak of milking season.
Alliance Smithfield	
Location	Smithfield, Timaru
Dedicated assets	11 kV connection to customer owned switchgear. Normally selected to one feeder with a second for backup (not contracted).
Impact on the network	Medium, GXP capacity can be used by other growing loads.

**Fonterra Co-Operative Group Limited**

Location	Studholme
Dedicated assets	12x 11 kV RMUs (one switching and two spare). 6x 11/0.4 kV distribution transformers. Supply teed off two of our rural lines, line reclosers fitted after tee offs.
Impact on the network	Medium to significant in that the rural feeders are restricted when plant load requirements are high.

**Oceania Dairy Ltd**

Location	Glenavy
Dedicated assets	33 kV switching bay at BPD. 33 kV bonded double circuit line (built in 110 kV construction) from BPD to CNR substation. 33/11 kV CNR zone substation with one power transformer. Eight cubicle 11 kV switchboard. 15x 11 kV RMUs (plus 3 more as part of current developments). 12x 11/0.4 kV distribution transformers (plus 3 more as part of current developments). Limited (0.5 MW) alternate supply from STU Morven feeder at 11kV.
Impact on the network	Significant, capacity constraint at BPD GXP during summer peak irrigation period.

**Holcim**

Location	PrimePort Timaru
Dedicated assets	3x 11 kV RMUs, 3x 1.5 MVA transformers, 1x 11 kV supply to the ship loader. At the site, we also created a network tie between Grasmere substation and North St substation.
Impact on the network	Significant since full load cannot be supplied from either Grasmere substation or North Street substation individually.

**Waihao Downs Irrigation**

Location	Corner of Pikes Point Road and state highway 82
Dedicated assets	11 kV circuit from BPD 11 kV switchboard, 3x 11 kV RMUs and 3x 1.5 MVA transformers.
Impact on the network	Significant, capacity constraint at BPD GXP during summer peak irrigation period.

Figure 3.2 below shows the Holcim dome shaped silo used to store bulk cement powder before it is loaded on to smaller ships for distribution throughout New Zealand.



**Figure 3.2 Holcim's cement silo**

Network energy and demand characteristics

Key energy and demand figures for our seven GXP areas for the year ending 31 March 2016 are detailed in Table 3.3.

**Table 3.3 Energy delivered and maximum demand at our GXPs**

GXP area	Energy delivered (GWh)	Max demand <sup>11</sup> (MW)
ABY	10.92	4.29
BPD	39.59	10.75
STU	68.82	14.20
TKA	17.75	4.22
TMK	283.95	52.79
TIM	359.92	64.38
TWZ <sup>12</sup>	12.780	3.46
Exported	-13.43	
Generation	25.46	
<b>Total</b>	<b>805.76</b>	<b>154.09</b>

<sup>11</sup> The individual GXP MD figures are not coincident with each other or the total system MD.

<sup>12</sup> The TWZ GXP is shared by two other customers whose asset utilisation is not shown here.

The maximum demand at the TIM and TMK GXPs have shown low growth over the last six years. Forecast growth in demand predicts a maximum demand increase to 137 MW in 2017/18 and to 152 MW in 2021/22, assuming a constant growth rate of 1.82% over a six-year period. More information on our demand forecasts can be found in Schedule 12c: Demand Forecast at Appendix F.

### 3.3 Network configuration

Section 3.3 describes our network assets in relation to Transpower GXPs. A brief summary is given for GXPs, zone substations, and sub-transmission assets (more detail can be found in Appendix G). A summary of the condition of our network assets is provided in Schedule 12A: Asset Condition of the information disclosure to the Commerce Commission (a copy of the schedule is available on our [website](#)).

Please note that, on limited occasions, network asset age profile data is inconsistent<sup>13</sup>. We currently address inconsistencies on a case-by-case basis. We intend to address the inconsistencies in the long term through the enhancement of our AMS ICT systems (due to go live on 1 April 2017). For more information on the enhancement of our AMS, please see Chapter 8-ASSET MANAGEMENT MATURITY.

#### 3.3.1 Historical constraints on our network

Our network is comprised of two historical line businesses which were merged in 1993—the Timaru Municipal Electricity Department (MED) and the South Canterbury Electric Power Board (SCEPB). The existing asset configuration comprises lines through a corridor in an SCEPB area to supply an encircled MED area (similar to cities like Invercargill, Palmerston North, Hamilton, and Nelson), and has three key characteristics.

- The compact MED is supplied at 11 kV from TIM GXP mainly via underground assets.
- Due to a difference in phase angle between the then MED (Timaru metro area) and the surrounding SCEPB areas, (Temuka and Geraldine) the networks cannot be easily meshed to improve security of supply. These networks must first be turned off before they can be connected to improve reliability.
- There are areas of supply at the boundary of the historical areas that can be improved by greater integration of the assets of the two legacy networks (e.g. by upgrading 11 kV lines and cables, and introducing additional, or upgraded, points of connection between the two networks).

---

<sup>13</sup> For example, the age profiles of 11 kV CBs, ripple plant, and LV cables are presently under review.

### 3.3.2 Transmission supply configuration

A summary of GXP asset information is provided below. Detailed information on Transpower GXPs can be found in Appendix G.

Figure 3.3 shows the transmission grid for South Canterbury including all the GXPs supplying our network.

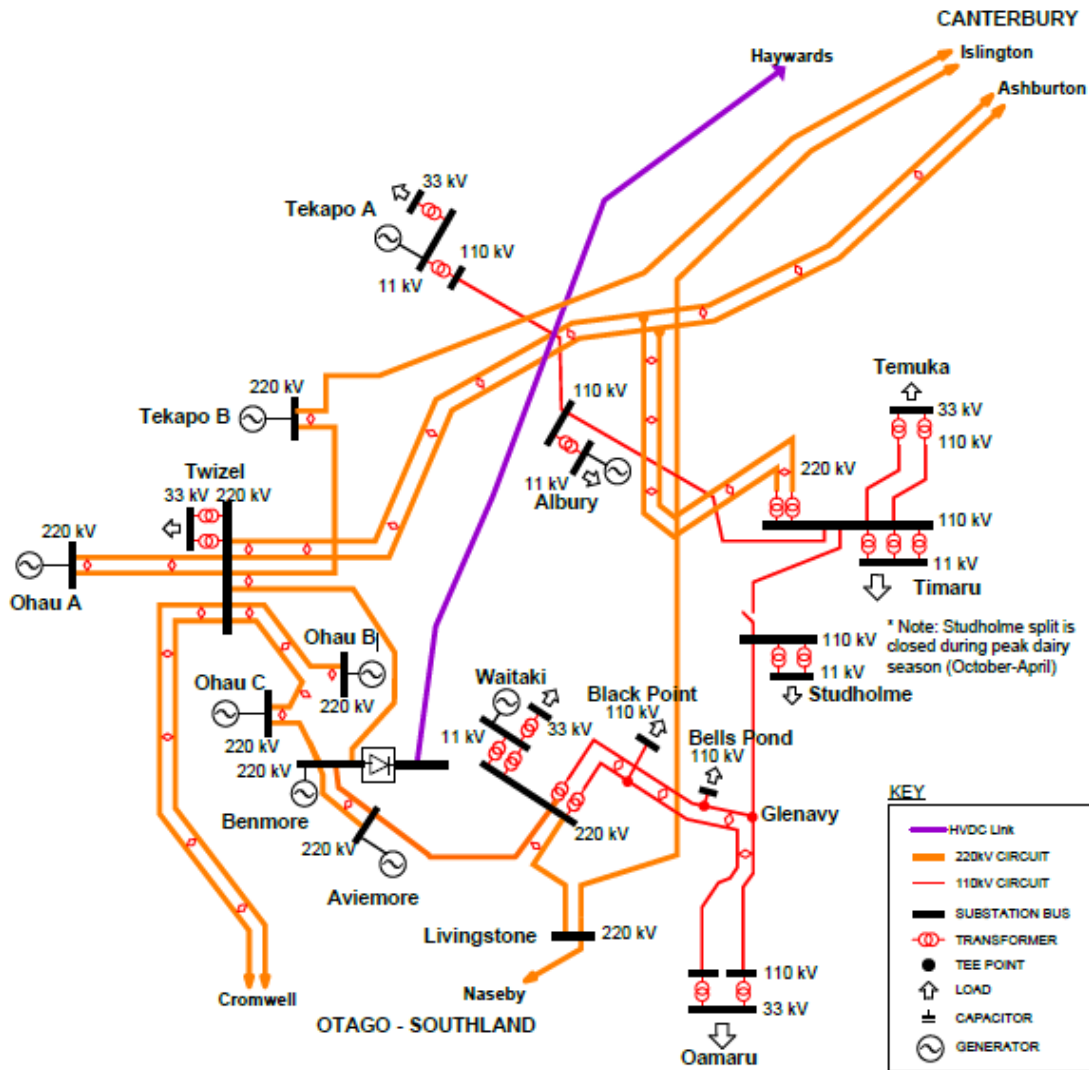


Figure 3.3 Transpower GXPs<sup>14</sup>

<sup>14</sup> Courtesy of Transpower’s Transmission Planning Report

Key energy and demand figures of our seven GXP areas for the year ending 31 March 2015 are detailed in Table 3.4 below.

**Table 3.4 GXP capacity, security, and demand details**

GXP	GXP voltage(s), transmission	GXP supply voltage to Alpine	GXP capacity <sup>15</sup>	GXP (N-1) capacity	Maximum demand <sup>16</sup>	Embedded generation (Opuha dam)
ABY	110 kV	11 kV	5 MVA	0	4.3 MW	7.2 MW
BPD	110 kV	110 kV	20 MVA	0	10.8 MW	
STU	110 kV	11 kV	20 MVA	10 MVA	14.2 MW	
TKA	110 kV	33 kV	10 MVA	0	4.2 MW	
TMK	110 kV	33 kV	108 MVA	54 MVA	55.6 MW	
TIM	220 kV, 110 kV	11 kV	141 MVA	94 MVA	64.4 MW	
TWZ	220 kV	33 kV	40 MVA	20 MVA	3.5 MW	

### 3.3.3 Assets by category

Our assets can be grouped as detailed in Figure 3.4 on the next page.

<sup>15</sup> Thermal limits for continuous operating from Transpower's connection branch report 2013

<sup>16</sup> From management report November 2016

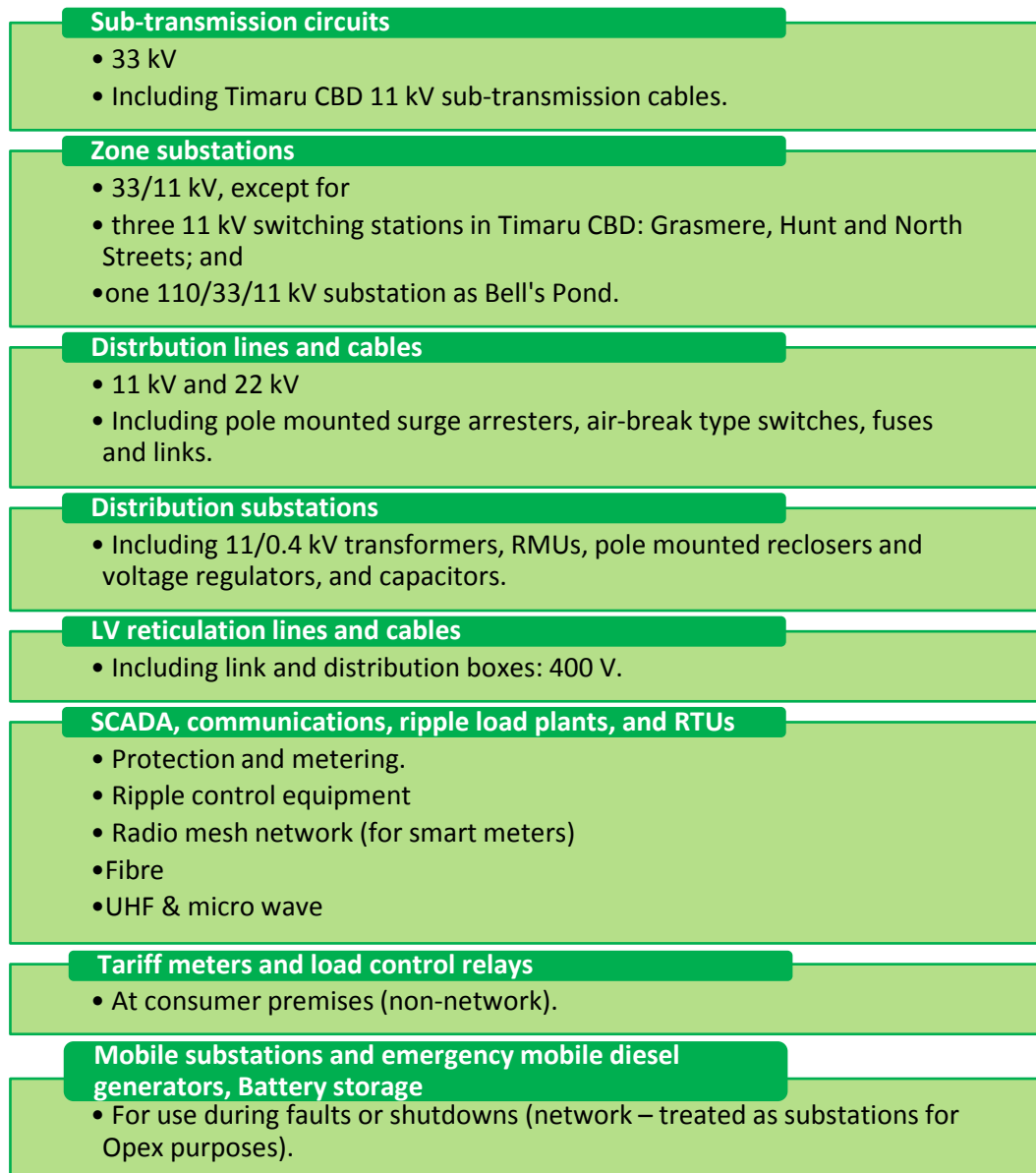


Figure 3.4 Assets by category

### 3.3.4 Sub-transmission and zone substation configuration

This section provides a summary of our sub-transmission and zone substation assets. Detailed information can be found in Appendix G.

The sub-transmission asset configuration is summarised in Table 3.5 below.

Table 3.5 Sub-transmission and zone substation configuration

GXP	Sub-transmission and zone substation configuration
ABY	<p>ABY 11/33 kV step-up substation, supplying a single circuit 33 kV sub-transmission line to FLE, and from there the 33 kV sub-transmission line to the privately owned OPU Power Station.</p> <p>Two 11 kV rural feeders that also supplies the ripple plant via two separate T-offs (selectable).</p>

GXP	Sub-transmission and zone substation configuration
	Connections for the mobile substation and standby/emergency diesel generation are available.
BPD	110/33/11 kV zone substation with four 11 kV feeders and one 33 kV sub-transmission line to CNR (double circuit built at 110 kV but operated at 33 kV). One 11 kV circuit breaker connecting a ripple plant.
STU	11 kV indoor switch room with two incomers from TP GXP, and six feeders supplying the nearby Fonterra Studholme dairy factory, Waimate township, and the surrounding rural area. The ripple plant supplied via a T-off from the Morven feeder.
TKA	Single 33 kV sub-transmission circuit to 33/11 kV TEK zone substation with four 11 kV feeders, and 33 kV sub-transmission line to GTN, UHT, and other smaller 33/11 kV zone substations. Connections for the mobile substation and standby/emergency diesel generation are available. A 33 kV ripple plant is connected via a T-off from the 33 kV sub-transmission circuit.
TMK	Four 33 kV sub-transmission feeders: two double circuit 33 kV lines and two 33 kV cable circuits, to Fonterra's Clandeboye dairy factory (two 33/11 zone substations at Clandeboye). Two 33kV cables (or circuits) to the local 33/11 kV TMK zone substation with six 11 kV feeders. One 33 kV sub-transmission line to GLD. One 33 kV sub-transmission line to RGA. One 33 kV sub-transmission line to RGA tapped off one of the Clandeboye 33 kV lines. A 33 kV ripple plant is connected via a T-off from the 33 kV
TIM	Two 11 kV circuits to TIM, two 11/33 kV step-up transformers, supplying one single 33 kV sub-transmission line to PLP, and two predominantly single circuit and some double 33 kV sub-transmission lines to PAR. Four 11 kV sub-transmission cable circuits to GRM, which then split into a double circuit ring configuration to HNT and NST 11 kV zone substations. Two 11 kV sub-transmission cable circuits to NST (cables rated at 33 kV). Ten 11 kV feeders.
TWZ	Single 33 kV sub-transmission circuit to 33/11 kV TVS substation with four 11 kV feeders.

Table 3.6 provides an overview of the peak load, installed capacity, and security of supply classification at each of our zone substations. A summary of the condition of assets can be found in Commerce Commission's Schedule 12A: Asset Condition (a copy of the schedule is available on our [website](#)).

**Table 3.6 Zone substation details**

Existing zone substation	Voltage Ratio (kV)	Current peak load (MVA) <sup>17</sup>	Installed capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)
ABY	11/33	4.6	5	N	2.5
BML	11/22	0.2	0.6	N	0
BPD	11/33/110	10.8	20	N	3.5
CD1	33/11	15.7	40	N-1	0
CD2	33/11	15.1	50	N-1	0
CNR	33/11	3.1	15	N	1.8/0.8/0.6 <sup>18</sup>
FLE	33/11	2.7	6.25	N	0.5
GLD	33/11	7.0	9	N	4
HLB	11/22	0.3	1	N	0
PAR	33/11	8.4	30	N-1	4
PLP	33/11	5.0	6.25	N	2.5
RGA	33/11	9.6	30	N-1	4
STU	110/11 <sup>19</sup>	14.2	10	N-1	3.5
TEK	33/11	3.5	5	N	0
TMK	33/11	13.3	50	N-1	4
TIM	110/11 <sup>20</sup>	62.8	94	N-1 <sup>21</sup>	0
TIM	11/33	13.4 <sup>22</sup>	50	N-1	0
TWZ	33/11	3.1	6.25	N-1	0
UHT	33/11	1.0	1.5	N	0

### 3.3.5 Major zone substation assets

This section describes the age and condition of substation transformers, as well as 33 kV and 11 kV substation switchgear, and ripple injection plants.

Zone substations convert sub-transmission voltage to distribution voltage—typically 33 kV to 11 kV in our case.

<sup>17</sup> From SCADA system in last 12 months

<sup>18</sup> CNR substation has three transfer capacities: winter/summer/BPD off-load.

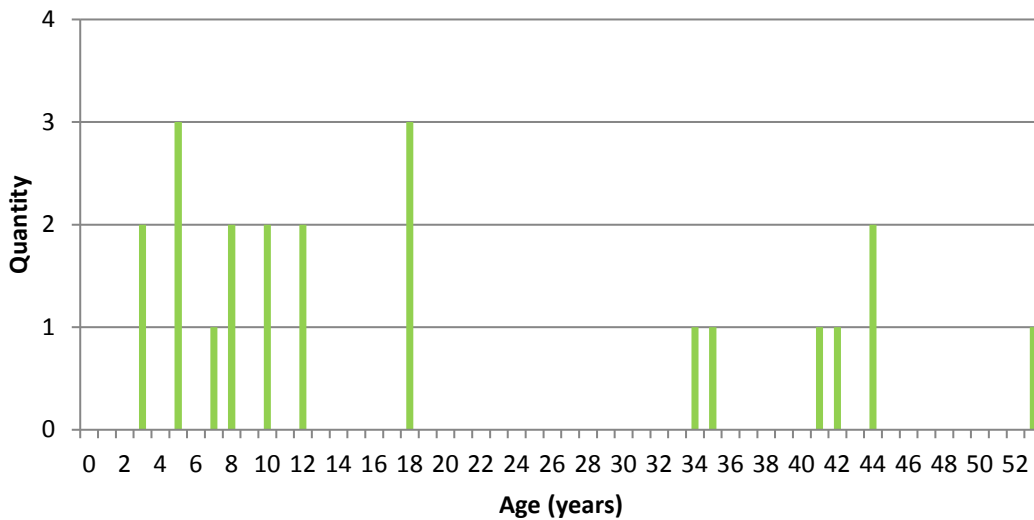
<sup>19</sup> STU substation does not have a transformer, the stated voltage ratio is of upstream TP transformer

<sup>20</sup> TIM substation does not have a transformer at the 110/11 kV level, the stated voltage ratio is of upstream TP transformer

<sup>21</sup> TIM have a third 47 MVA transformer as a hot standby

<sup>22</sup> This value is part of the 110/11 kV TIM peak, however, it is not coincident with the 62.8 MVA observed

### Zone substation transformer age profile



**Figure 3.5 Zone substation transformer age profile**

The zone substation transformer population is in good condition. The older transformers are typically at low loaded sites and have been refurbished mid-life to ensure they reach expected service life of 50 years. The single transformer in excess of 50 years old is located at the Balmoral substation. This substation of 600 kVA supplies mainly rural households and the occasional irrigation pivot, a total of 29 ICPs. This transformer is due for replacement within the next two years. We are also considering alternative solutions, including new technologies such as PV and battery storage to accommodate the load growth in the area. This could influence the replacement of the transformer.

#### 3.3.5.1 Switchgear

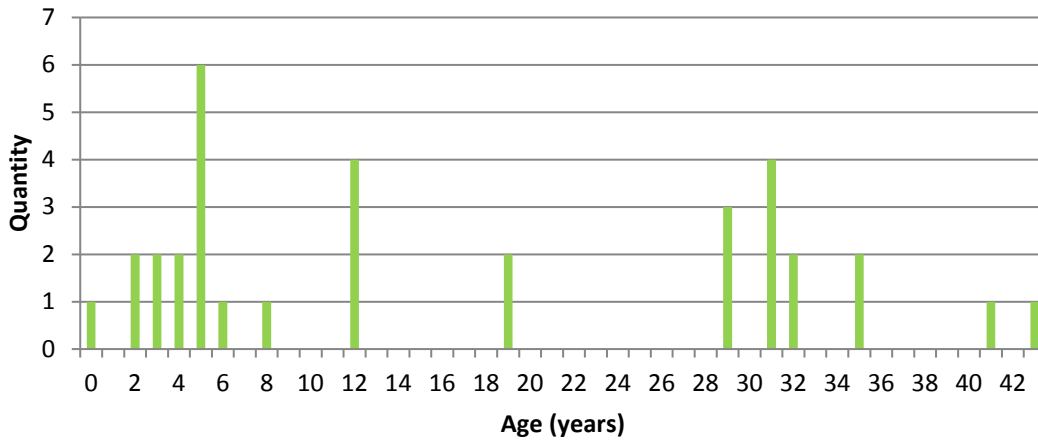
There are three 110 kV rated SF<sub>6</sub> outdoor circuit breakers (CB) on our network. Two are installed at BPD, commissioned in 2008 and 2013 and operating at 110 kV and 33 kV respectively.

In 2014, one 110 kV SF<sub>6</sub> outdoor CB (operated at 33 kV) was commissioned at CNR.

Figure 3.6 shows the age profile of 33 kV switchgear. The age of switchgear ranges between 0 to 43 years.

There are 34 x 33kV circuit breakers and reclosers (switchgear) on our network. The majority of which are located within zone substation compounds to protect zone transformers or sub-transmission lines. Each CB has associated protection relays and/or controllers.

### 33 kV circuit breaker age profile

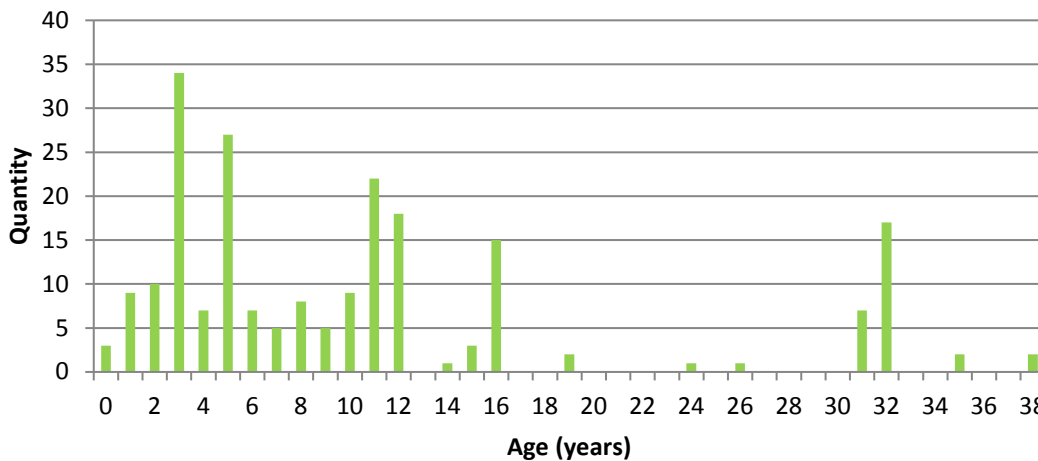


**Figure 3.6 33 kV circuit breaker age profile**

There are 12 with vacuum interrupters and 13 uses SF<sub>6</sub> as an insulating medium. Nine units are contained in bulk oil tanks of which two are due for replacement during the planning period. The remainder is in a good to excellent condition.

Figure 3.7 depicts the age of our 11 kV CBs and reclosers on the network. The majority are vacuum CBs and only 17 are of the bulk oil variety and were installed between 1951 and 1985. The vacuum type CBs are used for new installations and where bulk oil CBs are being replaced. The oil CBs that are older than 40 years will be replaced within the first half of the planning period. The most recent condition assessment recorded their condition as fair. The remainder of the circuit breakers are in a good to excellent condition.

### 11 kV circuit breaker age profile



**Figure 3.7 11 kV circuit breaker age profile**

Inspection of CBs is in line with manufacturer recommendations. Following maintenance, circuit breakers are only returned to service if the condition guarantees sufficient remaining life for the next maintenance period.

### *3.3.5.2 Battery banks*

Battery banks, used to run our protection systems at zone substations, have been replaced with sealed recombinant type batteries that have a higher initial cost, longer expected service life<sup>23</sup>, and low maintenance requirements.

### *3.3.5.3 Protection systems*

Most of the protection assets installed on our network are related to the age of the overhead line, cable, switchgear, or transformer protection. The 33 kV and 11 kV feeder protection systems are generally the same age as the associated switchgear. Protection is tested regularly; if tests and condition assessments determine that the asset is reaching the end of its reliable service life, it is programmed for change-out.

### *3.3.5.4 Substation sites*

The condition of existing zone substation control and alarm varies considerably throughout the system, and is generally dependent on the age of the substation and whether the substation has recently had major switchgear and/or protection systems replaced or upgraded.

The gravelling of switchyards to reduce ground maintenance and enhance personnel safety has been achieved at all sites. Security fencing around sites is regularly checked to maintain site security and prevent unauthorised access. Substation buildings and grounds are regularly inspected and maintained. Detailed information on the life cycle of network assets, including asset condition assessment, replacement, and maintenance can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

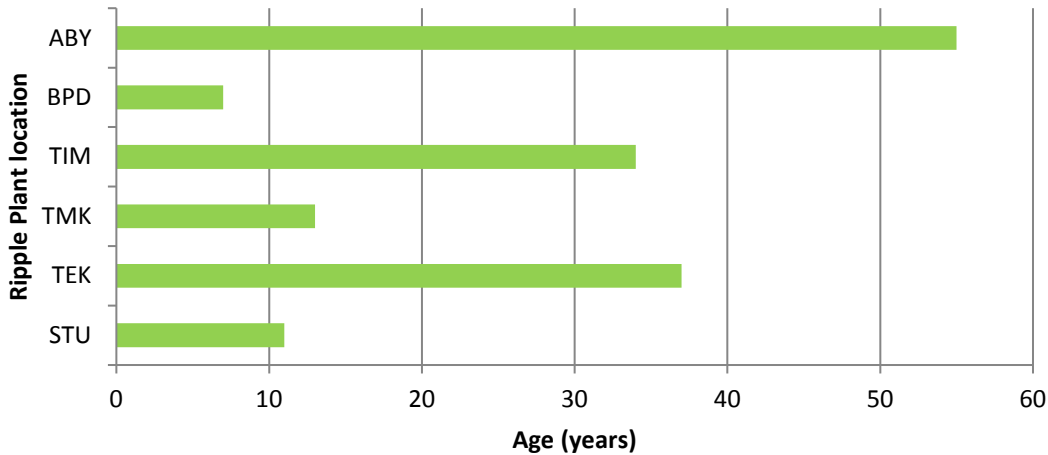
### *3.3.5.5 Ripple plants*

The age profile of current ripple injection plants is shown in Figure 3.8 below.

---

<sup>23</sup> The economic life is 10 years, but we usually change battery banks out after 8 years.

### Ripple Plant age profile



**Figure 3.8 Ripple plant age profile**

To date, we have standardised our 317 Hz static ripple plants at BPD, TIM, STU, and TMK GXP. There are two 500 Hz rotary plants in service at TEK and ABY. The ABY plant will be replaced in the 2016/17 financial year while the TEK plant replacement will be reviewed in light of the use of smart meters to control load. The controllable load in the Tekapo area is small and will not aid in managing a network emergency.

A shared ripple plant is located at the TWZ GXP with Network Waitaki Limited (NWL). The plant's frequency is akin to NWL's as they hold the larger population of ripple receivers. With the TWZ 33 kV bus run split, and NWL on the other side, we have not been able to use the plant. Tariff control is accommodated by time clocks and more recently advanced meters with a time clock function enabled.

The STU ripple plant will have insufficient power output to suit the network if the forecast load growth is realised. It was suggested by the supplier to increase the size of the injection cell from 40 kVA to 80 kVA. This is planned in conjunction with Transpower replacing or upgrading the two supply transformers.

### 3.3.6 Sub-transmission and distribution lines and cables

Our network consists of overhead circuits and underground cables operating at voltages of 110 kV, 33 kV, 22 kV, 11 kV, 6.6 kV, and 400 V that distribute electricity from Transpower GXPs to all consumers' points of supply. The majority of the rural network is overhead lines with a mixture of soft wood, hard wood, and concrete poles. Urban networks are a mix of underground cables and overhead lines.

The proportion of overhead and underground circuit kilometres to total circuit kilometres at each voltage is shown in Table 3.7 below.<sup>24</sup>

**Table 3.7 Circuit length percentages**

Circuit voltage:	110 kV	33 kV	22 kV	11 kV	6.6 kV	400 V
Overhead (%)	100%	84%	99%	88%	0%	52%
Underground (%)	0%	16%	1%	12%	100%	48%
<b>Total (circuit km)</b>	<b>0.1</b>	<b>245</b>	<b>145</b>	<b>3,072</b>	<b>7</b>	<b>669</b>

### 3.3.6.1 Overhead lines

Our overhead network was developed over several decades so it is difficult to identify a single overhead feeder that has reached its predicted 50 year asset life with all of its original components. However, there are well-performing original subsections due to the fact that regular inspection and maintenance can extend the service delivery of overhead systems to the point of distorting the actual age of an asset.

### 3.3.6.2 33 kV sub-transmission

The majority of the 33 kV sub-transmission network was installed in the 1960s and 1980s to meet the growing demand from the rural network. The growth spike of 1996 was due to the construction of the 30 MVA dairy factory at Clandeboye. In 2004, a new line was constructed to supply RGA substation. In 2013, a new double circuit 110 kV designed line, energised at 33 kV, was constructed to supply the ODL dairy factory at Glenavy.

The age profile of 33 kV sub-transmission poles is shown in Figure 3.9 over the page.

Sub-transmission lines built in the last 10 to 12 years are due for inspection in the 20<sup>th</sup> year of service. Earlier inspection and maintenance can be triggered by fault reports.

<sup>24</sup> The circuit kilometres are provided irrespective of construction type (i.e. three-phase, single-phase, and SWER).

### Sub-transmission pole age profile

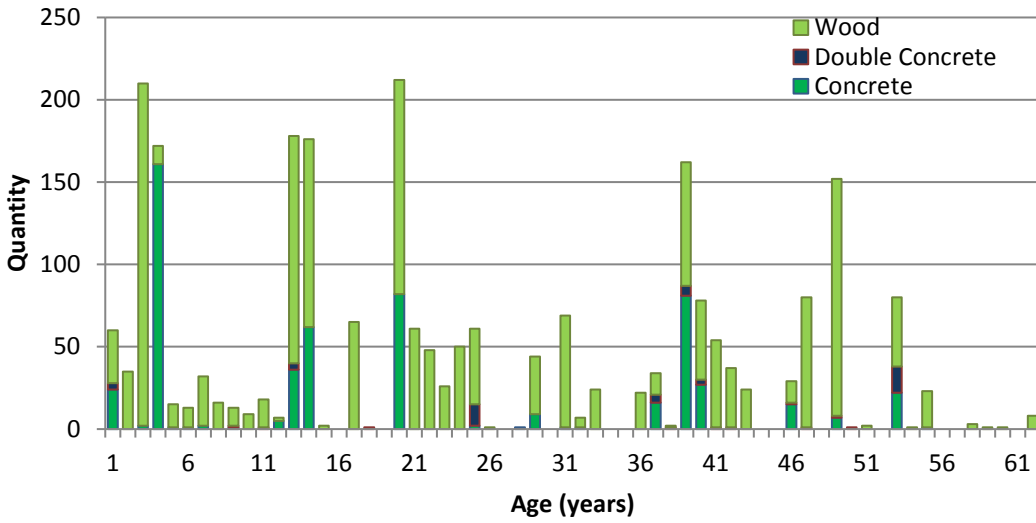


Figure 3.9 Sub-transmission pole age profile

#### 3.3.6.3 11 kV and 22 kV distribution

The majority of the 11 kV and 22 kV distribution network was developed in the 1950s and 1970s. There was little development during the 1980s and early 1990s, with load growth accommodated within existing network capacity.

### Distribution pole age profile

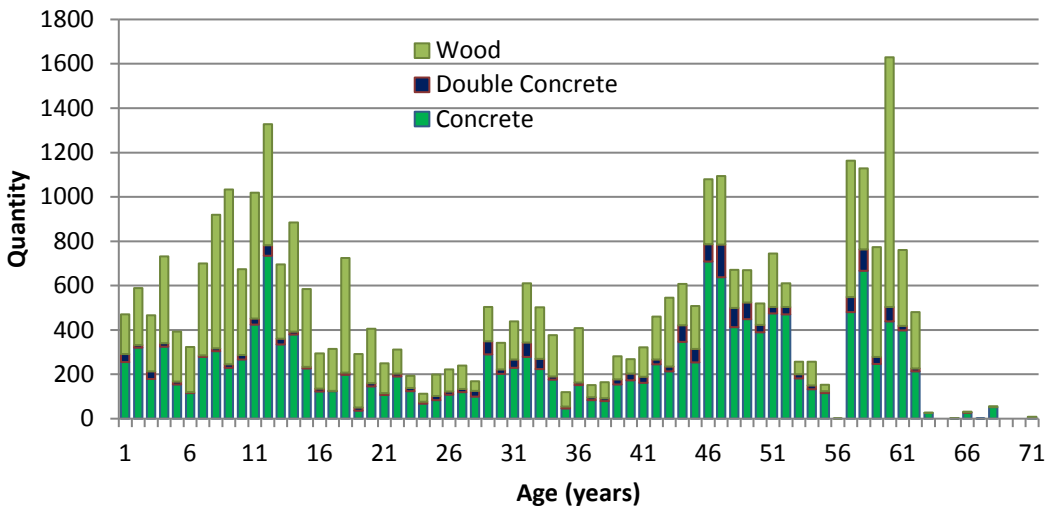


Figure 3.10 Distribution pole age profile

The majority of overhead 11 kV and 22 kV distribution systems developed in the last 15 years are a result of the significant growth in dairying and irrigation. To accommodate the growing demand, we replaced poles and lines with new poles capable of supporting a larger conductor, or by reconstructing existing single-phase lines to meet the three-phase requirements of dairy and irrigation load.

The age of overhead 11 kV and 22 kV distribution poles is shown in Figure 3.10 on the previous page.

**3.3.6.4 LV distribution**

All new LV reticulation in urban areas must be underground in accordance with district plans. Rural LV overhead lines are maintained in conjunction with the 11 kV systems.

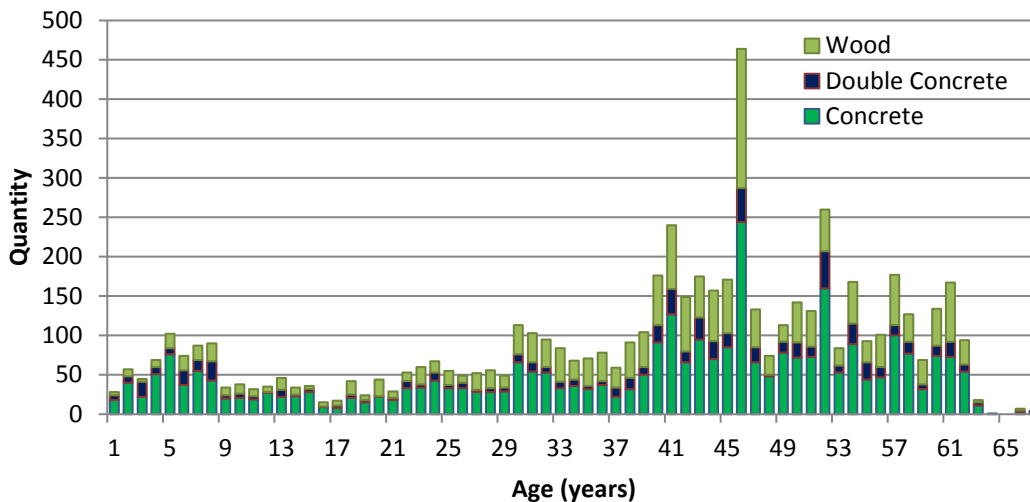
Existing overhead infrastructure will only be undergrounded if:

- health and safety reasons, or
- justified by engineering ,or
- requested by the district council.

Existing overhead lines will be maintained with like-for-like overhead components.

Figure 3.11 show the age profile of LV distribution poles. The majority of poles, including softwood, hardwood, and concrete, are more than 35 years old.

**Low voltage pole age profile**



**Figure 3.11 Low voltage pole age profile**

There are 4% of the poles on our network that we do not have accurate age information on. These poles are inspected as part of our ongoing pole inspection program and when their condition requires, they will be replaced and the data in our systems updated.

### 3.3.6.5 Poles and crossarms

The number of and type of poles are summarised in Table 3.8. The number of poles is sourced from the GIS field capture project conducted in 2007, and subsequent works updates.

All poles have now been individually identified through the field data capture projects and entered into the GIS/AM database (2008/09), with appropriate data relating to age, type, etc. Condition information will be laid over asset information in successive years to build up a complete electronic asset record. In January 2014, a review of softwood poles concluded that softwood poles would no longer be used on the network. Following the review, the estimated life of softwood poles has been reduced as shown in Table 3.8.

A review of our mass reinforced concrete pole making factory in 2013 determined that it was no longer sustainable. The factory was subsequently closed and all concrete poles are now purchased from industry compliant suppliers; pre-stressed concrete poles are specified.

**Table 3.8 Number and service life for pole types**

Pole type	Number of poles	Estimated life (years)
Wood (hard & soft)	19,315	40-60
Concrete	22,299	60-100

Many poles have been replaced to support the growth of the dairy industry in the last 20 years; the adjustment of estimated life will be based on condition assessment.

There are approximately 90% more crossarms than there are poles on the network, allowing for combined HL/LV lines and double arms. Each crossarm has a life of 30 to 40 years. Crossarms are replaced when a condition assessment determines the crossarms are no longer capable of supporting serviceability limit state loads.

### 3.3.6.6 Insulators

Insulators made of porcelain on overhead lines appear to have a life in excess of 60 years and have generally given good service. However, it has become evident that grey NZI porcelain, manufactured between 1980 and 1985, has an issue with the cement used to secure metal or cast components into the insulator or porcelain to porcelain connections. The cement expands over a period of years, causing the porcelain to crack and fail. Glass is now specified for all new termination insulators and the porcelain insulators are replaced as part of the scheduled refurbishment program.

Other suspect porcelain components in devices such as air break switches and blade or fuse connection equipment are identified and replaced as part of the condition and maintenance programmes.

The standard 33 kV pin insulator has been replaced with a superior post type insulator for all new and refurbishment work. In long spans and high wind areas, clamp top and armour grip support type insulators are now specified.

Composite type insulation is permitted on the network only if there are no glass or porcelain alternatives.

### 3.3.6.7 Conductors

Overhead conductors are either copper (Cu), galvanised steel (Fe), steel reinforced aluminium (ACSR), or all aluminium (AAC) and all aluminium alloy (AAAC) types. Early ACSR conductors use an ungreased galvanised steel core and are susceptible to premature corrosion in the comparatively hostile coastal environment. The condition of this type of conductor is closely monitored, especially around joints and terminations.

There are a number of older copper conductor lines on our network. While copper conductor in general has given good service, smaller copper conductor is inherently more susceptible to tensile failures than ACSR.

The circuit kilometres of all overhead network lines, by three-phase, single-phase, and single wire earth return (SWER), are shown in Table 3.9.

**Table 3.9 Overhead circuit length in km**

Construction type	110 kV	33 kV	22 kV	11 kV	6.6 kV	400 V
Three-phase	24	217	28	1937	0.0	226
Single-phase	N/A	0	116	830	0	139

Conductor lifespan has been estimate at 60–100 years. However, not all conductors perform uniformly, with some single strand and seven strand copper and smaller smooth bodied aluminium conductors older than 50 years, exhibiting signs of reduced ultimate tensile strength. To date, the performance of the seven strands galvanised steel conductors in the Mackenzie area has been acceptable and the conductor is not considered at risk of failure.

Assessment will determine replacement priority for smaller inherently weak copper and ACSR conductors, and the older smooth body type conductors that frequently suffer damage during weather events. Special focus is on areas where conductor failure would disrupt the largest number of consumers and/or pose a threat to public safety.

All single strand 11 kV copper conductors in the distribution network are identified and replaced with ACSR.

Some areas of the network were reticulated using smooth body ACSR conductor strung at 40% of its ultimate tensile strength due to designs incorporating many large spans. Some of this conductor has been subject to Aeolian vibration over its life time however this has proven to not have been damaging.

Some ungreased conductors installed in coastal environments between Studholme and Glenavy are now showing signs of corrosion. Due to capacity demands, a large amount of the rural overhead network has been rebuilt in recent years, resulting in the replacement of the older, inherently weak and corrosion susceptible conductors. Replacement of these conductors are continuing.

Corrosion of ACSR conductors has also become prevalent under the older type parallel groove (PG) clamps, resulting in a small number of premature joint failures. PG clamps are now routinely replaced with AMPACT connectors during maintenance.

High strength conductors such as Magpie, Wolf Core, Cub, Snipe, etc. installed on large spans and in snow prone areas are closely monitored. The network’s all aluminium conductors (AAC) are in relatively good condition.

A new industry wide initiative is looking to provide a more informative method of identification for predicting remaining life of conductor. Modern design standards (eg. NZS 7000) are more conservative, resulting in a more resilient network.

3.3.6.8 Pole mounted switches

Figure 3.12 shows the age profile of our pole mounted switches. A significant proportion of pole mounted switches is less than 15 years old, while some date from nearly 60 years ago.

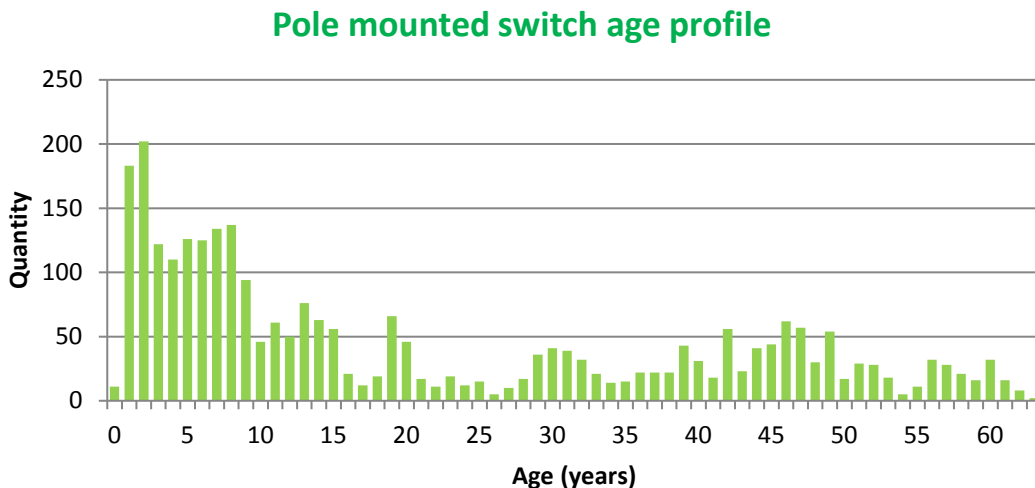
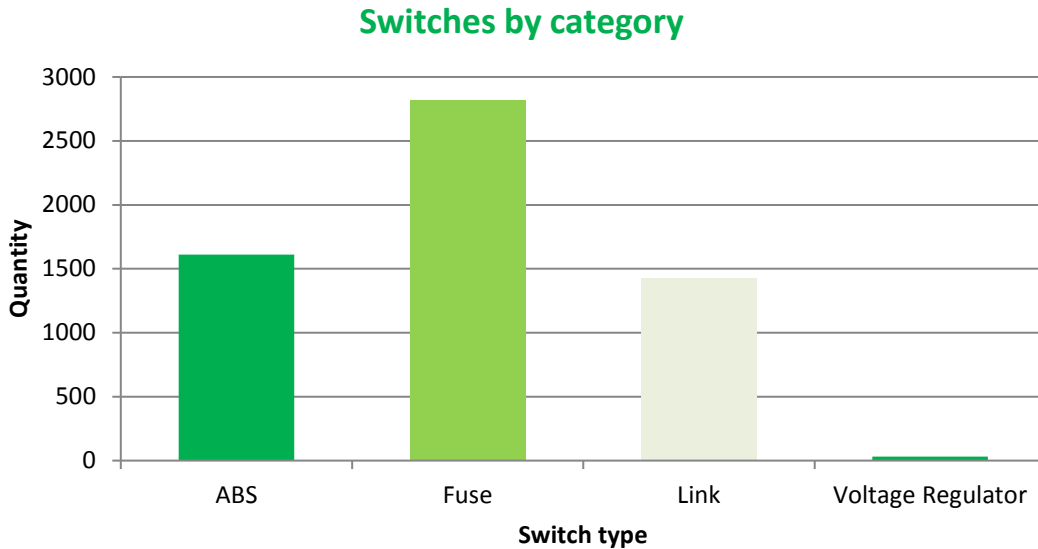


Figure 3.12 Pole mounted switch age profile

The distribution network supports a range of switches from 11 kV drop out fuses, disconnectors (air break switches or ABS) and 11 kV links. Transformer fuses and LV switches are not included in the data. Figure 3.13 shows the pole mounted switches by category.



**Figure 3.13 Pole mounted switches by category**

Older types of 11 kV fuse drop-out units have begun to fail under operation. We are replacing the older drop-out fuses, including the old glass tube type fuses, with modern drop-out expulsion fuse units during maintenance. The ABS population is managed as part of line maintenance, with some further expenditure to ensure switches are adequately rated for the breaking of line loads, or are updated with suitable load break equipment.

To avoid ferroresonance where transformers are connected with a cable circuit, the cable connection is through a disconnector (three-phase disconnect), surge arresters, and a three-phase ganged drop-out unit. With ganged drop-out units becoming difficult to source, we have introduced the use of transformers with internal HV fuses. Switching will still be carried out via the disconnector.

We are installing more reclosers to improve reliability by breaking longer line sections into smaller zones to limit the number of consumers interrupted.

### 3.3.6.9 Voltage support

Areas north of TMK, including Rangitata, have been part of re-conductoring and re-poling projects, as have the feeder sections from STU substation, to support load growth in Otaio, Waimate, Morven, Waihouranga, and Springbank.

Voltage regulators have been added to maximise the conductors' capacity, providing greater economic benefit than full re-conductoring of the feeder. We have 60 voltage regulators in operation on our network. They are all in very good condition.

Shunt capacitors have been introduced to support voltage and maintain an adequate quality of supply to the longer overhead 11 kV feeders. They are mainly switched into the network during the summer peak demand from irrigation motors.

### 3.3.6.10 Pole mounted transformers

Due to seismic constraints, our network standard requires any new transformer 300 kVA or larger to be ground mounted. In future, the existing two pole overhead transformer structures in urban areas not meeting our standard, or seismic constraint criteria, will be converted to ground mounted design or be replaced with smaller pole mounted transformers. For more detail see Section 6.10.4.1

### 3.3.6.11 Underground cables

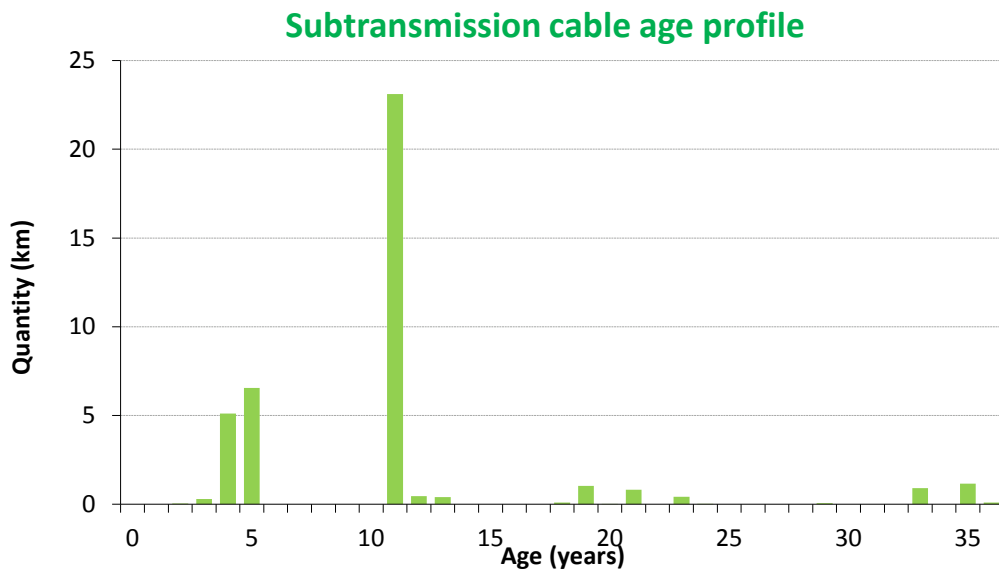
Our network contains over 600 km of underground cabling of both the XLPE and PILC varieties. The cables supply power at 400 V, 11 kV and, to a lesser extent, 33 kV.

The type and quantity of cable on our network is shown in Table 3.10.

**Table 3.10 Underground circuit lengths**

Construction type	33 kV (km)	22 kV (km)	11 kV (km)	6.6 kV (km)	400 V (km)
Three-phase	41.3	0.5	319.9	0.0	324
Single-phase	0.0	1.4	38	0.0	9.7
Single wire earth return	0.0	0.0	0.0	7.2	0.0

All 33 kV cables on our network are less than 37 years old. The age profile of our sub-transmission cables is shown in Figure 3.14



**Figure 3.14 Sub-transmission cable age profile**

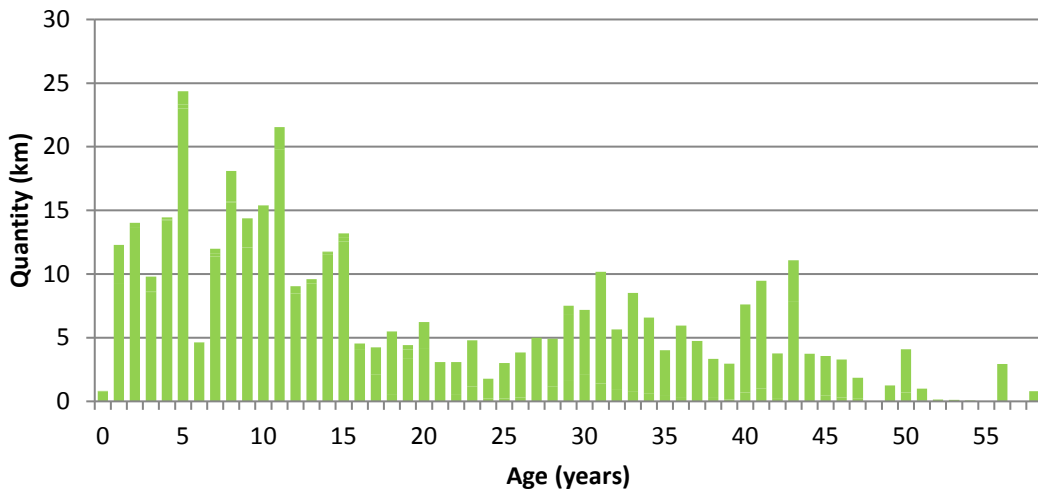
The Fonterra Clandeboye supply was reinforced with two 33 kV cables in 2004 to meet Fonterra’s security of supply requirements. Cabling was chosen as there was no easy route for a double circuit overhead line without significant easement negotiations. As part of our preventive maintenance programme, partial discharge mapping is performed biennially on the Clandeboye cables.

In the past, major transmission cables were offline partial discharge tested every five years to monitor condition. Recent joint failures to the sub-transmission cables have increased the partial discharge to a biennial test as a means to determine change in cable joint condition. Our cable faults tend to be due to joint failure, unfavourable installation conditions, or foreign body or mechanical interference. We have not found a quantitative analysis method to accurately predict the occurrence of faults.

In the absence of reliable data on the longevity of cables of either type under conditions experienced on our network, we have assumed the lifespan of our cables to be the same as that specified by the Commerce Commission in its ODV handbook<sup>25</sup>.

<sup>25</sup> Commerce Commission, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses*, 30 August 2004, Table A.1: Distribution ELB Standard Replacement Costs and Lives.

### Distribution cable age profile



**Figure 3.15 Distribution cable age profile**

The ODV handbook gives us a lifespan of approximately 70 years for PILC cables. We assume a life of roughly 40 years for XLPE cables installed prior to 1986, and a life of 50 years for those installed afterwards. The difference is due to advances in XLPE materials and construction made in 1986 that led to XLPE cables having a significantly longer service life. It should be noted that our lifespan assumptions are conservative as the areas in which the bulk of our cables are laid are considerably drier than those for which the ODV handbook figures were calculated. We continue to monitor the trends in cable condition assessment and use the knowledge gleaned from premature failures to reassess the remaining population's future performance.

We have adopted VLF partial discharge testing as the preferred HV cable test technique to avoid treeing of the XLPE insulation from HVDC test techniques.

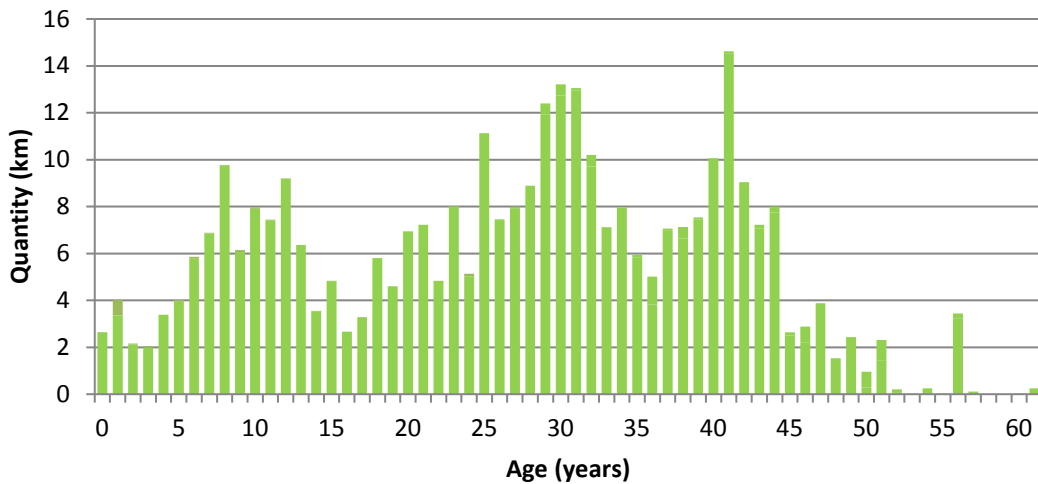
The HV and LV distribution networks include distribution boxes, oil switches, and ring main units. Most of these assets have been installed in the last 20 to 40 years (the estimated life is 60 to 80 years). Fifty percent of the underground 11 kV distribution network was installed in the last 25 years. The majority of the oldest cables are of PILC construction, which has a 70 year life. The more recently installed cables (20 to 40 year age group) are of PVC and XLPE construction, and have an expected service life of 45 years.

The distribution cable age profile is shown in Figure 3.15 on the previous page.

We operate a system to log cable faults, building up a history of statistical data to monitor cable performance and record failure modes. There have been, until recently, only one or two 11 kV joint failures per year, which is low relative to the number of joints.

The majority of LV cable circuits in the Timaru CBD is a conduit system attached to the fronts of buildings. Our approach is to maintain the LV conduit system above ground unless the building is to be demolished. The cost to replace the LV conduit system with an underground system is relatively high and not always economically justifiable.

### Low voltage cable age profile



**Figure 3.16 Low voltage cable age profile**

A programme was commenced in 2014/15 to replace all the Lucy boxes with above ground distribution/link boxes to eliminate operational constraints and allow easier access to the underground and other distribution subs for maintenance and operation.

The LV cable age profile is shown in Figure 3.16 above.

### 3.3.7 Distribution substations and transformers

Distribution substations and transformers step down voltage for local distribution. We have 5,661 oil filled distribution transformers in service and the age profile resembles that of the 11 kV overhead lines and cables. The most significant investments in distribution substations and transformers were made in the late 1950s, early 1970s, 2000s, and 2010s.

While the majority of our distribution transformers are less than 30 years old, some date back more than 70 years. The age profile of the transformer population is shown in Figure 3.17.

The expected lifespan of a distribution transformer is 50 years. However, there is a large variation in the actual life due to climatic conditions and how it is loaded during its life.

Lightly loaded distribution transformers in cold conditions can be expected to last well beyond their design life especially in colder climates. Our average ambient temperature of 12°C is well below design standards that typically uses 20°C as ambient temperature.

Irrigation installations use the transformer capacity available for less than half of the year on average. Replacement of transformers is therefore undertaken with consideration to asset condition rather than solely on an age profile basis.

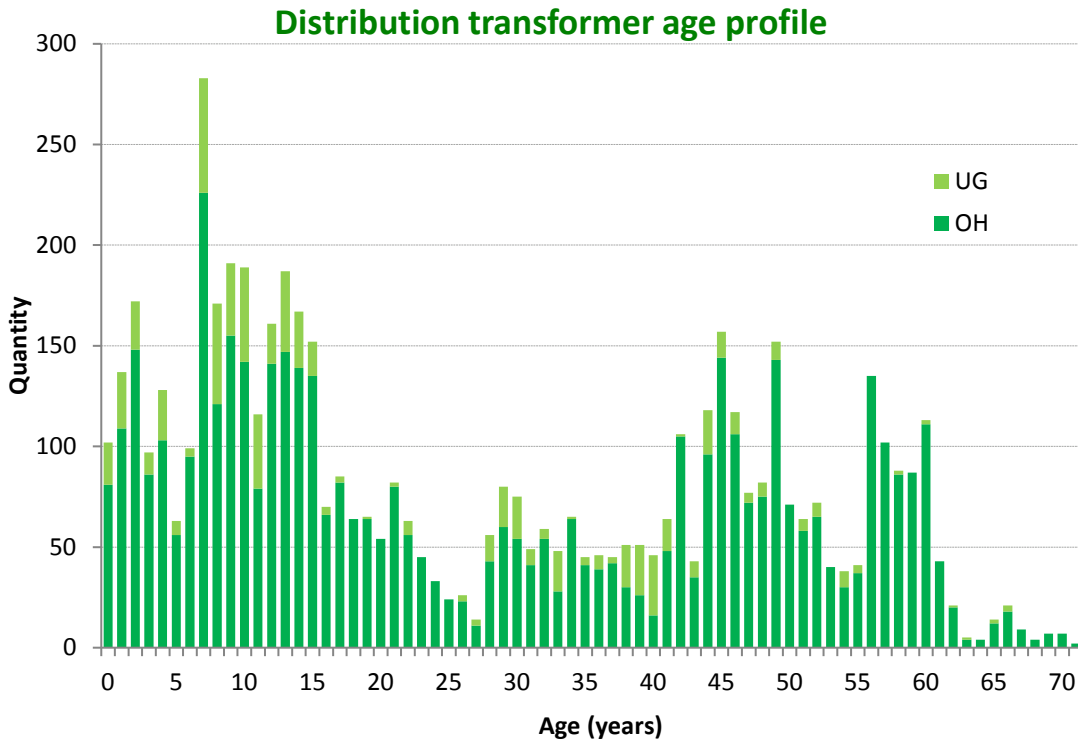


Figure 3.17 Distribution transformer age profile

The in-service quantities of distribution transformers by distribution substation type and kVA rating are given in Table 3.11.

Table 3.11 Distribution transformer quantities

Type	< 20 kVA	< 50 kVA	< 100 kVA	< 200 kVA	< 300 kVA	< 500kVA	< 750 kVA	< 1 MVA	>= 1 MVA	Total
Concrete pad mounted	1	74	26	67	152	97	58	11	8	494
Ground mounted (double end)	0	0	2	7	52	32	14	0	2	109

Type	< 20 kVA	< 50 kVA	< 100 kVA	< 200 kVA	< 300 kVA	< 500kVA	< 750 kVA	< 1 MVA	>= 1 MVA	Total
Ground mounted (single end)	1	2	0	0	1	0	0	0	0	4
Ground mounted (T.E. cubicle)	0	0	0	0	5	32	21	3	2	63
Mounted in U/G sub	0	0	0	0	0	17	13	1	2	33
Mounted indoors	0	0	1	1	4	12	7	5	13	43
Pole mounted	2,612	975	659	414	68	7	3	0	2	4,740
Pole mounted (1.5 pole)	0	0	0	0	2	0	1	0	0	3
Pole mounted (2 pole)	1	0	1	5	101	28	1	0	0	137
Substation (ground mounted)	1	2	3	5	7	3	9	2	3	35
<b>Total</b>	<b>2,616</b>	<b>1,053</b>	<b>692</b>	<b>499</b>	<b>392</b>	<b>228</b>	<b>127</b>	<b>22</b>	<b>32</b>	<b>5,661</b>

### 3.3.7.1 Ground mounted distribution substations

A variety of methods is employed to safely enclose ground mounted transformers. The majority of equipment is commercially manufactured integral with the transformer and provides enclosures for LV and HV connections and fittings. The typical ground mounted transformers on our network are categorised as follows.

