Asset Management Plan

The 10 year management plan
for Orion's electricity network

1 April 2018— 31 March 2028

Orion is very aware of the importance of electricity to the wellbeing of our central Canterbury region. We are committed to providing our customers with a safe, reliable and cost-effective power supply, and with a friendly, responsive service.

Foreword

Welcome to Orion's 10-year network Asset Management Plan, which details how we plan to extend, maintain and reinforce our electricity distribution network over the next decade, to meet the needs of our community; all with a strong focus on the safety and wellbeing of the public and workers.

Our AMP is central to our day-to-day operations, and is a comprehensive, practical resource that captures the valuable insights and experience of our highly-skilled employees and customers.

Key issues discussed in the plan include:

- our approach to cost-effectively delivering a resilient and reliable network service
- our measures to mitigate and prevent major electricity outages
- our proactive approach to ensuring public, contractor and employee safety
- our continued investment in new technology.

We trust you find this report informative and we welcome your comments on it or any other aspect of Orion's performance. Comments can be emailed to john.langham@oriongroup.co.nz

Rob Jamieson

CHIEF EXECUTIVE OFFICER

Liability disclaimer

This Asset Management Plan (AMP) has been prepared and publicly disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012.

Some of the information and statements contained in this AMP are comprised of, or are based on, assumptions, estimates, forecasts, predictions and projections made by Orion New Zealand Limited (Orion). In addition, some of the information and statements are based on actions that Orion currently intends to take in the future. Circumstances will change, assumptions and estimates may prove to be wrong, events may not occur as forecasted, predicted or projected, and Orion may at a later date decide to take different actions to those it currently intends to take.

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When considering the content of this AMP, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgement and expert advice obtained.

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1.1 Business context

1.1.1 Purpose of AMP

Our AMP sets out our asset management practices and forecasts our expenditure requirements for our electricity distribution business. We update and publish our 10 year AMP in March each year.

This AMP looks ahead for the 10 years from 1 April 2018. Our main focus is on the first three to five years, with the highest level of certainty in the first year. Beyond three to five years our forecasts are necessarily more indicative as we respond to the changing needs of our customers and community.

Our AMP goes beyond the regulatory requirements of the Electricity Distribution Information Disclosure Determination 2012. We aim to demonstrate responsible stewardship of our electricity distribution network — in the long term interests of our customers, shareholders, electricity retailers, government agencies, contractors, financial institutions and the general public.

A cross reference of how the format of our AMP meets the regulatory information disclosure requirements is shown in Appendix B.

1.1.2 Business strategy

We believe our AMP supports our aim to work collaboratively with our customers to achieve successful outcomes. Our strategy is focused on:

- as our key priority, operational excellence in our core electricity distribution business
- opportunities for collaboration and efficiencies with other industry players
- profitable non-regulated activities
- the opportunities and challenges of emerging technologies and their integration into our core business.

Other key documents that form part of our annual business planning process are our:

- statement of intent
- business plan
- financial forecasts.

Our activities are guided by our vision "*Connecting communities, igniting innovation*" and our values "*Connect, Create and Collaborate*".

1.1.3 Asset management strategy and initiatives

Community use of electricity and expectations of the network that delivers it is changing. Electricity has always been an essential service but community dependence on it is increasing. Rapidly changing technologies are providing opportunities for our customers to produce, store, and consume electrical energy rather than primarily just consuming it. This change has the potential to alter the demands on our network assets and the services that our customers require. Our assessment is that while requirements will change, our customers will continue to rely upon our network services for the foreseeable future.

Our asset management framework provides structure and process that ensures that our decisions, plans, and actions are in alignment with our vision, values, and corporate goals. It is a hierarchy of documents and processes that provide a clear path from our corporate statement of intent and business plan, to our investment and operational decisions and actions.

Our asset management objectives are based around six focus areas:

- customers
- safe, reliable, resilient system
- health and safety
- environment
- capability
- future networks.

1.1.4 Asset management drivers

When we extend, replace, maintain and operate our network we consider the balance between cost, quality and safety of supply provided. The optimum point of investment in the network is achieved when the value of further expenditure would have exceeded the value of benefits to our customers. We seek to achieve this optimal point by whole-of-life economic analysis when we develop and review our asset management practices and expenditure requirements.

1.1.5 Asset management process

We undertake lifecycle management and asset maintenance planning using whole of life cost analysis, reliability centered maintenance (CBM), condition-based maintenance and risk management techniques. The techniques are based on performance and reliability targets. Our high level forecasts are discussed in section 3.

A Safety in Design standard is used to identify hazards throughout the lifecycle of assets from concept to disposal. The Safety in Design process aligns with industry best practice and ensures that designers carry out duties in line with the Health and Safety at Work Act 2015.

We have sets of standards and specifications to manage the health and safety, cost, efficiency and quality aspects of our network as we seek to standardise components, design and work practices. They are available to approved designers and authorised contractors over the Internet using an in-house document control process.

New equipment types are reviewed to carefully establish any benefits they may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost effective utilisation to support our supply security requirements.

Our routine asset inspection and maintenance process ensures that we meet our service level objectives. Our performance levels are measured to allow us to set optimal management standards to meet our customer and regulatory requirements.

1.1.6 Stakeholder interests

We have identified our key stakeholder interests through various forums and have instigated practices to accommodate these interests. If a conflict between stakeholder interests is identified then we will adopt an appropriate conflict resolution process to suit the issue and stakeholder concerns. Stakeholder/customer research is covered further in section 3 – Service levels.

Our key stakeholders are:

- customers (includes all end users of electricity)
- shareholders – Christchurch City Council Holdings Limited and Selwyn District Council
- community
- energy retailers
- Transpower
- government agencies - the Commerce Commission and Electricity Authority
- contractors and suppliers
- financial institutions
- employees.

1.1.7 Accountabilities and responsibilities

Orion's directors are appointed by its shareholders to govern and direct Orion's activities. The board is responsible for the direction and control of the company including commercial performance, business plans, policies, budgets and compliance with the law. The board receives formal updates from management of progress against objectives, legislative compliance and risk management and performance against targets.

It is our responsibility to identify capital works and maintenance programmes as detailed in sections 4 and 5 of this AMP, subsequently approved in an annual budget. The board reviews and approves our revised AMP prior to the start of each financial year (1 April). We then specify the work to be done by competent and appropriate consultants or contractors who work with us to meet our asset management objectives. They do not have direct