- Underground—below ground bunker (Timaru MED area only).
- Cubicle—large steel enclosure type with restricted personnel access.
- Padmount—commercially manufactured kiosk with LV and HV cabinets.
- Building—dedicated or consumer shared concrete block building.

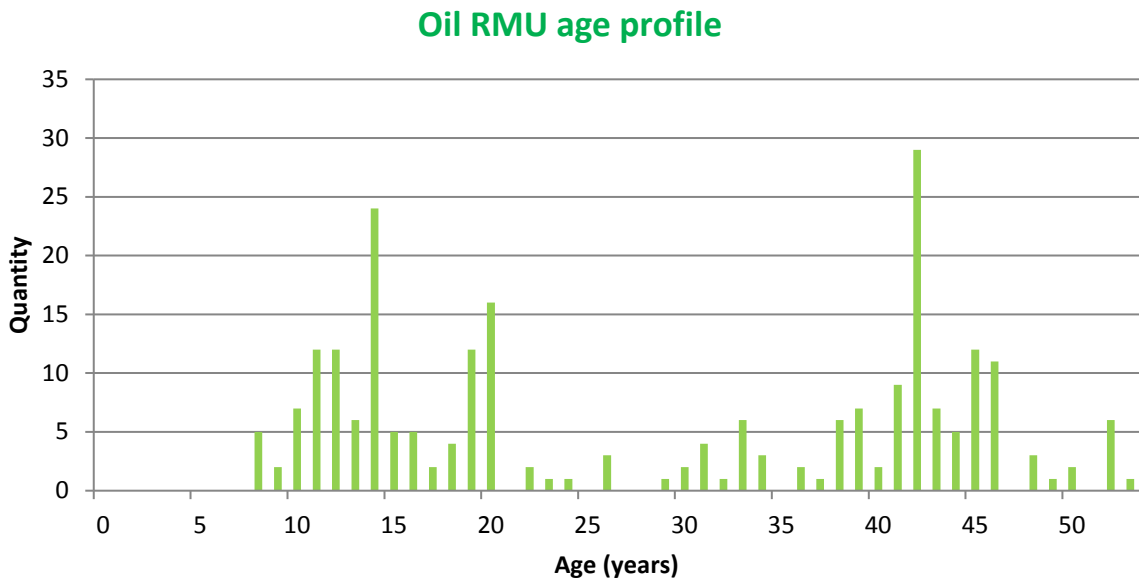
### 3.3.7.2 Ring Main Units (RMUs)

Many ground mounted distribution substations also incorporates a RMU. In addition RMUs are also used for network switching points to alter the network configuration. We have mainly two types namely:

- oil insulated, and
- air/gas insulated

Historically we installed oil insulated RMUs but for the last seven years we have only been installing SF<sub>6</sub> insulated RMUs. The main reason for this is due to the additional safety and environmental concerns surrounding oil filled equipment.

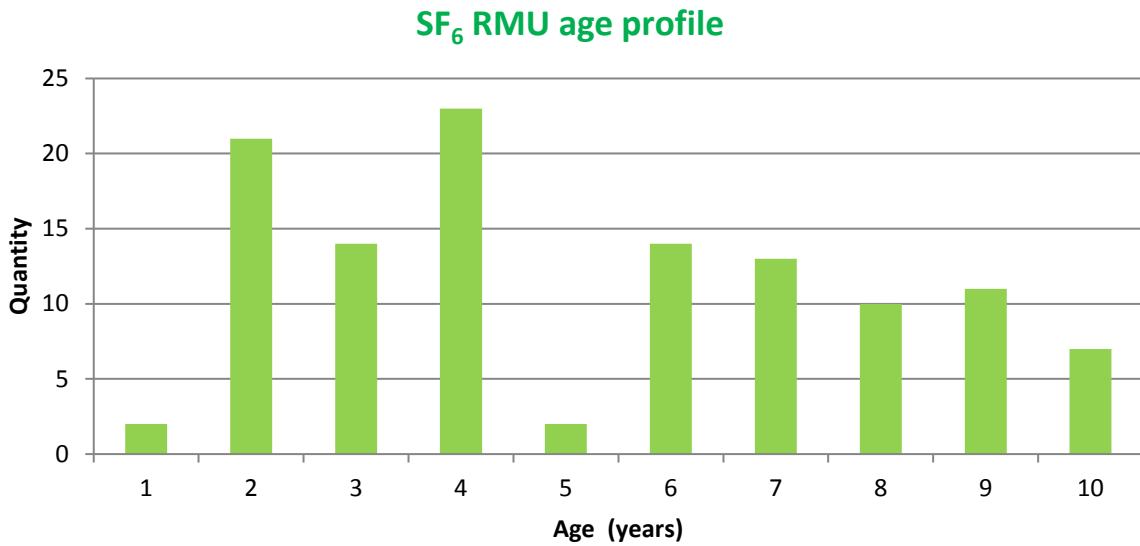
Figure 3.18 and Figure 3.19 shows the quantity and age profiles of the two types of RMUs on our network.



**Figure 3.18 Oil RMU quantities and age profile**

The condition of our oil RMUs is reasonable. Where units have not been maintained within our specified maintenance period, operational restrictions are enforced to ensure the safety of our staff, contractors and equipment.

Due to the fairly young age profile of our SF<sub>6</sub> RMUs, they are all in good to excellent condition.



**Figure 3.19 SF<sub>6</sub> RMU quantities and age profile**

### 3.3.7.3 *Underground substations*

The old substations in Timaru currently in service, were built in the 1960's. A newer generation of underground substations in Timaru, dating back to the 1970's, replaced the older designs. The newer substations are generally located just below pavement level and are constructed of reinforced concrete wall modules, roof slabs, and cast floor.

The roof slabs are designed to be removed to allow the changing of transformers and switchgear. The removal of roof slabs is rare and would normally be avoided unless absolutely necessary. Underground substations would normally contain a 400 kVA or 500 kVA transformer (a few contain two of each or one 1000 kVA), one RMU, and an LV switchboard. The substations have continuous fan-forced air ventilation for transformer cooling and operator fresh air. Underground substations also contain a sump pump as some substations can be prone to flooding under heavy, extended rain conditions. All underground substations are checked and maintained, as necessary, after heavy rain. Most underground substations are entered through a man hole in the pavement and a vertical ladder.

There are 29 underground substations on the inner city network that need to be refurbished before reaching the end of economic life. A number of options are being investigated to refurbish or relocate. Individual risk analysis is carried out on a case-by-case basis.

For central city underground substation that require renewal or refurbishment, but where land is not available above ground, a design review was undertaken in 2008–09 to study the feasibility of developing a modern underground substation design with SF<sub>6</sub> or vacuum 11 kV

switches with motor operation. The motorised switches would have had to allow remote operation of the 11 kV and, possibly, some LV functions, as well as load monitoring above ground. The remote operation would not only have had to improve safety, but also allow more efficient switching operations by removing the need for confined space procedures before operating the equipment. However, the cost of this option proved prohibitive, even with the project spread over 20 years.

More recently, consideration has been given to the refurbishment of underground substations in three stages. The stages would be as follows.

1. LV switch/fuse gear renewal (either within the underground substation or relocated above ground in boundary cabinets).
2. HV RMU renewal to above ground berm location or upgrade to remote controllable RMU within the underground substation.
3. Renewal of the distribution transformer within the underground substation.

Our plan has the advantage of minimising annual refurbishment costs and spreading the total cost over a longer period. It also enables the more frequently operated and inspected equipment to be renewed first, based on individual equipment condition assessment (e.g. LV and RMU units), and risk analysis. Renewal may include either relocation above ground or upgrading with a remotely operable unit. Equipment requiring less frequent access and attention (e.g. transformers) would be renewed last in the overall programme. The condition of our underground substations is generally good.

#### *3.3.7.4 Surface mounted substations*

Surface mounted substations on our 11 kV distribution network are of various sizes, designs, and configurations, depending on the age of installation, manufacturer, and site conditions. The types of surface mounted substations include cubicle, padmount, and building.

A surface mounted substation includes a transformer which often has integral LV and HV cabinets attached at each end or on one side (e.g. a padmount substation). The HV cabinet may include an 11 kV switch, such as an RMU (e.g. kiosk or building sub), or an 11 kV termination connecting the transformer to a remote RMU in a neighbouring substation or free standing nearby.

Most surface mounted substations include an LV panel in the LV cabinet, generally consisting of a frame supporting LV bus bars (three phases, neutral and earth bars), isolating links for the transformer connection to the panel, and HRC fuse ways connected to LV reticulation cables. Older kiosk substations have Lucy type porcelain HRC fuse link holders fitted, with the newer kiosk, padmount, and building substations since the 1970s having modern plastic type shrouded HRC fuse link ways fitted.

An exception to the HRC fuse links are certain ex-SCEPB kiosks that, in the 1970s, were fitted with MCCBs rather than HRC fuses. In the event of a problem with the older Lucy HRC fuse link or MCCB LV panels both would be replaced with the modern plastic type shrouded HRC fuse link ways or modern MCCBs respectively. Another exception to the HRC fuse links is the use of Statter LV oil switches in underground substations, some kiosks, and on two pole substations.

The main maintenance issues with surface mounted distribution substations are graffiti, rust, deteriorating paintwork, accumulation of dust, leaves and other environment related material, weed control and we conduct regular checks of the condition of electrical assets and for oil leaks (which are rare) from the transformer and/or HV switchgear.

### 3.3.8 Voltage regulators, capacitors, and rural switches

The predominantly rural 11 kV distribution line network includes a number of different types of specialist assets used to control voltage and provide fault protection and operational flexibility, assets include:

- voltage regulators—to correct for varying voltage drop
- capacitors—to correct from voltage drop and provide bulk power factor correction
- reclosers—pole mounted rural circuit breakers
- load break switches—SF<sub>6</sub> gas filled puffer switches to aid sectioning where there are high feeder load currents
- local break disconnectors—standard disconnectors with load break heads fitted, allowing isolations on higher loaded feeders and at tie points
- disconnectors—pole mounted non-load break switches, often called air break switches (ABS)
- fuse links—pole mounted, single-phase break, for protecting spur lines and pole mounted transformers
- ganged fuse links—pole mounted, three-phase break (non-simultaneous), for protecting rural spur lines, with underground cable between the fuses and transformers that are prone to ferroresonance problems
- surge (or lightning) arresters.

#### 3.3.8.1 Voltage regulators

Voltage regulators are automatic devices that monitor the voltage at the point of application and, according to its pre-settings, adjust the downstream voltage, to compensate for changing loads.

11 kV and 22 kV voltage regulators are generally used to maintain an acceptable voltage to consumers' Point of Supply. 11 kV voltage regulators are a relatively economical solution

for compensating for varying load induced voltage fluctuations compared to the cost of re-conductoring. 11 kV voltage regulators are, in some cases a temporary solution, particularly if the average load on the 11 kV line continues to grow beyond the capacity of the regulator, necessitating a conductor upgrade. At a more extreme level of load growth, a new zone substation may become necessary to shorten the distance from each zone substation to the end of the distribution lines where distribution lines have been upgraded to optimum size.

The size of the regulators currently in use for general line regulation varies from 150 A units to a 300 A unit. The rapid increase in irrigation and dairy-related rural load in recent years has necessitated installation of a relatively large number of 11 kV line regulators, in some cases with more than one regulator on the same feeder.

The regulators provide a useful buffer period in which the load increase trend on a particular line can be studied and, when sufficient load has been added, conductor upgrades and/or additional feeder or zone substations can be realised.

Regulators displaced by conductor upgrades or new substations may be redeployed elsewhere as growth in irrigation, dairy, and other rural load is currently widespread throughout our area of operation.

### *3.3.8.2 Capacitors*

11 kV capacitors are another means of compensating for voltage drop on an 11 kV line. The compensation cannot be varied as for a regulator as the capacitor installation has a fixed value. Capacitors are particularly useful where there is significant inductive load such as from irrigation and other motor loads.

Caution is needed; misapplied capacitors can attenuate ripple signals which can be a hindrance to our load control activities.

We have 10 capacitor sites deployed on our network.

### *3.3.8.3 Reclosers*

We use pole mounted reclosers in rural areas for feeder circuit breakers in small rural substations. Reclosers are also used as overhead line circuit breakers for automatic fault clearance and reclosing to clear for example an intermittent fault such as a bird strike, or momentary tree branch contact.

Reclosers are sometimes used for protection permitting clearance of outlying faults via the operation of fuses. Also, reclosers break a long feeder up into smaller sections, avoiding the tripping of the zone substation circuit breakers (which supply large urban and rural loads) for remote faults. When used for protection in this way reclosers also help avoid both

unnecessary momentary supply interruptions and longer outages due to permanent faults affecting the majority of consumers when the fault is beyond the recloser site.

We have 50 recloser deployed on our network excluding reclosers that are used as circuit breakers in substations.

#### *3.3.8.4 Load break enclosed switches*

Load break enclosed switches (load break disconnectors) are generally SF<sub>6</sub> or vacuum insulated switches that are rated to interrupt load, but not fault current. Load break disconnectors are operable via a radio network allowing remote switching of the feeder to perform a load break or load make operation as part of the sectioning and reinstatement procedure. We have three of this type of switch, which are configured for manual operation at this time.

#### *3.3.8.5 Disconnectors*

We have a large number of disconnectors (air break switches) of various models and ages installed on the network. Disconnectors are standard items that are required in steady quantities to allow off-load sectioning where there is overhead 11 kV network and three-phase breaking of connected unloaded or very lightly loaded lines.

#### *3.3.8.6 Load break disconnectors*

Load break disconnectors (air break switches fitted with interrupters) are effectively disconnectors with additional load break interrupter devices fitted to each phase unit to break load current, particularly at ties between heavy feeders or zone substations.

Some of the older types of switches can be prone to going out of adjustment over time and require a certain amount of maintenance to remain reliable. Since 2008, we have standardised on an interrupter model that is much less prone to going out of adjustment.

#### *3.3.8.7 HV fuse links*

We have a large number of HV fuse links installed that are used to protect all pole mounted transformers, for certain cable terminations onto an overhead lines, and for spur lines.

We are replacing the older glass type fuse links with more modern, reliable and versatile drop out type.

#### *3.3.8.8 Surge (or lightning) arresters*

Surge (or lightning) arresters are often associated with particular types of assets such as transformers, regulators, HV cables, etc. as well as for general line surge protection. Arresters are designed to passively detect and limit overvoltage surges due to direct or

induced charge from a lightning storm, switching surges, induced power frequency surges, etc.

In the event that the surge current is too great or a follow-through fault current starts, the earthing lead at the bottom of the arrester blows off in a fuse-like fashion, protecting the arrester from damage and prevents a short circuit which may trip the upstream protection. The arresters in this situation need to be replaced.

### 3.3.9 LV reticulation lines, cables, link, and distribution boxes

LV lines and cables distribute electricity from distribution substations to services. LV induced voltage at or below 400 V phase to phase and 230 V phase to neutral.

LV overhead construction was the traditional method of reticulating urban as well as rural areas in the early days of the New Zealand electricity industry. Now LV overhead distribution lines exist primarily in urban areas. However, for many years now, new LV reticulation has been required by the district council to be placed underground, both in town and country.

The cost of underground versus overhead depends on several factors including cost of labour, materials, topography, and terrain. The economics of placing overhead LV distribution underground presently relies on the district council contributing the cost difference between overhead renewal and undergrounding.

We still have a significant amount of overhead LV reticulation in the town and country areas. Following the damage to underground cables during the Canterbury earthquakes, we decided to cease our undergrounding programme and to instead underground on an application basis.

#### 3.3.9.1 LV underground cables

LV reticulation cables in service include four-core, three-core and neutral screen, and single-core cables. Our current standard for LV reticulation includes for the use of single and three-core Al and Cu cores (with each core XLPE insulated), neutral screen Cu (with PVC sheath), complying to AS/NZS 4026.

#### 3.3.9.2 Distribution boxes (boundary boxes)

The connection between underground reticulation cables and consumer mains cable is achieved via distribution boxes. The boxes are usually located on every second boundary in residential and small commercial subdivisions.

We have incorporated a number of different distribution box types into service as styles, materials, and technology have changed over the years. Some examples include concrete, painted electro-galvanised steel, galvanised steel, and plastic boxes.

### 3.3.9.3 Link boxes

Link boxes contain isolating links that permit the LV reticulation of normal open and closed points (between different circuits and distribution transformers) to be shifted to suit operational and maintenance requirements.

As with distribution boxes, there are several models of link box, of different construction and materials, in service.

## 3.3.10 Protection, SCADA, and communication systems

### 3.3.10.1 Protection relays

Protection relays protect the network against electrical faults by detecting over-currents or over-voltages, or other out of limit conditions. Protection relays trip circuit breakers to clear the fault or abnormal conditions from the network. It is necessary to protect such assets as transformers, cables, lines, etc. from hazardous power flow and to remove unsafe conditions that may endanger persons or property. The protection relays are generally automatic, while newer models are monitored by the SCADA system via associated communications systems.

### 3.3.10.2 Protection schemes

We have a number of different types of protection relays and associated assets on our network, including:

- electromechanical relays
- electronic relays
- numerical relays
- integration protection and control devices (e.g. recloser controllers).

The protection relays form part of protection schemes and systems that include equipment such as:

- tripping source, generally a battery, a few CT internally powered devices
- instrument transformers (e.g. CTs, NCT, VTs, etc.)
- protection relays
- wiring looms
- cabinets
- trip coils in the circuit breaker/recloser
- fuses
- auxiliary contacts
- terminal blocks.

The protection schemes and settings are designed to clear faults as quickly as practicable to protect life, assets, and property from the effects of the fault. Our network contains a variety of GXP, sub-transmission, and zone substation arrangements with varied fault levels. Each arrangement and fault level combination requires a particular protection application. Consequently, the simpler network arrangements with low fault levels have suitably simple protection schemes (e.g. rural zone substation with small single transformer bank), while the more complex network arrangements with high fault levels have quite complex schemes (e.g. Timaru CBD's three 11 kV switching substations with closed ring 11 kV sub-transmission interconnects and Transpower GXP supply bus).

As part of our present capex programme of network upgrades, we are replacing older protection relays and associated legacy assets with modern numeric relays and new associated assets as each zone substation is refurbished. We have plans to replace all electromechanical and static relays in the substations not scheduled for major upgrades with numeric relays in the planning period. Works may include re-loomng wiring and replacing the auxiliary as appropriate.

#### *3.3.10.3 SCADA*

The SCADA (Supervisory Control and Data Acquisition) system enables remote control of connected substation assets and the acquisition of data. The data describes the present state of the assets including analogues such as currents and voltages; digital points such as position of switches, status of components, etc.; alarms and events such as protection trip events, equipment condition limit alarms, and security alarms. The SCADA system also enables control of certain assets such as circuit breakers. It also records historical data such as events and analogues, for future reference and analysis.

The SCADA system consists of a master station, remote terminals units (RTU) located at substations and controllable devices, and a communications system that connects the master station to the RTUs.

We replaced our master station in 2014/15 with a Survalent system. The replacement includes the addition of modules in 2015/16 to upgrade the capability. The load control module of the previous IPOWER SCADA master has also been replaced with Qcontrol. The master station allows for DNP3 and SNMP communication to field devices.

#### *3.3.10.4 SCADA communications–radio system*

We have a legacy SCADA communications system which is comprised of:

- two UHF FM tone modulated, 1200 baud rate, Conitel protocol paths
- one hired microwave broadband TCP/IP link, DNP3 protocol path
- two landlines as communication paths.

A communications upgrade project, which includes a microwave frequency digital network combined with fibre optic within the Timaru CBD area, was initiated in 2008. The project has multiple stages designed to complement, upgrade, and ultimately replace the legacy system. The new system is discussed further near the end of this section.

The legacy SCADA system communications system pathways are:

- Washdyke—Mt Rollesby—TVS and TEK substations (Conitel)
- Washdyke—TIM substation (Conitel on landline)

Replacing and broadening the extent of communications devices is proceeding as part of the communications upgrade project. The project is still ongoing and, once completed, will resemble a network illustrated in Figure 3.20.

The new communications utilises 5 GHz and other licensed frequencies forming a digital radio network, supplemented in Timaru with a fibre optic network for the three Timaru CBD zone substations (GRM, HNT, and NST), the TIM GXP, and the Washdyke depot control room. It also includes a new fibre optic network between TMK and CD1 and CD2 that links to the 5 GHz digital radio network at TMK.

Only TIM ripple plant, TVS, and TEK zone substations are still using legacy UHF/Conitel network. These zone substations will be upgraded into the digital radio network in the next three years.

An interim upgrade step for TVS and TEK zone substations will include replacing the aging legacy Conitel RTUs with permanent, new RTUs incorporating DNP3/IP communications in the 2017/18 financial year. The communications would then be temporarily passed over a leased TCP/IP link from each substation to the Washdyke control room. FLE is now on an IP system over the cell network.



Figure 3.20 Data communications map

When the digital radio communication is eventually established for TVS, TEK, FTE, and other western substations, the temporary leased communications links would be phased out in favour of the new 5 GHz system.

Replacement of the current system is over a five year period to enable us to retain a level of service coverage while renewing and extending the functionality radio communication system. Cell phones are used to complement and back up radio telephones in many situations. All communications for system operation and control are through voice radio where practical.

### *3.3.10.5 Voice radio*

Our voice communication system consists of FM, E band, VHF, mobile, portable and fixed site radios operating through hilltop repeaters. The four repeaters used are normally linked via a UHF repeater linking radio control from Washdyke. Each of the linked repeaters can be remotely disconnected from the linkup, again via UHF signalling, to enable local repeater operation.

We also use voice radio arrangement to return alarm signals from some zone substations using tone encoding signals that feed through to the SCADA master. Control and alarms are also sent and received over the radio system to each repeater site for on/off repeater linking.

The age profile of the SCADA and communications equipment in our zone substations is shown in Figure 3.21. The voice radio repeaters and main radio shelf are represented in the figure as the equipment older than 30 years and are due for replacement. The technology is becoming obsolete due to the aging assets requiring more servicing to maintain transmit levels within the correct power regions.

### Zone substation SCADA and communications age profile

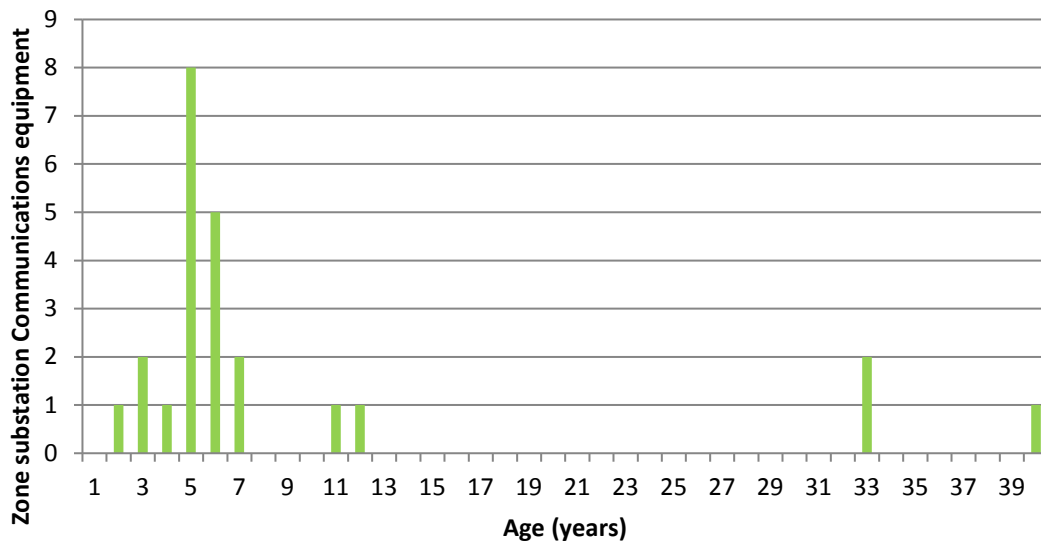


Figure 3.21 Zone substation SCADA and communications age profile

#### 3.3.10.6 Load control ripple injection plant

We operate load control of energy storage devices (e.g. hot water cylinders) located at consumers' premises via the operation of ripple injection plants located at ABY, BPD, STU, TIM and TMK. We also use ripple control to shed irrigation load in emergencies and to operate the majority of streetlights. Details of the plants are contained in Appendix G.

The aging legacy Conitel RTU that controls the plant at TEK substation is planned for replacement in the first half of the planning period.

#### 3.3.10.7 LV metering and load control

We have provided meters and relays at consumers' premises for electricity retailers as part of our current standard use of system agreement. In June 2013, we became a meter equipment provider (MEP) under Part 10 of the Electricity Act. Retailers may choose us as the MEP or seek metering services from another MEP. Our smart meters provide network benefits (e.g. frequency readings) and, accordingly, we have included in our standard use of system agreement provisions that protect our smart meters from interference or damage by a retailer and/or a customer.

### 3.3.11 Distributed generation

This section summarises key elements of our policy for distributed generation including connection terms and conditions, safety standards, and technical standards. The policy includes:

- health and safety standards
- connection and operation standards
- congestion management policy
- emergency response policies
- industry rules and standards
- policy on connection below and above 10 kW
- distributed generation plant and commissioning reports, and statement of compliance.

Figure 3.22 shows an example of a photovoltaic array on the roof of a dairy shed.



**Figure 3.22 Solar array on a dairy shed near Waimate**

Table 3.12 summarises the positive and negative effects of distributed generation on our network.

**Table 3.12 Positive & negative effects of distributed generation**

Positive effects of distributed generation	Negative effects of distributed generation
<ul style="list-style-type: none"> <li>• Potential for large uptake to assist in reduction of peak demand at Transpower GXP's.</li> <li>• Reducing the effect of existing network</li> </ul>	<ul style="list-style-type: none"> <li>• Increased fault levels, requiring protection and switchgear upgrades.</li> <li>• Increased line losses if surplus energy is exported through a network constraint.</li> </ul>

Positive effects of distributed generation	Negative effects of distributed generation
<p>constraints.</p> <ul style="list-style-type: none"> <li>• Delaying investment in additional network capacity.</li> <li>• Making a very minor contribution to supply security where consumers are prepared to accept that local generation is not as secure as network investment.</li> <li>• Making better use of local primary energy resources thereby avoiding line losses.</li> <li>• Avoiding the environmental impact associated with large scale power generation.</li> </ul>	<ul style="list-style-type: none"> <li>• Stranding of assets, or at least of part of an asset’s capacity.</li> <li>• Altering power flow which requires re-setting and recalibration of protection and controls.</li> <li>• Adding very large point injections at lightly loaded points on the network.</li> <li>• Potentially high localised voltages</li> <li>• Providing for LV to MV transformation that facilitates forward and reverse power flow, as in the case of a significant number of PVs exporting into the network on the LV side of a shared distribution transformer. PV installations cannot generate beyond levels prescribed for New Zealand.</li> <li>• Possible introduction of harmonics from grid tie inverters.</li> <li>• Islanding protection not 100% effective through slowness to operate, or the like, which raises safety concerns.</li> </ul>

*3.3.11.1 Connection terms and conditions for distributed generation*

We have developed procedures with a simple series of steps that owners of distributed generation can follow to have small scale (<10 kW) and large scale (>10 kW) distributed generation connected to our network.

We adhere to the prescribed charges in Part 6 of the Electricity Industry Participation Code 2010.

Distributed generation that requires a new connection to the network is charged a standard connection fee with adherence with Part 6 of the Electricity Industry Participation Code 2010. We may also recover the costs to reinforce the network from the distributed generator back to the next transformation point.

Installation of suitable metering (as per the technical standard) is at the expense of the distributed generator and its energy retailer.

We recognise the benefits of distributed generation that arise from reducing costs such as those of transmission and deferred investment in the network. However, the distributed generation needs to be of sufficient size and provide peak transmission demand reduction to provide real benefit.

Those wishing to connect distributed generation on our network must satisfy us that a contractual agreement with a suitable party is in place to consume all injected energy—generators will not be permitted to lose energy in the network.

### *3.3.11.2 Safety standards*

A party connecting distributed generation must comply with any and all industry safety requirements and operational advice from us.

We reserve the right to physically disconnect any distributed generation that does not comply with such requirements.

### *3.3.11.3 Technical standards*

Import and export metering must be installed. If the owner of the distributed generation wished to share in any benefits accruing to us, such metering may need to be half hourly.

We may require a distributed generator of greater than 10 kW to demonstrate that operation of the installation will not interfere with operational aspects of the network, particularly protection and control.

All connection assets must be designed and constructed to technical standards not dissimilar to our own prevailing standards, which references mainly the following:

- AS/NZS 4777 parts 1& 2
- AS/NZS 3000
- AS/NZS 5033

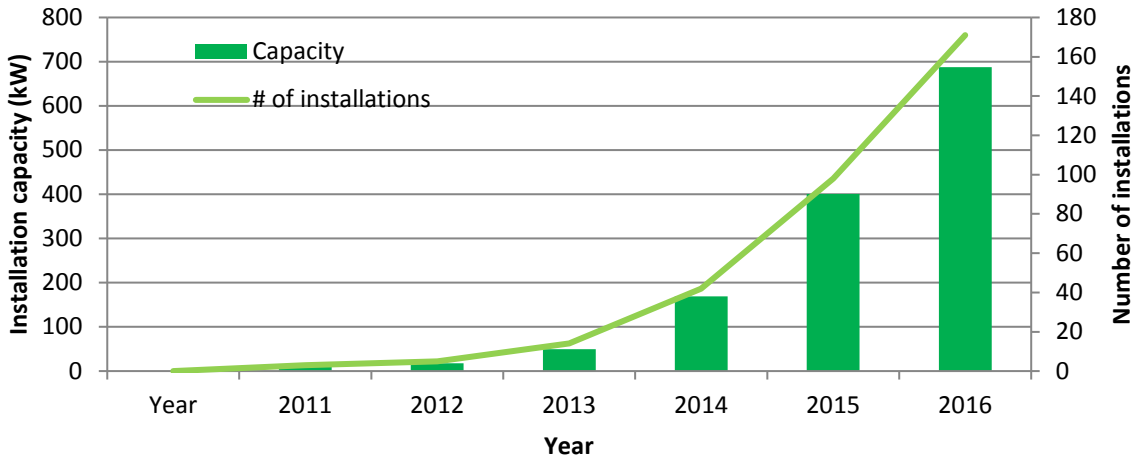
### *3.3.11.4 Opuha Dam*

A major embedded generator on our network is the 7 MW hydro generator which is an integral component of Opuha Water Limited's irrigation scheme. The Opuha Dam operates on the requirements for environmental, as well as irrigation, flow and has a duty factor of 20%, meaning it is not available regularly for improvement in supply security. Subject to owners' consent, the dam can be used for islanding in order to maintain local supply during Transpower outages for one to two days per year. The generator is unable to black start, hence it is not deemed a secure supply during islanding operations.

### *3.3.11.5 Photovoltaic (PV) generation on the network*

There is growing consumer interest in installing PV with inverters which permits the export of surplus energy to energy retailers back through the network. The rate of connection and the total capacity of such installations have been exponential since 2010, as illustrated in Figure 3.23.

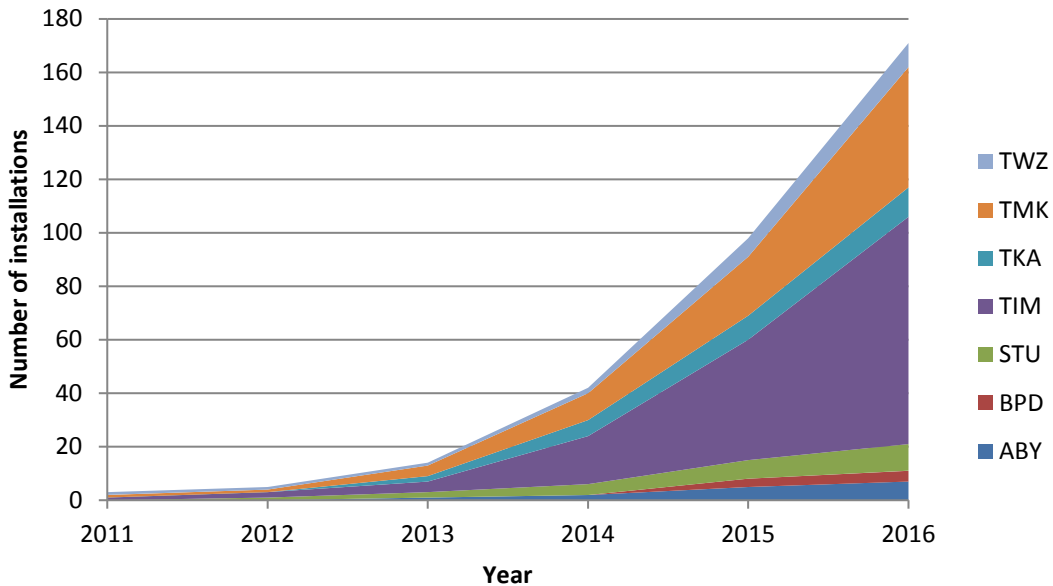
### PV installations



**Figure 3.23 PV installation numbers and total capacity**

Recent changes in pricing for consumer generated electricity by retailers do not appear to have affected the growth of PV installations. To provide local data on the efficiencies and economics of such systems within our area of operation, we recently installed a PV array and inverter system on the TEK substation building. Interested person can access that data on our website. The number of PV installations and total capacity per GXP is depicted in Figure 3.24 and Figure 3.25 below.

### PV installations by GXP



**Figure 3.24 Number of PV installations per GXP**

### PV installation capacity by GXP

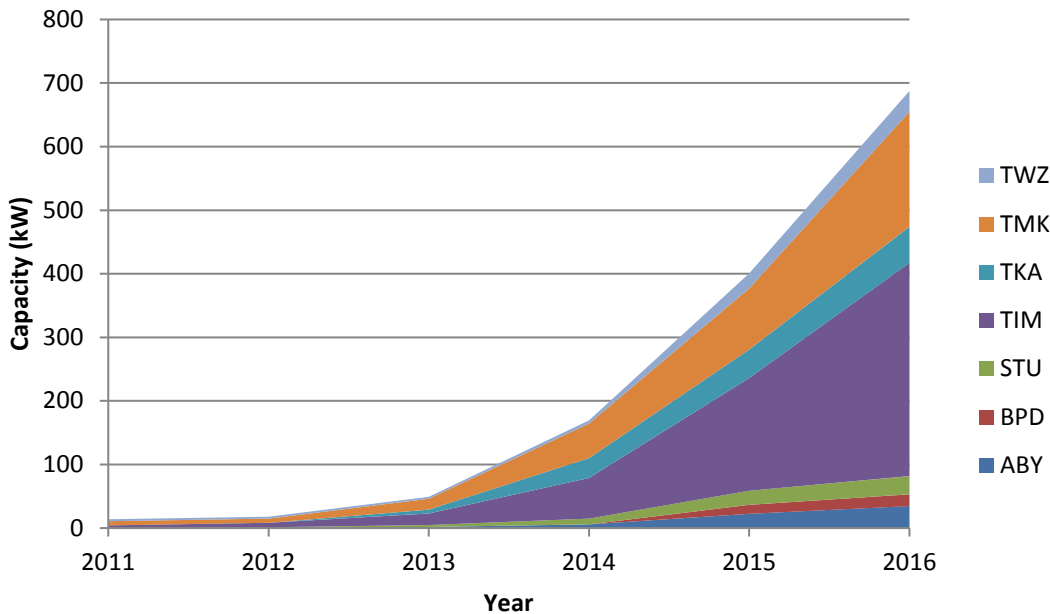


Figure 3.25 Total capacity of PV installations per GXP

#### 3.3.12 Outlook for existing asset configuration

The high demand growth in South Canterbury has effectively consumed the available headroom at a number of lines and substations. The reinstatement of headroom is driving the need for investment to provide additional capacity on the network in a sustainable and efficient manner. The options for network development and configuration are discussed in detail in Chapter 5-NETWORK DEVELOPMENT PLANNING.

### 3.4 Justifying assets

A key measure of asset justification is the degree of optimisation applied by the Commerce Commission's ODV valuation methodology and, accordingly, we recognise that the ratio of ODRC to DRC provides a good measure of asset justification. The ratio of ODRC to DRC is typically in excess of 99%, meaning that very little optimisation is necessary. However, we also recognise that our network has been built over 88 years by incremental investment decisions. While optimal at the time, those investments may not be optimal if the network was rebuilt in a single instance to supply the needs of today's consumers.

We create stakeholder service levels by carrying out a number of activities on our assets (please see Chapter 4—Performance measures), including the initial step of building assets such as lines and substations. Some assets need to deliver greater service levels than others. For example, our GRM substation supplying the Timaru CBD has a higher capacity

and security level (with four sub-transmission feeders and 11 kV switchboards with bus coupler) than our PLP zone substation supplying a residential township and farming areas north-west of Timaru via a single overhead line. Hence the level of investment will generally reflect the magnitude and nature of demand.

Matching the level of investment in assets to the expected service levels required consideration and understanding of:

- how asset ratings and configurations create service levels such as capacity, security, reliability, and voltage stability
- the asymmetric nature of underinvestment and overinvestment, i.e. overinvestment supports higher service levels than expected while underinvestment can lead to service interruption
- the discrete sizes of many classes of components; in some cases, capacity can be staged through the use of modular components
- how past design decisions has resulted in much of our existing network being built up over 80 years by incremental investments that were optimal at the time, but are now considered sub-optimal
- the need to accommodate future demand growth over the expected service life of the asset
- the need to allow for sufficient line regulation in long rural overhead feeders by using large low resistance conductors which are constrained by voltage rather than current carrying capacity.

In theory, an asset would be justified if the service level created were equal to the service level required. In practice, there are asymmetric risks, discrete component ratings, non-linear behaviour of materials, and uncertain future growth rates. We consider an asset justified if its resulting service level is not significantly greater than the level required, subject to allowing for demand growth and discrete component ratings.

All assets on our network are necessary to meet the load demand and maintain the reliability and security of supply expected by consumers, while meeting regulatory voltage requirements. A small number of assets have been optimised for ODV purposes (most recently in 2004). All of the optimisations have been capacity related (i.e. a 33 kV line operating at 11 kV recorded as an 11 kV line, or a medium conductor optimised to a light conductor). We have not identified any assets as superfluous.

Key new load areas are developing adjacent to river boundaries for irrigation of farmland to increase land productivity. Assets supplying key new load areas are being transformed from single to three-phase, while core assets are being strengthened in capacity and augmented

with voltage regulation. From here, feeder load can be diversified with additional lines to provide capacity and improve supply security. Consumer expectations are also an important consideration as supply for dairying load is preferable to irrigation load in the event of fault induced supply disruption. Once a centre of load has been established, further demand is provided by changing supply voltage and installing a new zone substation, typically with 5 MVA capacity.

The AMP does not include non-system related land and buildings, or non-network assets such as motor vehicles, office equipment and furniture, etc. We own meters and charge retailers trading on our network for metering services where we are the metering equipment provider. Metering assets are not covered in this AMP.

## 4. PERFORMANCE MEASURES

### 4.1 Introduction

Chapter 4 details our performance targets, explains how we set and performed against those targets, and, where appropriate, provides forecasted future performance.

### 4.2 Why measure performance

We measure performance in order to support the process of continuous improvement. The regulators (e.g. Commerce Commission) also set a number of performance targets in accordance with the various acts and regulations under which we operate. Our performance measures can be broken down into four high level categories:

- safety
- service standards
- service levels
- financial

### 4.3 Safety

One of our values is “Health and Safety always”. We maintain our safety policies to keep the public, contractors and our staff safe. We conduct an extensive education programme to make the public aware of the dangers of electricity. More information on our policies and public awareness campaign can be found in Chapter 7 – RISK MANAGEMENT.

Our performance measures are based on critical aspects and specific goals established annually through our Safety Plan. Our safety performance is measured by both internal and external audits of our safety management systems for compliance with the following legislation:

- Health and Safety at Work Act 2015
- Electricity Act 1992
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from Trees) Regulations 2003
- NZECP34:2001: Maintaining safe clearances from live conductors
- NZECP35:1993: Power system earthing.

#### 4.3.1 Internal audits

We carry internal audits out regularly by requiring that:

- the CEO, General Manager—Safety and Risk, and the Health and Safety Committee conduct an annual audit of the Health and Safety Management Plan
- an annual self-assessment is carried out by applying the ACC Workplace Safety Management Practices criteria; managers and the chairperson of the Health and Safety Committee confirm staff training records annually
- managers conduct regular tours and audits covering the contents of the Health and Safety Management Plan
- managers audit contractors as work progresses on tendered projects.

### 4.3.2 External audits

External audits are carried out annually by JAS–ANZ accredited audit bodies. The audit determines compliance against standard AS/NZS7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety. Following a successful audit, an audit certificate is issued. Our current audit certificate was issued on 27 September 2015 and remains current till 27 September 2018.

An external auditor also undertakes technical field audits commissioned by the board.

## 4.4 Service standards

### 4.4.1 Measuring the impact of interruptions

Based on 2015 information, our consumer surveys have shown that our consumers consider the reliability of supply to have the greatest impact on them. We measure reliability of supply through the indices of SAIDI, SAIFI, and CAIDI.

#### 4.4.1.1 System average interruption duration index (SAIDI)

SAIDI measures the total system minutes that supply was interrupted during the year. SAIDI is derived using the formula—

$$\frac{\sum(\text{Interrupted consumers} \times \text{interruption duration})}{\text{Total number of connected consumers}}$$

SAIDI provides the consumer with an indication of how long the electricity supply was interrupted during the year. The measure can be reported as a whole of network or it can be applied at a much lower level (e.g. feeder).

#### 4.4.1.2 System average interruption frequency index (SAIFI)

SAIFI measures the number of interruptions that occurred during the year and is derived using the formula—

$$\frac{\Sigma(\text{Number of interrupted consumers})}{\text{Total number of connected consumers}}$$

SAIFI provides the consumer with an indication of how many times the electricity supply was interrupted during the year. The measure can be reported as a whole of network or it can be applied at a much lower level (e.g. feeder).

Considering the measures of SAIDI and SAIFI side-by-side gives consumers an indication of whether interruptions on the network are short but frequent, or long but rare.

#### 4.4.1.3 Consumer average interruption duration index (CAIDI)

CAIDI measures the average system minutes that consumers were without supply during the year. CAIDI is derived using the formula—

$$\frac{\Sigma(\text{Number of interrupted consumers} \times \text{interruption duration})}{\Sigma(\text{Number of interrupted consumers})}$$

CAIDI provides the consumer with the average time that they were without electricity supply during the year. CAIDI can also be reported as a whole of network or be applied at a lower level (e.g. feeder).

#### 4.4.2 Setting the reliability targets

The Commerce Commission sets annual targets for performance against SAIDI and SAIFI<sup>26</sup>. The targets set from 1 April 2015 are set using the 10 year average normalised performance for the period 1 April 2009 to 31 March 2014<sup>27</sup>.

The Commerce Commission does not set a target for CAIDI as the measure is an average and is derived by dividing SAIDI performance by SAIFI performance.

Performance measures are intended to indicate if current performance has improved compared to historical performance. The Commerce Commission compares performance against targets to judge whether there has been a sustained material improvement in the network over the reported period.

The Commerce Commission sets its targets on the assumption that consumers do not want to pay a significantly higher cost for a small increase in reliability. Our consumer surveys have historically supported our assumption.

<sup>26</sup> Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2010, Decision No. 685, 30 November 2009.

<sup>27</sup> Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2015, [2014] NZCC 33, 28 November 2014, Schedule 4B: Adjustments to Quality Measures, clause 7.

### 4.4.3 Performance against the targets

Table 4.1 shows our normalised performance against target between 1 April 2008 and 31 March 2016, as well as forecast performance for the current year<sup>28</sup> and the year ending 31 March 2018<sup>29</sup>.

**Table 4.1 Performance summary – SAIDI, SAIFI, and CAIDI over 10 years**

Year	SAIDI (reported in system minutes)		SAIFI (number of interruptions)		CAIDI (reported in system minutes)
	Performance	Variance <sup>30</sup>	Performance	Variance <sup>31</sup>	Performance
2008/09	200.94	+112.74	1.69	+0.59	118.90
2009/10	145.58	+57.38	1.47	+0.37	99.03
2010/11	225.89	+61.70	1.71	+0.02	132.11
2011/12	161.60	-2.62	1.26	-0.43	128.14
2012/13	148.27	-15.95	1.30	-0.39	117.54
2013/14	281.12	+116.9	2.03	-0.34	138.48
2014/15	140.28	-23.94	1.16	-0.53	97.17
2015/16	155.29	+1.13	1.18	-0.33	131.49
2016/17 <sup>32</sup>	107.32	-25.49	0.84	-0.46	127.76
2017/18	132.81	-21.35 <sup>33</sup>	1.30	-0.21 <sup>34</sup>	102.29

#### 4.4.3.1 Normalisation of reliability performance

In setting of the performance measures, the Commerce Commission recognises that the reliability data is susceptible to variation resulting from events that are outside of the electricity businesses' control, such as force majeure events (e.g. earthquakes) and other major events (e.g. snow storms). To account for variability, the Commerce Commission uses the IEEE 2.5 Beta<sup>35</sup> method to normalise our annual performance.

<sup>28</sup> Current year performance (1 April 2016 to 31 March 2017) is not finalised at the time that the AMP is published (i.e. 31 March 2017).

<sup>29</sup> Forecast performance for both SAIDI and SAIFI for 2017/18 is based on Commerce Commission targets.

<sup>30</sup> The SAIDI target from 1 April 2010 was 164.22 minutes, and from 1 April 2015 is 154.155 system minutes per annum.

<sup>31</sup> The SAIFI target from 1 April 2010 was 1.69, and from 1 April 2015 is 1.507 interruptions per annum.

<sup>32</sup> SAIDI and SAIFI figures are as forecast at the end of January 2017 and presented to the Board of Directors at the March 2017 Board meeting.

<sup>33</sup> Based on our Target compared to Cap under the incentive scheme

<sup>34</sup> As per footnote 33

<sup>35</sup> The IEEE 2.5 Beta is based on an EDB's reliability data exhibiting a log-normal distribution from which a boundary value is derived as being 2.5 standard deviations from the mean. Currently, where the cumulative

We have had our performance normalised at 3 of the last 10 annual review dates.

In 2010 we experienced severe weather events, which saw our performance of 332 system minutes normalise to 146, exceeding the target SAIDI level by 57 minutes.

In 2013, heavy rain and snow storms in June, followed by high winds in July and September saw lines brought down, predominantly by trees that are outside of the fall zone falling on the lines. Severe weather events contributed over 660 system minutes to our reported un-normalised SAIDI of 858 minutes. Our normalised performance was 281 SAIDI minutes, exceeding the target level by 117 SAIDI minutes.

In 2015, we had a major snow storm in June, a wind storm in July, and a cross arm fire in April. These events added a total of 264 system minutes to our un-normalised SAIDI.

#### *4.4.3.2 Quality incentive scheme*

Under the quality incentive scheme, 1% of our maximum allowable revenue is at risk based on our performance for the financial year. The Commerce Commission sets three levels of performance: collar, target, and cap (the cap being our limit). If our SAIDI and SAIFI performance comes in under the target, we gain up to 1% in revenue. If we come in between the target and the cap, we lose up to 1% of revenue. Exceeding the cap would result in a breach, potentially triggering an investigation.

#### *4.4.3.3 Planned and unplanned interruptions*

To get a fuller understanding of our performance, we measure planned and unplanned interruptions separately. Planned interruptions are those where consumers are given at least 48 hours' notice of power going out. Normally we strive to provide five working days' notice to residential consumers and ten days' notice to commercial and industrial consumers. Unplanned interruptions are those where consumers are given less than 48 hours or no notice at all.

Measuring planned and unplanned interruptions gives us an indication of the inconvenience caused to consumers on our network. We assume that the inconvenience of a planned interruption is less than that of an unplanned one, as consumers are better able to plan for the outage. The Commerce Commission allows us to normalise performance by halving the actual SAIDI and SAIFI figures for planned interruptions. Halving the SAIDI and SAIFI associated with planned outages is designed to encourage planned outages to do network maintenance, thereby reducing the risk of unplanned interruptions. We try to avoid

---

effect of an outage over a 24 hour period exceeds the boundary value, the total SAIDI minutes of this period are replaced by the boundary value.

disruption to consumers during planned maintenance where reasonably practicable by use of industry recognised live line techniques.

Table 4.2 provides our actual performance against target for planned and unplanned interruptions for the year ending 31 March 2016.

**Table 4.2 Performance summary—planned and unplanned outages**

Measure	Target 2015/16	Actual 2015/16
SAIDI Class B—planned	46.2	57.5
SAIDI Class C—unplanned	107.9	357
SAIFI Class B—planned	0.45	0.21
SAIFI Class C—unplanned	1.05	2.62

#### 4.4.3.4 Vegetation management

Vegetation management has been and remains a concern for us due to the number of outages and SAIDI minutes attributable to vegetation getting into contact with our lines.

We are of the view that the Electricity (Hazard from Trees) Regulations 2003 is inadequate with respect to the defined ‘growth limit zone’, as the limit only considers distance from trees in calm weather conditions. The limit set under the regulations of 1.6 m from an 11 kV line is of no significance during moderate to high winds or storm conditions. During high wind conditions, branches are broken off trees and blown hundreds of metres by the wind creating a hazard.

To counter this hazard we offer a Tree Fell Agreement for trees that are outside the regulation zones and don’t meet the First Trim and Trim Notice criteria, but still pose a potential threat to our network. Tree work will be subsidised to an extent based on a risk assessment undertaken by our utility arborists. This risk assessment takes into account variable factors such as risk to the public, tree health, voltage level and the importance of the adjacent power line. We are also working closely with forestry contractors around plantation blocks in close proximity to power lines. We are focusing on coordinating the harvest of plantation instead of the standard trimming of plantation corridors. This has proved successful for us with the safe removal of a number of problematic plantations from our network in the last year.

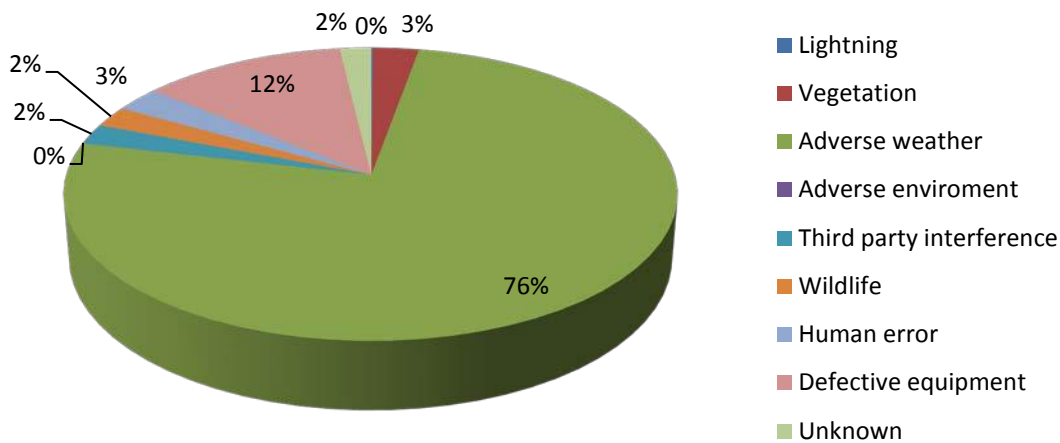
#### 4.4.4 Causes of unplanned interruptions

The breakdown of unplanned interruptions by cause is shown in Table 4.3 and Figure 4.1 on the next page.

**Table 4.3 Unplanned outages by cause**

Number of unplanned outages by cause (in SAIDI minutes) during 2015/16			
Cause of fault	No. of outages	Consumers affected	SAIDI minutes lost
Adverse environment	0	0	00:00
Adverse weather	65	12964	262:16
Defective equipment	50	10406	42:19
Human error	4	2537	09:26
Lightning	4	260	00:22
Third party interference	17	2805	07:50
Unknown	24	2110	06:30
Vegetation	13	3031	09:27
Wildlife	14	1541	07:57
<b>Total</b>	<b>191</b>	<b>35654</b>	<b>346:08</b>

### SAIDI Minutes Lost



**Figure 4.1 Percentage of unplanned outages by total SAIDI minutes**

#### 4.4.5 10-year reliability targets

Table 4.4 on the next page provides our 10 year reliability target levels for SAIDI and SAIFI. Information on five year forecasts for Class B and C interruption SAIDI and SAIFI can be found in Schedule 12d: Report Forecast Interruptions and Duration published on our website.

**Table 4.4 Primary consumer service levels**

Measure	Year ending 31 March									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
SAIDI	154.16	154.16	154.16	154.16	151.07	151.07	151.07	151.07	151.07	148.05
SAIFI	1.51	1.51	1.51	1.51	1.48	1.48	1.48	1.48	1.48	1.45

The remote controlling of pole mounted reclosers and other network improvements are expected to increase the efficiency of switching for planned outages and reduce the response time associated with switching for faults. Improvements can lead to gains in SAIDI and allow us more planned outages for upcoming Capex projects.

Similarly for SAIFI, the revised targets will allow savings from reduced frequency of fault related outages.

#### 4.4.6 Worst performing feeders

Looking at the worst performing feeders can help us identify and target necessary maintenance or improvements on the network.

The ten worst performing feeders as at 31 March 2016 are listed in Table 4.5 and Table 4.6.

**Table 4.5 Ten worst performing feeders by number of outages in 2015/16**

Feeder	No. of events	SAIDI (in system minutes)	SAIFI(no. of interruptions)
St Andrews	11	04:20	0.05
Morven	11	03:39	0.04
Cave	10	47:53	0.03
Otaio	9	01:45	0.04
Levels	9	4:54	0.04
Mt Cook	8	11:25	0.03
Holme Station	8	06:10	0.05
Fairly Rural	8	02:42	0.02
Woodbury	7	35:03	0.06
Raincliff	7	23.27	0.06

**Table 4.6 Ten worst performing feeders by SAIDI minutes in 2015/16**

Feeder	No. of outages	SAIDI (in system minutes)	SAIFI(no. of interruptions)
Fairlie	1	84:14	0.04
Cave	10	84:14	0.04
Woodbury	7	47:53	0.03

Feeder	No. of outages	SAIDI (in system minutes)	SAIFI(no. of interruptions)
Raincliff	7	23:27	0.06
Highfield	4	15:50	0.09
Waihaorunga	4	14.54	0.02
Mt Cook	8	11:25	0.03
PLP-TIM	7	10:32	0.04
Haldon Lilybank	1	08.58	0.01
Temuka East	3	07.48	0.13

#### 4.4.7 Energy delivered

Our energy delivery efficiency measures are load, loss ratio, and capacity utilisation.

##### 4.4.7.1 Load factor

Load factor is the average consumption divided by the peak load in a specified time period. Load factor is derived using the equation—

$$f_{load} = \frac{kWh \text{ entering the network during the year}}{(max \text{ demand for the year}) * (hours \text{ in the year})}$$

A high load factor means power usage is relatively constant with very shallow peaks and troughs. A low load factor means that high demand is reached only occasionally. To service the network peak we must have available capacity to meet the seasonal, weekly, and daily electricity demand variations. Catering for peaks requires more headroom, increasing the overall network cost.

##### 4.4.7.2 Loss ratio

Loss ratio measures the difference between the electricity entering the system at a GXP and the energy supplied at the consumer connection point. Loss ratio is derived using the equation—

Loss ratio

$$= \frac{kWh \text{ entering the network during the year} - kWh \text{ leaving the network during the year}}{kWh \text{ entering the network during the year}}$$

The Commerce Commission requires us to report our loss ratio each year as part of the Information Disclosure Requirements. The definition used by the Commerce Commission results in a loss ratio that comprises of both technical and non-technical losses. A technical loss is a loss that represents the electricity that is consumed (heating of conductor and transformers) during its delivery to a consumer's installations. A non-technical loss represents the inaccuracies caused by measurement and data handling, and includes losses

resulting from metering and reading errors, incorrect meter installations, theft of electricity, and unread meters.

#### 4.4.7.3 Capacity utilisation

Capacity utilisation measures the rate at which potential output levels for transformers are met or used. Capacity utilisation is derived using the equation—

$$\text{Capacity utilisation} = \frac{\text{max demand for the year}}{\text{installed transformer capacity}}$$

Displayed as a percentage, capacity utilisation measures the spare transformer capacity at any given point in time.

#### 4.4.7.4 Our energy delivery efficiency

The actual and projected energy delivery efficiencies are listed in Table 4.7.

**Table 4.7 Actual and projected energy delivery efficiencies**

Measure	2016	2017	2018	2019	2020
Load factor in %	70.3	70.4	70.5	70.6	70.7
Capacity utilisation in %	30.9	30.8	30.7	30.6	30.5
Loss ratio in %	3.4	3.3	3.2	3.1	3.0

## 4.5 Service levels

We recognise that the performance indices of SAIDI and SAIFI do not have a practical meaning for individual consumers; that is, SAIDI minutes are not the same as actual minutes without electricity supply. Accordingly, we publish service levels by location to give consumers an expected level of service.

Table 4.8 shows the number of unplanned outages consumers might broadly expect in any given year by broad geographical areas.

**Table 4.8 Expected service by location**

General location	Sustained outages	Momentary outages
Dairy processing	1 outage of 4 hours every 5 years	1 outage every 2 years
Other large industrial	1 outage of 4 hours every 5 years	1 outage every year
Timaru CBD	1 outage of 3 hours every year	2 outages every year
Timaru industrial and Port of Timaru	2 outages of 3 hours every year	2 outages every year

General location	Sustained outages	Momentary outages
Suburban Timaru	2 outages of 2 hours every year	2 outages every year
Waimate, Temuka, Pleasant Point, Fairlie, Geraldine, Tekapo and Twizel urban areas.	1 outage of 5 hours per year	2 outages every year
Rural areas on east coast	3 outages of 4 hours every year	4 outages per year
Rural Mackenzie Basin, including Mt Cook	4 outages of 6 hours per year	6 outages per year
Other rural areas	4 outages of 6 hours per year	8 outages per year

#### 4.5.1 Consumer service level preferences

We conduct biennial surveys to establish consumer preferences for quality and security of supply. In 2015, we surveyed 580 of our consumers. We received 275 completed responses on perceptions of reliability, inconvenience, community disruption, and price. The key conclusions were as follows.

- Most of the consumers surveyed believe that their electricity supply reliability is similar to what it has been over the last few years, with 13% believing that reliability has improved, and 7% believing that supply reliability has worsened.
- 76% of consumers had their electricity supply interrupted for more than a few hours during the 2013 storms, with a further 9% without supply for a whole day.
- 65% of consumers experienced no inconvenience from electricity supply interruptions during the 2013 storm, while 27% experienced some inconvenience.
- 83% of consumers surveyed indicated an unwillingness to pay more to reduce the risk of prolonged supply interruptions due to storms.

The conclusion of the survey is that mass market consumers have little if any willingness to pay additional line charges to improve the storm resilience of the network.

We decided to use 2015 survey result as we have been receiving consistent responses from our customers for the past years. For 2016 customer survey we put a new series of questions that are more focused on the customers' ability and willingness to participate in demand management initiatives.

## 4.6 Financial performance

Our financial performance for the year ended 31 March 2016 is shown in Table 4.9 on the next page. The figures for our performance for the year ended 31 March 2017 are not available at date of publication.

**Table 4.9 Financial performance**

Parameter	Target ('000)	Actual ('000)	Variance	
			('000)	As a %
Lines charge revenue	50,969	52,105	+1,136	+2%
Capital expenditure	14,245	21,095	+6,850	+48%
Operational expenditure	18,810	14,767	-4,043	-21%

#### 4.6.1 Line charge revenue

Target revenue for 2016 was \$50.9 million. Our total billed line charge revenue was \$52 million. The result is a variance of 2%, which we do not consider material.

#### 4.6.2 Actual versus forecast expenditure

##### 4.6.2.1 Operating expenditure

Table 4.10 shows the variance between our budgeted and actual operating expenditure for the year ended 31 March 2016.

**Table 4.10 Variance in operating expenditure as at 31 March 2016**

Operating expenditure category	Target ('000)	Actual ('000)	Variance	
			('000)	As a %
Service interruptions and emergencies	1,450	1,528	+78	+5
Vegetation management	500	716	+216	+43
Routine and corrective maintenance and inspection	2,801	4,212	+1,411	+50
Asset replacement and renewal	598	190	-408	-68
<b>Expenditure on network assets</b>	<b>5,348</b>	<b>6,646</b>	<b>+1,298</b>	<b>+24</b>
System operation and network support	4,552	2,877	-1,675	-37
Business support	8,910	5,245	-3,665	-41
<b>Expenditure on non-network assets</b>	<b>13,462</b>	<b>8,121</b>	<b>-5,341</b>	<b>-40</b>
<b>Total operational expenditure</b>	<b>18,810</b>	<b>14,767</b>	<b>-4,043</b>	<b>-21</b>

##### **Service interruptions and emergencies**

We were 5% above forecasted spending. This is a good figure for us due to the uncertainty around forecasting the impact of severe weather events. However it also shows the effectiveness of programs to remove vegetation around lines to reduce tree in line outages, which are a common cause of outages during wind and snow storms.

### **Vegetation management**

Vegetation management was 43% over budget this year. This is because of the emphasis we have placed on vegetation management to help reduce unplanned outages. We now have a program to remove trees out of the fall zone at our cost. The uptake of this offer by tree owners is hard to predict.

### **Routine and corrective maintenance and inspection**

We were 50% higher than forecast this year, and asset replacement and renewal was 68% lower. This indicates a change in priorities this year between the two groups. By increasing inspection of assets we were able to defer replacing or renewing.

### **Non-network Opex**

We were under budget by 34% on non-network assets due to reduced spending on new IT projects and reduced costs to business support after the accounting department was transferred from NETcon to ourselves (Alpine).

There were no re-classified items for either OPEX or CAPEX.

#### **4.6.2.2 Capital expenditure**

Table 4.11 shows the variance between our budgeted and actual capital expenditure for the year ended 31 March 2016.

**Table 4.11 Variance in capital expenditure as at 31 March 2016**

Capital expenditure category	Target ('(\$000))	Actual ('(\$000))	Variance	
			('(\$000))	As a %
Consumer connection	2,850	8,031	-5,181	+182%
System growth	1,660	3,079	+1,419	+86%
Asset replacement and renewal	4,163	4,131	-32	-1%
Asset relocations	495	108	-387	-78%
Reliability, safety and environment	1,310	2,495	+1,185	+148%
<i>Expenditure on network assets</i>	<i>10,478</i>	<i>18,600</i>	<i>-+8,122</i>	<i>+78%</i>
<i>Expenditure on non-network assets</i>	<i>3,767</i>	<i>2,495</i>	<i>-1,272</i>	<i>-34%</i>
<b>Total capital expenditure</b>	<b>14,245</b>	<b>21,095</b>	<b>+6,850</b>	<b>+48%</b>

The variance between the forecast reported in our Asset Management Plan 2016–2026 and the updated forecast reported here is due to the inclusion of work in progress in this AMP's figures.

***System growth***

When we budget for system growth we only include those builds which have a high level of certainty of proceeding, where capital contributions are paid or are expected to be paid. This is due to the size of the intended builds which involve significant investment on our part. While this method of forecasting is not ideal it does reveal the nature of our customer's sensitivity to announcing their intentions to us as a third party. That is they are often unwilling to reveal their plans to us until the last moment.

For this year we have started work on three large developments of over \$1m. Large developments for 2015/2016 included:

- Holcim Cement
- Waihao Downs Irrigation (WDI)
- A dedicated feeder to WDI

***Consumer connection***

As with System Growth above, the consumer connection budget remains conservative by not taking into account large capex projects which may or may not occur in the forecasted year.

***Asset replacement and renewal***

There was little variance between actual and budget for 2016.

***Asset relocations***

For 2016 we were under budget for asset relocations. The majority of this budget is for overhead lines to underground cable conversion (OH/UG). Budget for 2016 has been transferred to 2017 for a major OH/UG project in the Timaru area (Pages Rd to Wai-iti Rd) which also requires undergrounding the 33 kV line which run over the 11 kV lines being converted to underground.

There was also some OH/UG which was budgeted for under reliability, safety and environment, (\$1.7m) which if it was included in asset relocations would bring budgeted and actual closer to together.

***Total reliability, safety and environment***

Overall we were 148% over budget but within the category of reliability, safety and environment, we had significant movements between quality of supply and other, reliability safety and environment. This latter movement is partly due to coding between the two descriptors, and largely due to conservative budgets being written.

## 4.7 Justifying service levels

We justify our service levels based on:

- by ensuring we design, build, operate and maintain a safe and reliable electricity supply network that meets our stakeholders' expectations
- the preference of the majority of consumers for us to maintain historical levels of supply continuity and restoration for paying about the same price
- the need to prioritise network spend within the constraints of maximum line charge revenue permitted under the default price-quality path
- the physical characteristics and configuration of our network that represent an implicit level of reliability which is costly to alter, but can be altered if a consumer or group of consumers pays for the alteration.
- the diminishing returns of each dollar spent on reliability improvements
- consumer specific request and ability to pay for a particular service level (e.g. uninterruptable supply)
- an third party imposing a service level or, in some cases, an unrelated condition or restriction that manifests itself as a service level (e.g. a requirement to place all overhead lines underground, or a requirement to maintain clearances).

Our consumer surveys have indicated that our consumer preferences for price and service levels are reasonably static.

## 5. NETWORK DEVELOPMENT PLANNING

### 5.1 Introduction

Chapter 5 describes our planning process, forecasted load (including load projections for each GXP and related substations). Planned Capex projects for the planning period, both material and non-material projects are detailed in Appendices A, B, and C respectively. Detailed information on asset renewal drivers and enhancement of the overall planning process can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

#### 5.1.1 Background

South Canterbury has traditionally been a sheep and crop farming region, with near zero annual population growth<sup>36</sup>. We have historically estimated load growth by calculating a monthly growth amount from the previous 15 years of monthly network peak load data, before adding in step load increases when confident that load will occur.

In recent years South Canterbury has seen major changes to rural land use with many farms converting to dairy on irrigated pastures.

Discussions with new and existing consumers reveal that growth over the next 5 to 10 years may increase peak network capacity by up to 30%<sup>37</sup>, but investment is uncertain. And in this environment of uncertainty we are unwilling to begin material Capex projects until a firm commitment from consumers is made to us in the form of capital contributions.

---

<sup>36</sup> Based on Statistics NZ census data, average annual population growth for South Canterbury 1996–2013 has been 0.14%. Historically, South Canterbury has had low dairying levels.

<sup>37</sup> Discussions with consumers have revealed potential future load from additional dryers at Fonterra, ODL, proposed irrigation schemes Waihao Downs and Hunter Downs, as well as from individual dairy conversions. The upper bound of forecasted load is close to 37 MW, or 30% of our present peak load.



Figure 5.1 Most of the proposed irrigation will be supplied by the Waitaki River

## 5.2 The strategic planning process

Section 5.2 summarises our planning process used to determine the material Capex spend over the next 12 months and over the next 10 years. Figure 5.2 shows our process.

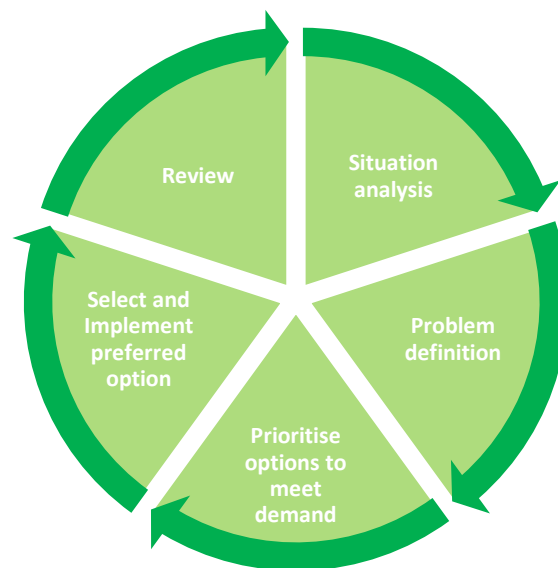
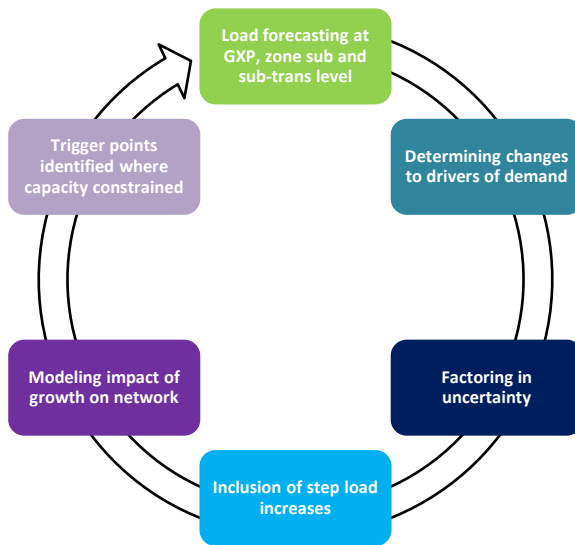


Figure 5.2 The planning process

### 5.2.1 Situation analysis

The first stage of the planning process is to analyse the impact of load growth on the network. The approach taken is shown in Figure 5.3.



**Figure 5.3 Situation analysis**

### 5.2.1.1 Forecasting growth

When forecasting growth, we use a model that uses historical data. We use a line of best fit across historical peaks from the previous 15 years<sup>38</sup> before adding in step load increases when we are confident the step load increases will occur. We also consider a shorter four to five year trend to improve our forecasting. Due to the close relationship between dairy farm conversions or production, irrigation scheme development, and dairy processing, the factors influencing growth and are considered in our forecasting are:

- available land for irrigation purposes
- approved water use consents
- approved consents for dairy processing

In addition we also factor in specific load growth that will result in a step change in demand that we are aware of and have a moderate to high probability of eventuating. This determination is made in collaboration with the entity requiring the increased demand. Examples of these are dairy factories, food processors, and irrigation scheme owners.

Due to the sensitivity of planned or proposed development, we often engage in confidentiality agreement with developers which sometimes explains the lack of specifics on load forecasts in our public documents.

<sup>38</sup> Data is sourced monthly from Transpower (who meters GXPs) and reconciled against data from the Electricity Authority's reconciliation manager.

### 5.2.1.2 Drivers for load growth

Load growth occurs in five distinct areas of our network: rural, residential, industrial, commercial, and emergent technologies (e.g. electric vehicles).

The drivers for load growth in each area are described in more detail in the following paragraphs.

#### **Rural load growth**

South Canterbury has seen a large number of farms convert to dairy. Dairy conversions have chiefly occurred because dairy has consistently offered better return per hectare than other forms of land use over the last 15 years.

Dairying in South Canterbury requires irrigation. Irrigation pumps and dairy sheds have a higher demand (network capacity) than traditional South Canterbury land use. With the increased irrigation, our peak demand has or will shift to a summer peak. The precipitation in a summer will greatly influence the demand.

#### **Residential load growth**

The traditional driver of residential growth has been population growth. From 1996 to 2013, South Canterbury population growth was 0.14% p.a. Recently, other drivers have been impacting on the use of electricity, including:

- environmental restrictions on the use of open fires
- the price and availability of alternative energy sources
- better insulation on newly built houses.

Heat pumps are more efficient than other forms of electric heating, leading to a decrease in demand. However, the change from log fires to heat pumps increases the amount of electrical heating on the network, leading to higher demand. We believe that the effects of conversion from log fires to heat pumps and the impact on residential load, is now over. This has resulted in an adjustment to the after diversity maximum demand (ADMD) used in out planning and forecasting.

#### **Industrial and commercial load growth**

Local economic growth is the main driver behind load growth on our network. We include growth as step demand increase in our planning once we are confident that load will occur. The most important of these are dairy processing and food processing developments.

#### **Electric vehicle (EV) growth**

We have two fast charging stations located in our network (Timaru and Waimate) and 5 more are planned to be installed over the next 12 months. They will be located in Geraldine, Fairlie, Tekapo, Twizel and Mount Cook village. The impact of this type of load

growth will largely depend on the uptake of electrical vehicles by South Canterbury residents as well as tourist industry transport operators.

### ***Distributed generation***

PV growth is steady in the South Canterbury region. Presently 750 kW of PV is connected to our network, with an exponential growth (see Figure 3.23 in Chapter°3).

Negative load growth could occur due to installation of distributed generation (DG), particularly from photovoltaics (PV) on sunny days. The impact of DG would increase by the installation of battery storage systems, enabling the DG to supply the network during periods of peak demand.

### ***Use of multivariate models***

It is important to identify the main drivers of load growth when forecasting. Ideally, a model that identifies and includes drivers that have an observable relationship with load growth would be useful. However, initial investigations onto rural demand for electricity have found it difficult to show observable relationships between the most obvious drivers of irrigation (the main drivers of future growth), such as temperature or rainfall. The volume of irrigation on a farm depends on a number of factors, such as conditions of the resource consent, existing soil moisture, substrate type, etc. A farmer in one region of South Canterbury may have different drivers for irrigation than a farmer in another region.

Therefore, the relationship between suspected key drivers of irrigation and the volume of irrigation is considered too complex to model accurately. Instead, a simple model that forecasts growth based on historical data is used, with the assumption that historical complex relationship will continue into the future.

Where it is known that there will be a change in a key driver, such as the number of resource consents issued, our planning team factors the change into the growth forecasts based on historical forecasts.

### ***Use of outside consultants***

In 2011 we recruited Sapere Group to model the relationship between rainfall and irrigation. Sapere found 'a weak negative correlation between rainfall and irrigation (-20%) which reflect a high degree of randomness'. Sapere concluded that, due to the number of drivers for irrigation, 'specifying [the relationship between irrigation and rainfall] with a high degree of certainty proves problematic'.

### 5.2.1.3 Inclusion of step demand increases

We include step increases in load when proposed load is certain. If the step in demand is material, we will not proceed beyond the conception planning stage until a capital contribution has been paid.

Often we are unaware of new load requirements until a customer requests to connect. In some cases, upgrades required to enable a connection take longer than a consumer expects. To overcome this timing issue, we are looking at ways to inform and educate local investors about the notice periods necessary for us to complete the required work.

### 5.2.1.4 Planning assumptions and impact of uncertainty

Table 5.1 describes how we factor uncertainty into the planning process.

**Table 5.1 Significant assumptions and the effect of uncertainty on planning**

Assumption	Uncertainty	Impact on asset management
<p>Consumers will continue to use and pay for energy supplied by our network.</p> <ul style="list-style-type: none"> <li>TIM and TKA subs will stay winter peaking and load will grow at 1-2% p.a.</li> <li>Summer peaking subs will have load growth around 3% p.a. driven by agricultural requirements.</li> </ul>	<p>Consumption patterns changing due to economic, political, or environmental changes.</p>	<p>Reduced revenue could impact on service levels.</p>
<p>Load growth forecasted accurately based on prior demand recordings.</p>	<p>A change to one or more key variables that influence demand from the time period the load forecast was based on.</p>	<p>Changes in investment direction and spending could occur as new information comes to light. An annual update of the AMP is needed to keep account of changes.</p>
<p>Return on investment is adequate to meet stakeholder requirements.</p>	<p>Unforeseen increase in costs or decrease in revenue occurs.</p>	<p>Capex and Opex could alter to meet shareholder requirements.</p>
<p>The regulatory framework will continue around its present format.</p>	<p>There may be major shifts in regulatory thinking, possibly from political change.</p>	<p>Could lead to greater expenditure to meet and understand compliance, as well as changes to the AMP.</p>

Assumption	Uncertainty	Impact on asset management
The level of capital expenditure will meet stakeholder requirements for safe, efficient, reliable, and cost effective energy delivery.	Uncertain events may force an increase in expenditure.	Level of Capex may have to be altered to meet stakeholder requirements.
The discount factor used to estimate present value of future cash flows will not significantly change.	There will be a change in the treasury outlooks, inflation, etc.	The present value of cash flows will have to be updated as new financial information comes to light.
Environmental legislation in relation to water rights and air quality will not significantly change.	A change in allocation of water will impact on irrigation and load requirements, while air quality will impact on the use of heat pumps.	Capex forecasts will have to alter to cater for changes in load demanded.
There will be no new unplanned large loads or generation appearing on our network.	New unplanned load or generation appears on the network.	Changes to investment and Capex planning required.
Our planning and prudent investment takes into account impact of natural events on the network.	The impact and timing of a natural event is beyond prudent planning and investment.	Could lead to significant changes across asset management and expenditure in particular.
The use of distributed generation will not increase significantly in the medium term.	The uptake of DG will increase significantly because of a reduction in costs and/or an increase in return from generation. The reverse also applies if returns of DG drop.	May require further investment and a change in how costs are recovered from DG owners, and how benefits are available to DG owners.
There will be a constant load factor throughout forecast period.	Load factor will change.	May have insufficient capacity for unplanned load, leading to changes in planned Capex.
Diversity across network will remain constant.	Diversity will change.	May have insufficient capacity for unplanned load, leading to changes in planned Capex. May cause increased in planned Opex.

### 5.2.1.5 *Use of software to model impact of growth*

Growth levels and feeder data, such as connected loads, are entered into modelling software to model the impact of growth on the network at GXP and feeder level. Trigger points (capacity constraints) are identified and include ampacity, voltage drop, or summed network demand.

### 5.2.1.6 *Identification of trigger points*

Load growth eventually results in asset operating parameter trigger points being reached for location, capacity, reliability, security, condition, or voltage.

If a trigger point is reached, we activate one or more of a range of network development options to bring the asset's operating parameter back within an acceptable range. For example, non-asset solutions available, capex projects to extend, upsize, or renew an asset enable that asset to meet the new level of demand. Consequently, the asset's trigger points are adjusted to correspond to its new operating parameters. More detail on this topic can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

## 5.2.2 Problem definition

Once a trigger point is identified, we define the issues behind it, before considering options to meet demand. All options considered must align with our mission for safe, reliable, and efficient energy delivery and infrastructure services.

When exploring various options we factor in the time needed to plan and build so that projects are completed on time. For example, some power transformers can take a year to source, while projects requiring changes to the transmission network can take up to five years to facilitate.

As network assets grow with increased load, the Opex life cycle tasks of operation and maintenance will grow in number and complexity. It is, therefore, important that planning and design options are chosen that consider life cycle costs of assets and options. Although such options may not have the lowest Capex cost, they are essential for evolving a more efficient and economic network.

## 5.2.3 Consideration of options

Table 5.2 described various options considered when capacity is exceeded or expected to be exceeded. The options are listed in order of preference.

**Table 5.2 Options considered for capacity constraints**

Option	Description of option	Example of a possible option
Do nothing	Simply accept that one or more parameters have exceeded a trigger point. In reality, the do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if option does not constitute an unacceptable risk as per our Risk Management Policy.	The voltage at the far end of an 11 kV overhead line falls below the threshold for a few days per year—the benefits (including avoiding the consequences) of correcting such a constraint are simply too low.
Operational activities	Switching the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment, or introducing a voltage regulator or capacitor bank to mitigate a voltage problem. A downside is that switching may increase line losses and reduce security of supply. This is a typical example of a non-asset solution.	
Influence consumers	To alter consumer consumption patterns so that assets perform at levels below the trigger points through tariff structures and/or demand side management.	Shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity.
Construct distributed generation	An adjacent asset's performance is restored to a level below the trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is underutilised.	Water being released from a dam that could be used in a hydro generator, or install a high pressure boiler for an electricity turbine, then use medium pressure outflow for industry.
Modify an asset	Essentially a sub-set of retrofitting, that generally involves less expenditure. Modifying an asset is more suited to larger classes of assets such as 33/11 kV transformers.	By adding forced cooling to a power transformer or considering cycling overload parameters.
Retrofitting	Retrofitting equipment with improved technology devices that can exploit the features of existing assets.	Installing relays and actuators on reclosers and regulators for automation so that they can be remotely controlled and operated.

Option	Description of option	Example of a possible option
Install new assets	A greater capacity will increase the assets trigger point to a level at which it is not exceeded.	Replacing a 200 kVA distribution transformer with a 300 kVA transformer or replacing light conductor with a larger conductor. We research likely ground conditions to rate underground cables as high as possible to allow maximum power flow.

The preferred option is chosen during planning sessions with the network managers based on risk management criteria.

We are presently implementing a software-based decision making tool that will assess and balance competing demands for growth, safety, and financial return, to identify the best options. Combined with the experience and knowledge of our engineers the tool will greatly enhance the network planning process.

#### 5.2.4 Implementation

Once the preferred option is chosen, the project will be included in the Network Development Plan (NDP) to be incorporated into the AMP. The projects in the NDP will be prioritised to a three and one year Works Plan. Budgets for the Works Plan projects are submitted to the CEO and the Board of Directors for approval.

Projects included in the Works Plan are prioritised against the criteria described in Table 5.3.

**Table 5.3 Criteria for prioritising options**

Criteria for assessing options	Description
Safety	Projects that require execution to improve safety and/or remove hazards. Criteria include: public safety, workplace safety, and network operating safety.
Risk reduction	Projects that allow the risk to the company to be reduced in accordance with our Risk management Policy. This includes health & Safety, Reputation (branding), Environmental, compliance and financial impact.
Reliability of supply	Projects that improve network resilience in the face of faults, undesirable events, and general use. Criteria include: improve network condition, interoperability, adaptability, flexibility, ease of use, and maintainability.

Criteria for assessing options	Description
Security of Supply	Projects that ensure our network assets comply with our Security of Supply standard (currently we use the EEA <i>Guide for Security of Supply</i> ) and such improve the capacity of the network to meet stakeholders expectations.
Efficiency	Projects that improve the performance and costs of the network to meet stakeholder needs. Criteria include: network operating performance, organisation of network assets, improvement of network design, and a reduction in maintenance and operating time through selection of maintenance-free equipment with minimum operation requirements.
Economy	Projects that produce the best return in terms of network improvement for funds expended and provide a reduction in life cycle costs through selection of “maintenance-free” equipment with lowest inspection and operation overheads.
Ease of project implementation	Projects that are the easiest to implement with respect to multiple contractors and stakeholders, high AEL resources commitment, implementation time and high risk of exceeding planned SAIDI.

Once accepted into the Works Plan, as listed in Appendix A the project will proceed as described in Figure 5.4.

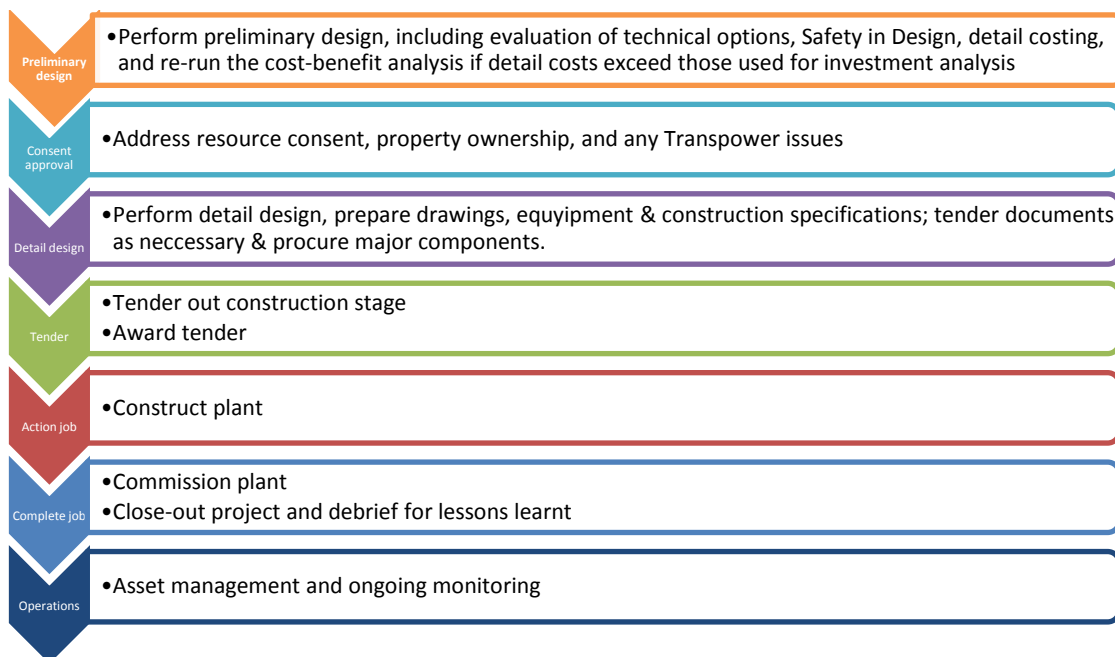


Figure 5.4 Project life cycle

## 5.2.5 Review

The NDP is reviewed to compare progress against goals and to check planning assumptions. New information on step load increases may result in the addition or subtraction of future loads from the NDP. Our planning process is being developed and improved through the development of the asset management framework (AMF) as described in Chapter 8-ASSET MANAGEMENT MATURITY. This will include a planning lifecycle strategy that aligns with our overall asset management policy and strategy.

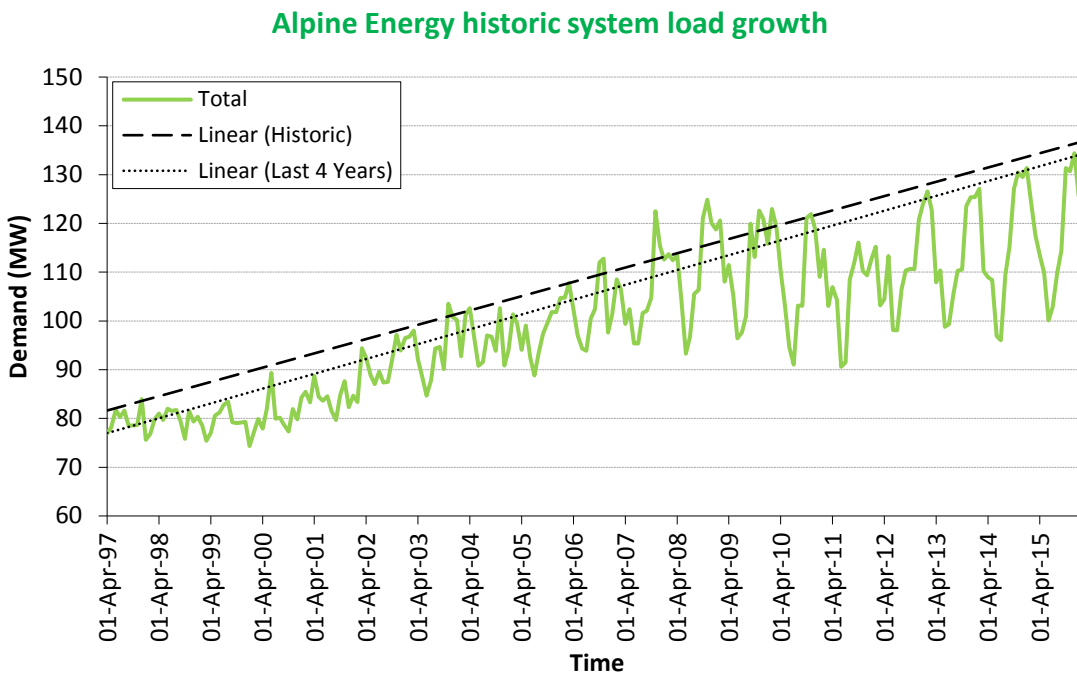
## 5.3 Demand forecasts on the network

Demand forecasts for GXP, sub-transmission, and zone substation assets can be found in Appendix G.

Residential demand is forecasted by extrapolating a trend line from the last 16 years, and four/five years respectively, of monthly peak demand at GXP level to determine historical growth. The likely impact of population changes, environmental legislation on heating and significant economic changes, is factored in by the planning team.

Large industrial load forecasts also rely on information from industrial and commercial consumers for step demand changes. For more detail, please see Section 5.3.1—Inclusion of step demand increases.

Figure 5.5 illustrates the historical total system load growth on our network.



**Figure 5.5 Alpine Energy historic load growth**

Figure 5.6 and Figure 5.7 show historical trends of anytime maximum demand and the peak maximum demand growth rate for each GXP is shown by the dotted line in each case.

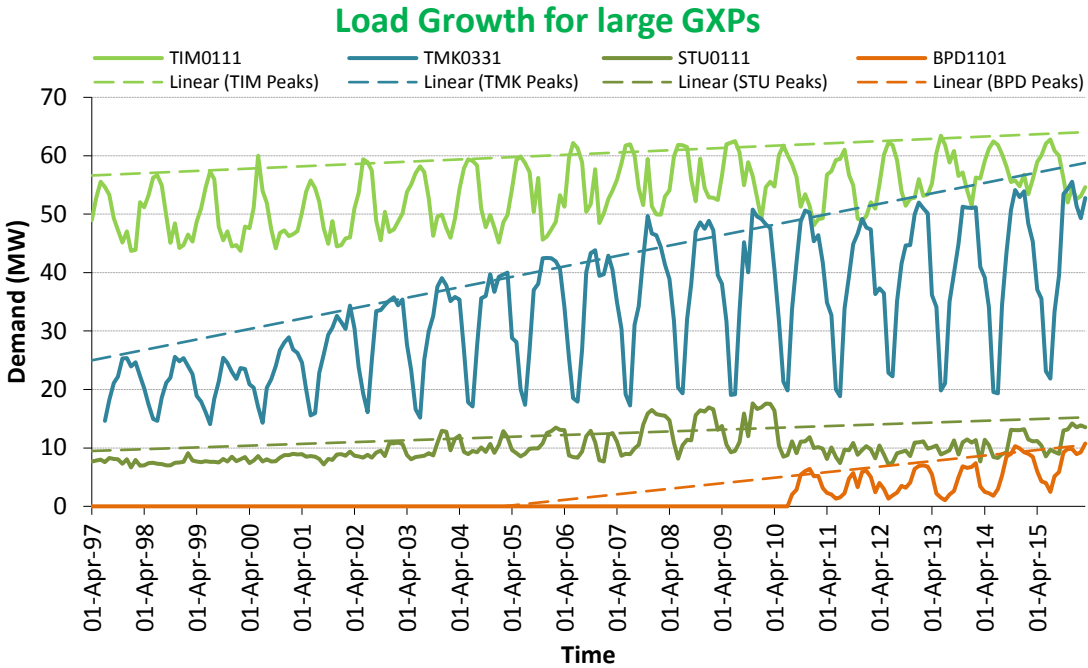


Figure 5.6 Load growth for large GXPs

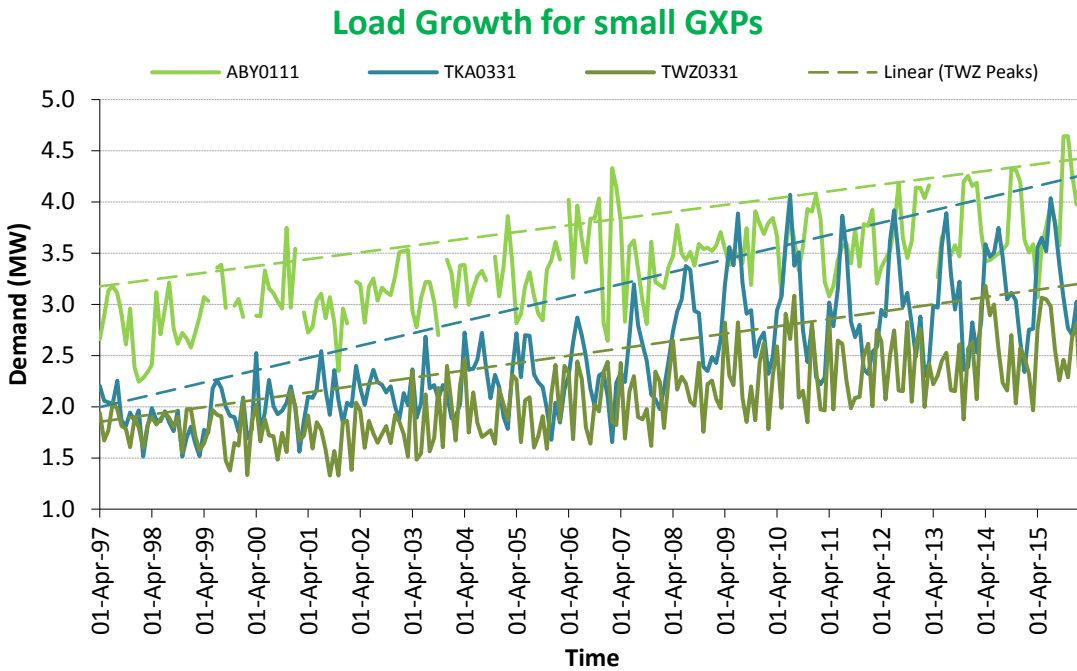


Figure 5.7 Load growth for small GXPs

The stagnated growth between 2009 and 2012 is likely to be attributed, in part, to the international financial crisis and its effect on development and the business climate in New Zealand.

The data in each of the graphs is summarised in Table 5.4. The figures reported here are current to March 2016 and are based in the highest single half-hour maximum rather than an average of the 12 highest peaks. The trend is over the last 16 years.

**Table 5.4 Historical demand and load growth**

GXP	Half hour max demand	Monthly growth (MW)	Annual growth (MW)	Annual growth (%)
ABY0111	4.64	0.005	0.061	1.318
BPD1101	10.75	0.072	0.866	8.058
STU0111	14.20	0.027	0.323	2.273
TIM0111	62.80	0.034	0.412	0.655
TKA0331	4.04	0.010	0.124	3.062
TMK0331	55.55	0.153	1.841	3.314
TWZ0331	3.07	0.006	0.073	2.387
<b>Total</b>	<b>134.4<sup>39</sup></b>			

### 5.3.1 Inclusion of step demand increases

The planning team must also take into account probable step demand loads that have been communicated to us by commerce or industry. Step demands listed in Table 5.5 are incorporated into our GXP load growth projections, along with the assumptions described earlier. Step increases are listed by their number to protect the confidentiality of some consumers.

**Table 5.5 Loads adding step changes in demand**

Project No	Demand (MW)	Year	GXP
Load 2017-001 (ODL UHT & canning)	2	2017	CNR
Load 2017-002 (Juice Products)	0.5	2017	TIM
Load 2017-003 (Simons Pass)	3.2	2017-2022	TWZ
Load 2017-004 (Tekapo Village)	3.3	2017-2020	TEK
Load 2017-005 (Show grounds)	2	2017-2018	TIM

<sup>39</sup> This total is our total coincident maximum demand, not the sum of the non-coincident GXP demand.

Project No	Demand (MW)	Year	GXP
Load 2018-001 (Hydro Grand)	0.5	2018	HNT/TIM
Load 2018-002 WDI 2	3.2	2018	BPD
Load 2018-003 (HDW)	24	2018-2020	STU
Load 2019-001 (ODL dryer 2)	4	2019-2020	CNR
Load 2207-001 (Fonterra dryer 2)	6	2020	STU

### 5.3.2 Estimated demand at GXP level

Once step demand loads are factored into our planning models, we estimate demand at GXP, zone substation, and feeder level. Summaries of demand at zone substation and feeder level are given in Section 5.3.3—Estimated demand at zone substation level.

Information on planning at the GXP level can be found in Appendix G and summarised in Table 5.6

**Table 5.6 Load growth by GXP**

GXP & substation (Season peak)	Forecast growth trend (Total MW MD) for the year ended 31 March										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ABY (summer)	4.7	4.8	4.9	4.9	8.0	8.1	8.3	8.4	8.5	8.7	8.8
BPD (summer) (Inc. CNR)	12.7	20.0	20.3	24.6	24.9	26.7	27.0	29.9	30.2	33.1	33.4
CNR	5.1	5.1	5.1	9.1	9.1	10.6	10.6	13.1	13.1	15.6	15.6
OAI (summer)	0.0	0.0	0.0	0.0	0.0	45.9	46.4	46.9	55.5	56.1	56.7
STA (summer)	0.0	0.0	0.0	18.6	19.9	21.3	22.7	23.2	23.8	24.4	25.0
STU (summer)	14.6	20.9	21.4	31.1	32.1	33.1	40.2	41.2	42.3	43.4	44.5
TKA (winter)	4.4	5.4	7.0	7.5	7.6	7.8	7.9	8.0	8.2	8.3	8.5
TEK Village	3.9	4.7	6.3	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5
Mt Cook	1.2	1.3	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7
TMK (summer)	58.2	59.3	60.5	61.7	63.0	64.2	65.5	66.8	76.1	77.7	79.2
TIM 110 kV (summer)	124.9	128.6	131.7	133.6	141.4	143.6	145.9	148.2	158.4	160.8	163.3
TIM 11 kV (winter)	70.4	72.3	73.9	74.5	78.2	79.1	80.0	80.9	81.6	82.3	83.0
PAR	8.7	8.9	9.1	9.3	9.6	10.0	10.4	10.6	10.8	11.0	11.3
PLP	5.2	5.3	5.4	5.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1

GXP & substation (Season peak)	Forecast growth trend (Total MW MD) for the year ended 31 March										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TWZ (winter)	3.7	5.2	5.6	5.9	6.1	6.2	6.3	6.3	6.4	6.5	6.6
TVS Village	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1
Irrigation on 33 kV	0.4	1.8	2.1	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

### 5.3.3 Estimated demand at zone substation level

Information on planning at zone substation level can be found in Appendix G. Demand growth at zone substation level is summarised in Table 5.7.

**Table 5.7 Zone substation load forecast**

Zone sub	2017 (MW)	Ten-year rate and nature of growth	2027 (MW)	Provision for growth
ABY 11 <sup>o</sup> kV board	4.6 (summer)	1.42% historical on ABY. Irrigation and dairying activity, residential load, small subdivision development.	5.5 (summer) 8.8 (with Raincliff/ Totara Valley)	Transpower asset under its management. Overall load not expected to breach Transpower's capacity unless Raincliff/ Totara Valley built.
FLE	2.7 (winter)	1.42% historical on ABY. Residential load, small subdivision development.	3.2 (winter / shoulder)	Transformer with OLTC has capacity of 6 MW - expect demand to grow from current demand of 2.7 MW to 3.2 MW over the planning period.
BPD	12.7 (summer)	8.4% per year expected. Residential load. Dairy and irrigation development.	BPD 17.8 CNR 15.6 Sum 33.4 (summer)	A second transformer will be installed in 2017/18 to increase capacity and security.
CNR	5.1 (summer/ winter)	Dairy processing.	15.6 (summer/ winter)	Assumption is to prepare site for two dryers/lactose and UHF products off BPD 33 kV initially with later extensions for two dryers forcing the primary potential for the site to 110 kV.

Zone sub	2017 (MW)	Ten-year rate and nature of growth	2027 (MW)	Provision for growth
STU	14.2 (summer)	2.5% per year expected as TMK Residential load. Dairy and Irrigation development (not including step changes).	44.5 (summer)	Transformer upsizing required pending load requirements for Hunter Downs Water scheme. 11 kV switchboard upsizing required after 24 MVA.
TEK	3.5 (winter /shoulder)	3.0% historical on TEK. Residential load. Tourism development.	7.5 (winter /shoulder)	Transformer upgrade planned for 2019/20 and 11 kV switchboard replacement in 2023/24.
HLB	0.3 (est. winter /shoulder)	3.0% historical on TKA but little on HLB.	Unknown at this time	If irrigation expands toward Haldon then it is likely that supply will come from TWZ. HLB would be retained for Lilybank.
BML	0.15 (est. winter /shoulder)	3.0% historical on TKA. Some irrigation is possible.	0.6 (winter /shoulder)	If irrigation expands toward Simon's Pass BML will require an upgrade with voltage support added to sustain additional load. Alternatively, supply can be established from TWZ.
UHT	1.0 (est.) (winter /shoulder)	3.0% historical on TKA. Residential load and tourism development.	1.4 (winter /shoulder)	Major substation refurbishment planned towards the middle of the planning period.
TMK	58.2 (summer)	3.6% historical on TMK. Dairy and irrigation development.	79.2 (summer)	Load growth due to expansion at Clandeboye. Rangitata South Irrigation could add more load. Solutions being discussed with Transpower.
CD1 & CD2	28.7 (summer)	3.6% Stepped to suit process expansion.	28 (summer) 36	Substation and sub-transmission capacity available. Additional CBs at substations and 11 kV cabling to new RMU and distribution transformers required – expect demand to grow from current demand of 28.7 MW to 36 MW by the end of the planning period. With careful load transfers existing assets can meet demand and retain N-1 security.

Zone sub	2017 (MW)	Ten-year rate and nature of growth	2027 (MW)	Provision for growth
GLD	8.7 (summer)	3.6% historical on TMK. Residential load. Dairy and irrigation development.	10.7 (summer)	Local concern may lead to a second 33 kV circuit to provide N-1 security—expect demand to grow from current demand of 6.5 MW to 7.8 MW by the end of the planning period. A transformer upgrade to increase capacity is planned for 2020/21.
RGA	12.5 (summer)	3.6% historical on TMK. Residential load. Dairy and irrigation development.	17.7 (summer)	Expect demand to grow from current demand of 9.8 MW to 18 MW by the end of the planning period. Note some of RGA load can be transferred to TMK and GLD as a temporary measure.
TIM	70.4	0.6% (winter).	83.0 (winter)	0.6% historical; some steps expected to come from residential growth, heat pump uptake, and industry growth (Washdyke).
TIM CBD	30.4 MW (winter)	0.6% historical on TIM.	35.0 (winter)	None required for local assets as substation and sub-transmission capacity is available. Expect demand to grow from present demand of 31 MW to about 35 MW by the end of the planning period. Existing assets can meet demand and retain N-1 security.
PAR	8.7 (summer)	3.4% per year expected on TMK until STA GXP built. From then 2% Residential load, dairy and irrigation development.	11.3 (summer)	Up-sizing of sub-trans lines underway to retain full N-1 security—expect demand to grow from current demand of 8.7 MW to 11.3 MW by the end of the planning period.
PLP	5.2 (summer)	4.62% per year expected as residential load growth, and dairy and irrigation development.	6.5 (summer)	Existing transformer rated for the period. Some security via 11 kV back up from ABY, TIM, and TMK.

Zone sub	2017 (MW)	Ten-year rate and nature of growth	2027 (MW)	Provision for growth
TVS	3.7 (shoulder)	2.2% historical. Residential load, large scale subdivision, dairy and irrigation development.	6.6 (shoulder)	Substation rebuild and possible relocation planned for 2018/19. Extend 33 kV line to new irrigation development and install smaller dedicated substations.

### 5.3.4 Effect of GXP forecasts on supply security

The continuing load growth at ABY, BPD, STU, TMK, and TIM GXPs, as well as forecasted load increases at TKA and TWZ, will cause capacity constraints within the AMP planning period. Appendix G details more information on network constraints. A summary of how we provide for growth is provided in Table 5.8.

**Table 5.8 GXP load growth and solutions**

GXP	Rate and nature of growth	Provision for growth (preferred option)
ABY	Med – rural	GXP investment if Totara Valley load is realised. Covert GXP to 33 kV from 11 kV.
BPD	High – rural, industrial dairy factory	Upgrade capacity with second transformer. New investment to secure the energy needed off the grid.
STU	High – dairy and irrigation Med – dairy processing	New investment to secure the energy needed off the grid.
TKA	Med – subdivision and tourism business	Supply transformer at TKA rated at 10 MVA, sufficient for planning period.
TMK	High – rural and industrial	GXP investment
TIM	High – industrial / commercial	GXP investment by Transpower
PAR	High – dairy and irrigation	Sub-transmission investment
PLP	Low – dairy and irrigation	None currently planned
TWZ	Med – rural and subdivision	GXP investment, rural investment to take electricity to areas presently unserved

## 5.4 Effect of capacity constraints on planning

A combined summary of all network constraints is provided in Table 5.9. A detailed description of the constraints for each GXP supply area can be found in Appendix G.

**Table 5.9 Network capacity constraints**

Constraint	Description	Intended remedy
Waimate Area— Holistic	Lack of capacity for BPD & STU.	Work with Transpower to ensure capacity is made available
STU GXP Supply Security to 110 kV bus	Upgrade N security to N-1.	From Feb 2010 110 kV bus is closed during peak dairy season. Bus could be opened in a contingent event.
STU GXP Supply Security via transformer capacity	Upgrade N security to N-1 if required. Lack of capacity for any major expansion.	New investment in transformers and unitised HV CBs. Additional circuits to dairy factory.
BPD GXP Supply Security at 110 kV	Upgrade N security to N-1 if required.	Work with Transpower to ensure capacity is made available.
BPD GXP Supply Security via transformer	Upgrade N security to N-1.	Second transformer to be installed in 2017/18
Timaru Area— Holistic	Lack of capacity in 220/110 kV interconnectors for ABY, TIM, TKA, and TMK. From time to time have to back up STU and BPD.	Request Transpower upgrade its 220/110 kV interconnecting transformers.
Washdyke feeder loadings	High loaded feeders.	Four new 33 kV sub-trans cables operating at 11 kV being installed in 2017 with RMUs in Washdyke to break into existing network. Ultimately establish Washdyke 33/11 zone substation off 33 kV TIM.
TIM Sub- transmission to CBD	High cable loadings.	Research feasibility to install four 11 kV 0.5 Ohm reactors in GRM and HNT sub-transmission to NST to force load onto new North-TIM cables or ultimately establish city 33/11 zone substation off 33 kV TIM GXP (.
PAR 1 and 2, 33 kV line regulation	Voltage constraint if total load exceeds 20 MW, or 10 MW in contingent event.	Shift some load to TIM and STU (as required). A paralleled feed from STU, first needs 110 kV system tied to get the 11 kV in phase. Alternatively, dead change overs are done.
PLP T1	Transformer capacity.	Any new transformer(s) need to be selectable between Dyn11 and Dzn0 to suit TIM 33 kV GXP vector group changes.
Temuka Area - Holistic	Lack of capacity for TMK 33 kV GXP new load.	Work with Transpower on upgrading supply assets.

Constraint	Description	Intended remedy
TMK GXP Supply Security	Load constraint over 54 MVA transformers, 71 MVA on lines, 71 MVA 33 kV switchboard.	Work with Transpower on upgrading supply assets.
RGA 33 kV sub-trans 1 line regulation	Voltage constraint over 8.4 MVA of load.	Replace cable in Winchester and check conductor sags when required.
GLD 33 kV sub-trans 1 line regulation	Voltage constraint over 8.64 MVA of load	Monitor GLD loading as RGA load is transferred. Load may be able to go back to RGA depending on final irrigation scheme load.
Otaio feeder regulation (STU) and St Andrews feeder regulation (PAR) Both to same area—feed from both ends	Voltage constraint at end of distribution feeders.	Load can be transferred to PAR's Holme Station feeder. Fonterra Studholme Dairy Factory off loaded to Mt Studholme feeder. Possible new feeders if/when significant dairy processing or irrigation load is required.

### 5.4.1 Non-electrical constraints

Our network is not only constrained electrically, but also by the environment within which it is constructed. Non-electrical constraints are discussed in this section.

#### 5.4.1.1 Coastal environment constraints

Part of our network is built within a coastal marine environment, which is hostile to most components used in an electricity network and is the principal driver of accelerated maintenance programmes. Assets designed specifically for the coastal marine environment are used wherever possible.

#### 5.4.1.2 State highway constraints

Proposed changes by road control authorities to road corridor utility access have meant that some projects along state highways have not proceeded. New restrictions requiring poles to be a minimum distance from the road edge line, depending on traffic volumes and other criteria, would result in lines being constructed on private land with associated easement negotiations and costs.

With a large part of our backbone network built along the dominant state highway traffic routes, there is considerable risk of us failing to gain approval from the road control authorities to replace works at end of life. While replacing poles like-for-like can occur,

conductor sizes often increase with the rebuild, requiring new pole positions to cater for changed span lengths. Shifting an overhead asset away from the highway (if private land owners' approval is gained) can cause significant additional risk and cost.

#### *5.4.1.3 Available resourcing*

Demand growth in South Canterbury has focused efforts on capital investment in the construction of new network assets to meet consumer needs. Consequently, maintenance work has had to be carefully triaged with priority given to the most urgent work, while minor maintenance is deferred pending available resource. Progress is being made in terms of maintenance work with increased resources.

#### *5.4.1.4 Land access agreements and easement constraints*

Access to private land is becoming more difficult where land owners may not receive direct benefit from the new works. There is now substantial cost and lead time associated with negotiating land access and electricity easement agreements, affecting the timing of new network projects.

#### *5.4.1.5 Resource consents*

The Timaru, Mackenzie, and Waimate district plans state that, for projects over \$50 million, no new overhead line, or line voltage or conductor upgrade can commence in commercial or residential areas without resource consent. The consent approval process involves consultation with every land owner whom the line passes over or is in view of, contributing to additional cost and lead time.

## 5.5 Criteria to consider when planning

Our planners must consider the following criteria when assessing the various options available to meet forecasted load<sup>40</sup>.

### 5.5.1 Non-network options

Our aim is to continually improve the utilisation and availability of existing network assets. Technological solutions have been implemented to improve operating efficiency and include the installation of a SCADA system, modern protection relays, line fault indicators, and a load management system. Decisions on asset replacement vs continued maintenance or refurbishments are subject to economic analysis to determine the most cost effective

---

<sup>40</sup> The criteria in section 5.5 will better complement our asset management strategy when we fully implement the Network Development Plan (NDP) prioritisation process discussed in Section 5.9—Continuous Enhancement.

option; in some cases, this may result in a partial replacement of an asset. Assets removed from the network during upgrades are assessed for condition and, where possible, reused elsewhere on the network.

One area where we can leverage energy efficiency is non-network solutions, particularly demand side management. Consumers with sensitive loads have considered installing stand-by diesel generation to provide a non-interruptible supply. Leveraging off the Transpower Demand Response Programme is often considered as part of our supply solutions. The distributed generation initiative is expected to be a more common approach in future network planning.

The high level risk of single transformers at zone substations has been identified in the risk management section of the AMP. The cost of purchasing a second transformer against the need for managing the planned loss of supply (LOS) for two to five-yearly Transpower maintenance at ABY and TKA GXPs has influenced plans for one national mobile substation (110/33 kV or 22/11 kV) for Transpower. We own and operate one 33/11 kV mobile substation that can double as an emergency back-up for faults and as a temporary second transformer for avoiding planned outages when maintaining single transformers.

Other risk treatment supports the use of distributed generation as a limited back-up supply to mitigate single transformer failure or to allow work on a mid-section of overhead line while keeping the far end live. We now have two 500 kW portable generators for emergency stand-by or voltage support duty. Our portable generators can run separate at 400 V, in parallel at 400 V, or parallel and stepped up to 11 kV, reducing maintenance outages and improved service levels. We also have a smaller 190 kW portable generator which has proved invaluable for smaller projects. We have also hired sets of generators for larger multi MW projects.

### 5.5.2 Innovations to defer investment

The need to innovate prior to committing to large Capex projects is an integral part of our network planning. An example of innovation in planning is the decision to install smart meters on our network over the next few years. We may use smart meters to optimise capital expenditure through a better understanding of load profiles and how that relates to existing capacity specifically with relation to after diversity maximum demand.

In addition we also consider new and or alternative technologies such as PV, battery storage and diesel generation as alternatives to conventional network solutions. Examples of this can be found in Appendix A.

We now also have a *Risk Management Policy* that we use to justify expenditure on our network based on acceptable risk levels.

### 5.5.3 Demand side management

Demand side management consists of contracting with consumers that have electric hot water storage units to place load on a controlled rate tariff, allowing load interruption at peak times. The ability to interrupt load lowers the peak demand on the network and the transmission grid. Retailer pricing, in some cases, has eroded the price signal between controlled and uncontrolled rates, in turn eroded available hot water storage heating control. A clearer pricing signal has been provided by us independent of retailer pricing, thus promoting restoring the use of controlled hot water heating.

Work has completed to ensure irrigation load is available for interruptible consumer load. Irrigation load, like electric hot water storage heating, can have supply interrupted during peak demand periods, while still meeting the consumer's irrigation expectations during times when control is not exercised. Currently this facility is only used in network emergencies.

### 5.5.4 Options to meet security of supply

A key component of security of supply is the level of redundancy that enables supply to be restored while a faulty component is repaired or replaced. Typical approaches to providing security of supply at a zone substation include the following.

- Provision of an alternative sub-transmission circuit into the substation, preferably separated from the principal supply by a 33 kV bus-tie.
- Provision of twin transformers with emergency rating, allowing one to cover the load of the other if it trips or faults.
- Provision of back-feed on the 11 kV from adjacent substations where sufficient 11 kV capacity and interconnection exists.<sup>41</sup>
- Use of local generation (e.g. Opuha Dam) or portable diesel generator set(s).
- Use of interruptible load (e.g. water heating or irrigation) to reduce overall load.

The difficulty with security is that it involves a level of investment beyond that needed to meet demand, and it can be easy to let demand growth erode security headroom.

#### 5.5.4.1 Prevailing security standards

The commonly adapted security standard in New Zealand is the EEA Guide for Security of Supply 2013.

---

<sup>41</sup> Such an arrangement requires that, firstly, the adjacent zone substations spare capacity and, secondly, that the prevailing topography enables interconnection.

A key characteristic of deterministic standards, such as UK standard P2/5 and the earlier EEA Guide is that rigid adherence generally results in at least some degree of over-investment. Accordingly, the latest EEA Guide for Security of Supply recommends that individual circumstances be considered.

#### *5.5.4.2 Contribution of local generation to security of supply*

To be of use from a security of supply perspective, local generation (hydro, wind, or solar in our case) would need to be 100% available. This is unlikely due to the nature of this distributed generation. It is for this reason that P2/6 provides for minimal contribution of such generation to security.

#### *5.5.4.3 Existing security of supply*

Existing levels of security of supply at GXP and zone substation level can be found in the Appendix G.

### 5.5.5 Issues arising from forecast demand

Description of significant issues arising from demand forecasts discussed in the section can be found in Appendix G.

#### *5.5.5.1 Transpower and GXP new investment estimates*

The increase of GXP capacity can be funded either by us or Transpower. At this stage, it is anticipated that Transpower will fund GXP investment and the cost will be passed through to the consumer as part of the transmission charge, and treated as a pass-through cost under the default price-quality path. The expected investment at each GXP is shown on a per project basis. The actual charges to consumers will be subject to the term of investment agreement and the cost of capital payments required by Transpower.

#### 5.5.6 Estimated asset utilisation

In contrast to the general emerging trend, we expect asset utilisation to increase in the dairy and irrigation areas as kWh throughput grows faster than maximum demand. Although encouraging asset utilisation, the flat and constant load profile of irrigation at elevated ambient temperatures during seasons of drought provides no thermal relaxation to the distribution assets.

#### 5.5.7 Impact of climate change on planning

In 2013, we experienced weather events that had not been seen in over 30 years and included flooding, wind and snow storms. A recent report from the Prime Minister's Science Advisory Committee on the localised impacted of climate change stated that we should

expect more frequent flooding events, stronger and more frequent north-west winds, and more snow at higher altitudes. We should also experience less rainfall overall.

In 2014, the Intergovernmental Panel on Climate Change (IPCC) issued its Fifth Assessment Report—Climate Change 2014. In regard to New Zealand, it stated the following.<sup>42</sup>

- ‘New Zealand’s predominantly hydroelectric power generation is vulnerable to precipitation vulnerability. Increasing winter precipitation and snow melt, and a shift from snowfall to rainfall will reduce this vulnerability (*medium confidence*) as winter/spring inflows to hydro lakes are projected to increase by 5 to 10% over the next few decades. Further deductions in seasonal snow and glacial melt as glaciers diminish, however, would compromise this benefit.’
- ‘Increasing wind power generation would benefit from projected increases in mean westerly winds, but face increased risk of damages and shutdowns during extreme wind.’
- ‘Climate warming would reduce annual average peak electricity demands by 1 to 2% per degree Celsius across New Zealand.’
- ‘In New Zealand, increasing high winds and temperatures have been identified qualitatively as the most relevant risk to transmission.’

### 5.5.8 Equipment used in capital expenditure

Using a set of parameters helps standardise the design and equipment used in capital expenditure, leading to cost efficiencies. We use the following criteria when determining the equipment required to manage load growth/capacity (for more information please see Appendix E – Standardisation and optimisation).

#### 5.5.8.1 Reliability and security of supply

We have adopted the EEA Guidelines for Security of Supply in our network, meaning that, on the sub-transmission system, we will strive to achieve a N-1 security level<sup>43</sup>.

It is difficult to set a MW level or ICP number at which N-1 security is required due to the diversity of consumer loads and requirements, as well as the significant variance in load levels. Each case is evaluated on its merits and the criteria used for evaluation include: the importance of supply to Timaru CBD, milk processing plants, dairy farms, tourism destinations, meat works, irrigation concerns; and where a loss of supply (LOS) could have significant economic and possible environmental consequences.

<sup>42</sup> Reference: IPCC’s website at: [www.ipcc.ch/report/ar5/wg2/](http://www.ipcc.ch/report/ar5/wg2/)

<sup>43</sup> N-1 security implies that the loss of a single asset would not result in the interruption of supply.

Existing security levels are listed in Appendix G.

#### *5.5.8.2 Voltage regulation*

Electricity regulations require us to control voltage at the Point of Supply to a consumer within  $\pm 6\%$  of the standard voltage of 230/400 V, except for momentary fluctuations (voltage dips). In order to comply, we take care to select the appropriate capacity when choosing equipment that may influence voltage regulation. Equipment with influence on voltage control includes: power transformers fitted with On Load Tap Changers (OLTCs), voltage regulators, capacitor banks, distribution transformers fitted with Off Circuit Tap Changers (OCTCs) switches, cables and overhead conductors.

#### *5.5.8.3 Harmonics*

Voltage and current harmonics are becoming more important with the large number of variable speed drives (VSDs) being installed on our network (specifically to drive irrigation pump motors). Since harmonics generated by one consumer can adversely affect the supply to others, consumers are required to comply with:

- i) the New Zealand Electrical Code of Practice for Harmonic Levels, NZECP 36:1993, and
- ii) the EEA Power Quality (PQ) guidelines 2013.

#### *5.5.8.4 Power factor*

The closer the power factor is to 1, the more optimally the infrastructure is utilised. We are achieving this through our new connections policy and technical requirements, which applies to all new plant connecting to the network. A combination of voltage regulators and capacitor banks is used on the network to improve voltage along loaded feeders, the capacitors giving added benefit by compensating for reactive power losses or, alternatively, improving network power factor. The sizing of capacitor banks is important since overcompensation can lead to high voltages during light loading conditions.

## 5.6 Network development

This section describes the network development plans for the planning period. Material Capex projects planned for the next 12 months are described in Appendix A as well as a summary of all non-material projects. Appendix B details all the material and non-material projects planned for the 2018 to 2021 period, while Appendix C details all known or anticipated material projects for the remainder of the planning period.

Detailed information on GXP, zone substation, and sub-transmission assets can be found in Appendix G.

### 5.6.1 Explanation of material variance in network Capex

This section deals with the differences between the 2016/17 AMP Capex budget totals and the 2017/18 AMP Capex budget totals for the overlapping nine years. For the purpose of comparison, this section considers the variance for the first year and the remaining eight years of the planning period separately.

#### 5.6.1.1 Planning period 2017/18

For the 2017/18 financial year our network Capex budget has increased from \$15.2 million to \$18.2 million. This increase is due to variation in the project expenditure categories as listed in Table 5.10.

**Table 5.10 Budget variations for 2017/18**

Expenditure category	Budget (million)	Variance
Replacement & Renewal	5.857	-620 k
Customer connections	2.2	-600 k
Growth	6.571	+2,641 k
Reliability, Safety & Environment	1.578	+568 k
Asset relocations	2	+1000 k

The decrease in the replacement and renewal budget is mainly related to overhead line refurbishment work and is mainly due to a lower materials component. The customer connection budget reduction is a reflection of the downturn in irrigation and dairy expansion as a result of the low milk pay outs by dairy processors.

The increase in growth expenditure is mainly due a substantial milk processing expansion which only surfaced in the public domain towards the middle of 2016. This development accounts for 60% of this budget increase, while the remainder relates to a project to increase capacity and security at one of our zone substations. This expenditure is for the installation of a second 110/33/11 kV transformer.

The increase in the reliability, safety and environment budget is attributable to the change out of locks on our equipment, many of which is accessible to the public such as transformer panels, as well as provision for preparing more zone substations for our mobile substation connection.

Asset relocations in this budget relates to undergrounding existing overhead lines. The increase in the budget is due the bringing forward work that was planned for 2018/19 to be completed with the 2017/18 projects which will save costs.

### 5.6.1.2 Planning period 2018/19 to 2025/26

For the period 2018/19 to 2025/26, the overall budget has increased from \$87.1 million to \$96.5 million. Table 5.11 below lists the material projects that have contributed to this increase.

**Table 5.11 Budget variations for 2018/19 to 2025/26**

Expenditure category	Budget (million)	Variance (million)
Replacement & Renewal	54.828	+15.67
Customer connections	18.500	-0.85
Growth	9.410	-5.45
Reliability, Safety & Environment	7.165	+1.54
Asset relocations	2.000	-1.40

The increase in the replacement and renewal budget is due to:

- a \$4 million budget over eight years to replace and renew our fleet of underground substations
- the Tekapo zone substation switchboard consists of oil circuit breakers which will be at the end of their ODV life in 2023/24 at which time the switchboard will be replaced at an estimated cost of \$3.5 million
- our Twizel zone substation has the oldest transformer and switchboard in our zone substation fleet, having being installed by the Ministry of Works for the Upper Waitaki Power Development project. This substation is now at the end of its life and will be replaced in 2018/19 at an estimated cost of \$4 million
- the budget for overhead line replacement and renewal has also increased by \$4.45 million over this period. This is mainly due to the increase in severe weather events and the age profile of our overhead line fleet.

The budget for customer related work has decreased by \$85 k. This expenditure type is difficult to predict and depends on the economic environment of the day.

In the growth expenditure category, the budgets over the comparative eight years are substantially less. This is mainly due to the removal of the previous year's budgets for a potentially new GXP and associated 110kV transmission lines required to connect to our network. This project is now under further scrutiny after a grid reconfiguration change proposed by Transpower. These two projects accounted for \$10.2 million in the previous budget. In addition we have included projects budgets totalling \$3.5 million for transformer replacements and upgrades at our Geraldine and Tekapo zone substations respectively.

The increase in the reliability, safety and environment budget is mainly attributable to an increase in network automation equipment, through SCADA system improvements and controllable network switches.

The budget for asset relocation over the eight year period has reduced by \$1.4 million mainly due to the fact that a large project was brought forward from the 2018/19 financial year to 2017/18 as detailed in the last paragraph of the previous section.

## 5.7 Large non-network capital expenditure

This section describes large non-network Capex projects. Large projects are those with a cost of over \$300,000. Our 10 year non-network expenditure can be found in Table 1.3. There is no large non-network Opex.

### 5.7.1 Smart meters

The roll out of smart meters will continue in 2017 to the value of \$3.17 million and continue through 2018 when spending will reduce to around \$80,000 per annum. It is forecast to remain at this rate.

### 5.7.2 Information technology

We have recognised the need to develop our information management technology and are continuing to investing a total of \$1.2 million in this area over the next three years. This investment includes the determination of business requirements for our asset management and finance departments, as well as the upgrading, replacement, or development of software fit for purpose. Note that our expenditure forecasts do not capitalise internal labour expenses unless the staff positions are backfilled from external resources.

Projects presently being worked on are listed below.

#### 5.7.2.1 GIS

Our GIS team has completed the implementation of the new ESRI GIS system and associated processes to provide:

- one source of truth for geospatial information on assets
- a fit-for-purpose and fit-for-use facility to identify assets to ensure compliance with the Electrical (Safety) Regulations 2010, clause 46(1): 'The owner of works must keep such records and plans of those works as will enable the owner, if required, to readily locate any fittings of the works.'
- information for operational purposes—both business as usual (BAU) and emergency use (not including switch or isolation statuses)
- easy reporting on asset types for maintenance purposes
- asset details with connections or proposed asset management system to allow New Connections to design and plan new extensions

- a single source of truth with asset management system for all asset data for load flow modelling (using Powerstation ETAP)
- a compatible interface with other enterprise solution such as SCADA (Survalent), ICP database, asset management system, etc.

#### *5.7.2.2 Asset Management System and new financial package*

We have contracted Technology One for our new Asset Management System. The implementation phase has a 'go live' date of 1 April 2017.

The Asset Management System is part of Enterprise Resource Planning (ERP) software called OneEnergy. The ERP includes a new financial package (also from Technology One) that will be fully integrated with and includes other important corporate functions that replace the present legacy financial systems. Funding has been approved for further system enhancements and functional developments.

#### *5.7.2.3 Future goals*

Our future ICT goals include:

- reliable vendor support
- retiring or replacing legacy applications
- documents and records management for single source of truth
- enterprise reporting platform that allows easy reporting by empowered end-users
- process automation.

### **5.7.3 Property development**

Our board has approved a budget of \$10.35 million for a new office building located on the same premises as the existing offices. This building will house both Alpine Energy Limited staff and NETcon Limited staff which will total around 180. The building construction will be completed at the end of 2017.

## **5.8 Capability to deliver**

We believe that the plans and objectives discussed in this AMP are realistic and achievable.

As a small company that works in close proximity (physically and culturally) to our preferred contractor, NETcon Limited, we benefit from an open-door approach to network planning. As part of our daily activities, planners and contractors meet face to face to identify efficiencies, resources, and solutions to constraints to ensure projects proceed as planned.

Planning continuous all year long with opportunities being recorded to consider and prioritise for the next planning period. Opportunities arising and requiring immediate

attention, such as significant supply requirements previously unknown, are prioritised and programmed into the work plan. Towards the end of the calendar year, planning sessions are where budgets and responsibilities are determined, resources and constraints identified, the approach to risk management discussed, and the timings of the project confirmed.

To ensure that we can deliver on the current year's work programmes, we meet fortnightly to discuss such topics as resourcing, timing, and expectations. Meeting minutes are held by our General Manager—Network.

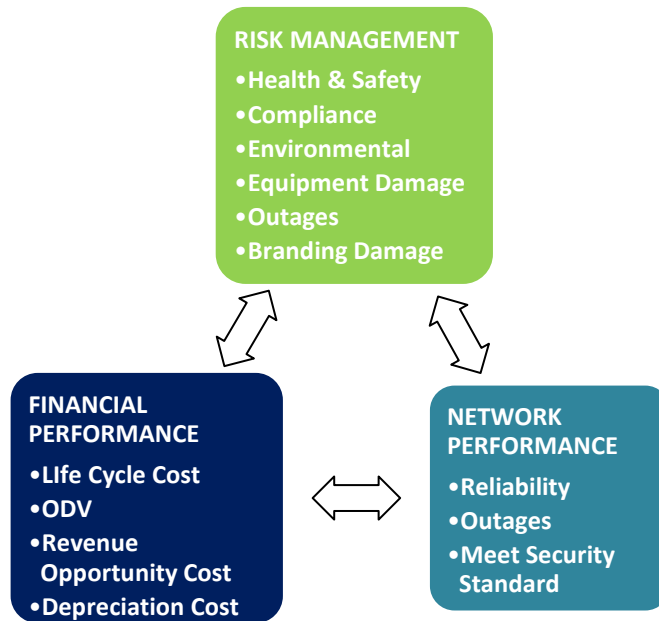
Our past contractual approach to the relationship with NETcon has served us well in supporting our asset management planning and decision making. However, we now have an Alliance Agreement with NETcon, helping us enhance asset management systems and processes. The Alliance management team represented by both parties meets on a regular basis to discuss the delivery and progress of the annual work plan. This collaborative approach ensures the efficient and timely delivery of our maintenance and capital programs.

We are also strengthening our planning with the introduction of a risk matrix that will factor in risks across the project including health and safety, financial, and asset-related risks.

## 5.9 Continuous enhancement

### 5.9.1 Network Development Plan prioritisation process

The Network Development Plan (NDP) prioritisation tool is a new process that balances our requirements for plant performance, risk management, and financial performance. The prioritisation process is shown in Figure 5.8.



**Figure 5.8 Balancing performance driver requirements**

A key enabler for the NDP process is the risk-based analytic hierarchical process (AHP). The AHP will prioritise projects based on the level of risk to:

- health and safety
- reputation
- finance
- the environment
- compliance.

Risk to each is assessed and projects investigated to reduce the level of risk to acceptable levels. Projects are ranked in order of priority depending on several criteria using the AHP with support from ISO 31000, to add weighting to each criterion.

To ensure a structured decision making process, the AHP is applied to all of our Capex projects. Table 5.12 describes the risk assessment criteria that were developed to facilitate the decision making process.

**Table 5.12 Risk assessment criteria for investment decisions**

Criteria	Description
Risk reduction	health and safety reputation environmental compliance financial impact

Criteria	Description
Reliability of supply	SAIDI (unplanned) SAIFI (unplanned)
Security of supply	Compliance with AEL Security of Supply Standard
Project implementation	cost ease of implementation SAIDI (planned)

## 6. LIFE CYCLE ASSET MANAGEMENT PLANNING

### 6.1 Introduction

Chapter 6 describes how assets are managed over their life cycle.

### 6.2 Maintenance planning

We manage our assets through the objectives set in our Statement of Corporate Intent (SCI) to provide a safe, efficient, reliable, and cost effective energy delivery system.

#### 6.2.1 Linking strategic objectives to life cycle management

The main planning criteria for the life cycle management of our network assets are:

- safety of public and employees
- statutory and regulatory requirements
- design
- economic efficiency
- cost benefits
- condition assessment of plant through its life
- service level and service target of plant
- operational procedures
- type and size of plant
- loading and relative importance of plant
- supplier and or manufacturer specifications for equipment
- maintenance in accordance with industry best practices
- field experience (operation and maintenance)
- age of plant.

Table 6.1 illustrates the linkages between our strategic objectives of our SCI and the asset life cycle planning criteria.

**Table 6.1 Lifecycle planning and strategic objectives**

Criteria	Safe	Efficient	Reliable	Cost effective
Safety of public and employees	X			
Statutory and regulatory requirements	X	X	X	X

Criteria	Safe	Efficient	Reliable	Cost effective
Design	X	X	X	X
Economic efficiency		X		X
Cost benefits				X
Condition assessment	X	X	X	X
Service level	X	X	X	X
Operational procedures	X	X	X	X
Plant type and size	X	X	X	X
Loading and importance		X	X	X
Suppliers' recommendations	X	X	X	X
Maintenance to industry best practice	X	X	X	X
Field experience	X	X	X	X
Age	X	X	X	X

### 6.3 Understanding asset life cycles

The life cycle of existing assets is outlined in and is defined in subsequent sections.

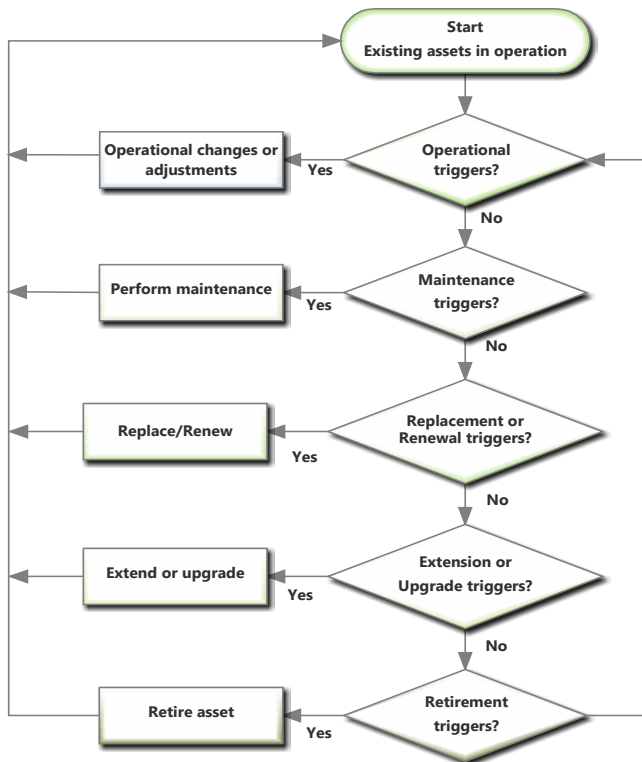


Figure 6.1 Asset life cycle

Table 6.2 provides definitions of our key life cycle activities.

**Table 6.2 Definition of life cycle activities**

Information Disclosure categories	Activity	Detailed definition
Routine and corrective maintenance and inspection	Operations	<p>Involves altering the designed operating parameters or state of an asset such as closing a switch or altering a voltage setting. Does not involve any physical change to the asset—simply a change to the asset’s operating state as defined or allowed by its design configuration which could include protection settings or SCADA alarm settings.</p> <p>Vegetation management, including tree cutting, is included in maintenance</p>
	Maintenance	<p>Involves replacing consumable components like: pole hardware, the oil in a transformer, or the contacts in a circuit breaker. Generally these components will wear out before the main asset replacement, e.g. a pole. 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. Lack of maintenance can also reduce the efficiency or operability of the asset and in some cases compromise safety.</p>
Asset replacement and renewal	Renewal and refurbishment	<p>Generally involves replacing a non-consumable item like a pole, transformer or switch. Such replacement is generally regarded as a significant milestone in the life of the asset and may significantly extend the life of the asset. Renewal tends to dominate the Capex in low growth areas (Quadrant 1 of Figure 5.1) because assets will generally wear out before their capacity is exceeded.</p> <p>The dominant reason for renewal is when the cost of operations and maintenance exceeds 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.</p>
	Upgrading	<p>Generally involves replacing a non-consumable item like a conductor, bus bar, or transformer with a similar item of greater capacity.</p>
Capex	Extensions	<p>Involves building a new asset where none previously existed because a location trigger has been exceeded e.g. building several spans of line to connect a new subdivision to an existing line. Notwithstanding any surplus capacity in upstream assets, extensions ultimately require up-sizing of upstream assets.</p>

Information Disclosure categories	Activity	Detailed definition
Asset disposals	Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement are when an asset is no longer required, or creates an unacceptable risk.

### 6.3.1 Operating the assets

As shown in Table 6.2, Operations does not involve making physical or functional changes to network assets. Operations' role is to control the connectivity states of the network through switching and operating asset controls so as to allow electricity to flow from GXP to consumers' premises. We operate a dedicated control room to intervene when an operational trigger point is exceeded and to carry out routine switching operations to allow access to the network and optimise connectivity.

Operational trigger points are set out in Table 6.3.

**Table 6.3 Operational trigger by asset class/location**

Asset class	Trigger event	Response to event	Approach
GXP	Voltage is too high or low on 33 kV or 11 kV	Automatic operation of tap changer to maintain voltage within limits	Proactive
	Demand exceeds allocated Transpower limit	Activate ripple injection plant to switch off load	Reactive
		Open and close 33 kV or 11 kV CBs to relieve load from 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 11 kV	Automatic operation of tap changer	Proactive
	Demand exceeds IEC 60354 transformer rating	Open and close 11 kV CBs to relieve load from zone sub	Reactive
Zone substation CBs	Fault current exceeds threshold	Automatic operation of CB or recloser	Reactive
Zone substation	Component current rating exceeded	Open and close CBs, reclosers and ABSs to shift load	Proactive or reactive

Asset class	Trigger event	Response to event	Approach
CBs, distribution reclosers, and ABSs	Fault has occurred	Open and close CBs, reclosers and ABSs to restore supply	Reactive
Distribution transformers	Voltage is too high or low on LV	Shift load or manually off-line raise or lower tap where fitted	Reactive
	Fuses keep blowing due to high load	Shift load to other transformers by moving LV link box open points	Reactive
LV distribution	Voltage is too low at consumers' board	Supply from another transformer or LV circuit, if possible, by moving LV link box open points	Reactive

Table 6.4 outlines key operational triggers for each asset category.

**Table 6.4 Operational triggers by asset category**

Asset category	Voltage trigger	Demand trigger	Temperature trigger <sup>44</sup>
LV lines and cables	<p>Voltage routinely drops too low to maintain at least 94% of standard voltage at the consumers' point of supply.</p> <p>Voltage routinely rises too high to maintain no more than 106% of standard voltage at the consumers' point of supply.</p>	<p>Consumers' pole or pillar fuse blows repeatedly.</p> <p>Load imbalance.</p> <p>Consumer complaint.</p>	<p>Infra-red survey reveals hot joint.</p> <p>Conductor sag diminishes ground clearances.</p> <p>Heating of grouped cables requires excessive de-rating.</p>

<sup>44</sup> Note that whilst temperature triggers will usually follow demand triggers, this may not always be the case. For example, an overhead conductor joint might get hot because it is loose or corroded rather than overloaded.

Asset category	Voltage trigger	Demand trigger	Temperature trigger <sup>44</sup>
Distribution substations	<p>Voltage routinely drops too low to maintain at least 94% of standard voltage at consumers' switchboards.</p> <p>Voltage routinely rises too high to maintain no more than 106% of standard voltage at the consumers' switchboards.</p>	<p>Load routinely exceeds rating where Maximum Demand Indicators (MDIs) are fitted.</p> <p>LV fuse blows repeatedly.</p> <p>Short term loading exceeds guidelines in IEC 60354.</p> <p>Harmonic load in excess of capacity.</p> <p>Consumer complaint.</p>	<p>Infra-red survey reveals hot connections.</p> <p>Transformer ambient temperature too hot, shortening life of transformer.</p>
Distribution lines and cables	<p>Voltage routinely drops too low to maintain at least 94% of standard voltage at the consumers' switchboards.</p> <p>Voltage routinely rises too high to maintain no more than 106% of standard voltage at the consumers' switchboards.</p>	<p>Consumers' pole or pillar fuse blows repeatedly.</p> <p>Load imbalance.</p> <p>Capacity of adjacent feeders insufficient to offload main feeder to retain supply following LOS to main feeder.</p> <p>Consumer complaint.</p>	<p>Infrared survey reveals hot joint.</p> <p>Conductor sag diminishes ground clearances.</p> <p>Heating of grouped cables requires excessive de-rating.</p> <p>Joint material migrates from termination.</p>
Zone substations	<p>Voltage drops below level at which On Load Tap Changer (OLTC) can automatically raise taps.</p> <p>Load steps too coarse for OLTC to react.</p>	<p>Load exceeds guidelines in IEC 60354.</p> <p>Security guideline breached.</p> <p>Consumer complaint.</p>	<p>Top oil temperature exceeds manufacturers' recommendations.</p> <p>Core hot-spot temperature exceeds manufacturers' recommendations.</p> <p>Connections anneal and fail from thermal cycling.</p>
Sub-transmission lines and cables	<p>Voltage drops below level of line regulation to allow zone sub OLTC to correct.</p>	<p>No spare capacity to maintain security levels.</p> <p>Consumer complaint.</p>	<p>Infra-red survey reveals hot joint.</p>

Asset category	Voltage trigger	Demand trigger	Temperature trigger <sup>44</sup>
GXP equipment	Voltage drops below level at which OLTC can automatically raise taps.	No spare capacity to maintain security of supply levels.  Loading exceeds equipment rating.	Infra-red survey reveals hot joint.

### 6.3.2 Maintaining the assets and systemic failure identification

Asset maintenance includes regular inspection and condition monitoring, and repair and replacement of faulty or deteriorating components. Condition assessment provides for the detection and recording of gradual deterioration of components (as well as any systemic or type faults) and an opportunity for minor maintenance such as cleaning, maintaining protective coatings, and housing of assets.

Information gathered from inspections is analysed and corrective action is planned and executed as appropriate. Where necessary, maintenance strategies, plans, standards, and procedures are modified in line with conclusions from the analysis, particularly where systemic or asset type issues are revealed.

Electricity distribution network assets are installed outdoors, in buildings, or in outdoor enclosures and all are subject to environmental conditions. Major or full routine maintenance or interventions are conducted offline and are necessary to examine asset components that cannot otherwise be inspected or monitored.

Examples of the way that consumable components wear out include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, wearing of pump seals, perishing of gaskets, and pitting of insulators.

Failure of components is usually based on physical characteristics. Exactly what leads to failure may be a complex interaction of variables such as:

- quality of manufacture
- quality of installation
- age
- operating hours
- number of operations
- loading cycle
- stress of components due to fault current or overvoltage events
- ambient temperature
- previous maintenance history

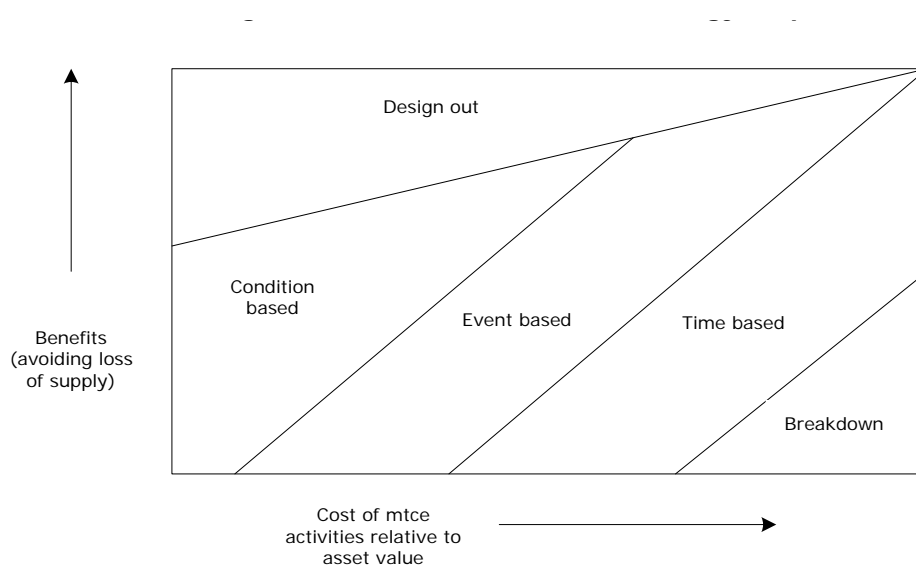
- environmental factors and presence of contaminants.

We determine when to perform maintenance based on the need to avoid failure.

The trade-off of avoiding failure is the increased cost of labour and consumables over the asset life cycle, along with the cost of the unused component life. Fixed operational maintenance costs are associated with regular monitoring of the condition of the assets and protecting the components while in service.

We base all our maintenance decisions on safety and cost-benefit criteria. The principal benefits are avoidance of hazardous conditions and supply interruptions. We closely monitor assets that supply large consumers, or a large number of consumers, and have an associated safety risk. Assets supplying only a few consumers and do not have an associated safety risk, such as a 15 kVA transformer, are more likely to be run to failure.

The maintenance strategy map in Figure 6.3 broadly describes our adopted maintenance strategy.



**Figure 6.2 Asset maintenance strategy map**<sup>45</sup>

Asset condition assessment requires regular maintenance inspections and testing, at times interfering with the immediate operational efficiency of equipment. However, failing to

<sup>45</sup> The map indicates that where the benefits are low, i.e. there is little need to avoid LOS, and where costs of maintenance are high, it is appropriate to run the asset to failure. As the value of an asset and the need to avoid LOS increases, we rely less on easily observable proxies such as calendar age, running hours, or number of trips to signal condition. Instead, we rely on actual component condition such as DGA for transformer oil, or below ground inspection of remaining timber diameter for hardwood poles. Please note that the map does not address asset maintenance for health and safety reasons, e.g. ground mounted LV distribution boxes, which could be run to failure were it not for the safety risk.

undertake maintenance inspections could lead to safety risk and greater loss of efficiency due to consequential failure of equipment causing a prolonged outage. The timing and frequency of inspection is chosen in balance with the risk and effects of an outage.

Component condition is the key trigger for maintenance. The precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 6.5 describes the maintenance triggers we look for.

**Table 6.5 Maintenance triggers**

Asset category	Components	Maintenance trigger
LV lines and cables	Poles, arms, stays, and bolts	<ul style="list-style-type: none"> <li>evidence of dry-rot</li> <li>concrete fatigue/steel showing</li> <li>loose bolts, moving stays</li> <li>rusted hardware</li> <li>displaced arms</li> </ul>
	Pins, insulators, and binders	<ul style="list-style-type: none"> <li>obviously loose pins</li> <li>visibly chipped or broken insulators</li> <li>rusted pins</li> <li>visibly loose binder</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>
	Conductor	<ul style="list-style-type: none"> <li>visibly splaying or broken conductor</li> <li>corroded or annealed conductor</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>
	LV distribution and link boxes	<ul style="list-style-type: none"> <li>visible rust or corrosion</li> <li>broken or damaged hinges or cover fixings</li> <li>cracked or worn fibreglass/plastic</li> <li>cracked or broken concrete</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>
Distribution substations	Poles, arms, and bolts	<ul style="list-style-type: none"> <li>evidence of dry-rot</li> <li>loose bolts, moving stays</li> <li>rusted hardware</li> <li>displaced arms.</li> </ul>
	Enclosures	<ul style="list-style-type: none"> <li>visible rust</li> <li>broken or damaged hinges or cover fixings</li> <li>cracked or worn fiberglass/plastic</li> <li>cracked or broken masonry</li> </ul>

Asset category	Components	Maintenance trigger
	Transformer	<ul style="list-style-type: none"> <li>• excessive oil acidity (500 kVA or greater)</li> <li>• visible signs of oil leaks</li> <li>• excessive moisture in breather</li> <li>• visibly chipped or broken bushings</li> <li>• excessive rust</li> <li>• thermographic evidence of unusual heating of components and/or connections</li> </ul>
	Pole mounted enclosed switches	<ul style="list-style-type: none"> <li>• excessive oil acidity</li> <li>• visible signs of oil leaks</li> <li>• excessive carbon in oil</li> <li>• visibly chipped or broken bushings</li> <li>• excessive moisture in oil</li> <li>• excessive rust</li> <li>• thermographic evidence of unusual heating of components and/or connections</li> <li>• partial discharge evidence of unusual current leakage in insulation</li> <li>• recloser controller batteries' age</li> </ul>
	Ground-mounted switches	<ul style="list-style-type: none"> <li>• excessive oil acidity</li> <li>• visible signs of oil leaks</li> <li>• excessive carbon in oil</li> <li>• visibly chipped or broken bushings</li> <li>• excessive rust</li> <li>• broken or damaged hinges or cover fixings</li> <li>• excessive moisture in oil</li> <li>• poor resistance test of fuse</li> <li>• corroded fuse carrier</li> <li>• significant partial discharge detected</li> <li>• thermographic evidence of unusual heating of components and/or connections</li> </ul>
	Regulators	<ul style="list-style-type: none"> <li>• excessive oil acidity</li> <li>• visible signs of oil leaks</li> <li>• excessive carbon in oil</li> <li>• visibly chipped or broken bushings</li> <li>• excessive moisture in oil</li> <li>• stability of regulating control system</li> <li>• excessive rust</li> <li>• thermographic evidence of unusual heating of components and/or connections</li> <li>• regulator controller batteries' age</li> </ul>

Asset category	Components	Maintenance trigger
Distribution lines and cables	Poles, arms, stays, and bolts	<ul style="list-style-type: none"> <li>evidence of dry-rot</li> <li>concrete fatigue/steel showing</li> <li>loose bolts, moving stays</li> <li>rusted hardware</li> <li>displaced arms</li> </ul>
	Pins, insulators, and binders	<ul style="list-style-type: none"> <li>loose pins</li> <li>chipped or cracked insulators</li> <li>rusted pins</li> <li>fouled insulators</li> <li>broken or chaffed binders</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>
	Conductor	<ul style="list-style-type: none"> <li>chaffed conductor</li> <li>inadequate ground clearance</li> <li>unequal sag in span</li> <li>corroded or annealed conductor</li> <li>obsolete conductor</li> <li>thermographic evidence of unusual heating of components and/or connections</li> <li>partial discharge evidence of unusual current leakage in insulation</li> </ul>
	Air break switches and fuses	<ul style="list-style-type: none"> <li>poor resistance test of fuse</li> <li>corroded fuse carrier</li> <li>excessive rust</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>
Zone substations	Fences and enclosures	<ul style="list-style-type: none"> <li>defects in earthing points</li> <li>check security of fence and gates</li> <li>gaps below gates and fences allowing access</li> <li>electric fence operation</li> <li>condition of materials—rust, damage, fatigue, and so on</li> </ul>
	Buildings	<ul style="list-style-type: none"> <li>secure, waterproof, vermin and bird proof</li> <li>fittings corroding</li> <li>condition of paint and finishings</li> </ul>

Asset category	Components	Maintenance trigger
	Bus work and conductors	<ul style="list-style-type: none"> <li>insulars chipped or cracked</li> <li>burn or tracking marks</li> <li>thermographic evidence of unusual heating of components and/or connections</li> <li>loose droppers, hot connectors</li> <li>earthing not intact and connected</li> <li>birds' nests</li> </ul>
	33 kV and 110 kV switchgear	<ul style="list-style-type: none"> <li>unusual noises</li> <li>oil leaks</li> <li>broken bushings</li> <li>droppers loose</li> <li>position indicator not legible</li> <li>earthing leads not intact and connected</li> <li>mechanism and recharge spring not operating</li> <li>protection not operating correctly</li> <li>cyclometers not operating</li> <li>unusual heating evidenced by odour, smoke, discolouration of surfaces, and/or distortion of materials</li> <li>corrosion</li> <li>significant partial discharge detected in switchgear</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>
	Transformer	<ul style="list-style-type: none"> <li>rust and paint not in good condition</li> <li>oil leaks, covers not secure</li> <li>broken bushings, droppers loose</li> <li>OLTC position indicator not legible</li> <li>earthing leads not intact and connected</li> <li>earthing leads not intact and connected</li> <li>inadequate seismic constraint</li> <li>DGA oil test results poor / breather maintenance</li> <li>unusual noise</li> <li>fans and pumps not operating</li> <li>thermal and temp alarms and trips not operating</li> <li>Buchholz relay site glass not clean</li> <li>Buchholz relay site glass containing oil</li> <li>OLTC not operating correctly</li> <li>thermographic evidence of unusual heating of components and/or connections</li> </ul>

Asset category	Components	Maintenance trigger
	11 kV switchgear	<ul style="list-style-type: none"> <li>• unusual noises</li> <li>• unusual heating</li> <li>• oil leaks</li> <li>• broken bushings, droppers loose</li> <li>• corrosion</li> <li>• position indicator not legible</li> <li>• earthing leads not intact and connected</li> <li>• mechanism and recharge spring not operating correctly</li> <li>• protection not operating correctly</li> <li>• cyclometers not operating</li> <li>• significant partial discharge detected in switchgear</li> <li>• thermographic evidence of unusual heating of components and/or connections</li> </ul>
	Station batteries	<ul style="list-style-type: none"> <li>• battery rectifier not operating correctly</li> <li>• battery cell voltages not to spec</li> <li>• loose connections</li> </ul>
	Instrumentation	<ul style="list-style-type: none"> <li>• protection relays not maintaining correct settings or displays</li> <li>• meters not reading</li> <li>• trip flags not activated</li> <li>• alarms not operating correctly</li> <li>• warning flags/lamps/LEDs/displays indicating faulty operation</li> </ul>
Sub-transmission lines and cables	Poles, arms, stays, and bolts	<ul style="list-style-type: none"> <li>• evidence of dry-rot</li> <li>• concrete fatigue / steel showing</li> <li>• loose bolts, moving stays</li> <li>• rusting hardware</li> <li>• displaced arms</li> </ul>
	Pins, insulators, and binders	<ul style="list-style-type: none"> <li>• loose pins</li> <li>• chipped or cracked insulators</li> <li>• fouled insulators</li> <li>• rusted pins</li> <li>• broken or chaffed binders</li> <li>• thermographic evidence of unusual heating</li> </ul>

Asset category	Components	Maintenance trigger
	Conductor	<ul style="list-style-type: none"> <li>chaffed conductor</li> <li>inadequate ground clearance</li> <li>unequal sag in span</li> <li>corroded or annealed conductor</li> <li>obsolete conductor</li> <li>significant partial discharge detected in cables</li> <li>thermographic evidence of unusual heating</li> </ul>
	Switchgear	<ul style="list-style-type: none"> <li>recloser controller batteries' age</li> </ul>

The details of our responses to maintenance triggers can be found in our policies, maintenance standards, and work plans. An outline of our maintenance policies and work plans is given in Section 6.9.1—Maintenance policies and Section 6.9.2—Maintenance work plans.

Typical responses to maintenance triggers are described in Table 6.6.

**Table 6.6 Typical responses to maintenance triggers**

Asset class	Trigger	Response to trigger	Approach
Sub-transmission lines	Loose or displaced components	Tighten or replace	Condition as revealed by inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
Zone substation transformers	Oil acidity	Filter oil	Condition as revealed by annual DGA test
	Excessive moisture in breather	Replace crystals in filter; check seals of breather; check moisture in oil; filter oil if necessary.	Condition as revealed by monthly inspection
	Weighted number of through faults	DGA Test; possibly filter oil, de-tank and refurbish; review protection	Event driven
	General condition of external components	Repair or replace as required	Condition as revealed by monthly inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection

Asset class	Trigger	Response to trigger	Approach
Distribution lines	Loose or displaced components	Tighten or replace	Condition as revealed by inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by routine inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by routine inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
RMUs (and other ground mounted, enclosed, 11 kV switches)	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by routine inspection
	Oil acidity	Filter or change oil	Full maintenance every five years
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by routine inspection
	Chipped or broken bushings	Replace	Breakdown or condition as revealed by five-year inspection
	Significant partial discharge detected in switchgear	Make minor repairs or remove to workshop for repairs/replacement	Condition as revealed by routine inspection
Distribution and sub-transmission reclosers	Weighted number of light and heavy faults	Repair or replace contacts, filter oil if applicable	Event driven
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
	Controller batteries' age	Replace batteries as per manufacturer's manual	Maintenance cycle to suit batteries' replacement
Distribution ABSs	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by routine inspection
	Seized or tight	Lubricate or replace components as required	Breakdown
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
Distribution transformers	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by routine inspection
	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by routine inspection

Asset class	Trigger	Response to trigger	Approach
	Oil acidity—only check ground mounted transformers of 500 kVA or greater	Filter oil or change transformer	When removed from service for full external maintenance every 15 years
	Excessive moisture in breather where fitted	Change crystals, check breather seals, filter oil	Condition as revealed by routine inspection
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by routine inspection
	Chipped or broken bushings	Repair or replace, according to severity of chip.	Breakdown or condition as revealed by routine inspection
	Enclosures (for ground mounted distribution subs) have: <ul style="list-style-type: none"> <li>•visible rust</li> <li>•broken or damaged hinges or cover fixings</li> <li>•cracked or worn fiberglass/plastic</li> <li>•cracked or broken masonry</li> </ul>	Repair or replace affected component	Conditions as revealed by annual inspection, or routine detailed condition assessment, or during 15 year full maintenance
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
LV lines	Loose or displaced components	Tighten or replace	Breakdown unless revealed by ten yearly inspection.
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	10-yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by 10-yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by 10-early inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
LV distribution and link boxes	Visible rust or corrosion	Repair or replace affected component	Condition as revealed by five-yearly inspection

Asset class	Trigger	Response to trigger	Approach
	Broken or damaged hinges or cover fixings	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Cracked or worn fibreglass/plastic	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Cracked or broken concrete	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Thermographic evidence of unusual heating of components and/or connections	Repair or replace affected component	Condition as revealed by five-yearly inspection

## 6.4 Renewing assets

We classify work as ‘renewal’ if there is no change in functionality (i.e. the output of the asset does not change).

A key criterion for renewing an asset is determining whether operation and maintenance costs are exceeding the renewal cost. The renewing assets criterion can be met in the following ways.

- Operating costs become excessive—for example, the cost of switching to enable maintenance or repairs is greater than the cost of renewal.
- Maintenance costs begin to accelerate—for example, a transformer needs more frequent oil treatment as windings and insulation paper reach end of life or as the seals and gaskets perish.
- Maintenance costs of new equipment are less than older existing assets—for example, ‘maintenance free for life’ vacuum and SF<sub>6</sub> insulated MV circuit breakers compared to oil insulated circuit breakers that require regular and fault operation related oil changes and contact servicing.
- Supply interruptions due to component failure become excessive.
- Renewal costs decline, particularly where costs for new technologies like SCADA decrease by several fold.

### 6.4.1 Refurbishment

Refurbishment involves the replacement of individual components and is done to extend the life of an asset. The remaining life of an overhead line reduces over time, meaning that capital expenditure will need to continue to avoid remaining life reduction.

## 6.4.2 Renewal triggers

Table 6.7 lists the renewal triggers for key asset classes.

**Table 6.7 Triggers for renewal of assets**

Asset category	Components	Renewal trigger	
LV lines and cables	Poles, arms, stays, and bolts	Condition based replacement	
	Pins, insulators, and binders		
	Conductor		
	LV distribution/link boxes		
Distribution substations	Poles, arms, and bolts	Condition based replacement	
	Enclosures		
	Transformer		
	Switches and fuses		
	Cable terminations, joints		
	Ring main switches, and so on		
	Reclosers, sectionalisers	Condition based replacement Controller batteries by age or condition, whichever is sooner	
	Regulators	Condition based replacement or maintenance costs exceed replacement Controller batteries by age or condition, whichever is sooner	
	Poles, arms, stays, and bolts	Condition based replacement	
	Pins, insulators, and binders		
Conductor			
	Cable terminations, potheads, joints	Condition or age based replacement	
Zone substations	Fences and enclosures	Condition based replacement or maintenance costs exceed replacement	
	Buildings	Maintenance costs exceed replacement	
	Bus work and conductors	Condition based replacement or maintenance costs exceed replacement	
	33 kV switchgear		
	Transformer		
	11 kV switchgear		
		Cable terminations, cable boxes, joints	Condition or age based replacement
		Batteries and chargers	Age or condition, whichever is sooner
	Instrumentation	Maintenance costs exceed replacement or equipment obsolete or age limit reached	
Sub-transmission lines and	Poles, arms, stays, and bolts	Condition or age based replacement	
	Pins, insulators, and binders		
	Conductor		

Asset category	Components	Renewal trigger
cables	Cable terminations, potheads, joints	Condition or age based replacement.
SCADA and radio	SCADA, radio, ripple control, and communications cables	Condition or age based replacement
Unspecified items	Unspecified	
Our equipment within GXP		Condition based replacement or maintenance costs exceed replacement or equipment obsolete

In accordance with our policies, classes of assets are renewed when:

- an operational or public safety hazard is likely
- capitalised operations and maintenance costs exceed renewal costs
- continued maintenance will not satisfy required service levels.

## 6.5 Upsizing or augmenting assets

If any of the capacity triggers are exceeded, we will consider upsizing or augmenting our network. The difference between the two modes of investment is described in Table 6.8.

**Table 6.8 Differences between ‘Upsizing’ and ‘Augmentation’**

Characteristic	Upsizing	Augmentation
Location	Within or close to existing network footprint (within a span or so)	Outside of existing network footprint
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 5.2	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 5.2.1	Generally can’t be avoided—a physical connection is required
Impact on revenue	Difficult to attribute revenue from increased connection number or capacity to up-sized components.	Generally results in direct contribution to revenue from the new connection at the end of the extension

Characteristic	Upsizing	Augmentation
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 consumer contribution
Means of cost recovery	Most likely to be spread across all consumers as part of on-going line charges	Could be recovered from consumers 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

### 6.5.1 Network asset delivery

We use a range of technical and engineering standards to achieve an optimal mix of the following outcomes.

- Meet likely demand to a reasonable time horizon, having considered issues such as modularity and scalability.
- Minimise overinvestment.
- Minimise risk of asset stranding.
- Minimise corporate risk exposure with other goals.
- Maximise operational flexibility.
- Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with environmental, and employee and public safety requirements.

Given the simple nature of our network, standardised designs are generally adopted for all asset classes, with minor site-specific alterations. Our standard designs represent current standards, industry guidelines, and manufacturers' recommendations.

### 6.5.2 Building new assets

Both internal staff and external contractors are used for upsizing or augmentation. As part of the delivery process, all new asset information is recorded and systems updated. This includes the 'as-building' of all drawings and recording and updating of test information.

## 6.6 Enhancing reliability

Our consumers have voiced a preference to receive 'about the same' reliability in return for paying 'about the same' line charges (Section 4.5.1—Consumer service level preferences).

There is no mandate to improve reliability simply because it can be improved, but there is a mandate to maintain supply.

There are many factors that can lead to a decline in reliability over time, for example:

- tree regrowth
- declining asset condition, especially in coastal marine areas
- extensions to the network that increase its exposure to trees and weather
- growing consumer numbers that increase lost consumer-minutes (SAIDI) for a fault
- installation of requested asset alterations that increase reliability risk
- increase in frequency and magnitude of extreme weather conditions due to climate change

Our reliability enhancement programme includes the following steps:

- identifying the consumer-minutes lost for each asset by cause
- identifying the scope and likely cost of reducing the lost consumer-minutes
- estimating the likely reduction in lost consumer-minutes if work is implemented
- calculating the cost of each enhancement opportunity per consumer-minute
- prioritising the enhancement opportunities by cost from lowest to highest.

## 6.7 Converting overhead to underground

Conversion of overhead line to underground cable does not fit neatly within the asset life cycle—conversions tend to be driven more by aesthetics than technical reasons and, consequently, rely on other road corridor users (e.g. councils) sharing the cost. However, in certain circumstances and geographic locations, conversion from overhead to underground limits or eliminates the risk of network damage and outages from extreme weather events (e.g. wind and snow storms). Where renewal or upsizing of overhead assets is needed, placing the new assets underground may be the best engineering and/or economic solution. In built up areas, public safety risk reduction or elimination may influence the decision on renewing an overhead line or replacing it with underground cable. Difficulties in gaining access for maintenance, due to location and proximity to private or public premises, may encourage not only relocating the line but also undergrounding it. For example, within the Timaru City area there are a number of 11 kV and 33 kV lines that cross built-up areas on private property. Consideration may be given to undergrounding overhead lines for safety and access reasons, before age or condition prompts renewal or upgrading.

We consider the risks in accordance with our Risk Management Policy. More detail on risk management can be found in Section 7.4—Risk management planning for network assets.

## 6.8 Retiring assets

Retiring assets involves doing most, if not all, of the following activities:

- de-energising the asset
- physically disconnecting from other live assets
- physically removing the asset from location or abandoning in-situ (underground cables are typically abandoned)
- disposing of the asset in an appropriate manner, particularly if it contains SF<sub>6</sub>, oil, lead, or asbestos.

Key criteria for retiring an asset include the following:

- it creates unacceptable risk exposure because its inherent risks have increased over time, or because emerging trends of safe exposure levels are declining<sup>46</sup>
- its physical presence is no longer required, usually because demand has reduced or ceased
- better options exist to create a similar outcome<sup>47</sup> and there are no suitable opportunities for redeployment
- a replacement asset has been upgraded a no suitable opportunities for redeployment exist.

## 6.9 Routine and preventive maintenance programmes

### 6.9.1 Maintenance policies

Maintenance work comprises of three main elements:

- routine inspections and testing to identify the condition of the asset
- evaluation of results to establish an appropriate course of action
- repair, refurbishment, and replacement of assets if condition requires corrective action.

We are developing defect criteria for condition based assessments. We give careful consideration to the selection of each criterion in order to avoid in-service failure and premature replacement. With the exception of some smaller items (e.g. station batteries), assets are not replaced based on age or other generic criteria but are kept in service until maintenance becomes uneconomic or they pose a safety or reliability risk.

---

<sup>46</sup> Assets retired for safety reasons are not redeployed or sold for reuse.

<sup>47</sup> For example, replacing lubricating bearings with high-impact nylon bushes.

Periodic inspections, patrols, servicing and test work are carried out to ensure that defects or emerging risks are identified so that corrective action can be undertaken. Servicing can involve minor component replacement (e.g. seals, bushings, etc.) but does not involve significant repairs.

The course of corrective action taken is usually the most economical, provided it does not jeopardise safety or reliability of supply. Repairs can be carried out directly following a fault-induced outage when restoring service. Work may involve temporary or permanent repair of the faulted asset—the objective is to restore service as quickly as possible by the most economical method. If further intervention is required, a planned outage may be needed.

Maintenance requirements are also influenced by network development projects that involve the decommissioning of assets such as when assets are replaced due to high network demand growth and are unable to reach expected service life. Maintenance strategies and programmes are reviewed regularly to ensure that the network is being maintained in an efficient and cost-effective manner.

### 6.9.2 Maintenance work plans

Our Maintenance Team raises a new set of maintenance jobs each financial year through our financial and asset management systems, thereby creating purchase orders throughout the year to cover maintenance work undertaken by our contractors. The team uses maintenance jobs and purchase orders to provide strategic control of maintenance that is planned and executed at a tactical level by NETcon and other contractors.

Table 6.9 lists the three dimensions of control and the work types associated with each dimension.

**Table 6.9 Dimensions of control and associated work types**

Dimension	Work type
Maintenance type	<ul style="list-style-type: none"> <li>• routine and preventive</li> <li>• refurbishment and renewal</li> <li>• fault and emergency</li> </ul>
Asset category	<ul style="list-style-type: none"> <li>• LV lines and cables</li> <li>• distribution substations</li> <li>• distribution lines and cables</li> <li>• zone substations</li> <li>• sub-transmission lines and cables</li> <li>• SCADA, communications, and ripple load control</li> </ul>

Dimension	Work type
Periodicity	<ul style="list-style-type: none"> <li>• immediate—fault and emergency</li> <li>• special one-off projects such as condition assessment of all items of a particular asset type, e.g. distribution boxes</li> <li>• monthly checks</li> <li>• six-monthly or annual inspection and minor maintenance</li> <li>• full maintenance periodicity defined by asset requirements</li> </ul>

There are also specific jobs included in the annual maintenance program: overall scheduled maintenance planning and the associated analysis of asset maintenance records, condition assessment reports, and other maintenance related asset data. The contractors' scheduled maintenance work plans include routine visits for testing, inspection, cleaning, maintenance and minor repairs. Any defects requiring urgent major repairs are attended to in special visits. Check sheets and reports from routine and subsequent visits are filed for future reference and analysis. Scheduled work is listed in Table 6.10.

**Table 6.10 Scheduled work**

Asset type	Description of scheduled work
Zone substations	<ul style="list-style-type: none"> <li>• monthly checks and cleaning</li> <li>• annual checks and minor maintenance</li> <li>• off-line (or full) maintenance programs with periods and actions generally as specified by suppliers or determined from experience or local conditions</li> </ul>
Urban distribution substations (generally over 100 kVA): ground mounted, underground, and 2-pole structure	<p>Annual checks and minor maintenance include:</p> <ul style="list-style-type: none"> <li>• routine maintenance programs and special checks and maintenance (such as after heavy rain for underground subs)</li> <li>• offline (or full) maintenance programs with periods and actions determined from equipment suppliers' recommendation, our experience, and local conditions.</li> </ul>
All substations (including single-pole mounted equipment)	Routine checks in association with earth tests
System-wide assets	Periodic tests such as partial discharge of circuit breakers and cables, thermographic checks of visible current carrying parts, and oil sample tests for transformers

Unscheduled work includes:

- inspections
- testing
- repairs or replacement of assets for
  - reported damage or deterioration
  - system fault damage

- asset failure
- environmental effects.

### *6.9.2.1 Zone substations, ground mounted distribution substations, and enclosed MV switchgear and regulators*

We have engaged NETcon to prepare, maintain, and execute a comprehensive routine maintenance programme for all our zone substations; ground mounted, underground, and two-pole distribution substations; and MV enclosed switches and regulators.

When checks reveal the need for immediate or more detailed maintenance, non-routine maintenance is scheduled. The maintenance may include onsite intervention or removal to the contractor's workshop (maintenance is undertaken onsite if possible). Maintenance may be undertaken earlier than scheduled while the asset is out of service for urgent work, and the date of the next round of maintenance is rescheduled.

### *6.9.2.2 Overhead lines and pole mounted assets*

NETcon undertakes overhead line patrols, pole inspections, and maintenance of our 33 kV, 22 kV, 11 kV, and LV lines. The inspection and maintenance is directed by us, on a job-by-job basis, with programming guided by age and condition of lines, poles, and associated assets. Our aim is to inspect all lines over 25 years of age every 10 years.

### *6.9.2.3 Partial discharge mapping of 11 kV sub-transmission cables*

Partial discharge (PD) mapping tests of the TIM sub-transmission cables interconnecting TIM GXT and GRM, NST, and HNT substations are conducted every two years; they started in 2006. The maps are compared with previous years' maps to glean valuable asset condition information (particularly the state of the 11 kV cable joints). Partial discharge testing of indoor and ground mounted switchgear

A programme of partial discharge testing is undertaken for all indoor HV and MV switchboards and outdoor ground mounted 11 kV switchgear. The tests are generally carried out biennially, with more frequent tests for assets that have exhibited partial discharge levels.

Depending on the nature of the partial discharge levels, repeat tests may be undertaken at 6, 12, or 24 month intervals. Where partial discharge levels increase significantly or are persistently high, immediate intervention is ordered, with switchgear taken out of service, inspected, and maintained as necessary.

### 6.9.2.4 Thermographic inspections

Thermographic inspections on hotspots on outdoor or exposed insulators and fittings on outdoor installations have been undertaken on a small scale for several years. We intend to increase the frequency and extent of thermographic inspections.

### 6.9.2.5 Services provided by NETcon as part of our maintenance programme

Table 6.11 describes the substation maintenance provided by NETcon.

**Table 6.11 maintenance services provided by NETcon**

Maintenance type	Description
Routine condition assessment	Zone substation assets: monthly sub checks. RMUs, distribution subs (building, kiosk, padmount, and enclosure types) and zone substations: <ul style="list-style-type: none"> <li>– annual, visual on-line inspections only</li> <li>– periodic detailed inspections as part of off-line full maintenance.</li> </ul>
Urgent reactive maintenance	Zone substation assets: immediate. Distribution substations: buildings, kiosks, padmounts, and enclosures: immediate.
Planned routine full maintenance	Zone substation assets: <ul style="list-style-type: none"> <li>– four-yearly cycle for protection systems;</li> <li>– periodic<sup>48</sup>, off-line, maintenance.</li> </ul> RMUs and distribution substations (buildings, kiosks, padmounts and enclosures): 5/15 year cycles.* <sup>49</sup>

### 6.9.3 Defect identification process

Regular maintenance inspections are carried out by our contractors (mainly NETcon) to determine the condition of the network. Condition assessment reports are submitted to us, and repair and maintenance work is scheduled. Urgent repairs are undertaken immediately after notifying our control room and receiving appropriate permits, operating instructions, and clearances.

Routine maintenance visits are scheduled based on manufacturers' recommendations, best industry practice, and field experience. The reports submitted to us include a description of the work done and any other matters requiring attention. Matters raised may result in a

<sup>48</sup> 'Periodic' refers to "x-year cycle", 'x' being specific to each type, make, and model of asset in accordance with our Maintenance Standards and the asset manufacturer's manuals and recommendations.

<sup>49</sup> RMUs have a five-year cycle—the cycle will be reviewed once condition assessment is completed. The rest of the distribution sub assets have a 15-year cycle. Many RMUs have not been maintained in over 20 to 30 years accordingly present condition is unknown and poses an unacceptable risk.

reactive order for repairs or a special condition assessment. Zone substations are inspected monthly, while ground mounted distribution substations are inspected annually.

#### 6.9.3.1 *Special condition assessment projects*

Special, one-off condition assessment programmes are initiated from time to time. Programmes are tailored to specific needs that are not met by existing maintenance programmes. For example, a one-off set of PD mapping of selected main 11 kV feeder cables in the Timaru CBD was conducted in 2011. The PD mapping was initiated in response to several cable joint failures in the CBD in the previous four years. The cables selected for mapping had several joints per section (or at least one joint of the 1987 era) that appeared prone to failure. Following analysis of the results, replacement of the suspect joint or whole cable sections was rejected. The risk and cost associated with leaving the joints to fail in the future were less than that of attempting immediate replacement of all joints. The data collected is retained to quickly locate and repair any future faulty joint.

Data collected from special assessments is analysed by our engineers with assistance from NETcon maintenance planners. Planned and coordinated action to correct deterioration and defects is then instigated. Action may be organised by geographical area or a particular type of defect correction, in order to optimise maintenance resources. Action involving many assets may be grouped into projects. Any urgent or safety compromising faults found during inspection are fixed immediately by the contractor or referred to us for immediate action.

#### 6.9.4 *Serious defect rectification process*

When a serious defect in plant or equipment is discovered, NETcon is authorised to take immediate action to correct the defect, or make the asset safe, if the defect constitutes:

- safety risk to the public or employees
- danger to continuity of supply
- risk of damage to the network.

Depending on the nature and urgency of the corrective action required, and the need for network access or permissions, our Control Room is notified of the defect as soon as it is discovered or immediately following corrective action. Minor defects may also be dealt with by the contractor.

All defects, major or minor, are submitted as 'Plant Fault Reports' to our Control Room where the fault is logged and referred for action (if required) before being passed to the Asset Management department for decision on the asset(s) involved. The department may decide to:

- issue a reactive maintenance order (major)
- schedule subsequent routine maintenance visits
- initiate a special project dependent on the type, size, and seriousness of the defect
- take no immediate action, but note for possible future action (minor).

### 6.9.5 Routine maintenance system

Table 6.12 summarises our routine maintenance system.

**Table 6.12 Routine maintenance system**

Asset class	Routine maintenance type	Frequency
Zone substations	Monthly inspection and clean.	Monthly
Zone substations	Six monthly detailed inspection, battery charger maintenance plus 12-monthly earth testing and protection relay settings check and test	Six-monthly, with some items only 12 monthly
Zone substations	Detailed maintenance of assets in accordance with the suppliers' recommendations, and our Maintenance Standards (currently in preparation)	Annually for certain items, biennially for others, four-yearly for protection systems, and otherwise to suppliers' recommendations
Ground mounted distribution substations and switches, 200 kVA	Annual visual inspection, including minor cleaning/maintenance, twice yearly MDI reading	Annual (MDIs: six-monthly, in spring and autumn)
Ground mounted, underground, and 2-pole distributions substations and switches with 200 kVA or greater transformers	Full maintenance of substation/switchgear, including cleaning, testing of oil/insulation, routine maintenance to suppliers' recommendations	Five yearly when RMU present; every 15 years when no RMU present
Sub-transmission cables	Partial discharge mapping	Biennially
TIM 11 kV sub-transmission switchboards (GRM, HNT, and NST)	Partial discharge tests	Annually, for the older switchgear (HNT), otherwise every 24 months as per 11 kV RMUs

Asset class	Routine maintenance type	Frequency
11 kV RMUs throughout system	Partial discharge tests	6 to 12 months if condition warrants, otherwise every 24 months
33 kV and 11 kV switchboards in zone substations	Partial discharge tests	Condition and age based, as required, otherwise every 24 months
Pole mounted transformers	Inspection and earth test—minor in-situ maintenance	Every 5 to 10 years, according to condition based need
Single-pole mounted transformers	No full maintenance	Replace when fails, or has less than 10 years remaining life
Pole mounted enclosed HV & MV switches (recloser, sectionalisers)	Inspection and earth test—in or in-situ maintenance	Annually
Pole mounted enclosed HV & MV switches (recloser, sectionalisers)	Full maintenance	5 to 10-yearly or more frequently if manufacturer, condition or age demands
Regulators (11 kV)	Yearly inspection and clean—Minor in-situ maintenance, including battery system, software, earthing checks	Annually
Regulators (11 kV)	Full maintenance, including oil and operational tests and associated assets—Corrosion treatment and water proofing	Five-yearly or more frequently if specified by supplier
Capacitors (11 kV line regulation type)	Inspect and test capacitance, check fuses, and maintain associated assets	Five-yearly or more frequently if specified by supplier
Pole lines, including associated overhead fittings and assets	All lines older than 25 years (or younger if condition dictates), inspection of poles, line fittings, conductors, disconnectors, fuses, and so on	10-yearly, with scheduling based upon age and condition

NETcon undertakes commissioning inspection of all new equipment and makes any necessary additions and modifications to the protective coatings and water sealing in order to reduce ongoing maintenance and extend the life of the asset.

## 6.10 Maintenance plans for the next 12 months

Section 6.10 discusses our maintenance plans and presents our maintenance expenditure projections. For information on how our maintenance plans take our service level targets in to account, please see Section 4.4.5—10-year reliability targets.

### 6.10.1 Sub-transmission lines and cables

The 2017/18 Opex budget for annual expenditure on sub-transmission lines and cable maintenance is \$21,000. This relatively low numbers is due to the fact that the majority of our sub-transmission circuits have recently undergone major refurbishment and renewal, and are hence in a very good condition.

33 kV sub-transmission lines and cables are high priority due to their potential impact on network reliability. Sub-transmission lines are built to the highest standards and, in the case of Clandeboye and PAR, have duplicate circuits to provide security of supply. The remaining lines are single 33 kV circuits.

The sub-transmission lines built in the last 10 to 12 years will be due for inspection and maintenance in the 20<sup>th</sup> year of service, unless condition calls for earlier inspection. Our sub-transmission line inspection priority is summarised in Table 6.13.

**Table 6.13 Sub-transmission line inspection and maintenance priority**

Location of line	Year of construction	Inspection priority
TIM sub to PAR sub #1	1979 and 1985	1
TIM sub to PAR sub #2	1963	2
TIM sub to PLP sub	1977	3
TMK sub to GLD sub	1966	4
TMK sub to Winchester Township	1979	5
Winchester Township to RGA sub	2003	12
TMK sub to Clandeboye sub	1997	10
ABY sub to FLE sub	1967	6
OPU Dam to FLE sub	1997	7
TEK sub to Mt Cook sub	between 1975 and 2001	8 and 11
TKA to TEK sub	1991	9
TWZ to TVS sub	1968	7
CNL CB to RGA sub	2010	13
BPD sub to CNR sub	2014	14

### 6.10.2 Zone substations

The 2017/18 Opex budget for annual expenditure on zone substation maintenance is \$544,000. The composition of this expenditure is detailed in this section.

### 6.10.2.1 Routine inspections

All zone substations are inspected on a biannual inspection cycle that includes battery and rectifier maintenance.

Zone substations are visited monthly for cleaning and routine visual inspections of switchgear, protection, instrumentation, and monitoring readings of temperature, tap change operations, breaker operations, protection flag resets, battery charger status, and maximum demand indicators.

Unplanned visits take place when a feeder fault operates a substation circuit breaker, requiring an operator to review and reset protection flags before commencing restoration procedures.

Regular zone substation inspections also include inspection of buildings and other assets such as fire protection and security systems. Periodic maintenance of the grounds includes lawn mowing, pruning, weed control, and clearing of drains.

### 6.10.2.2 Protection systems

Protection system maintenance is needed to confirm that the protection is calibrated within tolerance and will operate as required. The introduction of microprocessor protection relays, with internal self-testing and monitoring software, has reduced the need for more frequent testing of assets. The older legacy electromechanical protection relays, however, still require biennial testing and adjustment.

All zone substation relay and circuit breaker control systems are secondary injection and operationally tested at least every four years, in accordance with the Electricity Industry Participation Code (Part 8), our relevant Maintenance Standards, and to manufacturers' recommendations.

The quadrennial testing incorporates any required maintenance. Prior to testing, protection scheme reviews are conducted and any changes to protection settings that are required are made during testing and maintenance. Similar routine protection and control system testing and maintenance and associated reviews are conducted for 33 kV and 11 kV line circuit breaker and recloser control equipment.

### 6.10.2.3 Power transformers

All power transformers (33 kV/11 kV) have a regular monthly in-service visual inspection and a biannual minor maintenance service. The biannual service includes visual inspection, routine diagnostic tests, operational checks, and minor work. In general, maintenance work on transformers consists of maintaining oil within acceptable dielectric and acidity limits, and corrosion and oil leak repairs. DGA tests are undertaken on an annual basis to

determine transformer health trends. Transformers fitted with on-load tap changers require periodic inspection and servicing based on manufacturers' recommended maximum number of operations and/or minimum number of years between maintenance, whichever is sooner.

Full oil refurbishment is initially carried out around 25 years after installation, and approximately every 10 years thereafter. Transformers with high moisture levels at 20 years are evaluated for core drying, where oil results indicate stable winding performance suitable for extending the transformer's life.

Painting is carried out on a regular basis (every 10 to 15 years), depending on site conditions.

#### *6.10.2.4 Circuit breakers*

Circuit breakers have regular in-service inspections and are subject to minor and major maintenance routines. Maintenance on oil circuit breakers is carried out annually and after it has completed a specified number of fault clearances. Modern vacuum contactors require minor servicing and condition monitoring tests only and at longer intervals. The frequency and scope of service varies for each type, make, and model of circuit breaker, and costs per breaker vary significantly. Older circuit breakers are routinely trip tested to ensure that clearance times are not compromised.

#### *6.10.2.5 Switchyards*

Routine maintenance of structures, buswork, and disconnectors is performed when a particular circuit or section of bus is released from service. Buswork and associated hardware is subject to inspection and maintenance, including the checking, tightening, and cleaning of insulators and connections.

Insulator cleaning is undertaken more frequently at zone substations that are subject to atmospheric pollution.

#### *6.10.2.6 Earth mats*

Zone substation earth mats are tested annually to verify the integrity of the installation.

#### *6.10.2.7 DC power systems*

Substation battery banks and rectifiers are inspected monthly during substation checks, while electronic equipment is virtually maintenance-free and only requires a basic inspection and charger check. The batteries are discharge tested and inspected in detail every year. Battery replacements are carried out every eight years.

### *6.10.2.8 Buildings and non-electrical assets*

Building repairs are ongoing and include interior and exterior painting, and roofing and wall repairs. Substation buildings, bunds, ducts, yard surfaces, and fences are inspected regularly to maintain safety, security, and good 'housekeeping' standards.

## **6.10.3 Distribution lines and cables**

The 2017/18 combined annual Opex budget for network distribution line and cable maintenance is \$3.135 million with an additional \$337,000 for LV lines and cables. Detail of this expenditure is discussed further in this section.

### *6.10.3.1 11 kV distribution configurations*

The 11 kV distribution lines and cables are typically open-ringed in the Timaru CBD and industrial areas, as well as in the denser loaded suburban and rural, areas. LV lines and cables also have interconnection in densely populated urban areas, but are typically short spur lines in other areas.

The open ring system is used for underground cable systems where fault repair time is much longer than for an overhead system. The probability and extent of an underground system fault is much lower than for an overhead system as overhead lines are exposed to risk from severe weather, bird and vegetation interference, and vehicle damage. The risk to underground cables is from inadvertent damage from contractor excavations and low probability severe earthquakes.

Historically, in the days of dry farming and cropping, lightly loaded rural areas were arranged as a single spur overhead line. With load density growing markedly due to dairying and irrigation, rural lines are built or upgraded to be open-ringed, providing alternative supply routes.

### *6.10.3.2 Line maintenance and replacement*

Areas reticulated with predominantly concrete poles from early 1960s to late 1970s have recently been maintained only as required. Over the coming years these areas will be re-inspected. The majority of crossarms and the few hardwood termination and angle poles will need to be replaced. The areas to be targeted are between the Waitaki River and Waimate township, and between Temuka and Geraldine.

Concrete poles have an estimated life of 60 to 100 years, softwood poles 25 to 50 years, and hardwood poles 40 to 60 years. Very few concrete pole replacements are expected due to age. An age based replacement estimate would indicate that, on average, 260 to 330 poles would need replacing each year. However, adequate maintenance of lines renders the age-

based replacement philosophy unrealistic. We use actual condition to inform the replacement of wooden poles.

The risk of premature failure of a softwood pole, due to brown rot or structural degradation, will necessitate inspection prior to its 25<sup>th</sup> year in service and a high inspection frequency towards end of life. We have, in recent years, discussed and monitored premature failure of softwood poles with other networks that have experienced similar issues.

Due to poor performance and premature cascade failures, softwood poles will no longer be used on the network. A programme to replace existing softwood poles over a number of years has been prioritised as follows:

- conjoint 33 kV and 11 kV lines
- 33 kV lines
- 11 kV lines with heavy conductor
- all others during refurbishment, unless required earlier.

Beyond the planning horizon, we expect that maintenance requirements will increase. A number of 50–60 year old lines with inherently weak conductor (such as 16 Cu, Herring and Mullet ACSR) are near end of expected service life. Some lines have been stretched during many snow and wind events, and have only been repaired before being returned to service each time. The majority of stretched lines will require re-poling to accommodate new conductor. In areas of little or no growth, reconductoring of some lines may suffice.

We estimate that approximately 5 km of conductor will need to be replaced each year, over the planning period and beyond. The replacement rate is expected to increase in the long term.

As an increasing number of hardwood poles need to be replaced, analysis indicates that line maintenance requirements will increase. To mitigate against an unrealistic workload in any one specific year of the planning period, replacements are brought forward based on the available resources, thereby levelling the quantum of workload across the planning period.

### *6.10.3.3 Line materials*

The refurbishment programme involves replacing the failing original poles with new concrete or hardwood poles fitted with hardwood crossarms. The supply of hardwood crossarms may be limited towards the end of the 10 year planning period and the use of steel, fibreglass, and composite crossarms is currently under evaluation.

From time to time, network lines are subject to extreme conditions such as floods, snow, earthquakes, major wind storms, etc., which results in failure. Failure of a pole line is relatively easy to recover from as spare poles and other fittings can be drawn from normal stock, and repairs can be completed without delay. Often, conductors are not badly

damaged and can usually be reused after repairs. Adequate stocks of conductor and accessories are held for most repairs. Although sub-transmission lines are designed and built to withstand most weather events, critical spares for unforeseen circumstances (e.g. car versus pole) are held.

#### *6.10.3.4 Routine patrols and inspections*

##### *Overhead lines are patrolled to monitor tree growth*

Vegetation control and repair work is scheduled following line patrols. Electrical Hazards from Trees Regulations 2003 require line owners to advise tree owners of their responsibilities for keeping trees away from lines and to provide advice and notification when growth limit and notice limit zones are breached. We have a dedicated database to administer tree management and notification processes.

##### *Fault patrols and repairs are carried out as required*

In addition to patrols, a detailed inspection of every line is endeavoured to be carried out on a rolling 10 year basis, covering 10% of the route length each year. Where a condition problem is identified, a design analysis is carried out and a solution implemented. Early line support failure and replacement usually occurs in areas subject to extraordinary winds.

Since 1985, areas predominantly reticulated with hardwood poles installed between 1955 and 1961 have been inspected every 10 years and poles replaced as required.

Approximately 10% to 20% of poles are replaced after each inspection. Within the next 10 to 15 years, it is expected that the remainder of the original hardwood poles will be replaced, with the oldest poles remaining being 25 to 30 years old. Crossarms are also renewed during pole replacement.

A regular 10 year inspection and replacement process ensures a level of confidence in the condition of the oldest remaining overhead lines and effectively staggers the capital required for end of life replacement. The aim of inspection is to identify and document all components that may not be able to support design load, and to comply with clearances in NZECP34:2001<sup>50</sup>.

Each timber pole is visually inspected from above and below ground to a depth of 500 mm via excavation. The excavation inspects the integrity of the timber in the zone of soil bacteria activity and requires removal of sapwood to measure the remaining healthy heartwood. The diameter of the healthy heartwood is used to determine the remaining service life of the pole, based on the structural design load being met for a further 10 years.

---

<sup>50</sup> *New Zealand Electrical Code of Practice for Electrical Safe Distances 2001*

In an attempt to remove human subjectivity, new technology for wood pole assessment is being trialled to establish the best combination of tools available. Although still in infancy, none of the technological solutions evaluated today have instilled confidence in the ability to assess pole condition correctly.

*A two coloured tag system is used to identify suspect poles*

A standard red tag identifies poles at risk of failure under normal structural loads, requiring replacement within three months of inspection. A standard yellow tag is used to indicate that a pole may not be capable of supporting structural design loads beyond the next 10 years. Applying a safety factor of two, the yellow tagged poles are replaced within five years of inspection. Poles found to be incapable of supporting structural design loads are replaced in conjunction with red tag poles.

#### *6.10.3.5 Underground LV maintenance and replacement*

The underground cable network system LV distribution boxes require inspection every five years, with maintenance as required by condition assessment. A survey to assess the condition of all out distribution boxes was completed in 2013. We are planning to repeat this exercise within the next twenty four months.

### 6.10.4 Distribution substations

The 2017/18 annual maintenance budget for distribution substations is \$1.14 million and covers inspection, assessment, and repairs. Replacement of significant items, such as transformers and RMUs, will be financed from the Capex budget.

#### *6.10.4.1 Distribution substation annual in-service inspections and minor maintenance*

Distribution transformers are inspected (and earths tested) every 10 years to comply with Electricity Regulations. Distribution substation earth testing is carried out within a specific earth testing programme with other HV earthed assets. Overhead pole mounted transformer servicing and testing is carried out in conjunction with distribution line inspection and maintenance<sup>51</sup>.

A targeted condition assessment project of in-service ground mounted distribution substations of 200 kVA or greater was undertaken in 2011/12. Inspection only projects allow urgent maintenance to be carried out as required.

In 2015, routine in-service inspections and minor maintenance activity were commenced for all ground mounted, underground, and two pole distribution substations of 100 kVA or

---

<sup>51</sup> Excludes earth testing for distribution substations.

greater. The inspection is spread over a five-year cycle, with approximately 20% of the total population of qualifying substations processed each year.

A seismic and structural analysis survey of all two pole distribution substations was instigated in 2016-17. This study will guide decision making for the refurbishment or replacement of individual two pole distribution subs according to the results of the analysis and degree of refurbishment that may be required. The two pole distribution substation electrical equipment refurbishment programme begun in 2014-15 is on hold until decisions have been made on refurbishment or replacement due to seismic or structural requirements.

Options for the two pole distribution substations include replacement with a ground mounted distribution substation. Economics, risk and technical requirements will influence the choice.

#### *6.10.4.2 Distribution substation full off-line maintenance*

Distribution substations without RMUs are on a 15-year cycle of full off-line maintenance. The routine maintenance is separate from the distribution substation condition assessment described above.

11 kV RMU switches, whether alone or incorporated within a distribution substation, are targeted for full off-line maintenance every five years. The whole population is inspected using partial discharge testing (biennially or less) and through oil samples taken during full maintenance to ensure oil moisture and dielectric breakdown components are at acceptable levels, and the oil switches remain safe and reliable.

#### *6.10.4.3 Distribution substation transformers*

Transformers are replaced when a failure occurs or is likely to occur within 10 years. It is more economical to replace distribution transformers than to refurbish. Failures generally result from lightning strikes, cable termination failures, and car accidents. Faulty transformers can usually be replaced within four to eight hours plus travel time from the spares stock held at our Washdyke yard.

Maximum demand indicators fitted to the larger ground mounted transformers indicate that few have been allowed to operate for long past the nameplate rating. Therefore, the expected life of a distribution transformer is 55 years.

### 6.10.5 LV lines and cables

The 2017/18 annual maintenance budget for LV lines and cables is \$337,000<sup>52</sup>.

### 6.10.6 SCADA, communications, and ripple plants

The 2017/18 maintenance budget for SCADA, communications, and ripple plants is \$170,000.

#### 6.10.6.1 SCADA system maintenance

The Master Station software upgrade (2013) included expansion of the present SCADA system database and software capacity to cater for the increasing number of zone substations, and monitored and controlled points from the communications upgrade project. The new SCADA does include a whole network view, thereby supporting efficiencies in the preparation, updating, and operational use of our network switching diagrams.

The integrity of the SCADA hardware and software systems is of paramount importance to the ongoing management and safety of the network. We have a maintenance contract in place with the New Zealand integrators of this system.

#### 6.10.6.2 DC power supply, battery, and rectifier maintenance

Our maintenance programme includes routine replacements of DC power supply batteries and chargers and minor systems.

#### 6.10.6.3 Zone substation security and fire alarm systems

The legacy security and fire alarm systems are past economic life and have been replaced by new systems. The supplier of the new systems has been contracted to carry out routine maintenance on the equipment.

#### 6.10.6.4 Communication systems

We are progressively introducing a new digital GHz frequency radio system for SCADA system communications.

Communications are installed as zone substations are added or upgraded on our network. Modern substations contain microprocessor based protection and control equipment that

---

<sup>52</sup> Does not include renewal or upgrade expenditure—this is covered by the Capex budget.

uses the DNP3<sup>53</sup> protocol and requires modern communications (for more detail, please see Chapter 3—NETWORK ASSETS and Chapter 5—NETWORK DEVELOPMENT PLANNING).

The legacy UHF analogue radio system has reached its end of life as determined by age, reduced manufacturer support, and obsolescence of legacy technology being replaced by modern microprocessor controlled technology. The legacy base station and repeater require regular inspection and service. Inspections, as far as possible, are non-intrusive and no adjustments are made until items are out of tolerance, or performance is affected. Antenna support structures are inspected every two to three years.

Network failures are normally random in nature and result from various causes such as drift in component settings, lightning strike, wind on antennae, etc. The 2013 severe winter conditions highlighted the importance of response to communications faults and the maintenance of battery backup systems during loss of supply, with helicopter access to install supplementary battery support as a fall back.

Communications equipment generally has a shorter life expectancy than heavy electrical assets. Typically, electronic equipment reached technical obsolescence in 5 to 10 years although equipment assets can be supported in service for 10 to 15 years. A number of analogue radio systems will require replacement in the next two years.

#### 6.10.6.5 Ripple load control plant

We are in the process of updating our ripple injection systems. Some old rotary injection installations are replaced with new solid state injection plant if it has an economic benefit. New smart meters has the functionality to switch load and can be controlled either by a ripple injection plant or operate via an internal time clock. The new injection plant requires minimum maintenance, and maintenance expenditure on ripple load control plant will diminish as older assets are decommissioned.

#### 6.10.7 Vegetation management

Vegetation that encroaches our lines and other overhead assets continues to be a threat to the safety and reliability of our network. To manage this risk we have taken a pro-active approach by implementing more resources to vegetation management (internal and external), providing information, advice and options to tree owners in particular forestry owners and farmers and developing a robust survey/ inspection system to identify and prioritise vegetation that encroaches our assets and also any high risk vegetation outside of the regulation corridor (fall distance trees). This pro-active approach has proven successful

---

<sup>53</sup> Distributed Network Protocol—a set of communications protocols used between components in process automation systems. *Source: Wikipedia*

with a noticeable drop in tree related faults in the last 12 months and a large amount of problematic trees and plantation blocks removed altogether.

#### 6.10.7.1 *Tree cutting programmes*

We have a full-time Vegetation Coordinator at AEL who manages and coordinates all vegetation work and cutting schedules. Our internal contractor has a vegetation crew made up of 3 utility arborists plus external contractors such as shelterbelt trimmers and additional utility arborists whom complete the vegetation cutting. The majority of vegetation work is aligned with lines refurbishment jobs to minimise outage requirements and disruptions to customers. Our vegetation crew works full-time on vegetation clearance using a range of tools and systems, in the past 12 months we have implemented the use of insulated tools for vegetation control which has also decreased the need for outages to complete work in the close worker zone. We have also approved a number of 3<sup>rd</sup> party contractors to undertake vegetation cutting near our network, mainly shelterbelt trimming contractors. This has enabled them to obtain a Close Approach Permit and schedule and manage their own workload. We do provide advice and assistance when requested.

## 6.11 Non-network asset maintenance and renewal

Non-network assets are those defined by the Commerce Commission as being related to the provision of electricity line service, but not directly used to provide line service. The information disclosure requirements provide a list of non-network assets used by us and include a description of use, and maintenance and renewal policies. We are currently developing policies for specific areas of asset management, including vehicle maintenance and replacement, ICT asset renewal, and property maintenance.

### 6.11.1 Motor vehicles

We own our vehicle fleet which is predominantly four wheel drive utility vehicles so as to be able to operate effectively off road, and in adverse weather conditions.

Vehicle maintenance is managed using proprietary software (EROAD) that records GPS locations, speed, distance travelled, vehicle age, maintenance and certification requirements.

The fleet is currently managed by our General Manager—Safety and Risk, and vehicles are replaced on average every six years or at 300,000 Km's as considered task appropriate.

### 6.11.2 Office buildings

A building that houses a network asset is considered to be a network asset in its own right. Buildings not classified as network assets include the four buildings used to house our engineers, controllers, and corporate staff, and are all located at our Washdyke depot.

The office buildings occupied by Alpine Energy and NETcon are currently managed by our Corporate Services, which conducts building warrant of fitness checks once a month. Safety issues are addressed on notification. Buildings and facilities are upgraded in line with our strategic requirements, ensuring that our facilities are fit for purpose. The NETcon building was upgraded in 2014/15 in line with this approach.

A new fit for purpose office building that will accommodate both Alpine Energy and NETcon staff has been approved and will be constructed in 2017.

### 6.11.3 Information systems

For a description of computer and communication systems specific to our electrical power network (e.g. SCADA system, ripple load control, etc., please refer to Section 2.7.1—Information technology for asset management).

ICT assets are managed by our IT Services according to life cycle principles of procurement, maintenance, and disposal, depending on user requirements and the most beneficial solution. ICT software is regularly updated and we pay licensing fees for software packages (including Microsoft products) in return for upgrades, support, and maintenance. We hold a service level agreement with our financial package provider. We have also service arrangements with Fujitsu, Code Blue and Information Leadership for support of various aspects of our IT infrastructure. Day-to-day ICT needs are met by our IT Services Team.

At present, information management is a high priority area of our business. We are investing in staff, knowledge based consultants, and software to find holistic solutions to our information needs. Spending on information management is expected to reduce once service level targets are met.

### 6.11.4 Business equipment

Maintenance and renewal of non-ICT office equipment (e.g. furniture, appliances, etc.) is managed by our Corporate Services. With the exception of electrical equipment, which is tested and tagged on an annual basis, non-network assets are maintained on a case-by-case basis. Non-network asset purchases of over \$500 are approved by department managers and/or our Group Manager—Corporate Services.

## 6.12 Maintenance (Opex) budget projections

Table 6.14 lists the projected maintenance expenditure by asset class for 2017/18 in nominal (non-adjusted) dollars. Nominal dollars are used to highlight the fact that we are reducing Opex in real terms by an amount equivalent to inflation for the next six years and that Opex is constant in nominal terms till at least 2022/23.

The maintenance expenditure projections are calculated under the following assumptions.

- Continued maintenance expenditure over the period due to ongoing condition assessment activity revealing in detail the extent of repair and maintenance requirements.
- Introduction of centralised control in 2009, with fault work contracted to NETcon, with consequential addition of an estimated \$1 million to the annual Opex budget for distribution lines and cables.
- Maintenance expenditure budget to be held constant in nominal dollars till 2022/23 (i.e. annual reduction of budget in real terms at CPI rate).
- Reduction in overall maintenance required as new lower maintenance assets are introduced onto the network as a result of upgrades and renewals.
- Limitations on network assets for maintenance intervention imposed by Operations (outages and switching).

The assumptions of reducing growth in maintenance expenditure may not eventuate should the following occur.

- Complexity and size of some of the new assets increase, requiring higher levels of technical attention during routine and reactive maintenance.
- Numbers of site and assets increase as the network load and load density grow.
- Higher levels of routine maintenance activity per site as condition assessment requirements increase and techniques for measuring condition improve.
- Existing plant that does not require urgent maintenance moves from low to high need for maintenance as it reaches end of life (e.g. Opex refurbishments that do not fall in the renewal or upgrade Capex categories).

## 6.13 Replacement and Renewal budget projections

Table 6.15 summarises the asset replacement and renewal budget by asset category for the 2017/18–2026/27 period in real (constant) dollars.

The large numbers in years 2018/19 and 2023/24 relates to replacing zone substation transformers and switchboards.

**Table 6.14 Opex expenditure per asset category**

Asset category	Forecast (in \$'000)									
	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
LV lines and cables	337	337	337	337	337	337	344	350	357	365
Distribution substations	1,141	1,141	1,141	1,141	1,141	1,141	1,163	1,187	1,211	1,235
Distribution lines and cables	3,135	3,135	3,135	3,135	3,135	3,135	3,197	3,261	3,327	3,393
Zone substations	544	544	544	544	544	544	555	566	578	589
Sub-transmission lines and cables	21	21	21	21	21	21	22	22	22	23
SCADA and radio	170	170	170	170	170	170	174	177	181	184
Unspecified	1	1	1	1	1	1	1	1	1	1
<b>TOTAL</b>	<b>5,349</b>	<b>5,349</b>	<b>5,349</b>	<b>5,349</b>	<b>5,349</b>	<b>5,349</b>	<b>5,456</b>	<b>5,565</b>	<b>5,676</b>	<b>5,790</b>

**Table 6.15 Asset renewal and refurbishment budgets 2016–26 (in constant dollars)**

Project category	Forecast (in \$'000)									
	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Sub-transmission, distribution, and LV lines and cables	3,822	3,980	3,940	3,940	3,940	3,940	3,940	3,940	3,940	3,940
Distribution substations, including transformer, regulators, ring main units, and so on	1,435	1,822	1,582	1,582	1,492	1,430	1,370	1,370	1,370	1,370
Zone substations including SCADA, comms, and load control plants	450	4,400	200	950	200	200	3,700	200	200	200
<b>TOTAL</b>	<b>5,707</b>	<b>10,202</b>	<b>5,722</b>	<b>6,472</b>	<b>5,632</b>	<b>5,570</b>	<b>9,010</b>	<b>5,510</b>	<b>5,510</b>	<b>5,510</b>

## 7. RISK MANAGEMENT

### 7.1 Introduction

Chapter 7 outlines the risk management approach we employ for managing our network assets and activities. All risk management plans form part of our integrated Safety Management System (SMS), which is described in Figure 7.1.

With the implementation of an extensive Risk Management Policy we are reviewing and strengthening our comprehensive risk management register to provide risk management consistency across all facets of our company, and to support and standardise our risk assessment and mitigation management. Further information on our Risk Management Policy development can be found in Section 5.9.1—Network Development Plan prioritisation process.

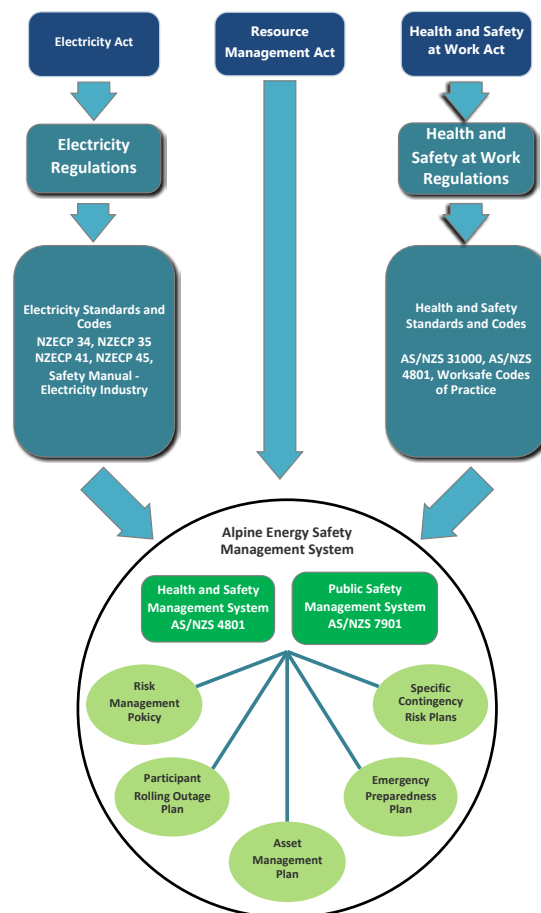


Figure 7.1 Safety management system framework

## 7.2 Safety Management System

Our integrated Safety Management System consists of the Health and Safety Management System and Public Safety Management System.

Our Public Safety Management System is subject to annual external audit to ensure compliance with the requirements of:

- NZS7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety
- AS/NZS 4801:2001 Occupational Health and Safety Management Systems.

Our integrated Safety Management System also feeds into our:

- Asset Management Plan
- Emergency Preparedness Plan
- Participant Rolling Outage Plan
- Civil Defence Emergency Management
- various specific contingency plans.

### 7.2.1 Public Safety Management System

The Electricity (Safety) Regulations 2010 require all electricity distribution companies to produce an audited Public Safety Management System. The purpose is to prevent serious harm to members of the public or significant damage to public property from network assets and/or asset operation. Risk management activities referred to in this AMP are consistent with the requirements of the Public Safety Management System.

There is a statutory requirement to be audited to *NZS 7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety* by an accredited audit body. The audits commenced in April 2012 and are carried out annually.

For further information, please refer to our Public Safety Management document.

#### 7.2.1.1 Public education

We reduce a number of external risks through public education. By placing regular safety messages in the media, we communicate to the public the consequences of their actions in relation to electricity and electrical assets. Communication through media helps us to create awareness in the community regarding potential hazards, and reminds the public to contact us when a hazard is perceived. Figure 7.2 provides an example of our communication through print media.

We also undertake joint public safety initiatives with South Island distribution companies. For further details, please refer to our Public Safety Awareness and Education Policy.



Figure 7.2 Media print example

### 7.2.1.2 Security of ground mounted assets

Our ground mounted assets are protected from public intrusion by the standard practice of locking the external body equipment and by sometimes placing the assets in secure compounds.

For distribution boxes and link boxes we are implementing tamper-proof uniquely keyed fasteners to replace socket headed cap screws.

We are in the process of a major overhaul of our current lock hardware to a single unique hierarchical keyed lock system.

### 7.2.2 Health and Safety Management System

The Health and Safety at Work Act 2015 requires all businesses to have an occupational health and safety management system in place. The purpose of the system is to prevent

serious harm to workers, and the general public or significant damage to property arising out of our work activities.

For further details, please refer to our Health and Safety Management System document.

## 7.3 Emergency response and contingency planning

We recognise that the local economy depends on a secure and reliable supply of electricity, and that a catastrophic event such as an earthquake, landslide, tsunami, flood, wind and snow storms, and terminal failure of key assets can have significant impact on both the network and the local economy.

We have developed emergency response plans for dealing with widespread abnormal situations created by either asset failure or catastrophic natural events. All emergency response plans are regularly reviewed to ensure that unique risks arising from emergency response have been identified.

Mutual Assistance Agreements have been signed with peer electricity distribution networks. These agreements were successfully implemented during the Canterbury earthquakes in September 2010 and February 2011, wind storms and snow events in 2013, and the Kaikoura Earthquake in 2016

For further details, please refer to our Emergency Preparedness Plan.

### 7.3.1 Business continuity planning

Regular electronic backups of mission critical records for retailer billing and consumer identification are carried out. The backup copies are securely stored offsite by our web host.

All ICT servers are virtually hosted across the North Street substation and Washdyke data centres. All systems can be run from either data centre in the case of loss of an entire site. Data backups are also physically held at each location.

SCADA is also duplicated at North Street including a set of paper copies of switching plans.

### 7.3.2 Emergency Preparedness Plan

Our Emergency Preparedness Plan complies with the requirements of *NZS 7901:2014* and *AS/NZS 4801:2001* and is regularly reviewed after each critical event, and on an annual basis.

The plan is distributed to our staff as part of our Health and Safety Management System, instructing them of the procedures to follow for emergency events, including:

- Civil Defence Emergencies

- major accidents
- fire and evacuation of site
- earthquake
- extreme climate events
- threats and conflict situations
- hazardous or toxic substances (oil spillage or SF<sub>6</sub> release)
- pandemic.

### 7.3.3 Emergency communications

Our emphasis on appropriate emergency communication ensures information is provided to stakeholders and the public in a proactive manner. Our communication responsibilities are:

- Chief Executive Officer: media, stakeholders, EDBs, and Transpower
- Group Manager— Corporate Services: general public
- General Manager—Safety and Risk: Police, Civil Defence, local councils and other local authorities, and large customers.

Responsibilities for communications are detailed in Section 4.2 of the Participant Rolling Outage Plan.

#### 7.3.3.1 Telephone Video Data and network status report

The public can keep up-to-date on the location of outages and resolution by logging on to the 'Network status' section of our website. Consumers can also subscribe to Telephone Video Data (TVD), which will send them a notification regarding outages in areas that they indicate they want information for. The public can also phone us for information and listen to the radio.

### 7.3.4 Participant Rolling Outage Plan

The Electricity Industry Participation Code 2010 Part 9 requires all specified EDBs to prepare and publish a Participant Rolling Outage Plan (PROP) for audit and approval by Transpower's System Operator.

The Plan is required to conform with the requirements set out in the System Operator Rolling Outage Plan (latest version 19 June 2016), and details how electricity distributors will assist the System Operator in managing either a total outage or rolling outages of up to 25% of normal load if there is a national or regional electricity shortage.

Our most recent Participant Rolling Outage Plan has been submitted to the System Operator for audit and approval. A copy of the current Plan can be found on our website ([Participant Rolling Outage Plan](#)).

### 7.3.5 Specific contingency plans

Specific contingency plans for the restoration of supply to essential services and to individual major industrial and commercial consumers exist to complement and supplement the Participant Rolling Outage Plan. For example, if we lost both 110 kV TIM–TMK circuits that supply our Temuka 33 kV zone substation, we have a specific plan developed jointly with Transpower to ensure electrical supply continuity to the Fonterra Clandeboye dairy factory.

### 7.3.6 Civil Defence Emergency management

In the event of a Civil Defence Emergency, nominated staff members are sent to man the local district council's Civil Defence Emergency Operations Centre. A dedicated radio telephone link is installed in the Timaru District Council's Emergency Operations Centre for direct communication with our control room.

The Canterbury Lifelines Utilities Group<sup>54</sup> promotes resilience to risks, and develops contingency measures for Civil Defence Emergencies arising from natural disasters.

As a lifeline utility, we participate in the development of both regional and local Civil Defence Emergency Management plans, and provide technical advice to local authorities and other lifeline utilities as requested.

We participate fully in Civil Defence's regional exercises such as 'Pandora', 'Olaf', and 'Ripahapa'. Lessons learnt from these exercises are used to enhance our current emergency response planning. Delegates from board and executive management level have also attended the recent workshop where the South Island regional preparedness for a magnitude 8 earthquake in the Alpine Fault line was discussed.

## 7.4 Risk management planning for network assets

All our activities involve risk. We manage risks by anticipating, understanding, and deciding whether or not to modify the activity to mitigate the risk. The purpose of risk assessment is to provide empirical knowledge and analysis to make informed decisions on the treatment and method of resolution of particular risks.

We will accept risk in order to achieve or exceed our objectives, provided that the risks are understood and appropriate mitigation is in place to ensure the risk is within our bounds of acceptable risk.

---

<sup>54</sup> We were a founding member of the South Canterbury Lifelines Group, which amalgamated with the Canterbury Lifelines Utilities Group.

We assess and treat risk as part of asset management. For confidence and consistency, we undertake our risk management activities in accordance with our Risk Management Policy. The Policy was approved by the Board of Directors, and the CEO, effective from 15 October 2015. Our Risk Management Policy is consistent with the international standard *AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines*, and was peer reviewed by experts in risk management.

We aim to integrate high quality risk management activities with all critical processes so that we are able to recognise and respond to risk before events occur. Responsibility for managing risks rests with all staff and the Board of Directors, as described in Table 7.1. Accountability for risk management includes ensuring that the necessary controls to modify the risks and control assurance activities are in place and are effective at all times.

**Table 7.1 Risk management responsibility and accountability**

Title	Responsibility
Board of Directors	The Board is responsible for approving of the Risk Management Policy, determining our risk criteria, ensuring the Policy can be implemented, monitoring ‘very high’ risks, the correct functioning of critical controls, and effective implementation of the Policy.
Chief Executive Officer (CEO)	The CEO is accountable to the Board for approving our risk management standards, and ensuring the standards are applied consistently to all planning and decision making.
Group Manager—Corporate Services	The GM—Corporate Services is accountable for: <ul style="list-style-type: none"> <li>• developing and maintaining our risk management standards</li> <li>• providing technical risk management support, and associated tools and practices</li> <li>• reporting to the Audit and Risk Committee (excluding Health and Safety matters).</li> </ul>
Executive Management Team (EMT)	The EMT is responsible for monitoring and reviewing our risk management activities and performance, including consistency with AS/NZS ISO 3300 and our guidelines and procedures.

Title	Responsibility
General Manager—Safety and Risk	The GM—Safety and Risk is accountable for: <ul style="list-style-type: none"> <li>• developing and maintaining our Health and Safety risk management standards</li> <li>• providing technical risk management support, and associated tools and practices.</li> <li>• reporting to the Board Health and Safety Committee</li> </ul>
Managers and team leaders	Managers and team leader are responsible for applying our standards to the assessment and treatment of risk in their business areas, and for monitoring the correct functioning and ongoing applicability of controls.
All personnel	All personnel are accountable for fulfilling their specific risk management functions.

Assurance of good governance will be achieved through the regular measurement, reporting, and communication of our risk management performance by ensuring that the resources, delegations, and organisational arrangements are in place. We are in the process of establishing an assurance programme to help us monitor our progress.

With our Risk Management Policy aligned to AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines, the risk management process involves risk

- identification
- analysis
- evaluation
- treatment
- monitoring and review.

Our network is exposed to a range of internal and external influences that can have an impact on our business objectives. These influences provide a context for risk identification. The nature of electricity networks means that the network may be exposed to events that push the integrity of the components past design capability. The subsequent failures have to be reviewed to determine the impact on the network, consumer supply, and our ability to limit the disruption through risk mitigation.

A risk management study based on AS/NZ 4360:2004—*Risk Management*, and the EEA’s *Guidelines for Security of Supply* in NZ Electricity Networks, was undertaken for sub-transmission and zone substation assets in the 2005/06 financial year. The EEA has since published a revised *Guide for Security of Supply* August 2013. With our Risk Management

Policy now in place, a full review of the risk management study will need to be undertaken in the 2017/18 financial year.

The appropriate plan of action in response to an identified risk may include capital development, maintenance or operational enhancement, business planning or training, and contingency planning. Our maintenance programme includes routine inspections to ascertain asset condition and regulatory compliance. Our policies rank public and environmental safety as top priority.

### 7.4.1 Risk identification

Identification of network risk is an iterative process. While our process is well developed, new techniques for predictive condition support and proactive risk management are being developed based on long-life assets (for example, the recent release of the new EEA guide—Asset Health Indicators).

Consequences of risk on our network can be grouped into the following categories:

- reputation
- natural environment
- compliance
- financial
- asset utilisation
- reliability of supply
- security of supply

#### 7.4.1.1 Environmental risks

We are committed to operating in a manner that is environmentally sustainable.

There are many events outside of our control that threaten to interrupt the operation of our distribution network (e.g. floods, high winds, lightning, snow, earthquake tsunami, fire, etc.). To counter the effects of such events on the environment and the public (e.g. chlorofluorocarbon gas emissions, oil spills, arc flash exposure, failure of line supports, etc.), we place great importance on the selection and installation of our network components.

#### 7.4.1.2 External risk

Risk to the network can be introduced by the public through:

- inadequate control of trees adjacent to overhead lines
- operating plant or stockpiling material without adequate clearance from overhead lines
- lighting fires adjacent to overhead lines

- moving irrigators under overhead lines
- undermining pole foundations
- colliding with our assets (e.g. car versus pole)
- illegal access into authorised areas
- leaving electric fence wire or other conductive material where wind or birds may carry it up into overhead lines.

### 7.4.2 Risk analysis

Risk analysis is used to determine the most effective means of risk treatment. A number of dimensions must be satisfied to meet our objectives of managing our assets in a safe, reliable, and cost-effective manner.

We have undertaken a qualitative assessment of risk that we face to determine its ranking. Table 7.2 lists the qualitative measures of likelihood we use in our risk assessment.

**Table 7.2 Measure of risk likelihood**

Level	Descriptor	Description	Indicative return period
5	Certain	Will occur frequently	Once or more per annum
4	Likely	Will occur infrequently	Once in 1–4 years
3	Possible	Might occur	Once in 4–10 years
2	Unlikely	Will seldom occur	Once in 10–50 years
1	Rare	Theoretically possible but unlikely to occur	Once in 50–100 years or less

Table 7.3 describes the qualitative measures of consequence or impact that we use in our risk assessment.

**Table 7.3 Measure of risk consequence**

Consequence level	Insignificant	Minor	Moderate	Severe	Extreme
Reputation	No interest outside Alpine Energy	Local papers, brief criticism, little controversy	Local and regional media, criticism not widespread, brief	Regional and national criticism for more than two days	Regional and national media criticism, highly adverse, sustained for a week or more

Consequence level	Insignificant	Minor	Moderate	Severe	Extreme
Natural environment	Little or no impact	Small scale contained event, short-term impact, managed internally	Event restricted to one locality, localised impact on habitat/environment; some external support required	External support required to contain, notifiable, potential long-term impacts	Massive environmental contamination damage to endangered flora/fauna
Compliance	No breach	Breach of legislation, code of practice, or industry standard; no applicable penalties	Financial penalty of up to \$10,000	Prison term of less than two years and/or financial penalty of up to \$100,000	Prison term of more than two years and/or financial penalty of over \$100,000
Financial	Potential loss or cost of up to \$20,000	Potential loss or cost of \$20,001–\$100,000	Potential loss or cost of \$100,001–\$1 million	Potential loss or cost of \$1 million–\$5 million	Potential loss or cost of > \$5 million
Asset utilisation		Network asset (to the value of under \$100,000) underutilised or stranded	Network asset (to the value of \$100,000–\$1 million) underutilised or stranded	Network assets (to the value of \$1 million–\$5 million) underutilised or stranded	Network assets (to the value of over \$5 million) underutilised or stranded

Consequence level	Insignificant	Minor	Moderate	Severe	Extreme
Reliability of supply	Unplanned outages (Class C): <1 SAIDI min or <40 ICP interruptions per event	Unplanned outages (Class C): 1<&<3 SAIDI mins or 40<&<100 ICP interruptions per event	Unplanned outages (Class C): 3<&<33 SAIDI mins or 100<&<1000 ICP interruptions per event	Unplanned outages (Class C): 33<&<161 SAIDI mins or 1000<&<1500 ICP interruptions per event	Unplanned outages (Class C): >161 SAIDI mins or >1500 ICP interruptions per event
Security of supply	Non-compliance on loads below 0.2 MVA	Non-compliance on loads 1<>0.2 MVA or inability to supply new load within three months	Non-compliance on loads >1 MVA or inability to supply new load within 12 months	Non-compliance on loads >9 MVA or inability to supply new load within 24 months	Non-compliance. Causes negative growth or inability to supply new load within 48 months

Figure 7.3 combines the qualitative assessment of consequence and likelihood to provide a level of risk matrix.

Likelihood	Certain	Low	Medium	High	Very High	Very High
	Likely	Low	Medium	High	High	Very High
	Possible	Low	Medium	High	High	Very High
	Unlikely	Low	Low	Medium	Medium	High
	Rare	Low	Low	Low	Medium	High
		Insignificant	Minor	Moderate	Severe	Extreme

**Consequence**

Figure 7.3 Risk matrix

Based on the risk score, specific response and reporting requirements are determined. The requirements are described in Table 7.4.

Risk analysis evaluates the factors that influence the consequences and likelihood of an event, as well as the effectiveness of existing controls and management strategies.

Quantitative analysis is used where specific performance measures are in place, e.g. oil sample testing of zone substation transformers. The testing provides a review of compounds in the oil sample to determine health and position on the age curve based on known operating history. The quantitative approach allows us to manage assets with the highest event consequence cost throughout expected service life.

**Table 7.4 Response by risk level**

Level of risk	Urgency for implementation of treatment	Authority for continued tolerance of risk	Reporting
Very high	Immediate corrective action to rectify or mitigate the impact of the identified risk to be implemented ASAP under GM—Network’s supervision	CEO	Advise GM—Network immediately, and the GM to advise CEO immediately after receiving advice and to include in next reporting cycle. CEO to advise Risk and Audit Committee (Board) as appropriate and to include in next reporting cycle.
High	Action plan to be developed within [x] <sup>55</sup> days of the identification to GM—Network (or such other period that is practical in the circumstances).	GM—Network	Advise GM—Network within 24 hours of identification, and the GM to advise CEO as soon as practicable after receiving advice and to include in next reporting cycle.

<sup>55</sup> Where [x] days or months, the number is determined by the GM—Network to suit the circumstance.

Level of risk	Urgency for implementation of treatment	Authority for continued tolerance of risk	Reporting
Medium	Action plan (if necessary) to be developed within [x] months of identification to the GM—Network (or such other period that is practical or necessary in the circumstances).	Managers	Advise GM—Network within five days of identification. If necessary, include in next reporting cycle.
Low	Treat in line with other priorities. Ongoing monitoring.	Manager	Advise Manager or, if appropriate, relevant committee or group (e.g. Planning Committee).

### 7.4.3 High consequence low probability risks

Our distribution network is built in a hierarchical structure with Transpower substations providing supply points for 33 kV sub-transmission to zone substation assets. The zone substations have multiple feeders that connect the 11 kV distribution lines. Distribution lines traverse the region and support 11 kV assets and distribution level transformers, which break down into the LV networks and more than 31,000 individual connection points.

Failure of a hierarchy asset at the Transpower connection level carries the serious consequence of potentially disrupting a large number of consumers. At our zone substations the failure of any equipment that would result in a substation outage would typically constitute a high consequence/low probability risk. Examples of these are transformers, circuit breakers, cables, etc. depending on the zone substation.

In order to mitigate against high consequence low probability events at five of our zone substations, we have procured and developed standby diesel generation plant and a mobile substation as described below.

- A mobile generator set (AMG) made up of two 900 kVA machines able to base load at 500 kW each or 1 MW in total. The machines can be used at 11 kV or 400 V to allow maintenance of distribution substations or provide small community back-up.
- A mobile substation (AMS) that steps 33 kV to 11 kV with a 9 MVA rating. We are preparing all of our single transformer zone substations so that the AMS can be installed in parallel to allow the release of the zone substation for maintenance.

### 7.4.3.1 Zone substation transformers

Table 7.5 below details our high consequence / low probability risks as it relates the highest consequence risk category with both pre- and post-mitigation risk scores. A detailed risk analysis based on our policy has been completed for each of our zone substation to obtain the listed scores. For all cases except Geraldine, Bells Pond and Twizel, the contingency plans details the use of back-feed (i.e. supply from adjacent zone substations) as well as the deployment of our mobile substation to restore supply.

Since commissioning of our mobile substation in 2014, we have to date completed five projects at five zone substations, to enable us to connect our mobile substation, or our mobile diesel generation at these zone substations in the event of an emergency. The remaining zone substations are:

- Geraldine where the project to enable connection of our mobile substation is due for completion in April 2017
- Bells Pond where we have started a project under our current capex workplan to install a second transformer. A request for tender for the supply of the transformer has been issued and we expect to award the contract in February 2017. The project will be completed under the 2017/18 workplan
- Twizel is included in the 2017/18 workplan to enable mobile substation connection.

**Table 7.5 Zone substation transformer risk analysis**

Zone substation	Risk Category	Current risk score	Risk category details
Pleasant Point	Reliability of supply	Low	Loss of supply to 1224 ICPs
Cooneys Road	Reputation & Environment	Medium*	Loss of supply to Oceania Dairy factory, 1 ICP. Factory unable to process milk and dairy farmers unable to get milk removed from their farms. Milk deposited on pastures or dumped.
Geraldine	Reliability of supply	Medium	Loss of supply to GLD township and surrounding rural areas 2496 ICPs
Bells Pond	Reliability of supply	Low	Loss of supply to Oceania Dairy factory and rural areas, 585 ICPs. Factory unable to process milk and dairy farmers unable to get milk removed from their farms. Milk deposited on

Zone substation	Risk Category	Current risk score	Risk category details
			pastures or dumped.
Albury	Reliability of supply	Medium	Loss of supply to 1017 ICPs
Fairlie	Reliability of supply	Medium	Loss of supply to 1014 ICPs
Tekapo	Reliability of supply	Medium	Loss of supply to 644 ICPs. Tekapo is a very busy tourist town and a loss of supply would also result in reputational damage not just to Alpine Energy but also NZ.
Twizel	Reliability of supply	High**	Loss of supply to 1396 ICPs. Twizel is a very busy tourist and business services town and a loss of supply would also result in reputational damage and economic loss.

**Notes:** *\*Even though mitigation has reduced the risk consequence from 'Severe' to 'Moderate', the resultant risk score based on the matrix is still 'Medium'.*

*\*\* The resultant 'High' risk score after mitigation is due to the fact that the reliability of supply threshold set for 'Extreme' consequence is 161 SAIDI minutes. So even through mitigation results in an improvement, based on the policy the score remains 'High'.*

Our other larger zone substations such as Timaru, Pareora, Rangitata, Temuka, Clandeboye #1, and Clandeboye #2 are all constructed with N-1 security (i.e. two transformers) and therefore the loss of one transformer would not affect the supply. The remainder of our zone substations are small and does not fall into the high consequence category for a loss of transformer or incomer circuit breaker.

Our maintenance procedures and schedules include regular inspections and oil sampling and testing. Major maintenance is done when a transformer is moved from one location to another and when a substation is equipped to connect our mobile substation.

#### 7.4.3.2 Incoming supplies

The highest risk of outages is the reliability of the incoming supply. Typically, the incoming supply is provided by Transpower. In cases where the substations are supplied via a single feeder, necessary repairs result in outages. Overhead line incoming supplies are clearly visible and any repairs are normally done within hours rather than days and hence these do not result in severe or extreme risk consequences. To reduce the level of risk, detailed

studies are undertaken to determine the costs and benefits of duplicate feeders or alternative generation options.

Where we have cable circuits for incoming supplies, there are duplicate circuits (i.e. N-1 security) at all zone substation except at Albury. However the incoming cable circuit is only 61 metres in length and laid within the substation fenced area as well as a section in an easement on private land and not readily accessible by the public. The likelihood of a failure is rare and due to the short length, finding and repairing a fault can be achieved within a day. Opuha generation is also available to supply all load at certain times of the year.

### 7.4.3.3 Switchboards

The loss of a switchboard will most likely be as a result of a fault in the busbar zone which will result in a loss of all outgoing feeders, which similar to the loss of a zone substation transformer, can result in a high consequence risk. Due to the nature of bus zones being totally enclosed and being indoors within a controlled access environment, the likelihood of bus zone faults are rare. For the zone substations where we have connection points for our mobile substation, the risk analysis is similar to the loss of a transformer as detailed in Table 7.5 above.

The risk assessment for remainder of our zone substations and major switching stations in the Timaru urban network, for the highest risk category, are detailed in Table 7.6 below. All new switchboards that were installed in the last seven years are arc flash rated boards and have been fitted with arc flash protection systems that significantly reduces the consequence of a bus zone fault since the fault is isolated from damaging other parts of the board. These systems are present at North Street, Grasmere Street, and the new Rangitata (transformer #2) substation switchboards.

**Table 7.6 Switchboard risk analysis**

Zone/switching substation	Risk Category	Current risk score	Risk category details
North Street	Reliability of supply	Medium	Loss of supply to 1195 and 826 ICPs for the two busbars respectively.
Grasmere Street	Reliability of supply	Medium	Loss of supply to 1404 and 1705 ICPs for the two busbars respectively.
Hunt Street	Reliability of supply	Medium	Loss of supply to 1952 and 1544 ICPs for the two busbars respectively.
Pareora	Reliability of supply	Low	Loss of supply to 389 and 838 ICPs for the two busbars

Zone/switching substation	Risk Category	Current risk score	Risk category details
			respectively.
Temuka	Reliability of supply	Low	Loss of supply to 1292 and 1646 ICPs for the two busbars respectively.
Rangitata <sup>56</sup>	Reliability of supply	Low	Loss of supply to 241 and 195 ICPs for the two busbars respectively.
Clandeboye 1	Reliability of supply	Low	Loss of 1 ICP
Clandeboye 2	Reliability of supply	Low	Loss of 1 ICP
Studholme	Reliability of supply	Low	Loss of supply to 2296 and 885 ICPs for the two busbars respectively.

The risks at the Clandeboye substations are mitigated in that the site has a supply security level of N-1.

The two PAR 33 kV switchrooms, one for each half bus, have arc flash containment and ducting to the exterior. It has N-1 supply security with respect to the switchboards and are therefore rated as low risk.

The Rangitata, Studholme, Temuka, and Pareora 11 kV switchboards are fitted with bus zone protection will restrict a bus fault to a half bus outage. With tie points outside the substation, supply can be moved to one side of the switchboard while the faulted part is repaired.

The medium risk scores in Table 7.6 above are acceptable risk. These scores were achieved due to the number of consumers connected, and an outage in these instances is acceptable compared to the costs of reducing the score to low.

#### 7.4.4 Other network asset risks

##### 7.4.4.1 Ripple injection plant risks

Our ripple injection plants are important in the management of controllable load on our network. With the deployment of smart meters on our network, there is an alternative available for load control that is required for energy tariffs. However this does not affect emergency load control which presently can only be done through the use of the ripple injection plant. In order to mitigate the risk of a ripple injection plant failure, we conduct

<sup>56</sup> This refers to the old switchboard for transformer #1

regular inspection and maintenance programs. In addition we also keep long lead time spares.

We have replaced all but one aged rotary ripple injection plant. The remaining one being located at our Tekapo substation will be replaced within the planning period.

#### 7.4.4.2 Environmental risks

Snow and wind typically create high risks in the Mackenzie area of our network. Our design standards ensure appropriate materials that meet the extreme weather conditions are used. For example, the 11 kV switch room at the STU substation has been elevated to minimise flood risk.

Earthquakes pose a significant risk of network interruption and difficulty in supply restoration. The likelihood of an earthquake on our network has been deemed 'possible'. The likelihood of an Alpine Fault<sup>57</sup> event in the next 50 years is 30%<sup>58</sup>. This translates to a likelihood descriptor of 'Unlikely' in our risk matrix. Combined with a 'Reliability of supply' consequence level of 'Severe' to 'Extreme' would result in a risk score of 'High'.

Following an earthquake, checks will be required to ensure substations close to the fault are structurally sound. An earthquake on the Alpine Fault could cause some Twizel and Tekapo consumers to be without supply for several weeks. The Mackenzie substations are closest to the Alpine Fault and the area of the largest expected disruption.

#### 7.4.4.3 ICT and Asset management systems

Our corporate and SCADA servers are duplicated and on hot standby in our North Street substation located 5 km from our Washdyke office site. This substation has additional space and facilities to provide a second base for control room operations in the event of a disaster damaging or destroying the Washdyke offices and depot.

### 7.4.5 Risk management strategies

Where we identify unacceptable risk, we will mitigate unacceptable risks (in accordance with our Risk Management policy) to an acceptable level through well documented actions plans. We are still recognising that risks may remain, but as long the impact is known, this may be acceptable. The Risk Management policy defines delegated authority for accepting risks.

---

<sup>57</sup> The Alpine Fault is a geological, right-lateral strike-slip fault that runs almost the entire length of the South Island. It forms a transform boundary between the Pacific and Australian Plates. More information can be found at [http://en.wikipedia.org/wiki/Alpine\\_Fault](http://en.wikipedia.org/wiki/Alpine_Fault)

<sup>58</sup> According to the GNS Science website.

In mitigation we look to eliminate, isolate or minimise the risk from health and safety and network investment or expenditure perspective.

#### *7.4.5.1 Justifying expenditure*

In ensuring we obtain the maximum benefit from every dollar we invest or spend, it is necessary for all investment and expenditure to be evaluated on a standard basis. Our Risk Management policy and Risk Management framework allows us to compare the potential benefit to the company for investment and/or expenditure on all projects and maintenance activities.

This will enable us to:

- prioritise our investment/expenditure to reduce any risks to an acceptable level
- prioritise our investment/expenditure to make best use of our resources
- ensure that our maintenance on assets are appropriate and based on risk mitigation

#### *7.4.5.2 Risk Management framework*

Our Risk Management framework is intended to help us understand the risks and respond to these through appropriate mitigation.

All staff are able to and encouraged to identify any perceived risk which is then recorded in a risk register for analysis. The risk analysis is performed using the risk matrix to determine a risk score and documented. The risk score will then determine whether any mitigation and/or escalation are required. If mitigation is recommended then a post mitigation risk assessment is completed and documented to evaluate the post mitigation risk score.

Recognising that risk assessment is a subjective process, we encourage staff to seek support in performing initial risk assessments before registering a risk on the register. All registered perceived risks are evaluated by a selection of staff experienced in performing such assessments.

Prescribed mitigation will be actioned based on the risk score and level of escalation within the management structure. This could result in immediate action, a project scheduled in the workplan, or an adjustment to our maintenance regime.

#### *7.4.5.3 Staff development*

As mentioned before a risk assessment is a subjective exercise. We acknowledge the fact that our staff requires training in and exposure to the risk assessment process. In this regard we include training as part of the development path of all staff related to or involved in asset management.

### 7.4.6 Network resilience

We are in general well positioned for high consequence low probability events. All new substation buildings are designed and constructed to a building importance level 4. Some of our existing large and important substation buildings have been strengthened for seismic events.

With less than 10% of our sub-transmission and distribution network underground and therefore more susceptible to earthquake damage than overhead infrastructure, our ability to respond to infrastructure damage as a result of an earthquake is good.

We have recently commissioned a study of the condition, structural strength and seismic resilience of all our two pole substations. The results for all the concrete pole substations were good. We will be replacing five hardwood pole substations in Twizel in the next financial year.

Our ICT and SCADA systems are duplicated off site and will allow us to continue operations in the event of us being unable to access our current offices and site.

## 8. ASSET MANAGEMENT MATURITY

### 8.1 Introduction

This chapter describes where we are at, and our journey to improve the maturity of our asset management. In order to effectively and accurately set course it is important to have a clear vision of where we would want to be. This is shown in the Asset Management Framework (AMF) depicted in Figure 8.1.

No asset management system is possible without the appropriate systems to capture asset data and information to evaluate and make decisions for investment, replacement or maintenance. These systems are detailed in Section 8.3.

The maturity of our asset management system is also detailed in the evaluation against the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

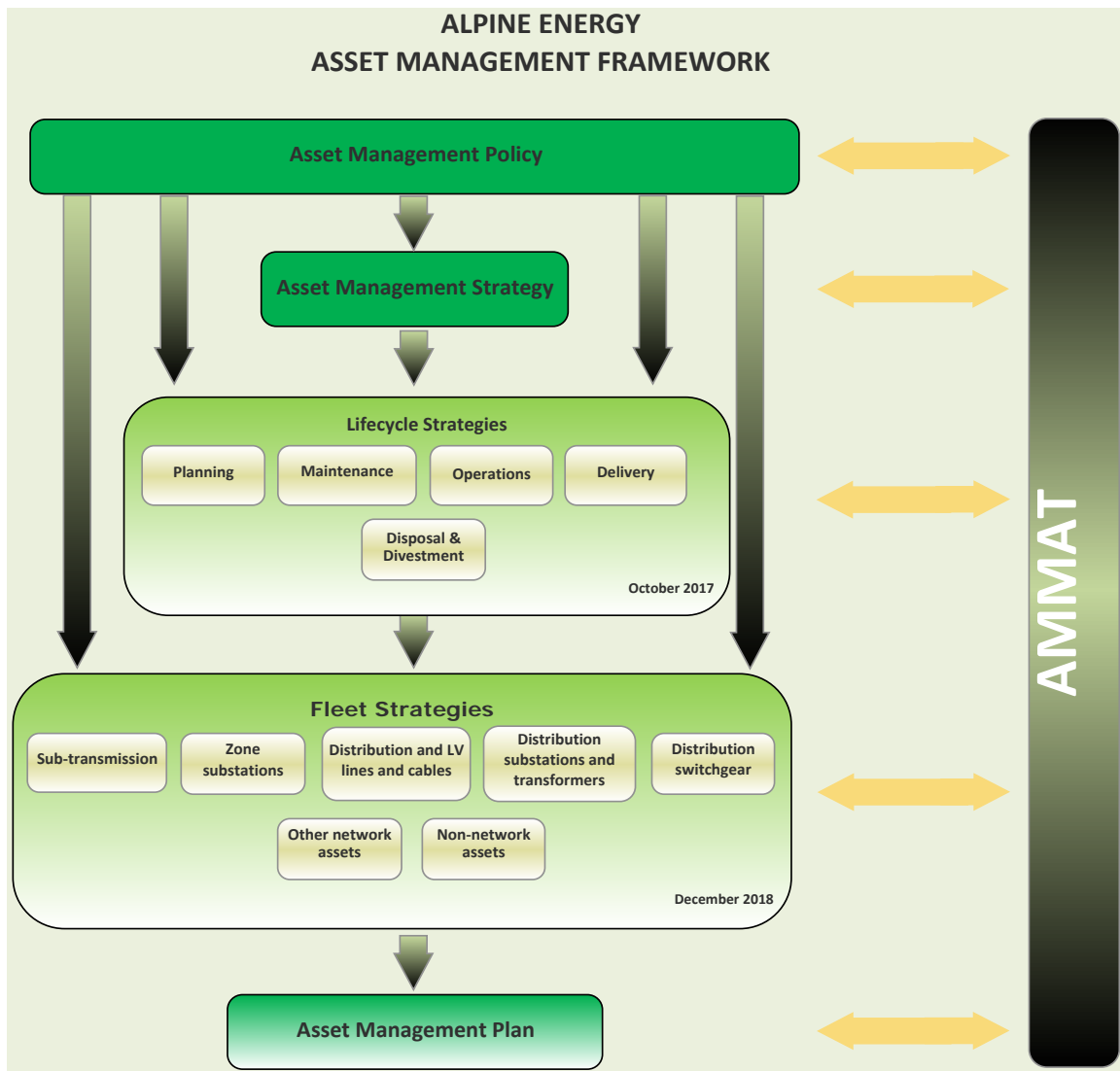
### 8.2 Asset Management Framework

The AMF is being developed to map a course for us to better align ourselves with the ISO 55000 standard. This standard was developed from the Institute of Asset Management's PAS 55 Asset Methodology, which in turn gave birth to the AMMAT.

The AMF depicted in Figure 8.1 below, represents the development of a suite of documents that are closely related to show a clear 'line-of-sight' connection between the high level company policies, strategic plans and objectives, and daily activities of managing our assets. Once developed and in place the arrows will become bi-directional rather than one directional to show that strategies at lower levels can also influence higher level strategies and even policies.

At the time of publication of this AMP, the asset management policy, which is an update of the 2011 document, and the asset management strategy has been developed and are in place as depicted by the dark green colour. The picture also shows the development timeframes of October 2017 and December 2018 for the remainder of the AMF documents. This AMP incorporates information from the completed documents and will be in the dark green colour once all the documents are completed.

The priority of the AMF is to address the current shortcomings as per the AMMAT. Recognising that all the AMF documents will be reviewed and updated on a regular basis, once we have achieved the AMMAT scores that we are aiming for, the AMF would be reviewed and updated to better align us with ISO 55000 provided there is a realisable benefit to the company, shareholders, stakeholders and the South Canterbury consumers.



**Figure 8.1 Asset management framework development**

### 8.3 Asset Information Systems

We are in the process of upgrading, replacing, and securing a number of our information technology systems (ICT), which are integral to our AMS. With the exception of GIS and our operational asset register database, our systems are not fully integrated. Consequently, individual data is often entered separately into more than one package in order to satisfy the different database and software package requirements. More of our systems will be integrated with the implementation of the OneEnergy EAM system which is planned to go live on 1 April 2017. Where appropriate, the new system will also replace paper and spread sheet based processes.

### 8.3.1 Enterprise Asset Management System

The OneEnergy solution by Technology One that we are implementing will also replace our current financial system (Nimbus). Due to the complexity of the task to replace our financial system and implement a linked asset management system at the same time, we have reduced the associated risks by keeping the asset management functionality to a minimum and to use the 'out of the box' functionality and processes for the go-live stage. There are however a number of additional asset management functionality that we want to implement as subsequent stages to the initial go-live stage.

### 8.3.2 Business Process mapping

We are and will be reviewing all of our existing business process maps as part of the introduction of the OneEnergy EAM solution. As noted above we are initially only utilising the 'out of the box' functionality and processes that OneEnergy offers which means we may have to alter/adapt some of our existing processes that will interface with or use OneEnergy. This will ensure that the processes, as they are mapped, remains relevant, effective and efficient, and, where appropriate, change the existing processes to take advantage of continuous improvements.

### 8.3.3 Geospatial Information System

Our bespoke geospatial information system (GIS) has now been replaced with ESRI's ArcGIS and ArcFM configuration model and tools. The system was rolled out companywide at the start of 2017. One of the major challenges was to incorporate all existing diagrams (schematic and general arrangement) as well as photographs related to our assets into the new system.

Since we now have one of the leading international 'off the shelf' GIS systems, integration with other asset information systems is feasible. When evaluating the OneEnergy solution from Technology One, integration with Arc GIS was paramount. We are currently making some final configuration changes to fully satisfy our integration requirements.

Our newly implemented SCADA system can also be integrated with ArcGIS. This functionality is on the development path and will become a reality once all processes around our new GIS has been finalised and approved. This will enable us to move even closer to a single source of truth as it relates to asset information.

### 8.3.4 Supervisory Control and Data Acquisition system

Our recently upgraded supervisory control and data acquisition (SCADA) system is now well embedded and productively used by the operations team. We are planning to add more

functionality to this with the addition of an outage management system (OMS). This system will provide us with the following benefits:

- Reduced outage durations due to faster restoration based upon outage location predictions
- Reduced outage duration averages due to prioritizing
- Improved consumer relations by providing accurate outage and restoration information
- Ability to prioritize restoration of emergency facilities and other critical consumers
- Reduced outage frequency due to use of outage statistics for making targeted reliability improvements
- Fast track down of problem location by meter ping analysis with Advanced Meter Interface (AMI) interface

### 8.3.5 Improving asset knowledge quality

Effective asset management, as well as any improvements to related ICT systems, can only happen with quality data (e.g. technical asset description, age, condition, and location of assets).

The field capture of our overhead distribution system has improved the accessibility and quality of our asset data, although gaps remain. Among the improvements is the unique pole identification system, which allows field staff to reference a number from the field back to the electronic record.

Asset condition information also remains a key area for enhancement. Significant progress has been made over the recent years with condition assessments conducted by NETcon on distribution boxes and distribution transformer installations.

GIS software and application development now allows accurate GPS information to be processed on the move.

## 8.4 Asset Management Maturity Assessment Tool

The Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT) forms part of the Information Disclosure Requirements<sup>59</sup>, and consists of 31 questions, which are a subset of the 121 questions of the Institute of Asset Management's PAS55 Asset Methodology. The AMMAT is intended to assist interested persons to assess the way that we manage our processes and people through the following capability assessment areas:

---

<sup>59</sup> Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, No. NZCC 22, 1 October 2012, clause 2.6.1(5).

- asset strategy and delivery—process
- documentation, controls, and review—process
- systems, integration, and information management—process
- Communication and participation—process
- structure, capability, and authority—people
- competency and training—people.

The AMMAT requires electricity distribution businesses to self-assess asset management maturity by applying a score of 0 to 4 to each question. We scored ourselves with a maturity level of 1 to 3.

- 1—we have a basic understanding of the standard and are in the process of deciding how the elements of the standard will be applied, and we have started applying the standard.
- 2—we have a good understanding of the standard and have decided how we will apply the elements of the standard, and work is progressing on implementation.
- 3—all the elements of the standard are in place, are being applied, and are integrated.

We use the latest EEA Guide to the AMMAT<sup>60</sup> to help us identify our level of maturity for each AMMAT question. For each question the Guide lists a number of requirements that should be evidenced in order to score a particular maturity. When we fulfil the evidence requirements for a maturity level and only partially fulfil requirements for the next maturity level, we score ourselves at the level we partially fulfil (i.e. we round our scores up).

Table 8.2 provides an extract of the information that we provide in Schedule 13 of the Information Disclosure: Report on asset maturity. The table provides the question number, the question, the score that we gave ourselves, as well as a comment as to what the score means in regard to our asset maturity.

#### 8.4.1 Changes to our AMMAT scores from last year

A number of our AMMAT scores have changed from last year. The main reasons for this are:

- a revised Asset Management Policy, and
- newly issued Asset Management Strategy as part of our AMF suite of documents, and

<sup>60</sup> Electricity Engineers' Association's Guide to Commerce Commission Asset Management Maturity Assessment Tool, March 2014.

- the progressing implementation of our EAM system OneEnergy, and
- the completion of the restructuring of the Network Department., and
- the formal implementation of the Alliance agreement.

The result of the revised asset management policy and issued asset management strategy was an improvement in our scores on questions 3, 10, and 11.

The process undertaken to utilise the OneEnergy system has satisfied a number of evidentiary requirements in the AMMAT review, namely through the scope of our asset management requirements and an audit of our current system. Scores that improved as a result of this were on questions 59, 63, 64, 91, and 95. Once the new system is fully implemented, we expect a steady improvement in our AMMAT scores.

Restructuring our network department and filling of all management vacancies has resulted in improved scores on questions 29 and 40 respectively while the formalisation and implementation of the *Alliance Agreement* through the management team has improved scores on questions 2, 45, and 113.

Our updated AMMAT scores and justifications are listed in Table 8.2 at the end of this chapter.

## 8.4.2 Continuous Improvement

The development of the AMP is closely tied to the overall development of our asset management systems and processes. The implementation of the AMF development will strengthen this tie. As systems and processes mature, e.g. through the implementation of our EAM and GIS, we will be better able to communicate our systems and procedures in our AMP. In 2015 we set out to enhance the AMP in three stages, over a three year period. Stage one (previous AMP) and two (this AMP) includes the restructure of the document through incremental changes, including the layout and overall structure. Stage three will commence once we finalise our EAM and AMF implementation, as described earlier in Sections 8.2 and 8.3.1 respectively.

Table 8.1 shows areas in our AMP identified as in need of enhancement.

**Table 8.1 Areas for improvement in our AMP**

Description of Compliance Requirements from Attachment A of the 2012 Information Disclosure	Intended measure to resolves
3.10 Asset management strategy and delivery	Links between the asset management strategy and the AMP will become clearer as we progress with the AMF development and implementing documentation as described in Figure 8.1.

Description of Compliance Requirements from Attachment A of the 2012 Information Disclosure	Intended measure to resolves
3.11 Systems and information management data	We are implementing a new (first) ERP system (OneEnergy from Technology One) for asset management in 2017. As part of this process we are in the process of cleansing existing asset data, identifying additional asset data requirements for whole of life management, and procedures for data quality control.
3.12 Asset data quality	As above, our migration of data from our existing legacy systems to our new asset management system currently underway, will identify data quality issues as well as gaps in required data. At the end of the implementation phase of OneEnergy we will be able to consolidate and develop a program to address any gaps in- or quality of our asset data.
3.15 Staff engagement in delivering asset management requirements	We do not have a communications plan at present, but we will develop one against the background of the AMF for vertical and horizontal level communications between the various groups and teams involved in asset management.
3.17 AMP structure and presentation	Improve the presentation of OPEX and CAPEX forecasts with supporting significant assumptions. Remove some of the highly technical content which will reside in the AMF documentation specifically related to life cycle planning, delivery, operations and maintenance.
5, 6, 7 Service levels	We are enhancing how we measure asset performance through the development of the AMF, and the implementation of OneEnergy. We will include target levels for all stated performance measures as we improve our systems required for capturing service level data for analysis.
9, 15.2 Historic service level measures presented alongside performance targets	Where historic data is available we will include with targets.

Table 8.2 Extract of Schedule 13: Report on asset management

Assessment category	Question no.	Question	Current year score	User guidance
Asset strategy and delivery	10	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	AM strategy is available, aligns with AM policy, as well as other policies. Strategic objectives identified and documented.
	11	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	The third and fourth tiers of the asset management framework will detail the life cycle and fleet strategies of all asset types including non-network assets. Currently parts of this are contained in chapter 6 of the AMP.
	26	How does the organisation establish and document its AMP(s) across the life cycle activities of its assets and asset systems?	2	Our AMP is in place, but we are yet to fully develop our AMS which includes developing our AMF, implementing our EAM and integrating with our GIS. When the AMS is completed we can ensure that the AMP reflects the life cycle activities of assets.
	33	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	4	We have a comprehensive Emergency Preparedness Plan in place that supports us to manage the continuity of critical asset management activity in an emergency event. Our plan is part of our Public Safety Management System that ensures consistency between our policies and strategies around asset management objectives.

Assessment category	Question no.	Question	Current year score	User guidance
Asset strategy and delivery	69	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	We have developed a Risk Management Policy and are in the process of identifying asset related risk across the asset lifecycle. We are in the process of implementing a risk management framework.
	91	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of AMP(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	We have BPMs that details requirements for maintenance and inspections. In addition we are drafting maintenance standards that also details requirements. As part of implementing OneEnergy (EAM), we are revising maintenance processes and setting up maintenance regimes based on asset condition, age and reliability data. As we capture more data, these processes will improve and result in increased benefits.
	109	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non-conformance?	3	We have processes for routine and preventive inspection, maintenance and performance programmes. In addition we have a plant fault report database for the capturing and action of all plant related faults that are discovered. Our investigation processes fully document incidents of asset failures taking note of nonconformities to establish root cause. Determining if there is appropriate preventative action to ensure similar

Assessment category	Question no.	Question	Current year score	User guidance
Asset strategy and delivery				incidents do not occur in the future is a key part of that process. Chapter 6, of our AMP provides detailed description of our inspection and maintenance programmes.
Documentation, controls, and reviews	45	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	We have an Alliance Agreement with our preferred contractor, NETcon. The Alliance management team meet weekly to discuss performance, operational progress and other relevant issues. The meetings are recorded in meeting minutes. The Alliance has a suite of management and control documents in place. As the Alliance grows in maturity this score will improve.
	59	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	We have completed the mapping of our processes under our BPM project. Copies of all BPMs are available to staff on our intranet. As part of implementing our EAM system OneEnergy, we will review and revise our existing BPMs for continuous improvement. The business case developed for our EAM describes the main elements and requirements of our AMS. We are continuing to develop out ICT systems, where appropriate, to improve and record key processes.

Assessment category	Question no.	Question	Current year score	User guidance
Documentation, controls, and reviews	82	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	We have compiled a compliance register that lists all of our compliance obligations. These are reviewed on a quarterly, six monthly and annual basis as is most appropriate and we report by exception to our board every quarter. The register is used as part of the overarching risk management plan that is linked to our asset management practices. We have yet to fully document our risk and control measures.
	88	How does the organisation establish implement and maintain process(es) for the implementation of its AMP(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	We have document control measures in place for all of our asset drawings. And we have established BPMs for the building of new assets. Currently we hold information in multiple systems, which make it difficult to demonstrate that lifecycle activities are carried out under specific conditions that are consistent with asset management policies and strategies. Installing a new asset management system will greatly assist us to demonstrate that we meet this requirement. We are now reviewing our initial BPMs as part of our implementation of the new EAM.
	95	How does the organisation measure the performance and condition of its assets?	2	Condition assessments are predominately paper based records. There are some gaps in the historical information held. Part of the installation of a new EAM will be data cleansing and ratification. Once complete we would expect an increase in score. We are yet to formalise or determine measures to review our processes.

Assessment category	Question no.	Question	Current year score	User guidance
Documentation, controls, and reviews	105	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1	We are now installing our new EAM. Our EAM has been designed around the review of our previous asset management systems and our present and future requirements. An audit procedure will be developed once the EAM is implemented and all relevant BPM revised.
	113	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Our Risk Management Policy as it relates to the network, focusses on risk levels, what is acceptable or not, and the associated costs. Justification of projects is based on the level of risk reduction to the company. One of the KPIs of the Alliance is to measure and improve productivity. This KPI however required the EAM system to be fully operational at what time this score will further improve.
Systems, integration, and information management	31	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)?	2	Since 2005 we have recruited additional staff to ensure that our work plan can be completed. In 2005 we had one network engineer and eight support staff. In 2012 we had grown to six network engineers and twelve support staff, and in 2016 we employ 11 engineers and 22 support staff. The Board approves unplanned works and notes monthly variances between budgeted and actual expenditure. Our current weakness is that we tend to be more reactive than proactive. We are working to resolve our weaknesses.

Assessment category	Question no.	Question	Current year score	User guidance
Systems, integration, and information management	37	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The roles and responsibilities, selection criteria and review processes for the appointment of members of the Network management team are documented, but have not reviewed against our strategies and objectives. We have developed and recruited more network managers to look after key asset responsibilities. The appointments have been made in line with our AM strategy outlined in Chapter 8 of our AMP.
	62	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	Business cases have been prepared and approved for our EAM system as well as our GIS. These documents broadly detail the system requirements. However, after implementation programs to better configure and utilise more functionality will be developed to better support the AMS and asset strategies.
	63	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Data verification, ratification, and cleansing are done continuously and on an ad hoc case-by-case basis. The implementation of our EAM and new GIS required the verification of all existing data. We are also in the process to develop new processes for data quality in GIS. We will look to improve our score during 2017 as we complete the data migration and cleansing as part of implementing our new systems.
	64	How has the organisation ensured its asset management information system is relevant to its needs?	2	The process of justifying the procurement and evaluation of an EAM system was based on the recommendation, and conducted in association with Deloitte after a review of our ICT systems some years

Assessment category	Question no.	Question	Current year score	User guidance
Systems, integration, and information management				ago. The evaluation process included site visits to our peers who had already implemented systems. During these visits functionality as defined and specified by us were demonstrated by the various distribution businesses. A function of the newly created ICT Manager role is to develop the ICT systems around our AMP requirements based on the process identified by the BPM project. We are establishing a review process.
Communication and participation	27	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	1	We circulate a copy of our AMP to our principle contractor, shareholders, large consumers, and key staff. A copy of our AMP is available, at reception and on our website. We do not, however, meet with large consumers or other smaller contractors; nor do we present all staff with the key components of the AMP. We leave it to stakeholders to read and interpret the AMP themselves.
	3	To what extent has an asset management policy been documented, authorised and communicated?	3	We have implemented an asset management policy as part of the development of our AMF. All network managers have been made aware of this policy.
	42	To what degree does the organisation's top management communicate the importance of meeting its asset management	1	An early draft of the communication strategy is in place.

Assessment category	Question no.	Question	Current year score	User guidance
Communication and participation		requirements?		
	53	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Our AMP is made available to all staff on our website and hard copies are distributed to the asset management and engineering teams. We meet with our contractors once a fortnight to discuss the progression of the works programme. We hold regular shareholder meetings where our asset management programme can be discussed. Our stakeholder engagement for consumers tends to be ad hoc. We will need to improve our communications to better our score.
Structure, capacity, and authority	29	How are designated responsibilities for delivery of asset plan actions documented?	2	Our recent network department restructure is based, in terms of the various teams, on all the asset life cycle stages. New position descriptions were developed for these roles. The majority of which also serves on the Alliance management team, as part of the Alliance agreement. All external contracts for major projects are conducted under a standard form of contract, mainly NZ 3910 and in one instance in the past under the NEC3 form of contract.
	99	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances is clear,	2	Our Emergency Preparedness Plan supports us to respond to emergency situations in an appropriate and timely manner. However, the manual nature of recording events does not allow us to score ourselves higher than a 2 at this time. The new EAM system that supports the centralisation of documentation will greatly

Assessment category	Question no.	Question	Current year score	User guidance
Structure, capacity, and authority		unambiguous, understood and communicated?		assist us in improving our score in the future.
	115	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2	We support and encourage all technical staff, especially engineers to attend the annual EEA conference where new technologies and systems are marketed and displayed. Some vendors also present papers as part of the conference program. The assistance of Deloitte in the evaluation of EAM systems exposed us to all the recognised systems on the market. All staff has internet access and we are regularly informed by staff and the industry of new technologies, product/system developments and training courses.
Competency and training	40	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Our new network department structure and associated position descriptions, our recent procurement and current implementation of EAM, GIS and SCADA systems. Expansion of our ICT team.
	48	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Our new network department structure with line managers and teams focussed on planning, delivery, maintenance and operations, account for the all asset life cycle stages. The team numbers were based on consultation with our peers and in accordance with the current and medium term workload around the dairy industry growth and irrigation schemes.

Assessment category	Question no.	Question	Current year score	User guidance
Competency and training	49	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	<p>For our contractors we hold a comprehensive database for all staff. We identify the training requirements by considering the planned work programme and the competencies that the work to be carried out will require. Enduring competency requirements are linked to our AMPs will be a function of our Alliance Agreement with NETcon.</p> <p>We have bi-annual development reviews where managers and staff are given the opportunity to discuss and plan training and development for the immediate future.</p>
	50	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	<p>Every position on our network department structure has newly created or revised position description. Many of these positions are newly appointed through a rigorous process where skills and experience are matched to the requirements of the various roles. All candidates are presented with the same technical and soft skill questions and are required to provide real examples from their work history to substantiate or demonstrate their skills. An evaluation matrix is filled out where scores are awarded for all competency requirements as required in the position description. An offer is made to the candidate with the highest score, provided the minimum threshold score is met.</p>

Assessment category	Question no.	Question	Current year score	User guidance
Competency and training	79	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	1	We have early drafts for resourcing, competency and training requirements in place and have plans to progress the drafts.

## Appendix A Capex workplan for 2017/18

This section provides details of the material and non-material projects planned for the next 12 months. For the material projects, constraints, options analysis, and preferred solutions are presented. Projects are listed in nominal dollars.

### A.1 Clandeboye zone substation no. 2

#### A.1.1 *Overview*

One of our largest consumers is in the process of expanding their operations. This has required us to increase our supply capacity on their premises. This project is driven by growth and initiated by the consumer. The increase in demand as a result of this development is expected to be between 6 MW and 9 MW when fully commissioned.

#### A.1.2 *Options*

As a result of site constraints and the wider network infrastructure capacity and configuration, we have considered both network and non-network solutions. Due to the magnitude of the supply required we are only considering diesel generation as the only viable non-network solution.

#### A.1.3 *Preferred solution*

In spite of any non-network solution, network infrastructure will have to be established to supply the new development which includes the following:

- Adding two additional 11 kV circuit breakers and associated protection to the existing CD2 zone substation
- Construct a 11 kV underground cable ring supply to the new load centre
- Install ten 11 kV three bay RMUs
- Install eight 1.5 MVA and two 1 MVA distribution transformers

The network infrastructure could be equipped with the ability to connect diesel generators in order to supply some or potentially all the load in the case of a network outage.

### A.2 Bells Pond upgrade

#### A.2.1 *Overview*

Our Bells Pond (BPD) zone substation (and GXP) supplies a dairy factory and a large number of dairy and irrigation farms. Load on this substation has increased rapidly since first commissioned in 2011, going from an initial 6 MW to almost 11 MW in 2016 with an

expected increase of another 3 MW to be taken by a recently commissioned irrigation scheme. Since most of the dairy producers in the area supply the dairy factory in this area, a loss of the substation transformer for an extended period of time can result in extreme consequences, both economically as well as environmentally. The load on the substation at more than 10 MW has also exceeded our N-1 security level. In addition based on projected future load growth, the transformer will be out of capacity by 2019.

### A.2.2 *Options*

We have considered both network and non-network solutions. Due to the magnitude of the load on this substation, and the fact that supply is provided at two different voltage levels namely 11 kV and 33 kV, the only potentially viable non-network solution is diesel generation.

The life cycle cost of diesel generation and the associated logistics coupled with the risk around uncertainty of future load growth especially with respect to the dairy factory, makes a non-network solution very expensive with a significant risk that the capacity would not meet future demand growth.

Network solutions we investigated included the following:

- Installation of a second transformer and 11 kV switchboard
- Preparing the site to connect a spare transformer to be sourced when needed

### A.2.3 *Preferred solution*

Based on our supply security requirements for this magnitude of load and the risk score for an unlikely but extreme consequence event if the transformer should fail, the recommended solution was to install a second transformer and 11 kV switchboard. This solution provides us with the N-1 security for a zone substation with more than 10 MW load connected. The spare transformer option is not viable due to the specific type and configuration of the existing transformer being a three winding transformer with different rating on the individual windings. We considered a possible spare from another distribution company but unfortunately the winding capacities did not mimic those of the existing transformer.

### A.2.4 *Timaru-Pareora OH to UG conversion*

### A.2.5 *Overview*

Our Pareora zone substation is supplied from our Timaru zone substation by two mainly overhead 33 kV circuits. One of these overhead circuits traverses private property through the Timaru residential area. The poles are mainly located along the boundary fences between properties and as a result they are difficult to access for inspections,

maintenance or in case of emergency repairs. It also presents a low probability and potentially severe consequence risk to the general public. We have therefore decided to relocate the sections of overhead line, and since the Timaru District Plan does not allow us to build new overhead infrastructure in the residential area, we are undergrounding these circuits.

#### A.2.6 *Options*

Since we are relocating an existing asset, and due to the security classification of this supply circuit, there are no non-network options available. The network options that are available to us are to re-build the circuit overhead, or to underground it.

#### A.2.7 *Preferred solution*

The preferred solution is to underground the exiting circuit along a route north to south through the Timaru residential area. This solution also provides us with an opportunity to underground additional sections of 11 kV overhead lines by utilising the same cable trench for both circuits. These sections also cross private property and access for inspections and maintenance is very difficult. This has resulted in having to increase this year's budget for undergrounding by advancing the 11 kV undergrounding by one year.

#### A.2.8 *Non-material projects summary*

Table A-1 below lists the non-material projects and programmes planned for the 2017/18 financial year.

**Table A-1 Summary of non-material projects for 2017/18**

Project	Description
Overhead line refurbishment	Various projects to refurbish overhead line feeders when triggered through our inspections regime. These are normally of smaller capital value (< \$200 k) than the material projects.
ABS replacements	Replacement of known ABS which are failing and replacement with load breaks to improve network switching.
Voltage regulator & Capacitor Bank Installations	Due to the loads on our system and the connection of new loads we are experiencing voltage regulation issues which can be addressed by the installation of voltage regulators OR shunt capacitors at various locations. Shunt capacitors does however influence our load control capability since the capacitors absorb the ripple signals which results in failure to operate loads via this means. This problem can be overcome with tuned capacitors.
Distribution Sub refurbishment	Budget to replace LV switchgear in U/G subs and replace leaky and rusted transformers.

Project	Description
Two pole distribution sub refurbish.	Safety & reliability due to inadequate fault ratings, statter switch replacements due to condition, pole and structure condition assessment, seismic strengthening of installation.
Replacement RMUs	Replacing last of Andelect RMUs and old SD oil units.
New RMUs	New RMU to improve system reliability and/or safety as well as network augmentation.
Earthing upgrades	Results from earth testing program shows numbers of sites have high earth resistances. We are systematically upgrading these mainly using deep driven earth rods and multiple earthing banks per installation. This is required to comply with the safety regulations.
Underground cable upgrades and replacements	Replacing of existing cables that are damaged or are not rated for load current. It includes the replacement of Lucy boxes to improve safety and reliability.
Communications upgrade	Establish a new comms site to enable automation of substation equipment at Tekapo and Twizel zone substations. We are also relocating to a new office building in 2017 and have to move all communications from the existing site to the new site with minimal disruption to the business.
Mobile substation and generator connections.	Preparing our zone substations so that we can deploy our mobile substation in order to be able to maintain all of the substation equipment without turning the power off. These connections are also used for connecting our mobile generators to provide supply in case of an emergency or to supply in peak loading scenarios.
Design expenditure	This budget is to enable design effort for large material projects coming up in the next financial year.

## Appendix B Capex workplan for 2018 - 2021

This section summarises the projects planned for the planning period 2018/19 till 2021/22. The projects are summarised in the Table B-1 below. Non-material projects for this period is the same as those listed in Table A-1 except for mobile substation and generator connections, and the project to relocate our communications system to our new building.

**Table B-1 Material projects for 2018 - 2021**

Project	When / Budget	Description
Overhead line replacement and renewal	2018/19 – 2021/22 \$3.5 M per annum	This is an ongoing program triggered through our pole inspection initiative to ensure our existing infrastructure is safe, and supply security and reliability is maintained.
Underground substation upgrades	2018/19 – 2021/22 \$500 k per annum	We have 29 underground substation constructed in the 1970's. These are confined spaces which makes operating and maintenance expensive. We are looking at a number of initiatives to improve safety and reduce costs through replacement of older equipment, relocation of some/all equipment and automation. Solutions will be developed on a case by case basis but since these substations are in the Timaru CBD, solutions could be expensive.
Relocation and upgrading of the Twizel zone substation	2018/19 \$4 M	The land that the substation is occupying does not belong to us and could be developed. The transformer is 44 years old and the 11 kV switchboard is 65 years old. Although the condition of the equipment is fair at worst, it is at the end of its economic and design life.
Tekapo zone substation transformer	2019/20 \$2 M	Based on current forecast load growth, the transformer will be out of capacity by around 2022 by which time the asset will be 50 years old.
Geraldine zone substation transformer upgrade	2020/21 1.5 M	The current load on Geraldine substation is almost 6 MW. The transformer capacity is good for the maximum feeder capacity of 8.6 MW. Barkers Foods are looking to increase their factory load which will most probably be the trigger for increased transformer capacity.

Project	When / Budget	Description
Refurbishment of Unwin Hut zone substation	2020/21 \$800 k	Unwin Hut is now 40 years old. The equipment is still in a fair condition. However it is with Tekapo some of the last oil circuit breakers on the network. We will run this equipment till end of life unless some other event/science/experience or engineering reason dictates otherwise.

## Appendix C Material projects for 2022 - 2027

This section gives an overview of the material projects being considered for the planning period 2022/23 till 2026/2027. The projects are listed in Table C-1.

**Table C-1 Material projects for 2022 - 2017**

Project	When	Description
Overhead line replacement and renewal	2022/23 – 2026/27 \$3.5 M per annum	This is an ongoing program triggered through our pole inspection initiative to ensure our existing infrastructure is safe, and supply security and reliability is maintained.
Tekapo zone substation switchboard replacement	2023/24 \$3.5 M	This project will replace the current oil switchgear which will be at end of life in 2024. If an engineering or safety concern arises with this gear, the project will be done earlier. A new switchboard will require a new switchroom since the current one is not fit for purpose. This project could be affected or accelerated by the dairying and irrigation developments at Simons Pass.
Albury GXP convert to 33 kV	N/A	This project will see the current 110/11 kV GXP converted to a 110/33 kV GXP. The new transformer to be deployed by Transpower in 2017 was specified to be able to be used in this conversion. Load growth will be the initiator for this but due to uncertainty no budget has been included in the
Upgrade Cooneys Road zone substation to 110 kV	N/A	This project will upgrade the existing zone substation from 33/11 kV to 110/11 kV. The trigger for this project will be the demand requirements of the Oceania Dairy factory. The proposed load forecast today is not sufficient to justify this project to be included in the planning period and therefore no budget is proposed.
Seadown zone substation	N/A	This project will see a 33/11 kV zone substation established in the Washdyke industrial area to supply the increasing load in this area and further north. We do not see this happening before the end of the planning period.

## Appendix D Schedule 14a

Company name Alpine Energy Limited  
For Year Ended 31 March 2017

### Schedule 14a Mandatory Explanatory Notes of Forecast Information

*(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015))*

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.8—Accountabilities for asset management.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a).

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts were inflated by approximately 2% per annum, on a straight line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 2% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% per year.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b).

In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

To derive the operational expenditure in nominal terms, the constant price forecasts were inflated by approximately 2% per annum, on a straight line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 2% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% per year. The real expenditure is reducing to reflect the expected efficiency gains per annum that will be found by improvements to our processes and practices. We expect to share realised benefits with consumers by reducing our operating expenditure, in real terms, over the next 10 years. Therefore the difference between nominal and constant operational expenditure forecasts is a reduction of 2% per year.

## Appendix E Standardisation and optimisation

In selecting equipment that helps to meet our objectives of providing a safe, efficient, reliable, and cost effective energy delivery service, we standardise on a large selection of network equipment. Through our designs we also strive to optimise existing assets for continued use and new equipment for a full lifecycle use.

The sections in this appendix detail some of the equipment that we have standardised on.

### E.1 Sub-transmission lines

Table E.1-1 describes key characteristics of equipment chosen for our sub-transmission overhead lines.

**Table E.1-1 Equipment used for sub-transmission lines**

Equipment type	Description
Conductor	Jaguar ACSR, Iodine AAAC, Mink ACSR,
Poles	18.5 m, Hardwood, 12 kN, 17 m 12 kN prestressed concrete, 11 to 17 m, 8 kN and 12 kN Hardwood, 12.2 m 7.35 kN and 12.5 m 8 kN prestressed concrete, 10.7 m mass reinforced concrete,
Insulators	Porcelain insulators – general range of product from NZI catalogue. All new 33 kV lines will be insulated with a superior NZI post type insulator. Strain insulators – generally glass disc ex Chinese manufacture for 11 kV and 33 kV work. Ball and socket ex Sediver for 110 kV. Post insulators – 110 kV NZI catalogue insulators have been adopted for 110 kV.
Protection	Schweitzer Engineering Laboratories equipment

### E.2 Sub-transmission cables

Table E.2-1 describes key characteristics of equipment chosen for our sub-transmission cables.

**Table E.2-1 Equipment used for sub-transmission cables**

Equipment Type	Description
Cables	400 mm <sup>2</sup> Al 1C and 3C, Al XLPE/HD CWS/MDPE, 11 and 33 kV. 300 mm <sup>2</sup> Al 1C and 3C, Al XLPE/HD CWS/MDPE, 11 and 33 kV, 1200 mm <sup>2</sup> Al 1C Al XLPE/HD

Equipment Type	Description
	CWS/MDPE for new sub-transmission 33 kV assets.
Terminations	Heat shrink terminations. EN50181, Type C, outer cone cable couplers
Surge arresters	110 kV, ABB Exlim Station class porcelain 33 kV, ABB Exlim Station class porcelain, Ohio Brass Station and Riser Class ESP. 11 kV, Ohio Brass Station Class ESP, Cooper Evolution 10 kV Silicon.
Protection	Schweitzer Engineering Laboratories equipment

### E.3 Zone substations

Table E.3-1 describes key characteristics of equipment chosen for our zone substations.

**Table E.3-1 Equipment used for distribution lines**

Equipment type	Description
Sites	Sites are selected so that they are either central to the load of the day if expansion is going to be uniform throughout the existing area or toward the edge of an industrial area should expansion plans be identified for that area. Land purchase negotiations may alter the best site selection; options are required.
Buildings, yards, and structures	Modern design is undertaken so that: <ul style="list-style-type: none"> <li>• buildings fit the local architecture</li> <li>• yards have equipment fitted on a low profile basis where possible</li> </ul> Suitable landscaping is established to fit the local community.
Transformers	Zone substation transformers are either purchased new or transferred from another site/stock. New transformers are tendered, with tenders invited from three or four different manufacturers with local NZ representation and after sale service.
Switchgear	110 kV, Areva GL312 33 kV, Areva GL107X adopted for sites at and above 4 kA fault level 110 and 33 kV instrument transformers generally from Artech's catalogue 33 kV, Cooper NOVA for sites below 4 kA fault level 11 kV, RPS LMVP range of product for zone substations 11 kV, Cooper NOVA for sites below 6 kA fault level 33 and 11 kV NCT from Transformer Winding Services. 33 kV, Schneider Electric GHA
Protection	Schweitzer Engineering Laboratories equipment

### E.4 Distribution cables

Table E.4-1 describes key characteristics of equipment chosen for distribution cables.

**Table E.4-1 Equipment used for distribution cables**

Equipment type	Description
Cable	<p>Selection of cable is based on two criteria:</p> <ul style="list-style-type: none"> <li>• required power flow</li> <li>• fault level presented with applied protection considered</li> </ul> <p>Cable types include:</p> <ul style="list-style-type: none"> <li>• 400 mm<sup>2</sup> Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV,</li> <li>• 300 mm<sup>2</sup> Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV, 185 mm<sup>2</sup> Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV,</li> <li>• 95 mm<sup>2</sup> Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV,</li> <li>• 35 mm<sup>2</sup> Cu 1C, XLPE/HD CWS/MDPE, 11 kV,</li> <li>• 35 mm<sup>2</sup> Al 3C, XLPE/HD CWS/MDPE, 11 kV,</li> </ul>
Terminations	Heat shrink terminations.
Surge arresters	11 kV, Ohio Brass Station Class ESP, Cooper Evolution 10 kV Silicon.

## E.5 Distribution substations—pole mounted

Table E.5-1 describes key characteristics of equipment chosen for our pole mounted distribution substations.

**Table E.5-1 Equipment for pole mounted distribution substations**

Equipment type	Description
Poles	<p>10 to 15 m, Hardwood 8 and 12 kN.</p> <p>10 to 15 m, Softwood 8 and 12 kN.</p> <p>9.5 and 11 m, pre stressed concrete, ex Busck.</p>
Transformer	We seek supply of transformers, up to 2 MVA from NZ manufacturers.
HV switchgear	'drop out' or 'cut out' style fuses on a single phase basis for pole mounted transformers. Both fuse styles are suitable up to 12.5 kA fault levels. If the fault level is above 12.5 kA ring main units are used.
LV fusegear	HRC fuses in a range of holders. If a three phase service is taken then a ganged holder is used.

## E.6 Distribution substations—ground and underground mounted

Table E.6-1 describes key characteristics of equipment chosen for the selection of sites.

**Table E.6-1 Site selection decisions**

Equipment type	Description
LV fusegear	<p>Sites are selected so that they are:</p> <ul style="list-style-type: none"> <li>• as safe as possible from public and traffic thoroughfare</li> </ul>

Equipment type	Description
	<ul style="list-style-type: none"> <li>removed from walls and outside of buildings to reduce fire hazards where possible</li> <li>central to the load toward the edge of an industrial area should expansion plans be identified for that area</li> <li>ideally within 200 m of significant loads</li> <li>preferred to be on council road reserve rather than private residential land with easement</li> </ul> <p>For industrial sites the preference is to have the transformer as close as possible to the sites 415 V MCC, 11 kV switchgear may be remote. It is essential that the 11 kV switchgear is accessible, so there is a preference for berm mounting.</p>
Enclosure	City pad, mini pad and micro pad style transformers.
Transformer	Transformers from NZ manufacturers.
RMU switchgear	<ul style="list-style-type: none"> <li>SF<sub>6</sub> filled ring main units (RMU). for transformers requiring an HRC fuse of 40 A or less an ABB Safelink is selected, or</li> <li>for transformers 500 kVA and above Schneider RN2c Ringmaster is selected if the HV fuse in an ABB RMU cannot be graded with upstream protection.</li> </ul>
LV switchgear	<p>At industrial sites, the LV switchgear is the responsibility of the customer. Our distribution substations have a 400 V fuse-link board made up of:</p> <ul style="list-style-type: none"> <li>DIN 1 vertical disconnect with solid links, 800 A rated up to 500 kVA, 1600 A for 750 and 1000 kVA.</li> <li>DIN 3 vertical disconnect units, 630 A rated with fuse elements to suit.</li> <li>Smaller DIN00 vertical disconnect unit to allow light wire connections for street light controls and maximum demand recording equipment</li> </ul>
Auxiliary equipment	Ground mounted transformers are fitted with a smart meter.

## E.7 Low voltage reticulation

For more information on LV reticulation, please refer to Section 3.3.9—LV reticulation lines, cables, link, and distribution boxes. Table E.7-1 describes key characteristics of equipment chosen for LV reticulation.

**Table E.7-1 Equipment used for LV reticulation**

Equipment type	Description
Cables	Selection of cable is based on required power flow and length of run to avoid excessive volt drop. Neutral screen cables are used. General sizes are: <ul style="list-style-type: none"><li>• 300 mm<sup>2</sup> Al, 476 A direct buried</li><li>• 185 mm<sup>2</sup> Al, 364 A direct buried</li><li>• 95 mm<sup>2</sup> Al, 251 A direct buried</li></ul>
Link boxes	Link boxes are installed in meshed reticulation so that two substations can be easily connected when the supply from of one substation is not available.
Distribution boxes	Non-metallic boxes are used with HRC fuse holders. Larger consumers may have smaller horizontal fuse disconnects installed.

## Appendix F Schedule 12c(ii) System Demand

Maximum coincident system demand (MW)	Current	CY+1	CY+2	CY+3	CY+4	CY+5
	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
GXP Demand	137	140	143	146	149	152
Distributed generation output at HV	7	7	7	7	7	7
Maximum coincident system demand	144	147	150	152	155	158
Net transfers to (from) other EDBs at HV	-	-	-	-	-	-
Demand on system for supply to consumers' connection points	144	147	150	152	155	158
<b>Electricity volumes supplied (GWh)</b>						
Electricity supplied from GXPs	836	853	871	889	906	924
Electricity exports to GXPs	6	6	6	6	6	6
Electricity supplied from distributed generation	13	13	14	14	14	14
Nett electricity supplied to (from) other EDBs	-	-	-	-	-	-
Electricity entering system for supply to ICPs	843	861	879	897	914	932
Total energy delivered to ICPs	828	845	863	880	898	916
Losses	15	16	16	16	16	17
Load factor	67%	67%	67%	67%	67%	67%
Loss ratio	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%

## Appendix G GXP and major assets

### G.1 General

This Appendix contains information on our network assets at the grid exit point (GXP), zone substation, and sub-transmission level, as well as possible developments at the strategic level.

This Appendix is divided into sections based on Transpower’s GXPs.

#### G.1.1 The grid

Figure G.1-1 represents the grid’s present (2016) state.

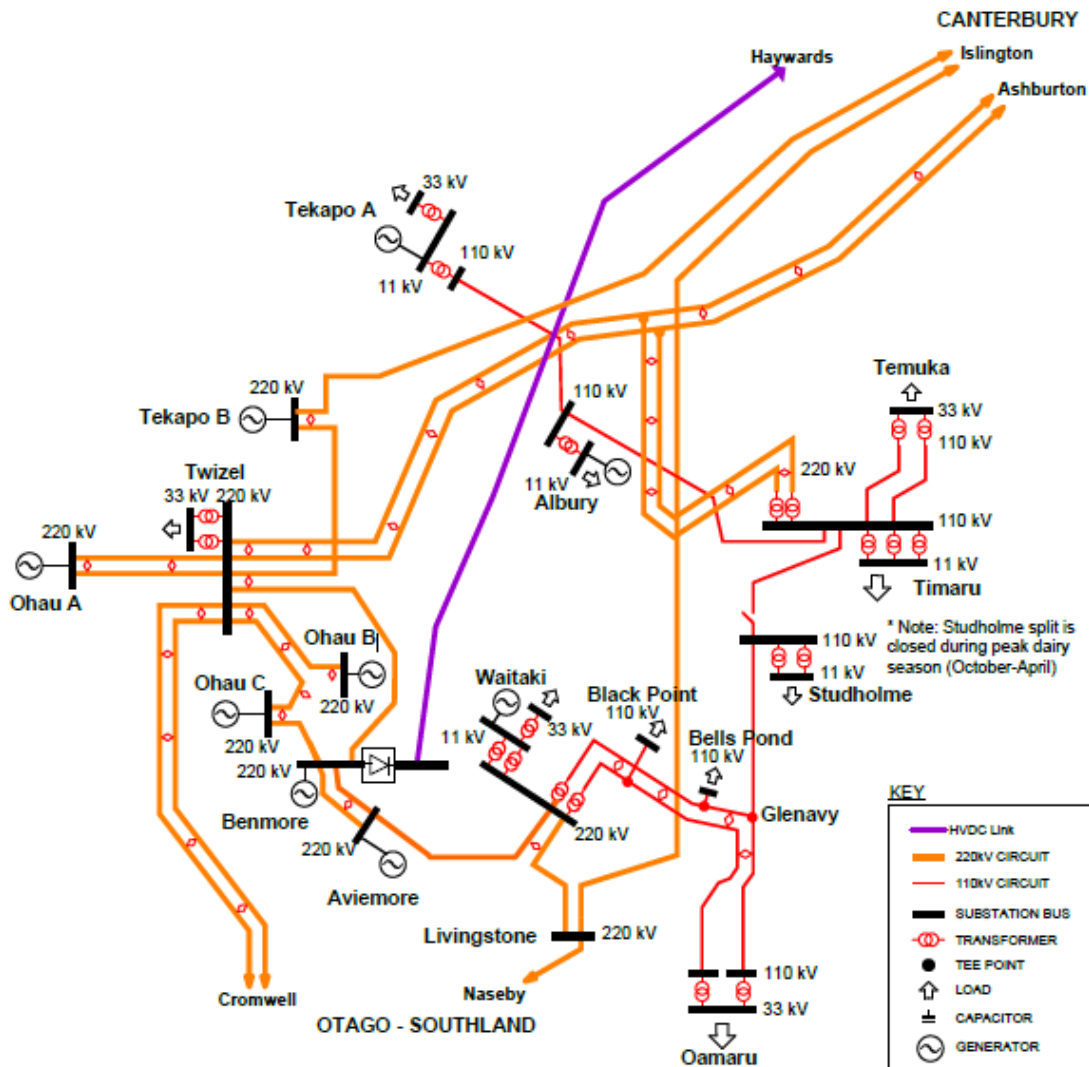


Figure G.1-1 Schematic diagram of the grid

Negotiations are underway with Transpower to make alterations to the grid to allow increased demand from irrigators and food processors.

### G.1.2 Security of supply levels

Industry classifications for security of supply level are described in Table G.1-1 and are typically N, N-0.5, or N-1.

**Table G.1-1 Security of supply classifications**

Security level	Description
N	The security level at which any outage will cause load to be lost and is often found where there is only one supply circuit or transformer that provides supply. This means the lost load will be restored in the time it takes to repair the fault.
N-0.5	The security level at which an outage will result in some load to being able to be restored after ties have been made to other substations. This means the lost load will be partially restored (in this example 50%) after switching (reconfiguration of the network) and the remainder of the lost load will be restored in repair time.
N-1	The security level that ensures supply after a single contingency event. This means no load will be lost due to a single failure.

### G.1.3 Substation list

Table G.1-2 list the existing seven Transpower GXP's and the associated zone substations in our network area. The first column details the section in this Appendix where the GXP and zone substations are discussed. We have also included the three letter code for reference purposes.

**Table G.1-2 Substation reference table**

Section	Transpower GXP	Zone substation	Code
G.2	Albury (11 kV)		ABY
G.2.4		Albury (11/33 kV Step-up) (33 kV)	ABY
G.2.4		Fairlie (33/11 kV)	FLE
G.3	Bell's Pond (110 kV)		BPD
G.3.3		Bell's Pond (110/33/11 kV)	BPD
G.3.4		Cooneys Road (33/11 kV)	CNR
G.4	Studholme (11 kV)		STU
G.4.5		Studholme (switching station) (11 kV)	STU
G.5	Tekapo A (33 kV)		TKA
G.5.5		Tekapo Village (33/11 kV)	TEK
G.5.5		Balmoral (11/22 kV)	BML

Section	Transpower GXP	Zone substation	Code
G.5.5		Haldon Lilybank (11/22 kV)	HLB
G.5.5		Unwin Hut (33/11 kV)	UHT
G.6	Temuka (33 kV)		TMK
G.6.5		Temuka (33/11 kV)	TMK
G.6.5		Clandeboye No.1 (33/11 kV)	CD1
G.6.5		Clandeboye No.2 (33/11 kV)	CD2
G.6.5		Geraldine Downs (33/11 kV)	GLD
G.6.5		Rangitata (33/11 kV)	RGA
G.7	Timaru (11 kV)		TIM
G.7.6		Grasmere St (switching station—11 kV)	GRM
G.7.6		Hunt St (switching station—11 kV)	HNT
G.7.6		North St (switching station—11 kV)	NST
G.7.6		Timaru (Grant's Hill) (11/33 kV Step-up) (33 kV)	TIM
G.7.6		Pareora (33/11 kV)	PAR
G.7.6		Pleasant Point (33/11 kV)	PLP
G.8	Twizel (33 kV)		TWZ
G.8.4		Twizel Village (33/11 kV)	TVS

## G.2 Albury GXP

### G.2.1 Introduction

Figure G.2-1 shows the position of Albury (ABY) GXP on the Timaru (TIM) to Tekapo (TKA) 110 kV transmission line.

ABY is fed off the TIM–TKA 110 kV line and has a single 110/11 kV transformer connected via one incomer to an 11 kV switchboard. There are three feeder circuit breakers (CBs). The GXP transformer is run on fixed tap due to a failed tap changer, which leads to some 11 kV voltage fluctuation as the 110 kV supply alters with load variation. Transpower is replacing the transformer in the second quarter of 2017. After the new transformer is installed, we will request that the transformer’s load tap changing function be restored, except when there is a reversal of power, i.e. while Opuha Power Station<sup>61</sup> (OPU) is generating.

The transformer is suitably rated for today’s load but is underrated to pass the embedded generation from OPU back onto the grid. Opuha Water has been requested occasionally to reduce their generation a small amount if there is less than 1 MW of Fairlie zone substation (FLE) load to offset the full generation. The new transformer’s rating is based on the smallest economic size for purchase being 20 MVA for a 110 kV primary rating. This will provide ample capacity for the planning period and beyond. The new transformer will also have the secondary connection arranged so it can be reconnected for use at 33 kV in the future.

A significant increase in demand in the Totara Valley area will be difficult to supply from the Pleasant Point (PLP) zone substation. A network option would be to build a new zone substation in Totara Valley area which would be supplied from ABY. This would require a ABY GXP supply change from 110/11 kV to 110/33 kV. Alternatives to this would be to investigate non-network options such as PV, battery storage and diesel generation.

Transpower has invested in a mobile sub with a 110 kV primary connection and one of 11, 22, or 33 kV secondary connections. TKA and ABY have been equipped and fitted with the mobile substation connection points to allow maintenance at each zone substation.

---

<sup>61</sup> Opuha Water Limited is situated at the confluence of the North and South Opuha Rivers 17 kms north-east of Fairlie, is a reasonably recent infrastructure project undertaken by the community of South Canterbury. The actual project itself consists of a 50 metre high earth dam, with a single hydro turbine and a lake covering up to 710 hectares and storing over 74 million cubic metres of water. The lake provides water to maintain environmental flows in the downstream catchment and for irrigation as well as urban and industrial supplies. Renewable hydroelectricity is generated with all the water released from the dam. More information about Opuha can be found on its website at <http://opuhawater.co.nz>.

**G.2.2** *GXP data*

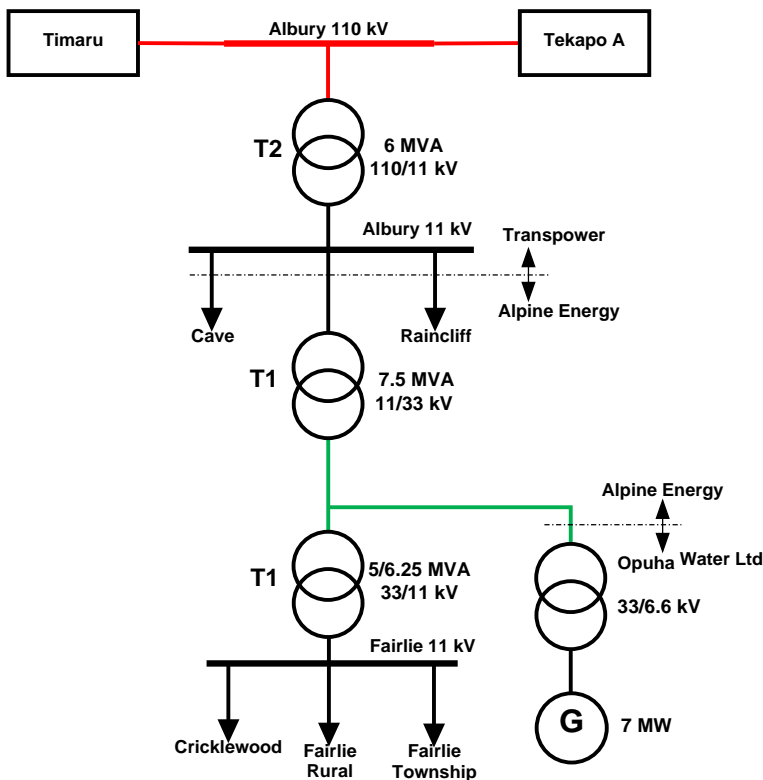
The GXP data shown in Table G.2-1 summarises the key physical attributes of the substation, the voltages, capacity security, and power flow.

**Table G.2-1** Albury GXP data

GXP	GXP transmission potential	GXP point of supply potential	Capacity	N-1 capacity	Demand to March 2016	OPU contribution
ABY	110 kV	11 kV	5/6 MW	0 MVA	4.64 MVA	7 MW less load

**G.2.3** *Albury GXP network information*

Figure G.2-1 shows the schematic diagram of the ABY GXP area. Transpower delivers 11 kV to our network at the ABY zone substation. Circuit breakers supply the ABY zone substation, Fairlie township and the Fairlie rural feeders respectively. From FLE zone substation a 33 kV sub-transmission overhead circuit connects the Opuha power station to our network.



**Figure G.2-1** Albury-Fairlie area schematic diagram

### G.2.4 Zone substation detail

The zone substation and sub-transmission equipment is shown in Table G.2-2. It details the major assets with respect to rating, age, and general condition, the maximum demand at the various substations, and the substation's communication systems and SCADA functions.

**Table G.2-2 Albury zone substation equipment information**

Zone substation site	Transformer		Switchgear		Ripple plant
<b>ABY</b>	7.5 MVA 33/11 kV T1 OLTC (1997) Condition: Excellent		1x 33 kV Recloser WVE (1994) Condition: Fair		Plessey/MetVic 605/510 Hz Rotary plant
<b>ABY AMS ready</b>	Yes				
<b>FLE</b>	5/6.25 MVA 33/11 kV T1 OLTC (1972) (Refurbished ex PAR) Condition: Good		1x 33 kV Recloser (1997) 4 x 11 kV RMU (2014) Excellent		
<b>FLE AMS ready</b>	Yes				
Sub-transmission	Make up	Voltage constraint Limit (MVA)	Limit of conductor at 50°C (MVA)	Limit of cable (MVA)	Lowest limit (MVA)
<b>ABY–FLE</b>	Dog	7.1	12.6		7.1
<b>FLE–OPU</b>	Jaguar/Cable 1/300	7.6	23.4	21.3	7.6
Comms	VHF	UHF analogue		UHF digital	Fibre optic
<b>ABY</b>	VHF for voice traffic			ABY–BRC BRC–MEC MEC–WDK	None
<b>FLE</b>	VHF for voice traffic Cellular for SCADA	None		None	
SCADA	Supervision	Control		Automation	Data acquisition
<b>ABY</b>	Current, voltage and CB status at ABY. Security at ABY.	ABY CB control, ripple plant load control.		Auto reclosing CB	Load data at ABY
<b>FLE</b>	Current, voltage and CB status at FLE. Security at FLE	FLE transformer and CB control		Auto reclosing CB, transformer automation	Load data at FLE

Table G.2-3 lists the existing level of security of supply at the zone substations and justification of shortfall.

**Table G.2-3 Albury and Fairlie security of supply levels**

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
<b>ABY Rural</b>	N-0.5	N	Limited fault back up from adjacent feeders from FLE, PLP and TMK.  Encourages consumers to self-manage their risk mitigation for outages for example, during a civil defence emergency.
<b>FLE</b>	N	N	Limited fault backup. Possibility of some supply from ABY and GLD or islanding FLE onto AMG (limited capacity) or OPU. OPU requires negotiation with generation management, careful islanding, does not have black start <sup>62</sup> capabilities, and does have speed control due to the flywheel of the generator being too small.  Encourages consumers to self-manage their risk mitigation for outages for example, during a civil defence emergency.

The estimated demand listed in Table G.2-4 shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table G.2-5.

**Table G.2-4 Albury and Fairlie zone substation demand**

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
<b>ABY 11 kV board</b>	4.664 (summer)	1.42% historical on ABY—irrigation and dairying activity, residential load, small subdivision development.	5.5 (summer)  8.8 (with Totara Valley)	Transpower asset under its management. Overall load not expected to breach Transpower's capacity unless the Totara Valley zone substation is built. New transformer project underway.
<b>FLE</b>	2.7 (winter)	1.42% historic on ABY—residential load, small subdivision development.	3.2 (winter / shoulder)	The recently installed refurbished transformer caters for the planning period.

<sup>62</sup> A black start is the process to restore a power station or a part of an electric grid to operation without relying on the external transmission network.

### **G.2.5** *Albury–Fairlie sub-transmission*

The ABY–FLE 33 kV line has undergone major refurbishment and maintenance in 2013. The next planned inspection of this feeder will be in seven years' time.

### **G.2.6** *Fairlie zone substation*

FLE zone substation supplies the Fairlie CBD as well as the rural surrounds. A new arrangement of four RMUs, one for the incomer and three for feeders has been installed. The feeder RMUs are fitted with auto-reclose to be turned on at the controller's discretion.

Back up for the FLE load is available using the AMG or OPU if a controlled islanding could be made. OPU does not black start so alternate supply from OPU cannot be relied on. The generation rough runs at part load so its use as back up to FLE is limited.

Limited back up of FLE can be made from the 11 kV distribution from ABY and GLD. This may be sufficient at low load times to supply the CBD alone. The AMG can be coupled to a weak infeed to boost capacity. The arrangement may not always meet the full demand put on FLE by the consumers.

### **G.2.7** *Opuha Power Station*

Opuha Power Station (OPU) is an asset owned Opuha Water Limited and operated by Trustpower. The maximum generating capacity is 7 MW.

### **G.2.8** *Development of Albury GXP and substations*

The calculated load growth at the ABY GXP is 1.42% as depicted in Figure G.2-2. This is mainly due to growth in the farming and tourism sectors. A new source of load (e.g. irrigation) would be required to see a step change in load growth.

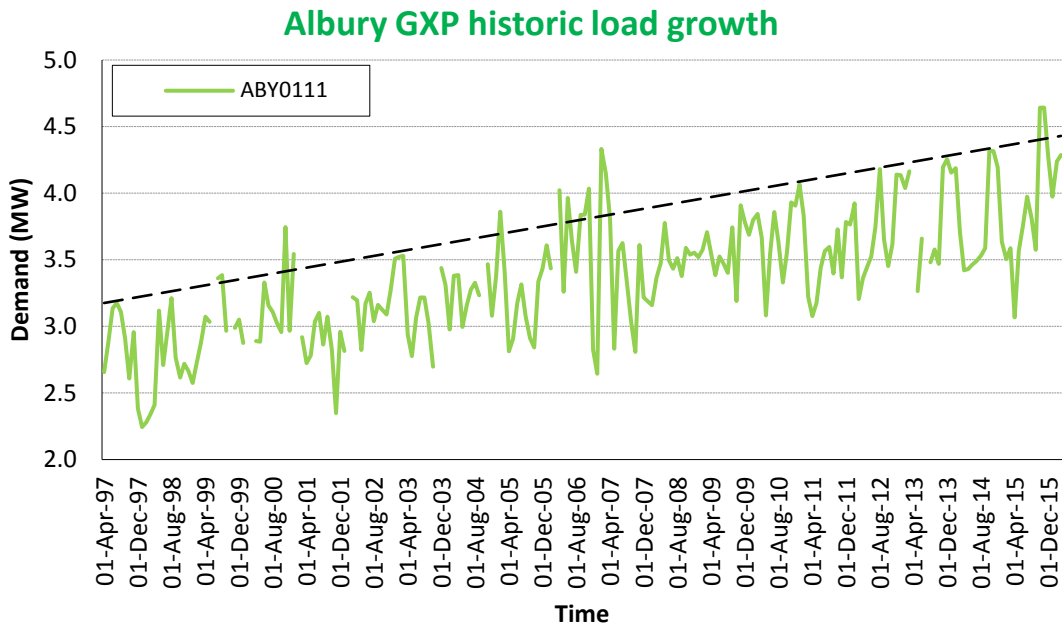


Figure G.2-2 Albury GXP historic load growth

Table G.2-5 shows the growth trend to the year 2026. The trend supports a new zone substation to be built at Totara Valley in 2020.

Table G.2-5 Albury zone substation load growth

GXP substation (season peak)	Growth trend (Total MW MD)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ABY (summer)	4.7	4.8	4.9	4.9	8.0	8.1	8.3	8.4	8.5	8.7	8.8

Figure G.2-3 depicts the security of supply level and the maximum demand at ABY.

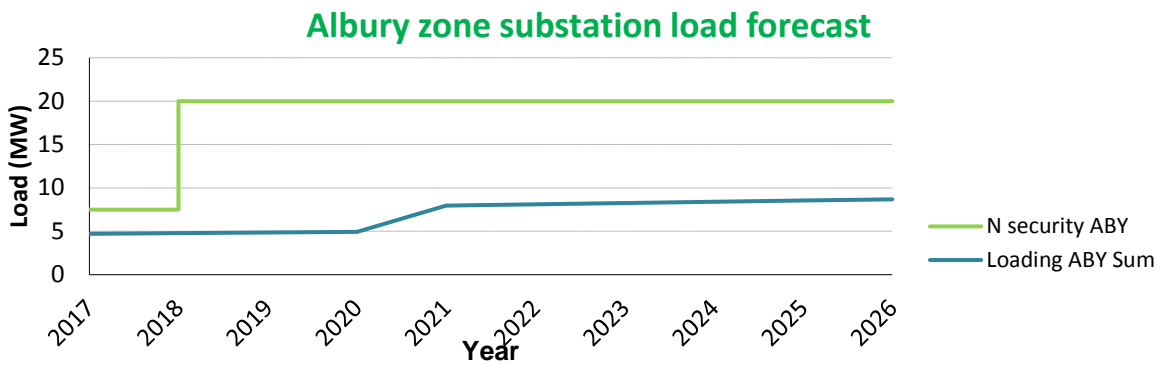
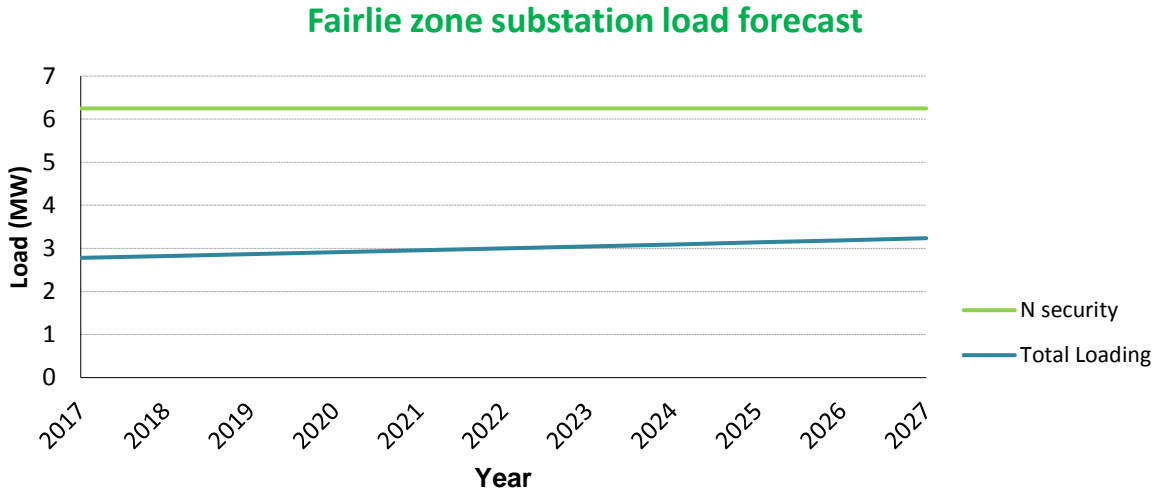


Figure G.2-3 Albury load forecast and supply security

**G.2.9** *Substation load forecast and supply security*

The load in the area continues to grow in response to the increase in farming and irrigation activities as depicted in Figure G.2-4 on the next page. Transpower is upgrading its transformer at ABY ensuring sufficient capacity for the loads forecasted for the planning period.



**Figure G.2-4** Fairlie load forecast and supply security

**G.2.10** *Rate and nature of GXP growth and provisions made*

Table G.2-6 summarises the characteristic of growth and the plans to meet the developers’ energy requirements.

**Table G.2-6** Albury/Fairlie area growth and response

GXP	Rate and nature of growth	Provisions for growth
ABY	Med—Rural	GXP investment only if load in the Totara Valley area increases significantly

**G.2.11** *Possible future developments*

**Totara Valley load increase**

Load flows indicate that the 33 kV PLP–TIM sub-transmission is capable of supplying a moderate increase in load off the PLP zone substation. At present, one of the PLP zone substation 11 kV feeders supplies Totara while ABY feeds down to Cave. The majority of the load in this area is presently on the PLP substation. The transformer at PLP has an upper rating of 6.25 MVA with a present peak load of about 4.7 MVA.

The option to install a second transformer at PLP to supply the load would also require alterations to the feeder to mitigate against volt drop due to the length of the feeder.

A second option is to partially offload PLP with the possible establishment of a zone substation at Totara Valley fed off the 33 kV ABY–FLE sub-transmission circuit. A zone substation will have to be established in the Totara Valley area.

A third option is establishing a zone substation at the Cave regulator site. This, like PLP, is distant from 33 kV source and the load, therefore voltage drop issues in the sub-transmission and 11 kV feeders would also need to be addressed.

Transpower's ABY transformer is rated 6 MVA but Transpower is upgrading its transformer at ABY to a 20 MVA in mid 2017.

A project to replace the existing 33 kV recloser and neutral earthing transformer (NET), and upgrade the protection at ABY will be completed in the first quarter of 2017.

#### Ripple injection plant

The ABY ripple plant's local service supply will be replaced with a new circuit breaker and a new local service transformer located outside the ripple plant building in 2017. The ripple injection plant is presently a rotating plant that will also be replaced by a static convertor as part of the same project.

## G.3 BELL'S POND GRID EXIT POINT

### G.3.1 Introduction

Figure G.3-1 shows the position of Bell's Pond (BPD) GXP on the 110 kV circuit from Waitaki to Studholme and Oamaru. BPD was established and commissioned in August 2010 off loading just over 6 MW from STU. BPD is a single tee off the STU–OAM–WTK2 110 kV circuit. The GXP is essentially a 110 kV metering point that was made available to us so that a 110/33/11 kV zone substation could be connected.

### G.3.2 GXP data

The GXP data shown in Table G.3-1 below summarises the key physical attributes of the substation, the voltages, capacity, security, and power flow.

**Table G.3-1 Bell's Pond GXP system data**

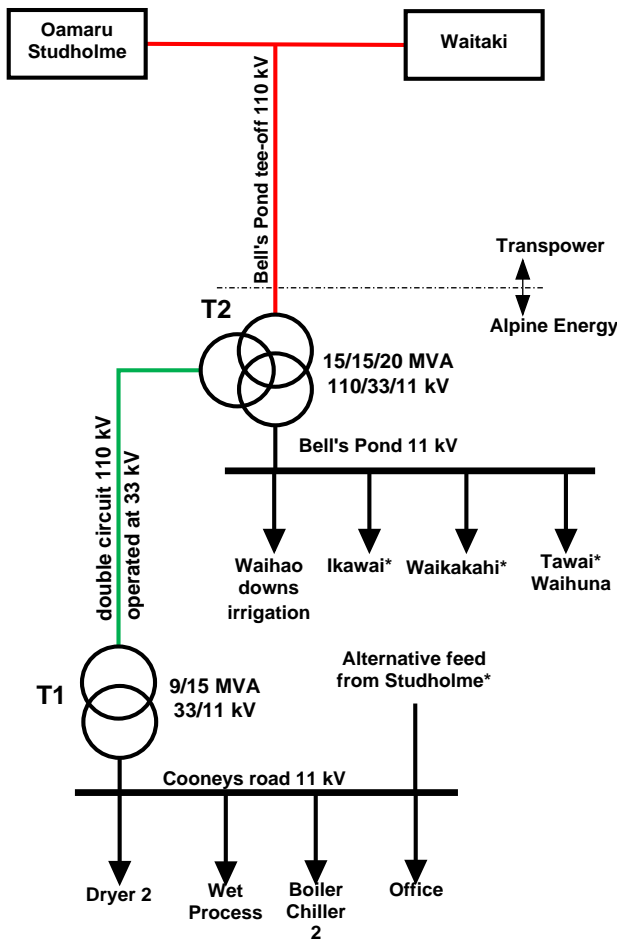
GXP	GXP transmission potential	GXP point of supply potential	Capacity	N-1 capacity <sup>63</sup>	Demand March 2016
BPD	110 kV	110 kV	20 MVA	0 MVA	10.8 MW

### G.3.3 Bell's Pond GXP network information

Figure G.3-1 shows the key assets in the area of the BPD GXP. Transpower delivers 110 kV to our network at BPD substation.

From the BPD 110/33/11 kV transformer's 33 kV winding, a sub-transmission line (constructed at 110 kV) supplies a zone substation at Cooneys Road (CNR). The line and substation were commissioned in April 2014 and supply Oceania Dairy Limited (ODL). The 11 kV winding at BPD supplies the local rural feeders.

<sup>63</sup> Some 5 MW can be supplied from STU but requires manual switching on the network.



\* Marked feeders interconnect with three STU feeders for back up supply

Figure G.3-1 Bells Pond area schematic diagram

G.3.4 Zone substation detail

The zone substation and sub-transmission key data for both BPD and CNR Road shown in Table G.3-2 and details the major assets with respect to rating, age, and general condition, the maximum demands at the various substations are provided, and the substation’s communication systems back to Meadows Rd and the SCADA functions.

Chorus provides telephone and fax services via a copper connection. BPD has an SEL 2032 for most IED connections and an Abbey RTU to control the ripple plant. CNR has dual SEL 3035 for most IED connections.

Table G.3-2 Bell's Pond zone substation equipment information

Zone substation site	Transformer	Switchgear	Ripple plant	
BPD	20/15/15 MVA 110/33/11 kV T2 OLTC (2010) Excellent	1x 110 kV GL312 Areva (2010) Excellent 1x 110 kV GL312 Areva (2014) Excellent 5x 11 kV RPS (2010) Excellent	Abbey Systems RTU Landis and Gyr Ripple plant (2010 cell/2011 processor) Excellent	
CNR	9/15 MVA 33/11 kV T1 OLTC (2014) Excellent	1 x 110 kV GL312 CB (SF <sub>6</sub> ) (2013) Excellent 8 x 11 kV RPS (2014) Excellent	None	
CNR AMS ready	Yes, while supplied at 33 kV			
Area of network with constraint	Capacity constraint	Description	Intended remedy	
BPD GXP	Lack of capacity for Waimate area	Lack of capacity for STU, BPD GXP's	Work with Transpower to ensure capacity is made available	
Sub-transmission	Make up	Limit of conductor at 75°C (MVA)	Lowest limit	Notes
BPD–CNR	110 kV double cct bonded, Jaguar, run at 33 kV	36 MVA per circuit at 33 kV 120 MVA per circuit at 110 kV	36 MVA (in current configuration)	2013 build Maintenance priority 10
Communications	VHF	UHF analogue	UHF digital	Fibre optic
BPD	VHF for voice traffic	None	BPD–MEC MEC–CHC CHC–NST or WDK	None
CNR	Voice	None	CNR–MEC MEC–CHC CHC–NST or WDK	None
SCADA	Supervision	Control	Automation	Data acquisition
BPD	Current, voltage, power and, CB status at BPD	BPD area CB, transformer, and ripple plant control	CB and transformer control	Load data and power quality at BPD

<b>CNR</b>	Current, voltage, power and CB status at CNR. Security monitor	CNR area CB and transformer control	CB and transformer control	Load data and power quality at CNR
------------	--	-------------------------------------	----------------------------	------------------------------------

Table G.3-3 lists the existing level of security at the substation and the justification of shortfall.

**Table G.3-3 Bell's Pond and Cooneys Road security of supply levels**

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
<b>BPD Rural</b>	N-0.5	N	Back up supply from STU. STU can presently take the majority of the 11 kV load if both STU transformers are in service (the spare STU capacity will be eroded should Fonterra build a dryer at STU). Some irrigation and ODL would have to be disconnected to put BPD on STU. Encourages consumers to be self-sufficient for their essentials, as for CD emergencies. Second transformer planned for 2017.
<b>Dairy processing ODL</b>	N-0.5	N	Supply is not presently N-1, as agreed by ODL. 0.5 MW <sup>64</sup> of back up supply from STU is available. Further investment will be needed if and when ODL want to increase supply security to N-1.

The estimated demand listed in Table G.3-4 shows the aggregated effect of substation demand growth for a 10 year planning period incorporating the anticipated step changes detailed in Table G.3-5.

**Table G.3-4 Bell's Pond and Cooneys Road zone substation demand**

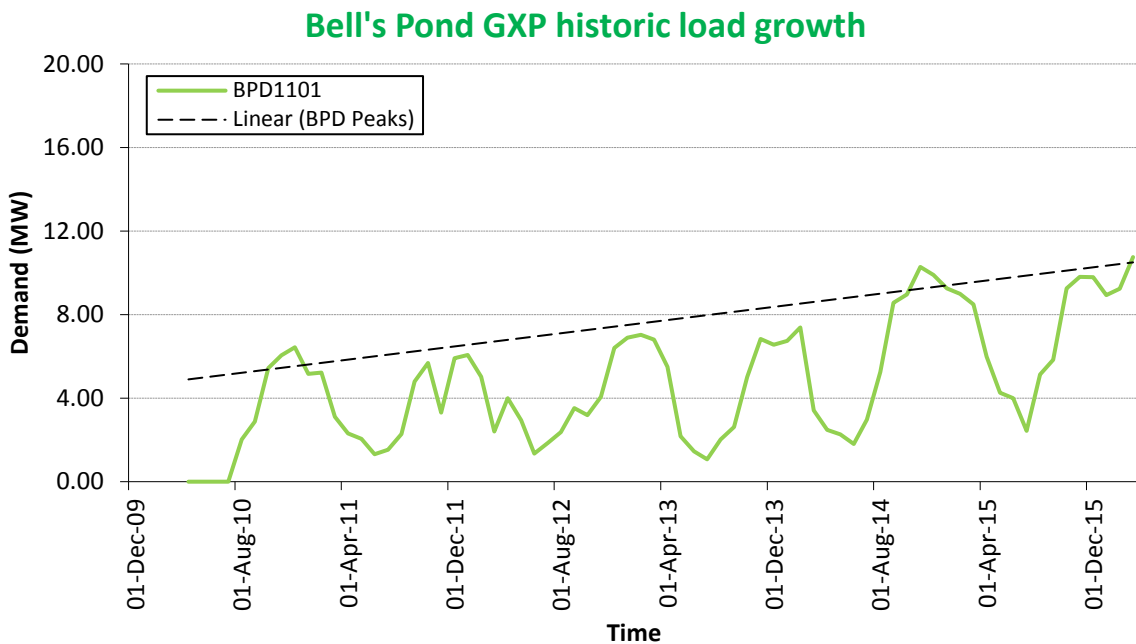
Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
<b>BPD</b>	12.7 (summer)	8.4% per year expected Residential load. Dairy and irrigation development.	BPD 17.8 CNR 15.6 (summer) Sum 33.4	Increase substation assets to offload STU and provide more security and capacity. Work needed to carry load, which depends on mooted projects progressing.

<sup>64</sup> Summer season

CNR	5.1 (summer/ winter)	Dairy processing	15.6 (summer/wint er)	Assumption is to prepare site for two dryers/lactose and UHF products off BPD 33 kV initially with later extensions for two dryers forcing the primary potential for the site to 110 kV. We have included for four 3.5 MW dryers and other sundry loads in planning.
-----	----------------------------	------------------	-----------------------------	--

**G.3.5** *Development of GXP and substations*

Figure G.3-2 shows the historic load growth for BPD.



**Figure G.3-2** Load growth Bell’s Pond GXP

A second transformer will be required for the site to increase the N transformer capacity to keep up with the load growth. A project to install a second transformer started in 2016 and will be completed towards the end of 2017.

The ODL dryer 1 has been commissioned with a load 2.6 MVA. An UHT (Ultra-high temperature treatment) and canning plant are being constructed and will be commissioned in the latter half of 2017. As the factory grows beyond what BPD can supply at 33 kV, a permanent 110 kV supply will be required.

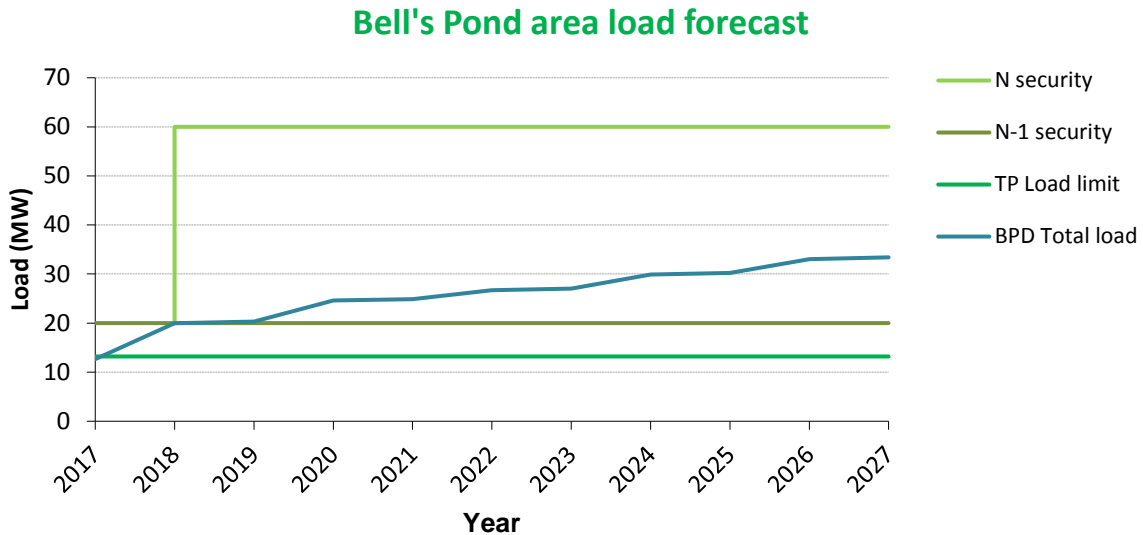
In mid-2014 there was a new connection request for 3.2 MW for stage 1 of the Waihao Downs irrigation scheme. This was commissioned in March 2016. The expected total load at completion of stage 2 could be 6 to 7 MW. The load will be supplied at 11 kV from BPD.

Table G.3-5 shows the forecast load growth to the year 2027.

**Table G.3-5 Substation load forecast**

GXP substation (season peak)	Growth trend (Total MW MD)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
BPD (summer)	12.7	20.0	20.3	24.6	24.9	26.7	27.0	29.9	30.2	33.1	33.4

Figure G.3-3 shows the maximum load forecast in the BPD GXP area.



**Figure G.3-3 Bell's Pond load forecast**

**G.3.6 Substation growth trend and supply security**

Load continues to grow in response to the farming and irrigation activities in the area.

ODL initially adds 2.6 MW to BPD's load, rising in the future to approximately 10 MW. The Waihao Downs irrigation scheme currently takes up to 3.2 MW when all the pumps are running. A future stage 2 to this scheme could add another 3 MW to BPD. We do not expect to see this development before 2018.

Security is presently reliant on 11 kV feeders from STU substation with a capacity of approximately 2 MW in the winter. The capacity decreases to 0.5 MW in the summer as this is when other users also load the lines; primarily irrigation load.

**G.3.7** *Rate and nature of GXP growth and provisions made*

Table G.3-6 summarises the characteristic of growth and summarises the plans to meet the energy requirements.

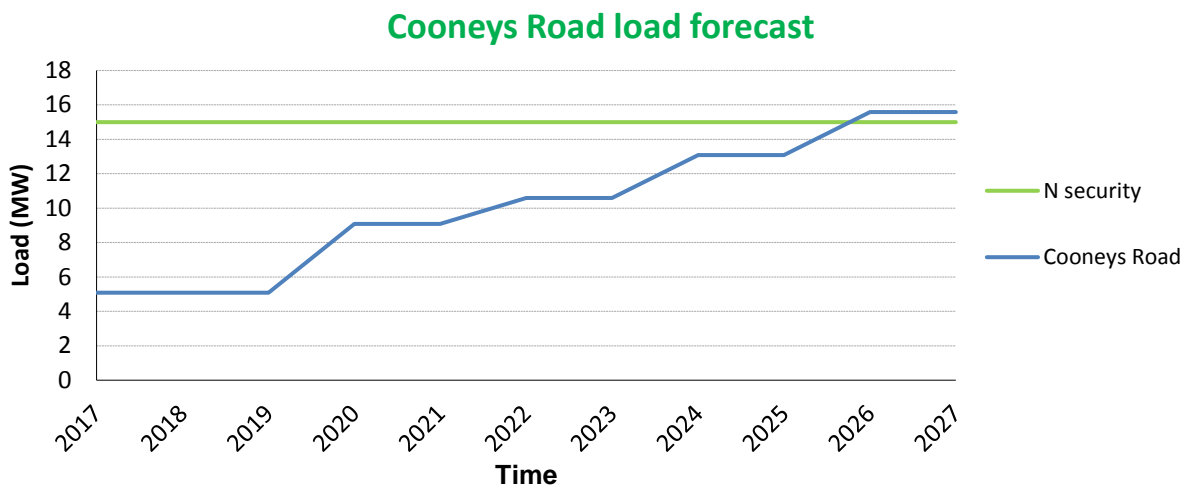
**Table G.3-6** Load growth characteristics

GXP	Rate and nature of growth	Provisions for growth
BPD	High—Rural, ODL	New investment to secure the energy needed off the grid.

**G.3.8** *Specific developments*

CNR zone substation has been constructed with 33/11 kV equipment to supply the first dryer in ODL’s dairy factory. The sub-transmission line from BPD to CNR is rated at 110 kV and with investment in 110/11 k V transformers at CNR the dairy factory will not be capacity constrained.

Figure G.3-4 plots the maximum demand load forecast for Cooneys Road zone substation.



**Figure G.3-4** Cooneys Road load forecast

**G.3.9** *Capacity constraints at the GXP*

With both BPD and STU GXPs connected to the Waitaki-Oamaru-Timaru circuit 2, we are constrained in terms of our offtake at these two GXPs. This constraint will limit the amount of load growth we can accommodate. Based on our load forecast, we will exceed this limit

in 2018 and more specifically when irrigation load and dairy processing load coincides. Transpower has implemented a special protection scheme (SPS) to curtail load in the event that one of the two Waitaki 110 kV circuits are lost.

The SPS will in certain instances allow us enough time to run our ripple plant with a view to shed some irrigation load, thereby maintaining supply to dairy processing plants and milking sheds, in order to prevent the scheme from turning off all load indiscriminately.

We are investigating the option of establishing a new GXP in order to mitigate against the Waitaki circuits' constraints.

## G.4 STUDHOLME GRID EXIT POINT

### G.4.1 Introduction

Figure G.4-1 shows the schematic diagram of how Studholme (STU) is configured and connected to the 110 kV TIM – Waitaki circuit 2. The demarcation between Alpine owned and Transpower owned assets are also shown.

### G.4.2 GXP description

STU provides two 11 kV incoming supplies to our 11 kV switchboard, which is co-sited at the GXP. Six 11 kV feeders provide supply to the Waimate township, Fonterra’s Studholme dairy factory, and the surrounding rural areas. The substation demand is summer peaking from strong growth from the dairy factory, arable/dairy farming, and irrigation demand.

The existing load is greater than the N-1 security offered from a single transformer. At times, BPD will have to be removed from service—for example, when the sole 110 kV line that supplies BPD is out of service for maintenance. STU then has to have capacity to supply as much load as the STU feeders towards BPD can support.

STU can supply up to 1 MW of load at CNR to assist when the main supply from BPD is unavailable.

### G.4.3 GXP data

The GXP data shown in Table G.4-1 summarises the key physical attributes of the substation, the voltages, capacity, security, and power flow.

**Table G.4-1 Studholme GXP system data**

GXP	GXP transmission potential	GXP point of supply potential	Capacity	N-1 capacity	Demand 2016
STU	110 kV	11 kV	11 MVA	22 MVA	14.2 MW

### G.4.4 Studholme GXP network information

Figure G.4-1 depicts the STU GXP area schematic diagram. STU GXP delivers 11 kV to our indoor switch room. This switch room supplies 11 kV to Fonterra’s Studholme dairy factory’s dryer 1 (and some rural load) via two feeders, and Waimate township and the surrounding rural area via the remaining four 11 kV feeders.

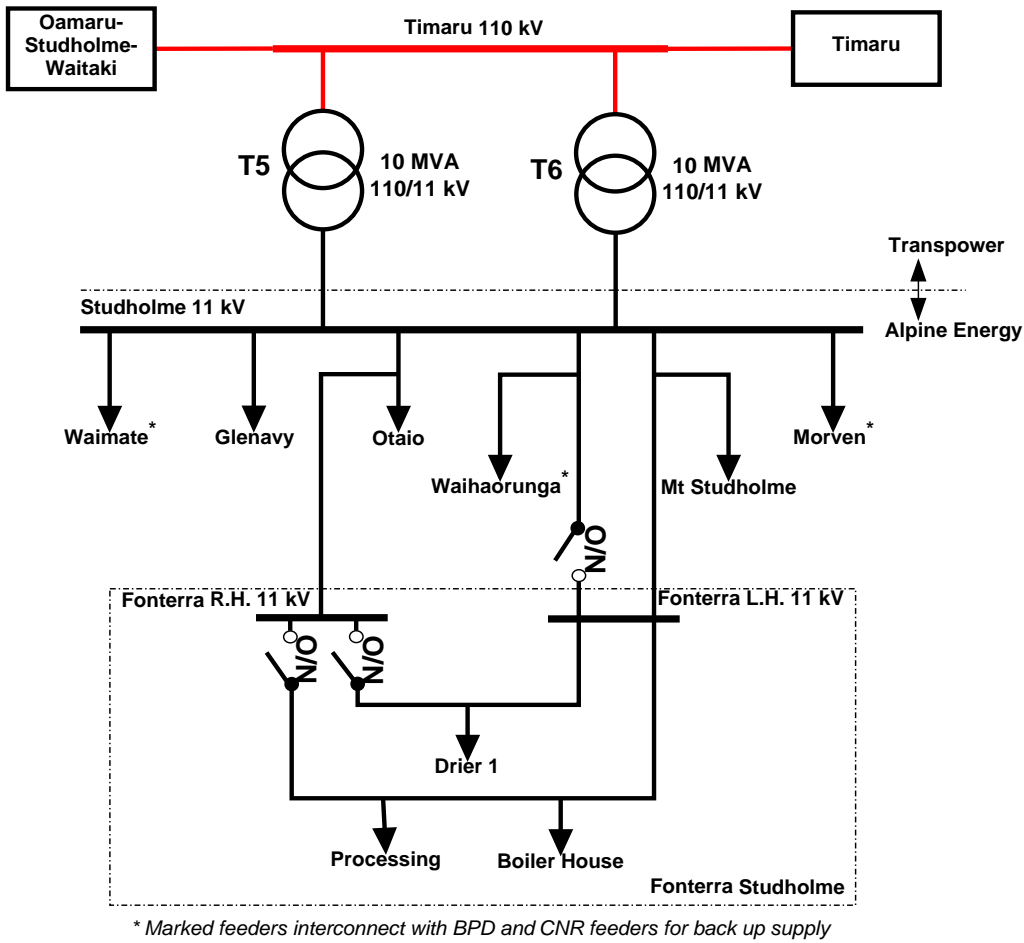


Figure G.4-1 Studholme area schematic

G.4.5 Zone substation detail

Table G.4-2 details the major assets with respect to rating, age, and general condition, the maximum demand, and the capacity constraints, substation’s communication systems, and SCADA functions.

Table G.4-2 Studholme zone substation equipment information

Zone substation site	Transformer	Regulator	Switchgear	Ripple plant
STU	NA	NA	9x 11 kV VCB (2005) Excellent	Zellweger 317 Hz

Area of network with constraint	Capacity constraint	Description	Intended remedy	
<b>STU GXP</b>	Lack of capacity for Waimate area	110 <sup>o</sup> kV line and transformers	Work with Transpower to investigate options.	
<b>Communications</b>	<b>VHF</b>	<b>UHF analogue</b>	<b>UHF digital</b>	<b>Fibre optic</b>
<b>STU</b>	VHF for voice traffic	Analogue for all 11 kV station SCADA and load control functions	STU-MEC MEC-CHC CHC-NST or WDK	None
<b>SCADA</b>	<b>Supervision</b>	<b>Control</b>	<b>Automation</b>	<b>Data acquisition</b>
<b>STU</b>	Current, voltage and CB status and security at STU	STU area CB and ripple plant control	Auto reclosing CB at STU	Load data and power quality at STU

Table G.4-3 lists the existing level of security at the substation and the justification of shortfall.

**Table G.4-3 Studholme security of supply levels**

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
<b>Waimate Residential</b>	N-1	N-1	Limited 11 kV rings from STU. Limited fault backup from BPD.
<b>Waimate Rural</b>	N-0.5	N-0.5	Limited fault backup from BPD and PAR. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
<b>Fonterra 11 kV</b>	N	N-1	Load over 3 MVA requires customer investment for dedicated feeders/cables. Present load restricting load growth and increasing voltage problems towards end of feeders.

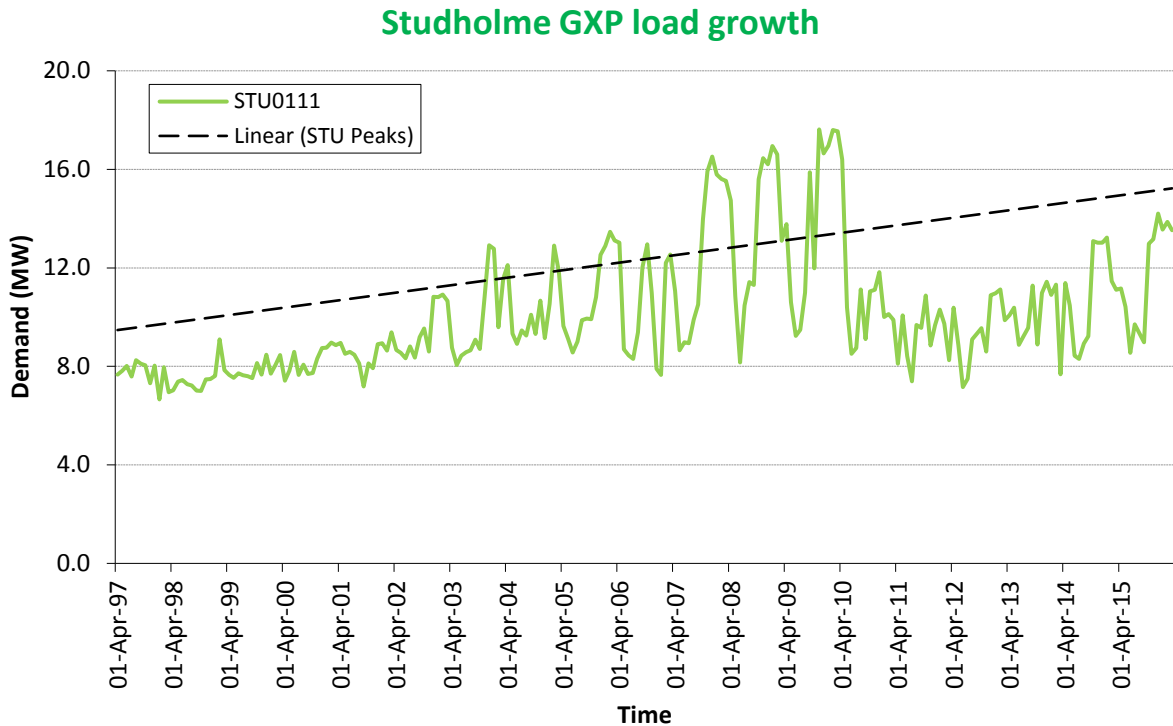
The estimated demand listed in Table G.4-4 shows the aggregated effect of substation load forecast for a 10 year horizon incorporating the anticipated step changes detailed in Table G.4-5.

**Table G.4-4 Studholme zone substation load forecast**

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
STU	14.2 (summer)	2.5% per year expected as TMK load. Dairy and irrigation development (not including step changes).	44.5 (summer)	Transformer upsizing required pending load split for Hunter Downs between STU and STA. 11 kV switchboard upsizing required after 24 MVA.

**G.4.6 Development of GXP and substations**

Figure G.4-2 shows the historic STU load growth. After the commissioning of BPD in 2010, the load on STU reduced by some 6 MW as can be seen in the same figure.



**Figure G.4-2 Load growth for Studholme GXP**

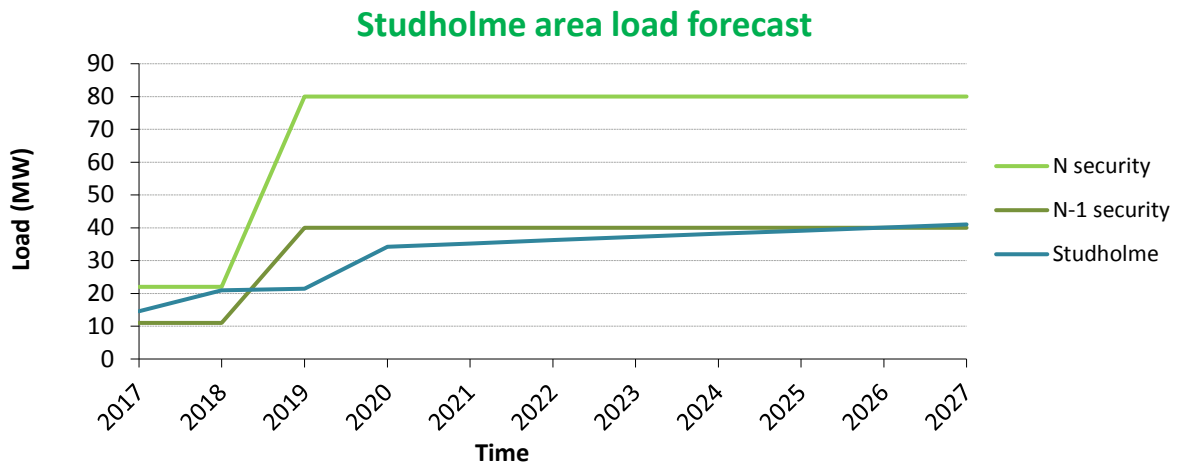
Table G.4-5 shows the load forecast for STU zone substation.

**Table G.4-5 Studholme zone substation load forecast**

GXP substation (season peak)	Growth trend (Total MW MD)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
STU (summer)	14.6	20.9	21.4	31.1	32.1	33.1	40.2	41.2	42.3	43.4	44.5

New transformers for STU would have a capacity of 40 MVA as these are practically sized to suit standard 11 kV switchgear (i.e. 48 MVA practical limit on CBs) and it also aligns with the maximum offtake from the 110 kV transmission line.

The date of the need for new transformers is load dependent and will be influenced by HDW, ODL load growth, and other Transpower work. Figure G.4-3 plots the STU forecast load growth security with a transformer upgrade in 2019. This forecast includes as at the date of writing this plan, uncommitted loads for Fonterra and the HDW scheme. If none of this realises then the transformer upgrade in 2019 can be delayed.



**Figure G.4-3 Studholme load forecast and supply security**

**G.4.7 Substation growth trend and supply security**

The Waimate district is presently fed off the 110 kV Waitaki Circuit 2, which has no spare capacity. We are of the view that a new GXP could be required to feed the existing BPD, CNR, and STU loads if the HDW irrigation, on farm loads, and ODL loads are confirmed and committed.

The feeders to the north of STU and south of PAR will need a new GXP to support the HDW load should it become realised. These feeders already have the maximum number of voltage regulators and capacitors applied.

STU GXP presently has two 10 MVA transformers that are connected giving 20 MVA<sup>65</sup> capacity of N security. If one of the transformers fails, Transpower would disconnect the transformers while the supply is off and then live the healthy transformer and restrict demand to 10 MVA. Present loads indicate that if this occurred some irrigation would have to be turned off until the faulty transformer had been repaired.

The rating of the STU 11 kV board is 24 MVA. If BPD was no longer reliant on STU for security of supply, the switchboard's rating would be sufficient until about half way into the present planning period unless the Fonterra and HDW loads are realised, which could require and upgrade around 2020. The switchboard should only be contemplated for an upgrade when larger transformers are required.

#### **G.4.8** *Rate and nature of GXP growth and provisions made*

Table G.4-6 summarises the characteristic of growth and summarises our plans to meet the demand requirements.

**Table G.4-6 Load growth characteristics**

<b>GXP</b>	<b>Rate and nature of growth</b>	<b>Provisions for growth</b>
<b>STU</b>	Med—Dairy and irrigation (not taking HDW into account) Low—Dairy processing (not taking Fonterra's additional dryer into account)	New GXP investment

#### **G.4.9** *Capacity constraints at the GXP*

The current load on this GXP have for some time been more than the N-1 security level. With a 15.5 MW maximum demand registered in 2016, a typical new 30 tonne milk dryer with an estimated electrical load requirement of 6 MW, cannot be supplied from this GXP. In addition we are also constrained in terms of the maximum load we can take from the Waitaki-Timaru circuit 2 as mentioned above.

We have a temporary arrangement with Transpower for a 110 kV bus tie through for the milk flush, to give Fonterra security. Transpower has installed a special protection scheme at STU to cater for the summer security needs. Transpower could still remove the tie; if this occurs Fonterra will experience less security of supply and significant economic losses.

<sup>65</sup> Each transformer is capable of running at 11 MVA each.

## G.5 TEKAPO GRID EXIT POINT

### G.5.1 Introduction

Figure G.5-1 shows how Tekapo A GXP (TKA) is configured with our network and Transpower's transmission network. TKA GXP is supplied by 110 kV circuit from TIM 110 kV bus via ABY.

### G.5.2 GXP description

TKA is connected to the grid via a 110/11 kV transformer to the generation bus and then via an 11/33 kV step-up transformer to our 33 kV sub-transmission feeder. Genesis Energy can make its generator available to supply our TKA load when the ABY–TKA 110 kV circuit is released, and the ABY and TKA load when the ABY–TIM 110 kV circuit is released.

TKA power station (25 MW) would be used in the case of loss of 220 kV supply to Timaru to bolster a weak in-feed (15 MW) from Waitaki to Timaru. This is only possible when the Waitaki-Bells Pond-Oamaru-Studholme-Timaru circuit 2 is operated with the disconnectors closed at Studholme. This would not be possible if this circuit is run open at Studholme under the proposed temporary grid reconfiguration contingency.

Transpower invested in a mobile sub with a 110 kV primary connection and an 11, 22 or 33 kV secondary connection. In 2014 TKA had the mobile substation connected between the ABY 110 kV line and our 33 kV feeder to our zone substation to maintain supply while significant maintenance was carried out to the GXP and 11 kV generation bus.

### G.5.3 GXP data

The GXP data shown in Table G.5-1 summarises the key physical attributes of the station, the voltages, capacity, security of supply, and power flow.

**Table G.5-1 Tekapo GXP system data**

GXP	GXP transmission potential	GXP point of supply potential	Capacity	N-1 capacity	Demand 2016
TKA	110 kV	33 kV (via 11 kV bus)	10 MVA	0	4.0 MW

### G.5.4 Tekapo A GXP network information

Figure G.5-1 shows the TKA GXP area network. There are a number of smaller zone substations to boost voltage to transmit energy to remote sparsely populated areas.

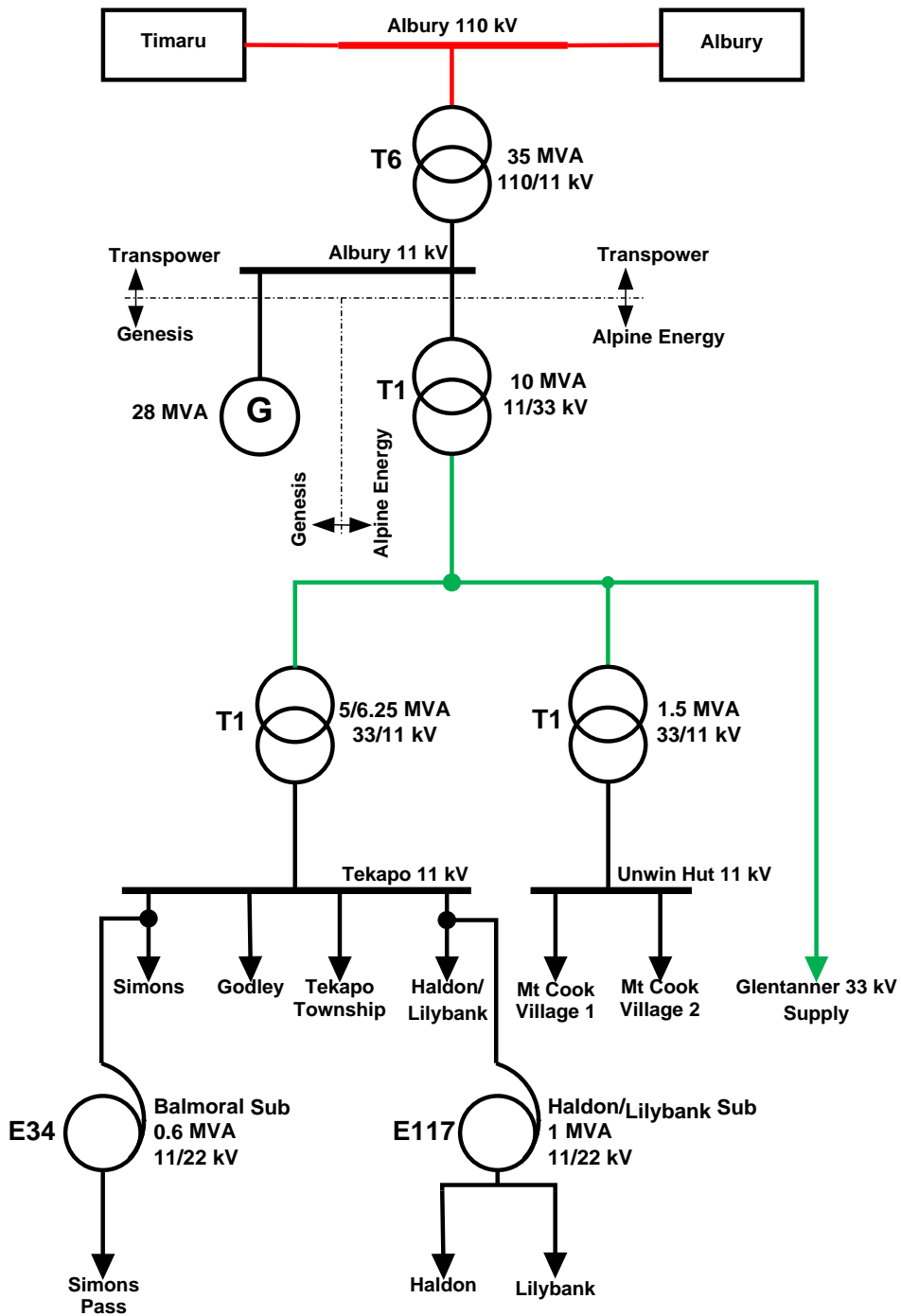


Figure G.5-1 Tekapo area schematic

From TKA, we receive 33 kV which is sub-transmitted to the nearby TEK zone substation, which also hosts the ripple injection plant. From TEK 33 kV is sub-transmitted to Glentanner and Unwin Hut (UHT). TEK zone substation supplies the Tekapo township and surrounding rural areas. Balmoral (BMR) and Haldon–Lilybank (HLB) are two zone substations fed off

TEK which act as voltage boosters to transmit energy at 22 kV into the remote Haldon, Lilybank, and Simon's Pass areas.

### G.5.5 Zone substation detail

Table G.5-2 shows TEK zone substation and sub-transmission key data, the major assets with respect to rating, age, and general condition, the maximum demand, and the capacity constraints, communication systems and SCADA functions.

**Table G.5-2 Zone substation equipment details**

Zone substation site	Transformer	Switchgear	Ripple plant	
<b>TEK</b>	5/6.25 MVA 33/11 kV T1 OLTC (1972) (Refurbished ex PAR) Good	1x 33 kV Recloser Mt Cook line (1984) Good 1x 33 kV OCB (T1) (1960) Poor 7x 11 kV OCBs (1984) Good	Zellweger 500 Hz	
<b>TEK AMS ready</b>	Yes			
<b>HLB</b>	1 MVA 22/11 kV T1 OCTC (2009) Excellent	1x Nova 15 (2015) Excellent		
<b>BMR</b>	0.6 MVA 22/11 kV T1 OCTC (Aged) Fair	1x 33 kV Scarpa Magnano (Aged) Poor (run at 22 kV) 1x 11 kV DDO type fuse		
<b>UHT</b>	1.5 MVA 33/11 kV T1 OLTC (1974) Fair	1x 33 kV OCB (1974) Fair 2x 11 kV OCBs (1977) Fair		
<b>UHT AMS ready</b>	Yes			
Sub-transmission line	Make up	Limit of conductor at 50°C (MVA)	Limit of cable (MVA)	Lowest limit
<b>TKA–TEK</b>	Dog	12.6	NA	12.6
<b>Mt Cook Station Tee–TEK</b>	Dog/ Flounder	12.6 8.6	NA	2.3
<b>GTN–Mt Cook</b>	Mink	10.3	NA	2.3 (from Mt Cook 6% PD)
<b>Mt Cook Station–UHT</b>	Mink/ Petrel	10.3 11.4	NA	1.2

Area of network with constraint	Capacity constraint	Description	Intended remedy	
TKA GXP	11/33 kV step up transformer, primary rating 10 MVA			
TEK	None			
Tekapo Rural	Distribution feeders	Light two phase, large spans	Feed HLB from TWZ.	
BMR	Distribution feeders	Light three phase, large spans	Feed Simon's Pass from TWZ.	
UHT	None			
Communications	VHF	UHF analogue	UHF digital	Fibre optic
TEK	VHF for voice traffic	TEK-MRC <sup>66</sup> MRC-WDK		None
HLB	Vehicle radio	None	None	None
BMR	Vehicle radio	None	None	None
GTN	Vehicle radio	None	None	None
UHT	VHF for voice traffic	None	None	None
SCADA	Supervision	Control	Automation	Data acquisition
TEK <sup>67</sup>	Current, voltage and CB status at TEK. Security at TEK	TEK CB control. TEK Ripple plant control.	Auto reclosing CB	Load data at TEK
HLB	None	None	None	None
BMR	None	None	None	None
GTN	None	None	None	None
UHT	Two bit alarms over VHF	None	None	None

Table G.5-3 lists the existing level of security at the substations and justification of shortfall.

**Table G.5-3 Tekapo GXP supply security**

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
TEK CBD	N-0.5	N-1	No alternate supply to station.

<sup>66</sup> Mt Rollesby (MRC) is not our site, as this is rented space.

<sup>67</sup> TEK's SCADA has L&N C68 RTU equipment installed.

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
			Mobile substation can be connectd. Limited 11 kV rings. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
<b>Mt Cook and GTN</b>	N	N	No alternate supply to station. Mobile substation can be connected at UHT to supply Mt Cook. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
<b>TEK Rural</b>	N	N	Radial lines, little backup. Generator port on 11 kV at HLB. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.

The estimated demand forecast listed in Table G.5-4 shows the aggregated effect of substation demand growth for a 10 year planning period incorporating the anticipated step changes detailed in Table G.5-5.

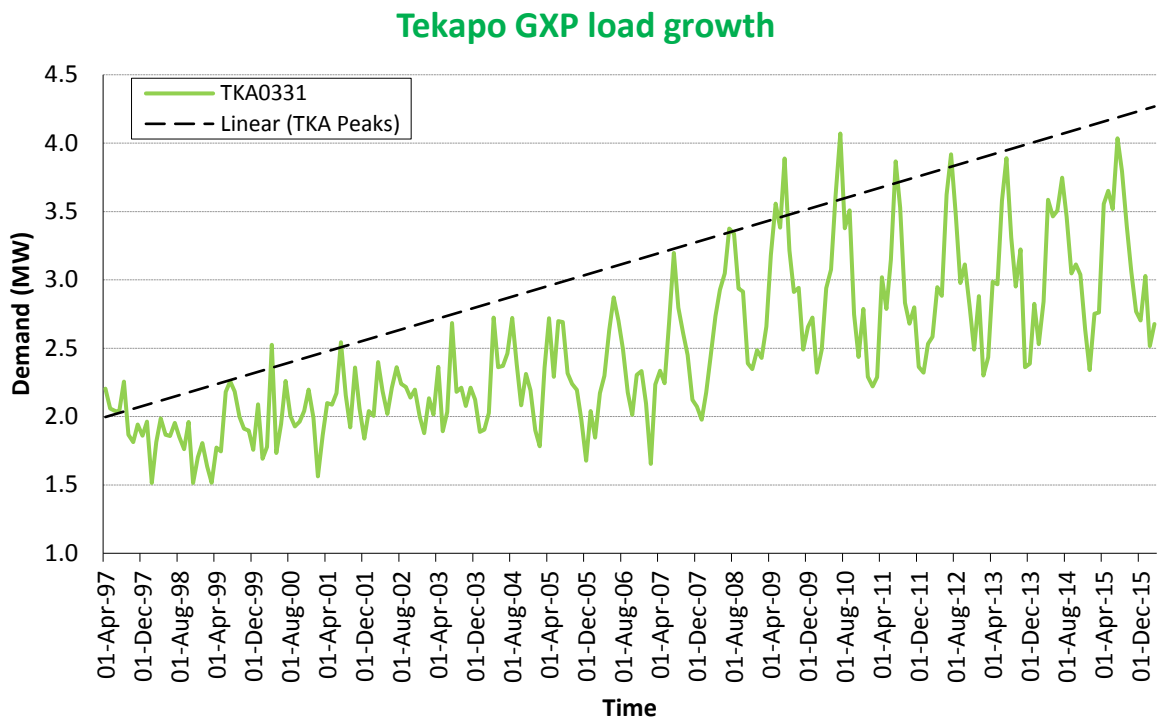
**Table G.5-4 Demand forecast at zone substation level**

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
<b>TEK</b>	3.5 (winter/shoulder)	3.0% historic on TKA. Residential load. Tourism development.	7.5 winter /shoulder	Transformer upgrade planned for 2019/20
<b>HLB</b>	0.3 (Est.) (winter/shoulder)	3.0% historic on TKA. Residential load. Tourism development.	Unknown at this time	Existing lines are light construction. If irrigation expands toward Haldon then it is likely supply will come from TWZ. This substation would be retained for Lilybank.
<b>BML</b>	0.15 (Est.) (winter/shoulder)	3.0% historic on TKA. Residential load. Tourism development.	0.6 winter /shoulder	Existing lines are light construction. If irrigation expands toward Simon's Pass BML will require an upgrade with voltage support added to sustain additional load. Alternatively, supply will be established from TWZ.

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
UHT	1.0 (Est.) (winter/shoulder)	3.0% historic on TKA. Residential load. Tourism development.	1.4 winter /shoulder	Transformer could possibly be changed out in the planning period if the condition deteriorates.

**G.5.6** *Development of GXP and zone substations*

Figure G.5-2 shows the historic TKA GXP load growth.



**Figure G.5-2** Tekapo GXP historic load growth

Table G.5-5 shows the growth trend for the TKA area.

**Table G.5-5** Substation load forecast

GXP substation (season peak)	Growth trend (Total MW MD)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TKA	4.4	5.4	7.0	7.5	7.6	7.8	7.9	8.0	8.2	8.3	<b>8.5</b>
TEK Village	3.9	4.7	6.3	6.8	6.9	7.0	7.1	7.2	7.3	7.4	<b>7.5</b>

<b>Mt Cook and Glentanner</b>	1.2	1.3	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.7
-------------------------------	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----

Figure G.5-3 to Figure G.5-5 shows the predicted maximum demand within the planning period.

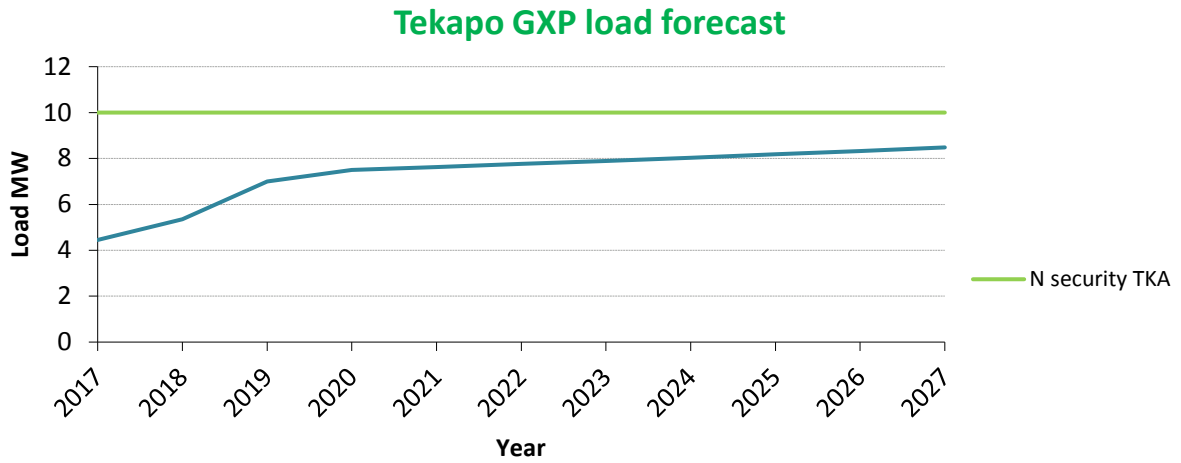


Figure G.5-3 Tekapo GXP load forecast

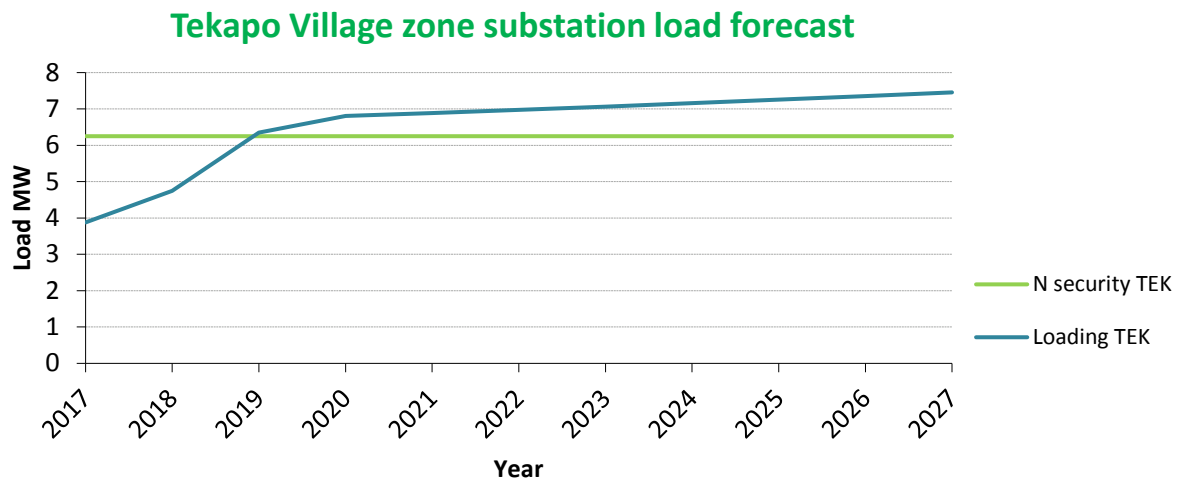


Figure G.5-4 Tekapo Village zone substation load forecast

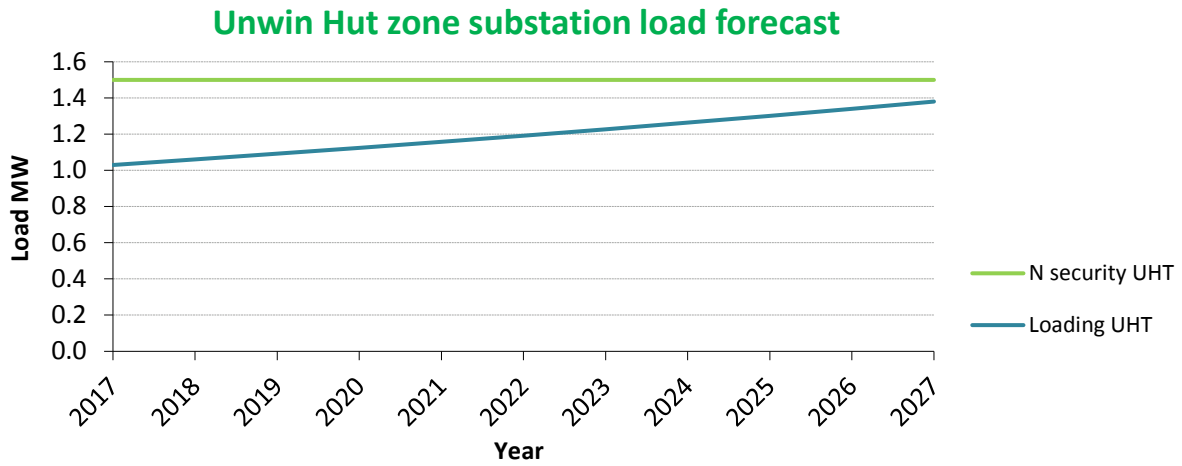


Figure G.5-5 Unwin Hut zone substation load forecast

**G.5.7 Substation load forecast and supply security**

Plans to expand the Tekapo CBD have progressed with construction starting on a New World supermarket, two major hotels, an extension to the hot pools, and numerous subdivisions announced during 2015 and 2016.

Our sub-transmission supply is on an N security basis from TKA. A GXP bus or step up transformer fault would result in a total supply loss until repairs were undertaken, or the Transpower mobile substation was deployed. As Transpower does not keep a spare transformer on-site, a fault within the transformer would result in an extended loss of supply while a change-out occurred.

We can support some of the TEK load with mobile generation (AMG or other generation) to help Transpower in case of a GXP outage.

**G.5.8 Rate and nature of GXP growth and provisions made**

Table G.5-6 summarises the characteristic of growth and summarises the plans to meet the energy requirements.

Table G.5-6 Tekapo growth and response

GXP	Rate and nature of growth	Provisions for growth
TKA	Medium— Tourism business and subdivision	Upgrade zone substation

### G.5.9 *Specific developments*

#### ***Tekapo A Transpower 11 kV switchboard***

Transpower carried out a strengthening and arc flash containment project on their Tekapo A 11 kV switchboard in early 2014, thereby extending the life of the existing switchboard.

#### ***Haldon–Lilybank zone substation upgrade***

Haldon–Lilybank (HLB) is a small step up substation on the edge of Tekapo. It consists of a Nova 15 recloser, an 11/22 kV step up autotransformer and two phase lines away to Haldon and Lilybank. The neutral of the autotransformer has earth fault protection installed. An enquiry has been made from a number of farmers about a stronger supply in the Haldon area for irrigation. The 22 kV distribution is not three-phase and does not have spare capacity. An alternative solution to upgrading the existing infrastructure could be to take supply from Twizel. We would also consider new technologies such as battery storage, PV in conjunction with diesel generation when a firm supply request is made. In the meantime the farmers are still developing the proposal, and there is no time frame given for the irrigation to be commissioned.

#### ***Balmoral zone substation***

BMR is a small 0.6 MVA step up substation on the edge of Tekapo that feeds Simon's Pass, it consists of a primary 11 kV fuse, an 11/22 kV step up auto transformer, a 33 kV 600 A Scarpa Magnano minimum oil CB and post CTs, and a 22 kV distribution feeder leading away from the substation. The neutral of the autotransformer has earth fault protection installed.

To supply the possible irrigation demand at Simon's hill and Simon's Pass, and the logistics of how to supply this load, one option would be to move the Balmoral substation to the TEK compound. It was originally situated at TEK but shifted to beyond the military camp in the mid 80's to assist their connection with lower cost 11 kV equipment.

#### ***Ripple plant and communications***

The replacement or decommission the old rotating ripple injection plant will be based on an economic analysis. Smart meters may provide load control in the future.

The existing RTU and communications is legacy equipment and is passed its economic life. It is likely that this RTU and communications replacement at TEK would be done in conjunction with a similar replacement at the Twizel zone sub as they share a common SCADA system communications link with TEK back to the Washdyke Control Room.

**G.5.10** *Capacity constraints at the GXP*

Based on current load forecasts, the transformer will be at capacity around 2023/24. Since the GXP belongs to Transpower, any upgrade of this capacity will be done through a customer investment contract. This will be initiated closer to the time.

## G.6 TEMUKA GRID EXIT POINT

### G.6.1 Introduction

Figure G.6-1 shows how the Temuka GXP (TMK) is configured with our network and Transpower's transmission network. TMK is supplied by dual 110 kV transformer feeder circuits from the TIM 110 kV bus.

### G.6.2 GXP description

As shown in Figure G.6-1 the 110/33 kV GXP has eight 33 kV feeders:

- four to Fonterra's Clandeboye dairy factory—of which two are cable and two are overhead circuits supported on a single pole structure
- two 33 kV cables to our 33/11 kV zone substation—co-sited at the TMK GXP
- one 33 kV circuit breaker to supply an overhead 33 kV feeder to GLD
- one 33 kV circuit breaker to supply an overhead 33 kV feeder to RGA

The latter two feeders can be tied at the substation to give security for a CB failure. Our 33/11 kV zone substation supplies the Temuka Township and surrounding rural area.

RGA is also supplied from a tee-off of the CD2 circuit at CNL.

Peak demand occurs during summer based on the predominant dairy and irrigation load.

### G.6.3 GXP data

The GXP data shown in Table G.6-1 summarises the key physical attributes of the station, the voltages, capacity, security, and power flow.

**Table G.6-1 Temuka GXP system data**

GXP	GXP transmission potential	GXP point of supply potential	Capacity	N-1 capacity	Demand 2016
TMK	110 kV	33 kV	108 MVA	54 MVA <sup>68</sup>	55.6 MW

### G.6.4 Temuka GXP network information

Figure G.6-1 shows the TMK GXP network area.

<sup>68</sup> The Transpower GXP 110/33 kV transformers were updated from 40 MVA to 54 MVA each in 2010.

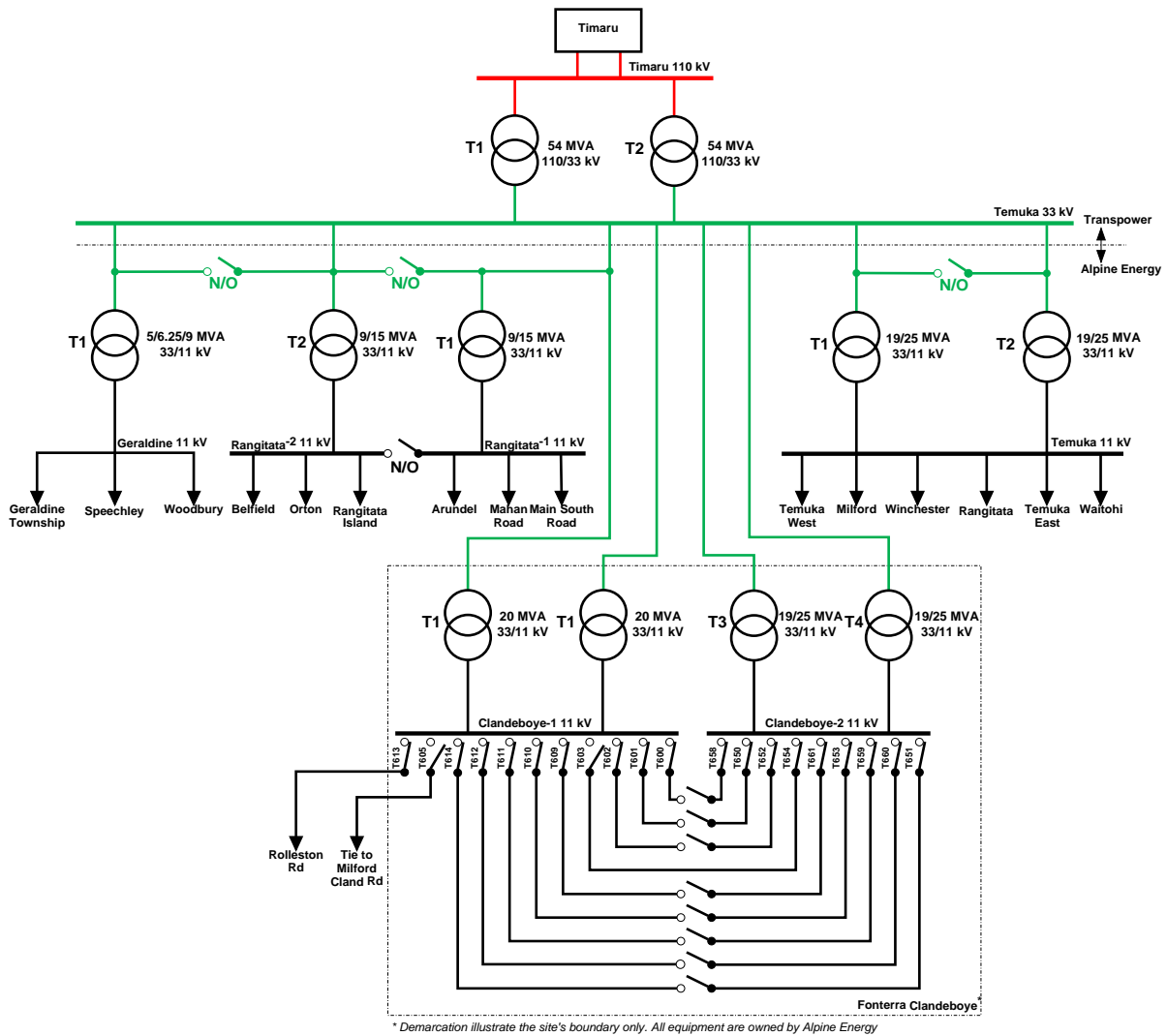


Figure G.6-1 Temuka GXP schematic diagram

G.6.5 Zone substation detail

The zone substation, switching station, and sub-transmission key data for TMK, Clondeboye, RGA, and GLD is shown in Table G.6-2. It details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table G.6-2 Temuka and Clondeboye zone substation equipment information

Zone substation site	Transformer	Switchgear	Ripple plant
TMK	25 MVA 33/11 kV T1 and T2 OLTC (2007) Excellent	9x 11 kV VCBs (2006) Excellent	1x Zellweger 317 Hz 33 kV
CD1	20 MVA	2x 33 kV Reclosers	None

<b>16 MW</b>	33/11 kV T1 and T2 OLTC (1997) (2013 refurb to T2) Good	WVE (1997) Good 15x 11 kV VCBs (1997) Excellent		
<b>CD2 14 MW</b>	25 MVA 33/11 kV T1 and T2 OLTC (2004) Excellent	2x 33 kV Recloser VWVE (2004) Good 12x 11 kV VCBs (2004) Excellent	None	
<b>RGA (9.8 MW)</b>	9/15 MVA 33/11 kV T1 and T2 OLTC (2011, 2012) Excellent	2x 33 kV GL107X CB (SF <sub>6</sub> ) (2011, 2012) Excellent 5x 11 kV VCB Tamco (2004) Excellent 5x 11 kV VCB RPS (2011) Excellent	None	
<b>RGA AMS ready</b>	No, this is a N-1 secure substation			
<b>GLD 6.1 MW</b>	5/6.25/9 MVA 33/11 kV T1 OLTC (1980) Good	1x 33 kV Recloser VWVE, T2 (2009) Excellent 1x 11 kV Recloser U Nulec, T2 (2009) Excellent 3x 11 kV Recloser U Nulec, feeders (2007) Excellent	None	
<b>GLD AMS ready</b>	No – project planned for 2017.			
<b>Zone switching station site</b>	<b>Transformer</b>	<b>Switchgear</b>	<b>Ripple plant</b>	
<b>CNL 8.5 MW</b>	None	1x 33 kV GL107X CB (SF <sub>6</sub> ) (2012) Excellent	None	
<b>Sub- transmission line</b>	<b>Make up</b>	<b>Limit of conductor at 50°C (MVA)</b>	<b>Limit of cable (MVA)</b>	<b>Lowest limit</b>
<b>TMK–CD 1<sup>69</sup></b>	Cable 1/400 and 1/300	N/A	21.3	21.3
<b>TMK–CD 2</b>	Cable 2x1/300 and Jaguar and	23.4	21.3	21.3

<sup>69</sup> We have an agreed maximum limit of 10 MVA to be taken of the CD1–TMK 33 kV circuit.

	cable 1/300			
<b>TMK-CD 3</b>	Cable 2x1/300 and Jaguar and cable 1/400	23.4	24.2	23.4
<b>TMK-CD 4</b>	Cable 1/400	N/A	24.2	24.2
<b>RGA 1-TMK</b>	Cable 1/400 and Dog/Iodine/Mink and cable 3/95 and Wolf Core	10.3	11.5	8.4
<b>RGA 2-TMK via Canal Rd teed off CD2-TMK</b>	Cable 2x1/300 and Jaguar	23.4	32	10
<b>GLD-TMK</b>	Cable 1/400 and Dog	12.6	24.2	8.64

Table G.6-3 details the substation’s communication systems and SCADA functions.

**Table G.6-3 Temuka and Clandeboye SCADA and communications data**

Communications	VHF	UHF analogue	UHF digital	Fibre optic
<b>TMK</b>	VHF for voice traffic	None	TMK-MEC MEC-WDK (main) TMK-WDK (backup)	CD2-TMK (services CD1and2 and CNL)
<b>CD1 and CD2</b>	VHF for voice traffic	None	CD1-CNL (services CNL)	CD2-TMK (services CD2) CD1-CD2 (services CD1)
<b>CNL</b>	VHF for voice traffic	None	CD1-CNL	None
SCADA	Supervision	Control	Automation	Data acquisition
<b>TMK</b>	Current, voltage and CB status at TMK Security at TMK	TMK CB and Transformer Control Ripple plant control	Auto Reclosing CB	Load data at TMK
<b>CD1 and CD2</b>	Current, Voltage and CB status at CD1 and CD2 Security at CD1 and CD2	CD1 and CD2 CB and Transformer Control	Control of CBs	Load data at CD1 and CD2
<b>CNL</b>	Current, voltage and CB status at CNL Security at CNL	CNL CB Control	Control of CB	Load data at CNL

The SCADA in TMK consists of an Abbey RTU connecting to our 11 kV switchgear and transformer zone IEDs, it controls the ripple plant, and connects to Transpower's data bridge to their RTU in the 33 kV switch room. CD1, CD2, CNL and RGA SEL 3530 substation processors connect the substation equipment. TMK communications connects via radio systems to WDK via CHC and is a communications hub for CD1, CD2 and CNL via the CD2–TMK fibre. CD2 is a communications hub for CD1 (via fibre) and CNL (via radio).

Table G.6-4 shows the capacity constraints at the TMK GXP.

**Table G.6-4 Temuka area network constraints**

Area of network with constraint	Capacity constraint	Description	Intended remedy
<b>TMK</b>	Temuka Area—Holistic	Lack of capacity for TMK 33 kV GXP load	Work with Transpower on upgrading supply assets. Transpower to prepare upgrade options.
	TMK GXP Supply Security	Load constraint over 54 MW on transformers. 71 MVA on 110 kV lines & 33 kV switchboard.	A SPS to be implemented in 2017 to manage risks associated with overloading assets post contingency.
<b>RGA</b>	Rangitata 33 kV sub-trans 1 line regulation	Voltage regulation constraint over 8.4 MVA	Second 33 kV feeder to RGA took load in 2013. For a sub-trans tripping, shifting load is required, most can be done via remote control so quick response.
<b>GLD</b>	Geraldine 33 kV sub-trans 1 line regulation	Voltage regulation constraint over 8.64 MVA	Watch on GLD loading as RGA load is transferred. Load may be able to go back on RGA depending on the final irrigation scheme load.
	Geraldine CBD	Voltage regulation constraint at end of feeder when load increases	Install capacitors when required.

Table G.6-5 lists the existing level of security of supply at the substation and the justification of shortfall.

**Table G.6-5 Temuka and Clandeboye security of supply levels**

Zone sub/load centre	Actual	Target	Shortfall from target
<b>TMK Residential</b>	N-1	N-1	None.
<b>TMK Rural</b>	N-0.5	N	Limited fault backup from GLD, RGA, PLP, and TIM. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
<b>CD1 and 2</b>	N-2 for 33kV circuits and N-1 for zone substations	N-2	None
<b>RGA</b>	N-1 for 33kV circuits and zone substation transformers	N	None. N-1 for 33kV circuits only as long as the load is less than 10 MW. Some load can be shifted onto 11 kV backup from GLD and TMK
<b>GLD</b>	N-0.5	N-0.5	33 kV investment to be considered.

The estimated demand listed in Table G.6-6 shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table G.6-7.

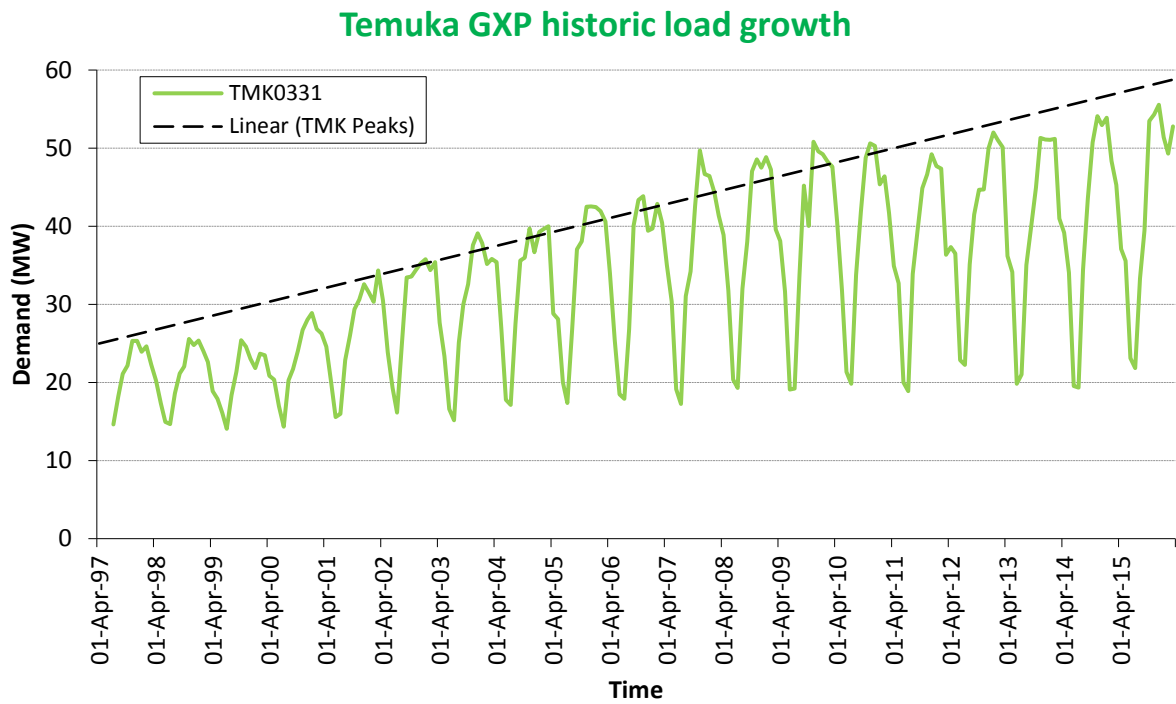
**Table G.6-6 Temuka area expected loads**

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
<b>TMK</b>	58.2 (summer)	3.6% historic on TMK. Residential load. Dairy and irrigation development. Dairy processing.	79.2 (summer)	Load growth due to expansion at Clandeboye. Rangitata South Irrigation has not yet taken full capacity. Transmission solutions being discussed with Transpower.
<b>CD1 and CD2</b>	28.7 (summer)	3.6% Stepped to suit process expansion and any new dier	28 (summer)	Substation and sub-transmission capacity available. Additional CBs at substations and 11 kV cabling to new RMU and distribution transformers to be installed in 2017. With careful load transfers existing assets can meet this demand and retain N-1 security.
<b>GLD</b>	8.7 (summer)	3.6% historic on TMK. Residential load. Commercial development.	10.7 (summer)	Local concern may lead to a second 33 kV circuit to provide N-1 security.

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
		Dairy and irrigation development.		
<b>RGA</b>	12.5 (summer)	3.6% historic on TMK. Residential load. Dairy and irrigation development.	17.7 (summer)	Second 33 kV circuit installed to provide additional capacity if required. Note some of RGA load can be transferred to TMK and GLD as a temporary measure.

**G.6.6** *Development of GXP and substations*

Figure G.6-2 below shows the historic TMK load growth.



**Figure G.6-2** Load growth for Temuka GXP

Table G.6-7 and Figure G.6-3 depicts the load forecast for the TMK area.

Table G.6-7 Temuka GXP growth trend

GXP substation (season peak)	Load forecast (MW)										
	2017	2018	2019	2020	202	2022	2023	2024	2025	2026	2027
TMK (summer)	58.2	59.3	60.5	61.7	63.0	64.2	65.5	66.8	76.1	77.7	79.2

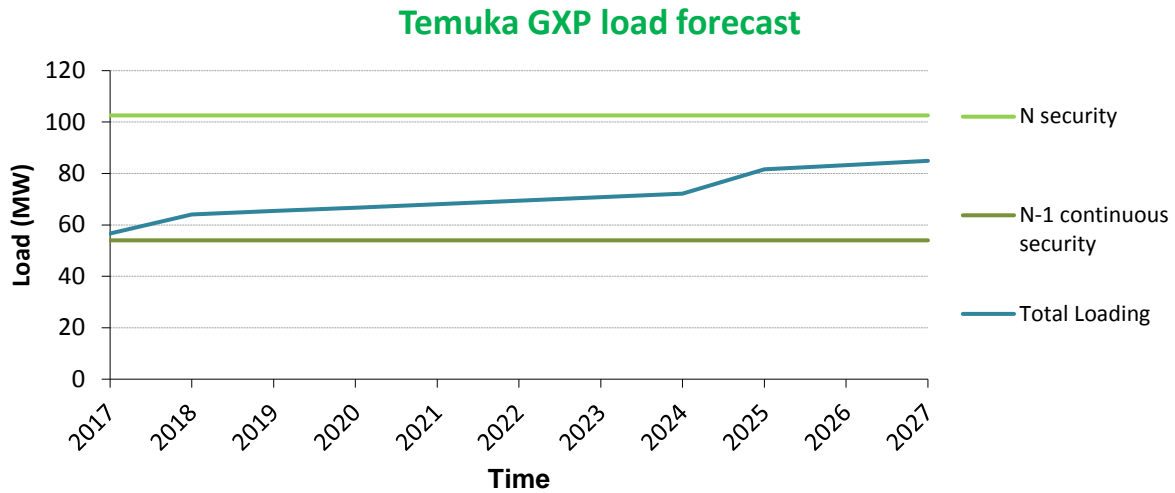


Figure G.6-3 Temuka GXP load forecast

The above trend shows that the TMK 33 kV GXP load will exceed the secure supply capacity in 2017. We are working with Transpower in evaluating options to upgrade the TMK GXP capacity. These options vary from upgrading the existing equipment to the building of a new green field GXP in close proximity to the existing substation.

A special protection scheme (SPS) is being developed for implementation in 2017 to mitigate against a post contingency overloading of the substation.

Any increase in capacity at TMK needs to be offset by an increase in TIM T5 and T8’s inter-connection transformer ratings.

The 110 kV lines to TMK from TIM are rated 71 MVA, and with re-conductoring they could be re-rated to allow more power flow. Transpower has also identified the need to upgrade these lines to supply any new transformer arrangement at TMK.

**G.6.7 Rate and nature of GXP growth and provisions made**

Table G.6-8 summarises the characteristic of the growth and summarises our plans to meet the energy requirements.

Table G.6-8 Temuka growth and response

GXP	Rate and nature of growth	Provisions for growth
TMK	High—Rural and industrial	GXP investment

G.6.8 Substation growth trend and supply security

Figure G.6-4, Figure G.6-5 and Figure G.6-6 shows the load forecasts for the rural zone substations at Clandeboye, Geraldine and Rangitata respectively.

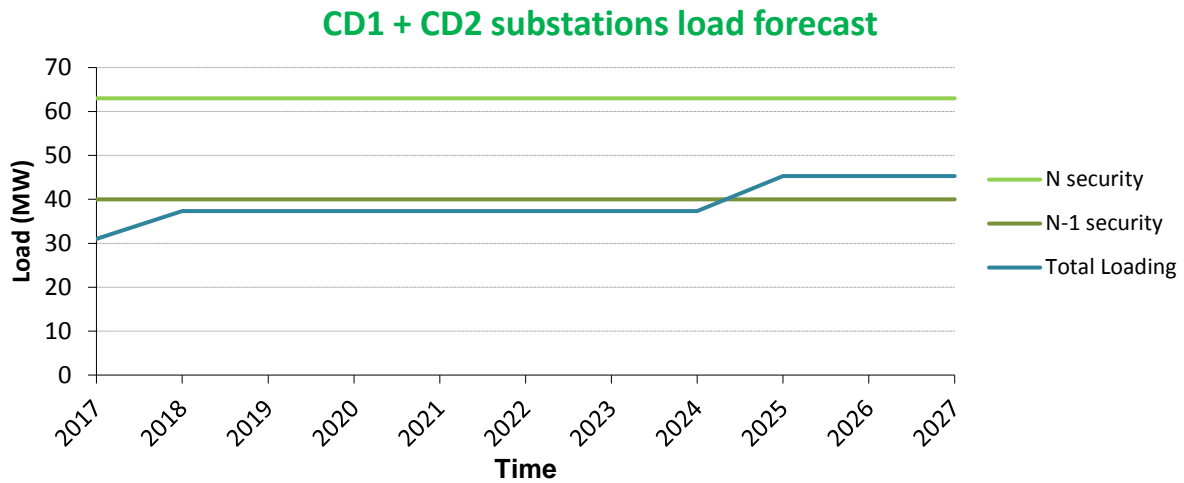


Figure G.6-4 Clandeboye substation growth forecast

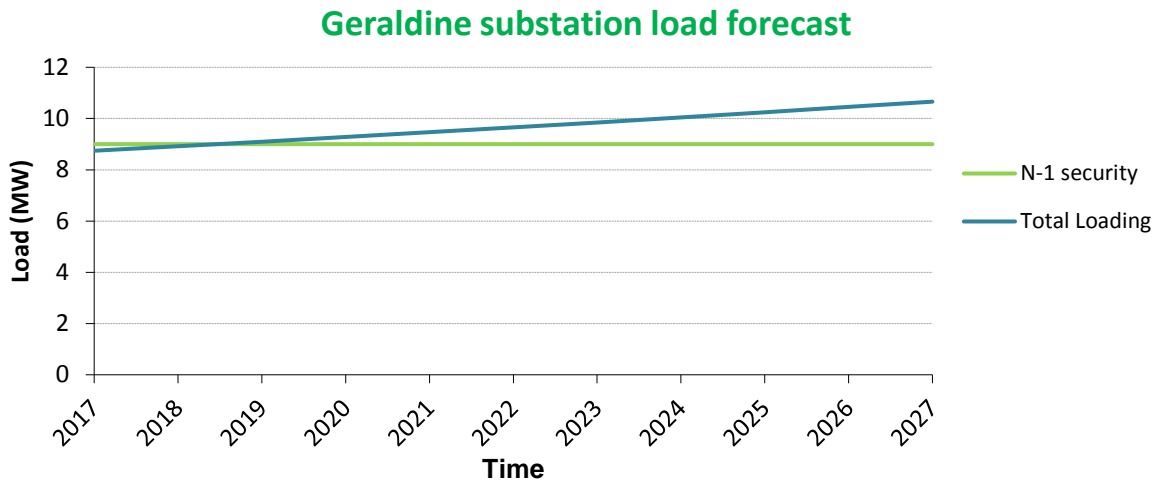
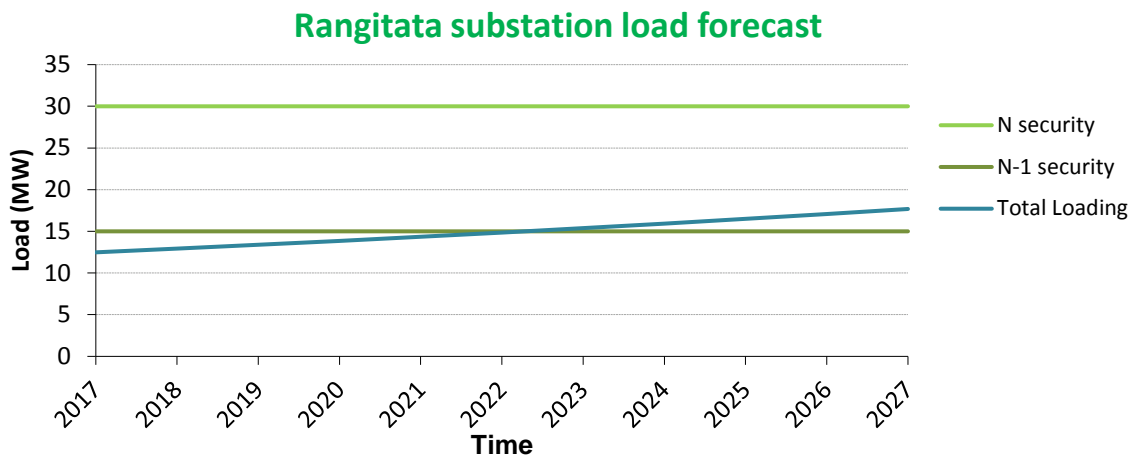


Figure G.6-5 Geraldine substation growth forecast



**Figure G.6-6 Rangitata substation growth forecast**

### G.6.9 Specific developments

#### **Temuka 110/33 kV GXP**

TMK has two 110/33 kV transformer feeders from TIM supplying the 33 kV bus. The 110 kV lines are rated at 71 MVA and the transformers at 54 MVA. A peak load of 59 MVA was recorded on 12 December 2015. A number of additional loads will be realised with future dry years and Rangitata South's irrigation scheme at full capacity. Proposed dairy processing loads of up to 6 MW are also under development. This will extend the total load on the GXP beyond the N-1 supply security level of 54 MVA. A contingent event can result in the loss of the whole GXP with serious consequences especially for Fonterra's Clondebroye factory.

As mentioned above, a SPS will be implemented in 2017 to mitigate against a total supply loss in the unlikely event of a transformer, or 110kV line trip while the load is more than 54 MVA. This will provide some security while the GXP constraint is being addressed.

#### **Capacity constraints at the GXP**

As mentioned above, we are working with Transpower to develop and evaluate solutions to the capacity constraints of the GXP. The current options being considered are:

- Upgrading of the existing transformers
- Install one new transformer and operate the existing two in parallel
- Construct a green field GXP adjacent to the existing one with appropriately sized transformers

- Install a third transformer of similar rating to the existing two. This option will require a 110°kV bus.

Based on information provided by Transpower, the process to evaluate the options, deciding on the preferred and constructing the final solution could take around three to four years. During this time the SPS will be heavily relied on for security purposes.

As mentioned above the two 110 kV overhead lines supplying the GXP will also require a capacity upgrade to accommodate a load requirement in excess of 71 MVA. As with the transformer capacity upgrade we are also working on a solution with Transpower for the supply circuits. The timeframe for this solution is expected to be well within the transformer upgrade timeframe.

### ***CD 2 substation***

As a result of increased dairy processing load we are planning to upgrade this substation by installing two additional 11 kV circuit breakers. The circuit breakers will be supplying a new 11 kV ring circuit with ten RMUs and ten transformers varying in size from 1 to 1.5 MVA.

### ***Geraldine substation***

We are planning a transformer upgrade for this zone substation in the 2020/21 financial year which is later than indicated by our prudent load forecast above. If the prudent forecast is realised this project will be started earlier.

## G.7 TIMARU GRID EXIT POINT

### G.7.1 Introduction

Figure G.7-1 shows the Timaru GXP (TIM) configuration including our network and Transpower's transmission network. TIM GXP is supplied by the Twizel–Islington (via Ashburton/Bromley) 220 kV double circuit to TIM's 110 kV bus via T5 and T8 inter-connection transformers.

### G.7.2 GXP description

TIM is our largest supply point connecting two 220/110 kV interconnectors to provide a 110 kV bus, which acts as a transmission hub for ABY, TKA, TMK, and BPD/STU. The 110 kV is stepped down through three transformer banks to supply the TIM GXP 11 kV switchboard. The 11 kV is split across three buses with 24 feeder circuit breakers (20 connected and the remaining four to be connected in early 2017).

Two 11 kV feeders are stepped up to 33 kV to supply three sub-transmission 33 kV feeders:

- two 10 km circuits to Pareora (PAR) zone substation supplying a meat works and rural load
- one 12 km circuit supplying a rural community at Pleasant Point (PLP) zone substation for township and rural consumers

There are six 11 kV sub-transmission cable circuits supplying around 35 MW to the CBD area. Four circuits to Grasmere St (GRM) and two circuits to North St (NST) substations respectively. There are also two circuits between GRM and Hunt St (HNT), and two circuits between NST and HNT as shown in Figure G.7-1. Each of these three substations has an indoor switchboard with between eight and 12 cable feeders that supply the CBD, PrimePort, Redruth, and surrounding residential areas.

TIM also supplies twelve 11 kV feeders to the western residential areas, the northern residential and industrial areas of Washdyke, and the meat-works at Smithfield.

There are two 11 kV CBs allocated for connecting a new ripple control plant and our local service transformer supplies which is not shown in Figure G.7-1 with the ability to pick-up load from the Seadown and Grants Rd feeders respectively. The TIM 110/11 kV 47 MVA transformers are operated with two in service and one on hot standby. This lowers the phase to phase fault levels in the surrounding area. Earth fault levels are limited by neutral earthing resistors (NERs).

A future TIM 33 kV GXP will allow the development of 33/11 kV zone substations in Washdyke and at NST to allow the supply of growing loads in the port and Washdyke areas. This will not be required within the planning period.

Presently the TIM peak demand occurs during winter due to the dominant residential load.

### G.7.3 GXP data

The GXP configuration is shown in Figure G.7-1, and the corresponding data in Table G.7-1 summarises the key physical attributes of the substation, the voltages, capacity, security of supply, and power flow.

**Table G.7-1 Timaru substation key data**

GXP	GXP transmission potential	GXP point Of supply potential	Capacity	N-1 capacity	Demand 2016
<b>TIM</b>	110 kV	11 kV	94 MVA <sup>70</sup>	94 MVA <sup>71</sup>	62.8 MW

<sup>70</sup> Due to fault level constraints, only two transformers will ever be operated in parallel.

<sup>71</sup> With two transformers in operation and a third on hot standby, a loss of transformer will still leave the capacity of two available.

G.7.4 Timaru GXP network schematic

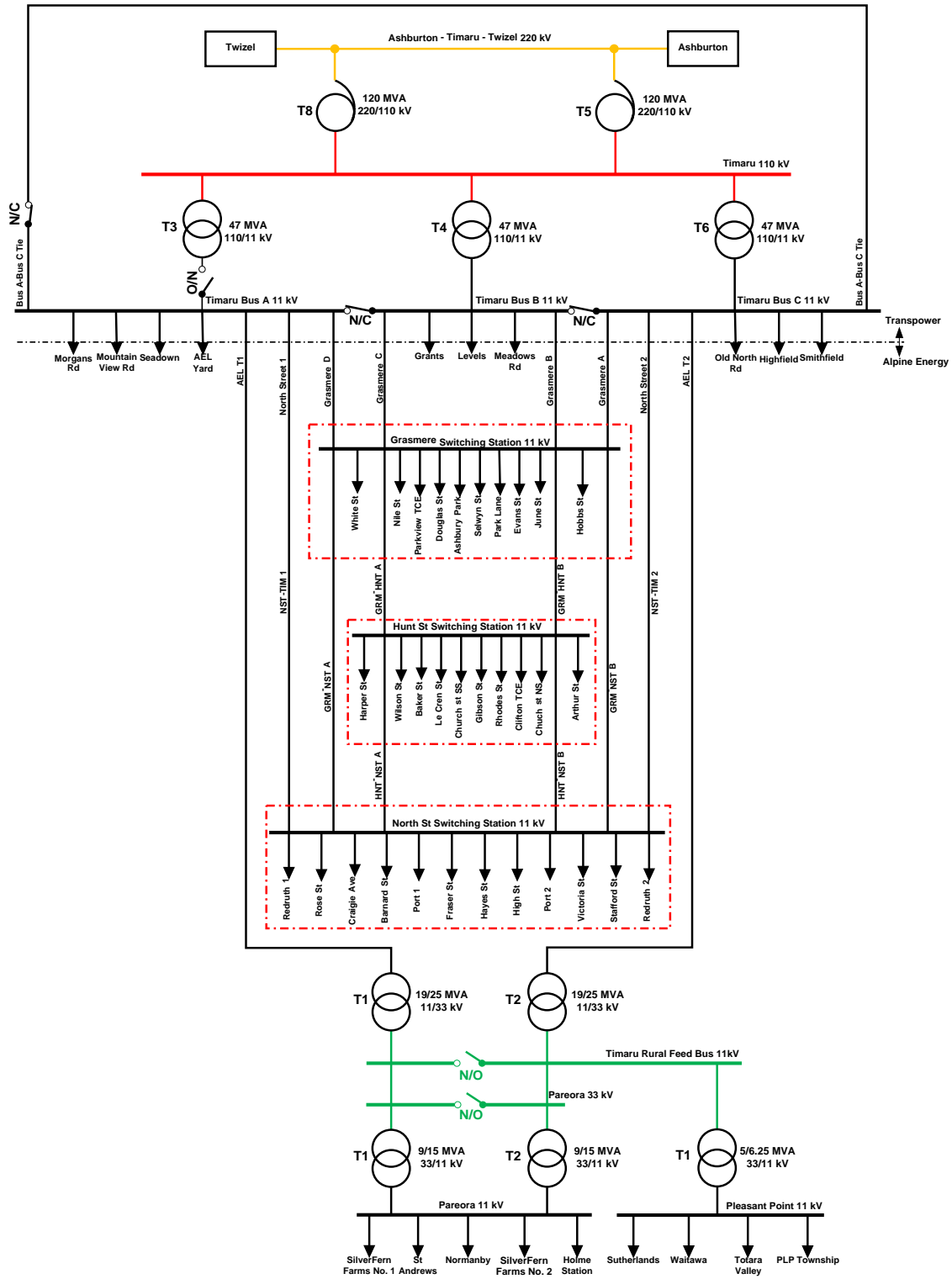


Figure G.7-1 Timaru area schematic diagram

### G.7.5 Zone substation detail

Table G.7-2 shows key data for our zone substation, the major assets with respect to rating, age, and general condition, and the maximum demand. The substation's purpose is to step up 11 kV to 33 kV to feed the PAR and PLP zone substations. The ripple plant is also located at the site. The Transpower 11 kV switchgear feeds the surrounding rural, residential, and Washdyke/Seadown areas.

**Table G.7-2 Timaru, Pareora and Pleasant Point zone substation equipment information**

Zone substation site	Transformer	Switchgear	Ripple plant	
<b>TIM</b>	2x 25 MVA T1 and T2 33/11 kV OLTC (2006) Good	3x 33 kV Reclosers (1986) Fair	1x Zellweger 317 Hz	
<b>PAR 9.6 MW</b>	9/15 MVA 33/11 kV T1 and T2 OLTC (2011) Excellent	6x 33 kV VCBs SF <sub>6</sub> isophases (2011) Excellent 9x 11 kV VCBs(2008) Excellent	N/A	
<b>PAR AMS ready</b>	Substation has N-1 security with two transformers.			
<b>PLP 4.8 MW</b>	5/6.25 MVA 33/11 kV T1 OLTC (1980) Good	1x 33 kV Recloser (1980) Good 5x 11 kV VCB (2006) Excellent	N/A	
<b>PLP AMS ready</b>	Yes.			
Zone switching station site	Transformer	Switchgear	Ripple plant	
<b>GRM 13 MW</b>	N/A switching station	20x VCBs (2012) Excellent	N/A	
<b>HNT 11 MW</b>	N/A switching station	16x VCBs (1984) Good	N/A	
<b>NST 11 MW</b>	N/A switching station	20x VCBs (2011) Excellent	N/A	
Sub-transmission line	Make up	Limit of conductor at 50°C (MVA)	Limit of cable (MVA)	Lowest limit
<b>GRM-TIM</b>	4x 11 kV 400 mm <sup>2</sup> Cu PILC Cables		7.5 per	7.5 per

	(1983) Fair		circuit	circuit
<b>GRM–HNT and GRM–NST and HNT–NST (11 MW)</b>	6x 11 kV 193 mm <sup>2</sup> Cu PILC Cables (1962) Fair		5.4 per circuit	5.4 per circuit
<b>NST–TIM (11 MW)</b>	2x 33 kV 1200 mm <sup>2</sup> Al XLPE Cables (2011) Excellent		14.6	14.6
<b>PAR–TIM 1</b>	Iodine/Petrel Cable 1/95	16.6/11.5	11.5	10
<b>Sub-transmission line</b>	<b>Make up</b>	<b>Limit of conductor at 50°C (MVA)</b>	<b>Limit of cable (MVA)</b>	<b>Lowest limit</b>
<b>PAR–TIM 2</b>	Iodine/ Cable 1/95	16.6	11.5	10
<b>PLP–TIM</b>	Quail/Dog/Weke/ 19/0.014 Cable 1/95	10.3/12.6/ 16.6	11.5	8.7
<b>Comms</b>	<b>VHF</b>	<b>UHF analogue</b>	<b>UHF digital</b>	<b>Fibre optic</b>
<b>TIM</b>	VHF for voice traffic	None	NST–CHC CHC–WDK (back up to fibre link break)	FO to WDK and back thru GRM/HNT to NST
<b>GRM/HNT/NST</b>	VHF for voice traffic	None	NST–CHC CHC–WDK (back up to fibre link break)	FO to WDK via a ring NST–WDK and NST– HNT– GRM–TIM– WDK
<b>PAR</b>	VHF for voice traffic	None	PAR–CHC CHC–WDK	None
<b>PLP</b>	VHF for voice traffic	None	PLP–BRC BRC–CHC CHC–WDK	None
<b>SCADA</b>	<b>Supervision</b>	<b>Control</b>	<b>Automation</b>	<b>Data acquisition</b>
<b>TIM</b>	Current, voltage and CB status at	TIM 11 kV CB control by	CB control	Load data at TIM

	TIM using SEL 3530's. Security at TIM.	Transpower. No remote control of 33 kV reclosers. TIM ripple plant on Abbey RTU to WDK via landline.		
<b>GRM/HNT/NST</b>	Current, voltage and CB status. Security.	CB control	CB control	Load data
<b>PAR</b>	Current, Voltage and CB status. Security.	Transformer and CB control	Transformer and CB control using SEL3032	Load data
<b>PLP</b>	Current, voltage and CB status. Security.	Transformer and CB control	Transformer and CB control using SEL3032	Load data

The capacity constraints on our network in the Timaru, Pareora, and Pleasant Point areas are shown in Table G.7-3.

**Table G.7-3 Timaru, Pareora, Pleasant Point network constraints**

Area	Constraint	Description	Remedy option(s)
<b>Timaru</b>	Timaru sub-transmission to CBD	High cable loadings	Investigate the application of inline reactors to better distribute sub-transmission circuit loadings.
<b>Pareora</b>	Pareora 1 and 2, 33 kV line regulation	Voltage constraint if total load exceeds 20 MW, or 10 MW in contingent event.	Shift some load to TIM and STU (as required). A paralleled feed from STU, first needs 110 kV system tied to get the 11 kV in phase. Alternatively, dead change overs are done.
<b>Pleasant Point</b>	Transformer capacity	Current load levels at 4.8 MW and expected load forecast will result in full capacity reached in 2027	Larger or second transformer towards the end of the planning period. Any new transformer to be selectable between Dyn11 and Dzn0 to suit TIM 33 kV GXP.

Table G.7-4 lists the existing level of security of supply at the substation and discusses configuration and options for security.

**Table G.7-4 Timaru, Pareora, Pleasant Point security of supply levels**

Zone sub/load centre	Actual security level	Target security level	Configuration and options
<b>TIM 33 kV step</b>	N-1 for PAR	N-1 for PAR	Two step-up transformers feed a split 33 kV

Zone sub/load centre	Actual security level	Target security level	Configuration and options
up zone substation	N for PLP	N for PLP	bus arrangement. PAR on each side of bus and PLP is fed off one bus with short duration loss with outage to that bus, until a tie is made to the remaining 33 kV bus.
Timaru Residential	N-1	N-1	None
Timaru Rural	N-0.5	N-0.5	Limited fault back up from adjacent feeders from TIM and then as second resort PAR, PLP and TMK. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
Washdyke/ Seadown	N-1	N-1	Four new 33 kV cable circuits from SDW to TIM to run at 11 kV will be installed in first quarter 2017.
Timaru CBD (GRM, HNT, and NST)	N-1	N-1	None
Redruth	N-1	N-1	None
Port	N-1	N-1	None
PAR 33/11 <sup>o</sup> kV zone substation	N-1 for transformers, 10 MVA for sub-transmission circuits	N-1 for all periods.	Some load can be transferred to STU and TIM in an emergency.
PLP 33/11 kV zone substation	N-0.5	N	Some load can be transferred from PLP to ABY, TMK and TIM in an emergency. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.

The estimated demand listed in Table G.7-5 shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table G.7-6.

**Table G.7-5 Timaru, Pareora, Pleasant Point load forecast**

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
<b>TIM</b>	70.4	0.6% (winter)	83.0 (winter)	0.6% historic some steps expected to come from: residential growth, heat pump uptake and industry growth (Washdyke).
<b>Timaru CBD</b>	30.4 (winter)	0.6% historic on TIM	35.0 (winter)	None required for local assets as substation and sub-transmission capacity is available. Existing assets can meet this demand and retain N-1 security.
<b>PAR</b>	8.7 (summer)	2.5% per year expected for residential load, dairy and irrigation development.	11.25 (summer)	Up-sizing of sub-transmission lines required to retain full N-1 security for expect load growth to the end of the planning period. Some security via 11 kV back up from STU and TIM.
<b>PLP</b>	5.2 (summer)	2% per year expected as TMK experiences residential load growth, and dairy and irrigation development.	6.3 (summer)	Existing transformer rated for the period. Some security via 11 kV back up from ABY, TIM and, TMK.

### **G.7.6** *Grasmere, Hunt St, and North St switching station detail*

GRM, HNT, and NST are switching stations, which mean the stations perform important switching, protection, and SCADA operations but do not transform voltages as for zone substations. Whilst NST is presently a switching station, there is space to fit 33/11 kV transformers when load requires the substation to be converted to a zone substation. These three switching stations are treated as zone substations with respect to operating and maintenance activities.

They are all connected via fibre to the control centre at Washdyke and a radio links from CHC to WDK and NST as back up.

### **G.7.7** *Development of GXP and substations*

Figure G.7-2 shows the historic TIM load growth.

### Timaru GXP historic load growth

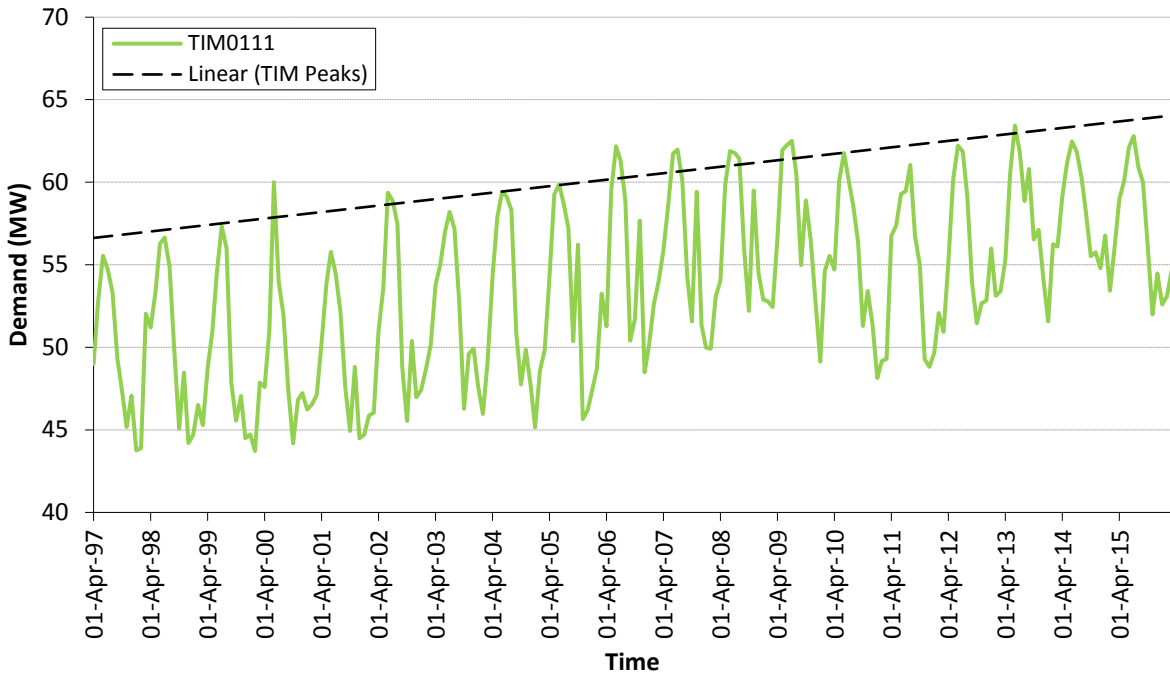


Figure G.7-2 Timaru GXP historic load growth

Table G.7-6 shows the maximum demand load forecast for the Timaru area which includes the TIM, TMK, ABY and TKA.

Table G.7-6 Timaru 110 kV bus load forecast

GXP substation (season peak)	Maximum demand load forecast (MW)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TIM 110 kV (summer)	122	125	132	130	138	140	143	145	155	157	160

Figure G.7-3 shows the TIM 110 kV bus load forecast, supply security level and capacity.

These inter-connection transformers supply the growing loads of ABY, TKA, TMK, and TIM. On occasion, additional load is required to be supplied south to BPD, STU, and OAM. During the dairy season STU is tied through. A tripping of the Waitaki feed into STU will lead to the inter-connectors combined load being taken beyond their 120 MVA individual rating; Transpower is investigating how to remedy this in the long term.

#### G.7.8 Substation growth trend and supply security

The TIM 110 kV bus capacity is monitored closely as it can run beyond firm capacity for the normal supply of ABY, TKA, TMK, and TIM. On occasion, supply to BPD, OAM, and STU could

be expected from this bus as well. With the 220/110 kV inter-connection transformers at capacity in a contingent event, ongoing load growth will result in a reduction in N-1 security for certain periods.

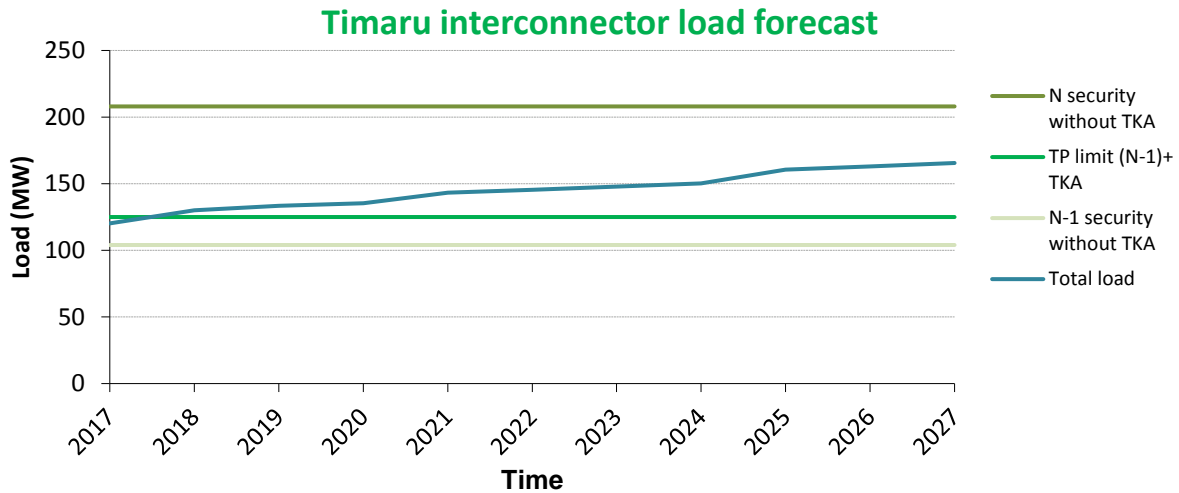


Figure G.7-3 Timaru 110 kV bus load forecast and supply security

Discussions with Transpower for load to be limited through the T5 and T8 interconnectors during maintenance periods is ongoing. Some 5 to 10 MVA may not be able to be supplied. During dry years generation at TKA is constrained, or if TKA released for maintenance, the situation becomes worse. A special protection scheme (SPS) has been installed to manage load shedding in the event where a contingency results in overloading of either T5 or T8.

Table G.7-7 shows the load forecast for the TIM GXP at 11 kV.

Table G.7-7 Timaru GXP load forecast

GXP substation (season peak)	Maximum demand load forecast (MW)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TIM 11 kV (winter)	66.4	68.2	69.8	70.5	74.1	75	75.8	76.7	77.4	78.1	78.8

Transpower has installed three new supply transformers. Two transformers supply load and the third is on hot standby<sup>72</sup>. The TIM 11 kV GXP has plenty of capacity for the planning period.

The 11 kV switch board was replaced in early 2012. The new board has been arranged to suit our needs for capacity and additional CBs to allow the new 33 kV rated sub transmission

<sup>72</sup> A method of redundancy in which the primary and secondary (i.e., backup) transformers run simultaneously.

cables for the CBD to be connected and run at 11 kV until the load growth requires an upgrade to 33 kV.

Figure G.7-4 shows the Timaru area load forecast, security level and capacity.

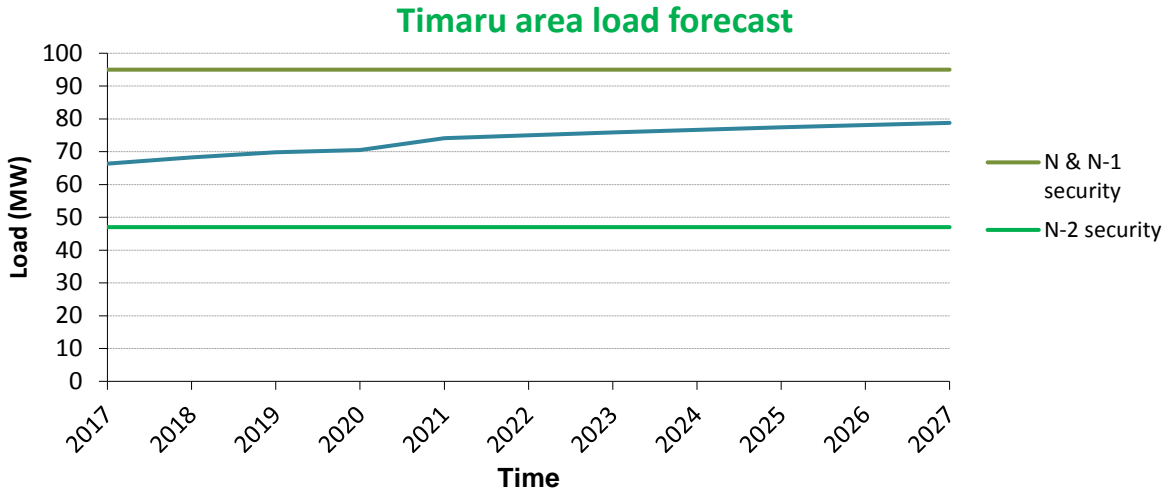


Figure G.7-4 Timaru area load growth forecast and supply security

Table G.7-8 shows the load forecast for the PAR and PLP zone substations.

Table G.7-8 Pareora and Pleasant point zone substation load forecast

GXP substation (season peak)	Load forecast (MW)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
PAR	8.7	8.9	9.1	9.3	9.6	10.0	10.4	10.6	10.8	11.0	11.3
PLP	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.1	6.2	6.3

Figure G.7-5 and Figure G.7-6 show PAR and PLP areas’ load forecast, security level, and capacity respectively.

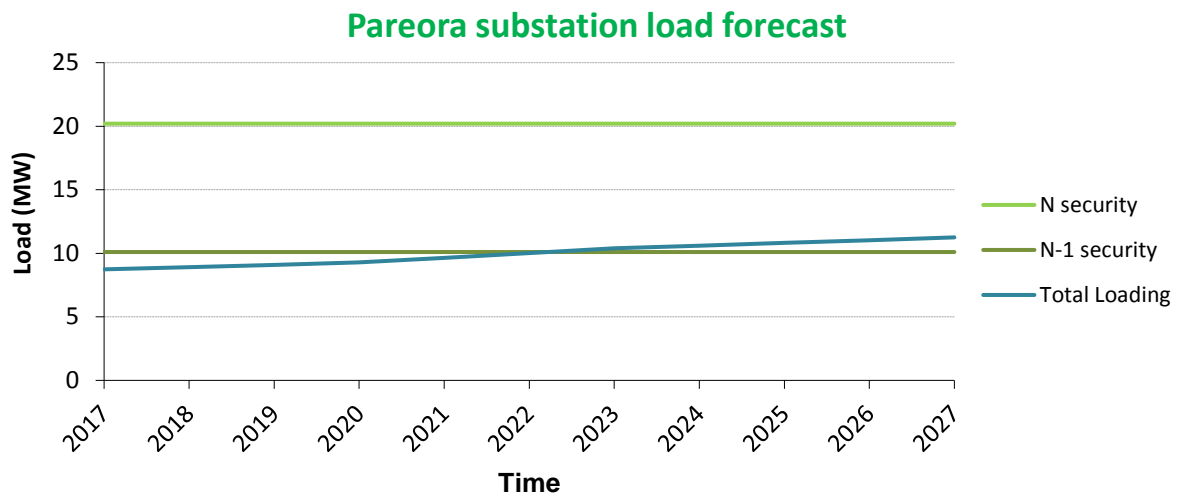


Figure G.7-5 Pareora substation load forecast and supply security

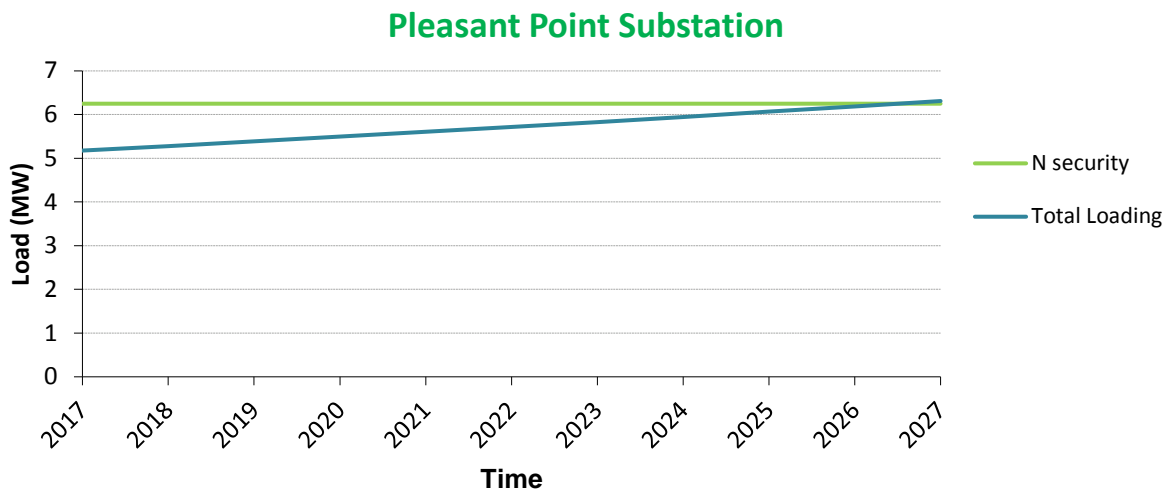


Figure G.7-6 Pleasant point load growth forecast and supply security

**G.7.9 Rate and nature of GXP growth and provisions made**

Table G.7-9 summarises the characteristic of the load growth and plans to meet the energy requirements.

**Table G.7-9 Timaru, Pareora, Pleasant Point growth and response**

Zone sub	Rate and nature of growth	Provisions for growth
TIM	Moderate—Industrial/commercial	GXP investment
PAR	Moderate—Dairy and irrigation	Zone substation and sub-transmission investment
PLP	Moderate—Dairy and irrigation	Zone substation and sub-transmission investment

### G.7.10 *Specific developments*

#### ***Timaru CBD and residential areas***

We have postponed the introduction of a 33 kV GXP since a large load that was expected did not eventuate. With the strengthening of the 11 kV sub-transmission supply to the CBD, no additional developments are planned.

#### ***Timaru–Hunt Street***

HNT was built in 1984 and is in good condition; vacuum circuit breakers (VCBs) are fitted. All the protection is now microprocessor based. This type of board has a nominal 40 year life; replacement will be based on condition assessment and should not be required until the end of the planning period.

#### ***Timaru 11/33 kV step-up substation***

Limitations within the equipment in the Timaru step-up substation (involving the existing 33 kV switchgear, Neutral Earthing Transformers (NETs) and protection) were originally expected to be eliminated with the proposed new 33 kV GXP at TIM. As this proposed 33 kV GXP has been delayed indefinitely, it is now necessary to upgrade the existing Timaru 11/33 kV step-up substation to provide adequate protection and control for the Timaru 19/25 MVA 11/33 kV step-up transformers and the three 33 kV sub-transmission lines (PAR–TIM 1, PAR–TIM 2, and PLP–TIM). Options will be developed and evaluated in the 2017/18 financial year.

The PAR and PLP zone substations are suitable for the immediate future. The PLP transformer load is monitored with a view to upgrade capacity at the end of the planning period.

## G.8 TWIZEL GRID EXIT POINT

### G.8.1 GXP description

Figure G.8-1 shows how Twizel GXP (TWZ) is configured with our network and Transpower's transmission network. TWZ is supplied off the 220 kV Twizel bus and supplies both us and Network Waitaki at 33 kV. It also provides a local service supply to Meridian and Genesis Energy at 33 kV which is not shown in Figure G.8-1.

TWZ supplies our TVS zone substation via a short 33 kV overhead sub-transmission. The TWZ-TVS supply is made up of a single 33 kV line, some tying ability to a NWL 33 kV line is available, and vice versa, to give limited security of supply from the TWZ 33 kV bus.

We have an indoor 11 kV switchboard with two feeders supplying Twizel township and two additional feeders supplying the surrounding rural areas. We have an embedded network in the Twizel township providing supply to new developments in this area. The embedded network is supplied from two connection points at Manuka Terrace and Mackenzie Park.

### G.8.2 GXP data

The GXP data shown in Table G.8-1 summarises the key physical attributes of the station, the voltages, capacity, security of supply, and power flow.

**Table G.8-1 Twizel GXP system data**

GXP	GXP transmission potential	GXP point of supply potential	Capacity	N-1 capacity	Demand 2016 <sup>73</sup>
TWZ	220 kV	33 kV	40 MVA <sup>74</sup>	20 MVA	3.1 MW

### G.8.3 Twizel GXP network information

Figure G.8-1 shows the TWZ GXP area network.

<sup>73</sup> This is Alpine Energy demand only

<sup>74</sup> This capacity is shared between Alpine Energy, Network Waitaki, Meridian Energy and Genesis Energy

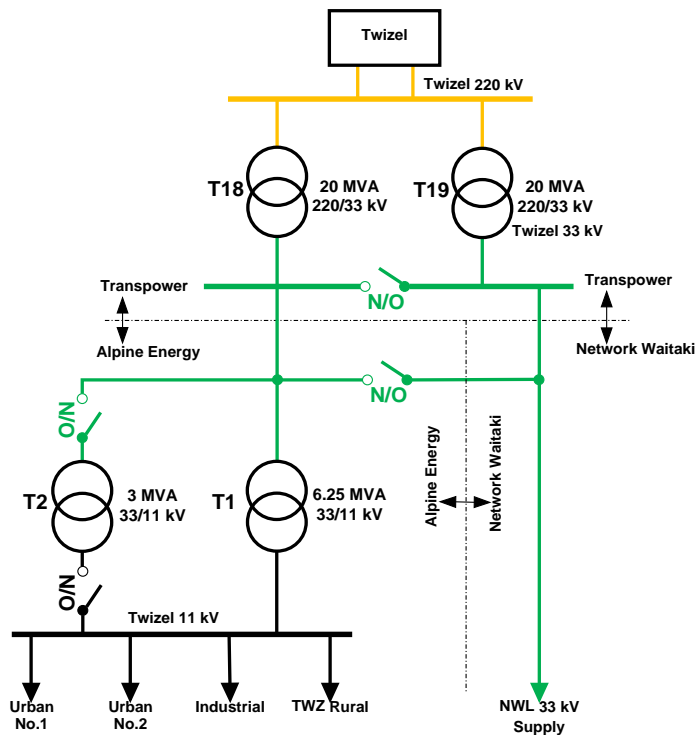


Figure G.8-1 Twizel area schematic diagram

#### G.8.4 Zone substation detail

Twizel is an expanding town that is popular as a holiday and tourism centre, being the nearest town to Mt Cook. It also serves as the main service centre in the Mackenzie Basin supporting agriculture, general engineering works, salmon processing and providing permanent accommodation for substantial numbers of Meridian Energy and Department of Conservation staff.

At present there is a peak demand of 3.2 MVA on a 5/6.25 MVA OLTC transformer, and 1951 vintage 11 kV BTH switchgear (with some Metro Vickers protection relays). The site was handed over from the Ministry of Works toward the end of the Upper Waitaki Power Development project. Condition assessment on the 11 kV switchgear shows it to be in serviceable condition. Some minor replacements of protection equipment were undertaken in late 2014.

TVS connects via radio systems detailed under communications in Table G.8-3 . TVS SCADA consists of L&N C68 RTU equipment.

The legacy RTU and analogue UHF radio communications will be replaced in 2017/18 with more modern digital equipment when the same type of equipment at TEK is replaced as

both TVS, and TEK substations use the same leased UHF radio link equipment at Mt Rollesby.

Table G.8-2 lists the existing level of security at the substation and discusses any shortfall.

**Table G.8-2 Twizel security of supply levels**

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
Twizel CBD	N-0.5	N-0.5	Limited 11 kV rings. We encourage consumers to self-manage their risk for outages for example, a Civil Defence emergency.
Twizel Rural	N	N	We encourage consumers to self-manage their risk for outages for example, a Civil Defence emergency.

Table G.8-3 shows the TWZ zone substation and sub-transmission key data, details the major assets with respect to rating, age, and general condition, the maximum demand and capacity constraints, TWZs' communication systems back to Meadows Rd and the SCADA functions.

**Table G.8-3 Twizel zone substation equipment information**

Zone substation site	Transformer	Switchgear	Ripple plant	
TVS	5/6.25 MVA 33/11 kV T1 OLTC (1972) Good	1x 33 kV OCB (1960) Poor 8x 11 kV OCBs (1951) Fair	438 Hz Landis and Gyr (shared with NWL, but we have no effective access)	
Sub-transmission line	Make up	Limit of conductor at 50°C (MVA)	Limit of cable (MVA)	Lowest limit
TVS-TWZ	Dog	12.6	N/A	12.6
Area of network with constraint	Capacity constraint	Description	Intended remedy	
TWZ GXP	None	N/A	N/A	
TVS	None	N/A	N/A	
TVS AMS ready	No, to be constructed in 2017.			
Communications	VHF	UHF analogue	UHF digital	Fibre optic
TVS	VHF for voice traffic	TVS-MRC MRC-WDK	None	None

SCADA	Supervision	Control	Automation	Data acquisition
TVS	Current, voltage and CB status at TVS. Security at TVS	TVS CB control. TVS pilot wire control.	Auto reclosing CB	Load data at TVS

The load forecast listed in Table G.8-4 shows the aggregated effect of substation load forecast for a 10 year planning period incorporating the anticipated step changes detailed in Table G.8-4.

**Table G.8-4 Twizel substation load forecast**

Zone sub site	2017 MW	10 year rate and nature of growth	2027 MW	Provision for growth
TWZ	3.7 (shoulder)	2.2% historic on TWZ Residential load, large scale subdivision, dairy and irrigation development.	6.6 (shoulder)	Possibly rebuild and/or relocate the substation which will include a transformer upgrade and new 11 <sup>o</sup> kV switchgear. Possible 33 kV line to new irrigation development and install smaller dedicated substations.

### G.8.5 *Development of GXP and substation*

Figure G.8-2 shows the historic TWZ load growth. This only relates to load supplied to us and not that supplied to Network Waitaki, Meridian Energy and Genesis Energy.

Twizel GXP historic load growth

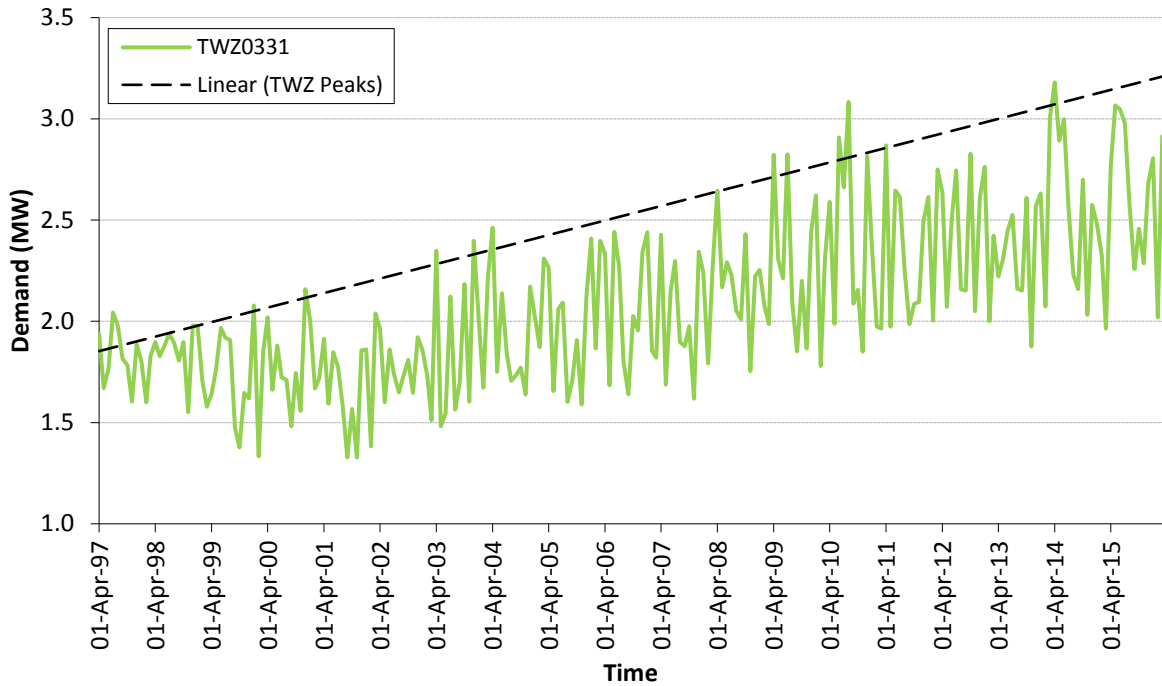


Figure G.8-2 Load growth for Twizel GXP

The load growth that was evident up to the 2009 international economic crisis has ceased. Growth is being monitored with a resurgence in new subdivisions in Twizel township.

Proposals for irrigation have been presented for the area on the Twizel side of the Waitaki River and as far as Simon’s Pass. If irrigation prospects proceed, a mix of 11 kV and 33 kV supply options are available depending on the size and location of the new loads.

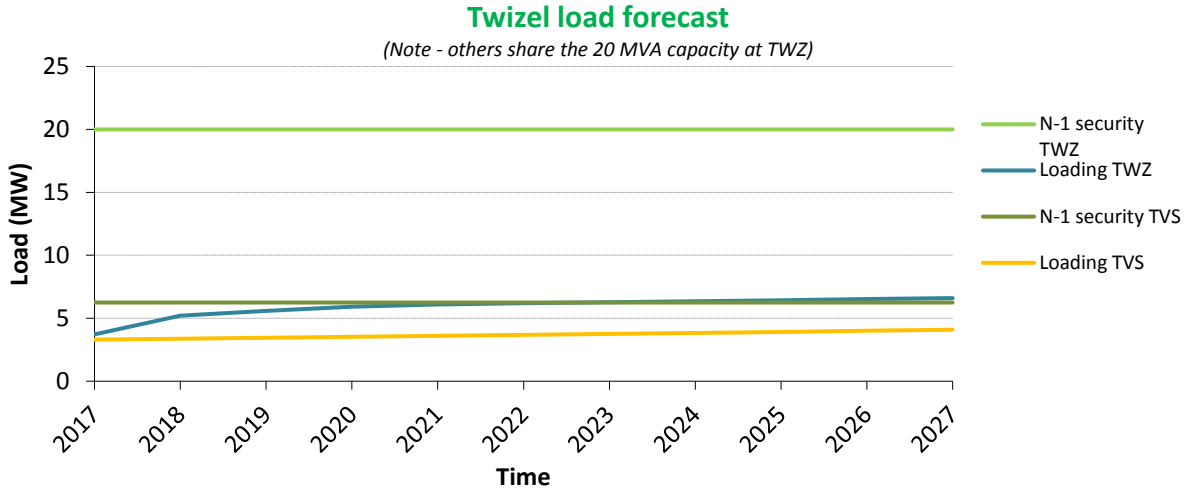
Table G.8-5 shows the load forecast for the TWZ area<sup>75</sup>.

Table G.8-5 Twizel zone substation load forecast

GXP substation (season peak)	Growth trend (Total MW MD)										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TWZ sum (autumn/spring)	3.7	5.2	5.6	5.9	6.1	6.2	6.3	6.3	6.4	6.5	6.6
TVS Village	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1
Irrigation on 33 kV	0.4	1.8	2.1	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

<sup>75</sup> The 20 MVA firm capacity is shared with Meridian Energy, Genesis Energy, and NWL.

Figure G.8-3 shown the load forecast for TWZ GXP as contributed by us and excluding NWL, Meridian Energy and Genesis Energy.



**Figure G.8-3 Twizel area<sup>76</sup> load growth forecast and supply security**

TVS zone substation has a transformer rated at 5/6.25 MVA. The transformer is fitted with an on-load tap changer (OLTC) which is important as the TWZ 33 kV bus voltage changes with differing generation patterns; this keeps the 11 kV voltage stable.

**G.8.6 Substation growth trend and supply security**

The load growth in Twizel in the tourism sector has stagnated with a slight reduction in peak demand. The highest loads occur on the autumn and spring holiday weekends, dependent on the weather at the time.

There have been enquiries for irrigation, but as we are uncertain about the potential for the loads to be realised we have forecast the load to increase from 2018 to 2022. The existing 11 kV distribution would be too light to carry the load that is being indicated. Further, indications are that the irrigation load will be remote from the TWZ substation. Accordingly we could need a new zone substation established to supply the load.

**G.8.7 Rate and nature of GXP growth and provisions made**

Table G.8-6 describes the rate and nature of growth at the GXP level as well as provision for growth.

<sup>76</sup> Others share the 20 MVA capacity at TWZ.

**Table G.8-6 Twizel growth and response**

GXP	Rate and nature of growth	Provisions for growth
TWZ	Med—Rural and subdivision	GXP investment

### G.8.8 *Specific developments*

#### ***Twizel GXP development***

Transpower's TWZ 33 kV GXP bus is run split, and is fed from two 20 MVA 220/33 kV OLTC transformers. The 33 kV bus was originally split as the 33/11 kV transformers are not able to withstand the full fault level. There is no 33 kV bus coupler or bus bar protection so running the bus tied would be problematic during a fault.

Our supply is not as secure as a tied bus arrangement, but this has been of little concern as the outage rate is very low. If a supply transformer is lost or released, Transpower can easily tie the two bus halves to the remaining transformer.

A sole 33 kV feeder is taken from the TWZ switching station to the TVS zone substation on the edge of Twizel. Preliminary discussions have been held with Transpower regarding the option of taking a second feeder.

Any project at TWZ substation will be funded via a new investment agreement with Transpower.

#### ***Twizel zone substation development***

Both the transformer and the 11kV switchboard are nearing the end of their expected life. We are planning to rebuild or move the substation in 2018. This will involve a new transformer as well as a new switchboard with upgraded protection and local service.

#### ***Ripple plant upgrade***

The ripple plant at TWZ is used by NWL. Currently all ripple relays in the area are controlled via their time clock function. Future ripple plant development will be based on an economic analysis. With the introduction of smart meters which have a load control function, the installation of ripple plants in areas of low population density and low electrical loads are questionable.

### G.8.9 *Capacity constraints at the GXP*

We have an N security supply at TWZ with ability to tie to NWL's feeder or to provide a reciprocal connection in case of NWL loss.

Transpower can also tie its 33 kV bus to connect our feeder to the alternate GXP transformer.

When Transpower replaces the outdoor 33 kV switchgear with an indoor switchboard we will be granted the opportunity to negotiate a second supply to our TVS zone substation.

## GLOSSARY

The following acronyms and abbreviations are used throughout the AMP.

A	—	Ampere
AAAC	—	All Aluminium Alloy Conductor
AAC	—	All Aluminium Conductor
ABS	—	Air Break Switch
ABY	—	Albury grid exit point/zone substation
ACSR	—	Aluminium Conductor Steel Reinforced
ADMD	—	After Diversity Maximum Demand
AHP	—	Analytical Hierarchical Process
Al	—	Aluminium
AMF	—	Asset Management Framework
AMG	—	Alpine Mobile Generator – 2 x 900 kVA (1 MW effective )
AMMAT	—	Asset Management Maturity Assessment Tool
AMP	—	Asset Management Plan
AMS	—	Alpine Mobile Substation – 33/11 kV (9 MVA effective )
AMS	—	Asset Management System
AVR	—	Automatic Voltage Regulator
BCL	—	Broadcasting Communications Ltd
BML	—	Balmoral Zone Substation
BPD	—	Bell’s Pond grid exit point/zone substation
Bus	—	Bus Bars

Capex	—	Capital Expenditure
CB	—	Circuit Breaker
CBD	—	Central Business District
cct	—	Circuit
CD	—	Civil Defence
CD1	—	Clandeboye No.1 Substation
CD2	—	Clandeboye No.2 substation
CDEM Act	—	Civil Defence Emergency Management Act
CFC	—	Greenhouse Gas
CFL	—	Compact Fluorescent Lamp
CNL	—	Canal Road Substation
CNR	—	Cooneys Road zone substation
Consumer	—	A person that consumes electricity from our network, or acquires electricity lines services
CPD	—	Coincident peak demand
CT	—	Current Transformer
Cu	—	Copper
Customer	—	A body which AEL has a direct contractual relationship with, normally in the form of a user of supply agreement, for example retailers and larger businesses
DCIU	—	Data Control and Interface Unit
DGA	—	Dissolved Gas Analysis
DNP	—	Direct Numeric Protocol
DO	—	Drop Out fuse
Dyn11	—	Transformer vector group

---

EAM	—	Enterprise Asset Management
EC	—	Electricity Commission
EDB	—	NZ Electricity Distribution Businesses
EEA	—	Electricity Engineers' Association
EF	—	Earth Fault
EMF	—	Electro Magnetic Field
FLE	—	Fairlie zone substation
FM	—	Frequency Modulation
GEC	—	General Electric Company
GIS	—	Geographic Information System
GLD	—	Geraldine Downs zone substation
GRM	—	Grasmere Zone Substation
GST	—	Goods and Services Tax
GWh	—	Giga Watt hours
GXP	—	Grid Exit Point
HDI	—	Hunter Downs Irrigation scheme (proposed)
HLB	—	Haldon/Lilybank zone substation
HNT	—	Hunt Street zone substation
HV	—	High Voltage
Hz	—	Hertz (a measure of frequency)
ICP	—	Installation Control Point
ICT	—	Information and Communications Technology
ID	—	Information Disclosure
IED	—	Intelligent Electronic Device

---

IPCC	—	Intergovernmental Panel on Climate Change
ISL–LIV	—	Islington Livingston
kN	—	kilo Newton
kV	—	kilo Volt
kVA	—	kilo Volt Ampere
KVAr	—	kilo Volt Ampere reactive
LOS	—	Loss of Supply
LTNZ	—	Land Transport New Zealand
LV	—	Low Voltage
MCC	—	Motor Control Centre
MDC	—	Mackenzie District Council
MDI	—	Maximum Demand Indication
MED	—	Municipal Electricity Department
MFE	—	Ministry for the Environment
MI	—	Mineral Insulated Cable
MSB	—	Main Switch Board
MT	—	Ministry of Transport
MVA	—	Mega Volt Ampere
Mvar	—	Mega Volt Ampere reactive
MVAr	—	Mega volt amp reactive
MW	—	Mega Watt
N-1	—	Reliability measure, where n systems can lose 1 element and still function normally
NER	—	Neutral Earthing Resistor

---

NET	—	Neutral Earthing Transformer
NIWA	—	National Institute of Water and Atmosphere Research
NSP	—	Network Supply Points
NST	—	North Street zone substation
NWL	—	Network Waitaki Limited
OAI	—	Orari grid exit point (proposed)
OAM	—	Oamaru grid exit point
OC	—	Overcurrent
OCB	—	Oil Circuit Breaker
OCTC	—	Off Current Tap Changer
ODL	—	Oceania Dairy Limited
ODV	—	Optimised Deprival Valuation
OLTC	—	On Load Tap Changer
OMS	—	Outage Management System
OPEX	—	Operating Expenditure (including maintenance spend)
OPU	—	Opuha power station
p.d.	—	Potential Difference
PAM	—	PAS 55 Assessment Methodology
PAR	—	Pareora zone substation
PAS 55:2008	—	Publicly Available Specification number 55
PC's	—	Desktop Computers
PCM	—	Protection, Control, and Measurements
PD	—	Partial Discharge
PIL	—	Paper Insulated Lead

---

PILC	—	Paper Insulated Lead Cable
PILCSWA	—	Paper Insulated Lead Steel Wire Armoured cable
PLP	—	Pleasant Point zone substation
POS	—	Point Of Supply
PROP	—	Participant Rolling Outage Plan
pu	—	per unit
PWC	—	Price Waterhouse Coopers
RGA	—	Rangitata zone substation
RMA	—	Resource Management Act
RMU	—	Ring Main Unit
RTU	—	Remote Terminal Unit
SAIDI	—	System Average Interruption Duration Index
SAIFI	—	System Average Interruption Frequency Index
SCADA	—	Supervisory Control and Data Acquisition
SCEPB	—	South Canterbury Electric Power Board
SCI	—	Statement of Corporate Intent
SDW	—	Seadown zone substation (proposed)
SEL	—	Schweitzer Engineering Laboratories
SSR	—	Solution Study Report
STA	—	St. Andrews grid exit point/zone substation (proposed)
STU	—	Studholme grid exit point
SVC	—	Static Var Compensation
TDC	—	Timaru District Council
TEK	—	Tekapo Village zone substation

---

THD	—	Total Harmonic Distortion
TIM	—	Timaru grid exit point/step-up zone substation
TKA	—	Tekapo grid exit point
TMK	—	Temuka grid exit point/zone substation
TP	—	Transpower
TPNZ	—	Transpower
TVS	—	Twizel Village zone substation
TWZ	—	Twizel grid exit point
UHF	—	Ultra High Frequency
UHT	—	Unwin Hut zone substation
V	—	Volts
VCB	—	Vacuum Circuit Breaker
VHF	—	Very High Frequency
VLf	—	very low frequency
W	—	Watts
WDC	—	Waimate District Council
WTK	—	Waitaki power station
XLPE	—	Cross Linked Polyethylene Cable
YNd9	—	Transformer vector group

## COMPLAINTS PROCEDURE (FREE)

At Alpine Energy we recognise that your complaint is important to you, and to us. We will endeavour to contact you within two working days of receiving your complaint to discuss the concerns you have and how we can find a resolution. This is a free service. In the first instance, any complaints should be sent to:

### ALPINE ENERGY LIMITED

---

Chief Executive Officer  
Po Box 530, Timaru 7940

---

P: 03 687 4300  
F: 03 684 8261

---

[mailbox@alpineenergy.co.nz](mailto:mailbox@alpineenergy.co.nz)  
[www.alpineenergy.co.nz](http://www.alpineenergy.co.nz)

---

## INDEPENDENT COMPLAINTS

If you prefer a free, independent approach to your compliant enquiry please contact:

### UTILITIES DISPUTES LIMITED

---

PO Box 5875, Lambton Quay, Wellington 6145, Freepost 192682

---

P: 0800 22 33 47 or 04 914 4630  
F: 04 472 5854

---

[info@utilitiesdisputes.co.nz](mailto:info@utilitiesdisputes.co.nz)  
[www.utilitiesdisputes.co.nz](http://www.utilitiesdisputes.co.nz)



ALPINE ENERGY LIMITED

PO Box 530 Timaru 7940  
New Zealand

P: 03 687 4300  
Fault line 0800 66 11 77

mailbox@alpineenergy.co.nz  
www.alpineenergy.co.nz

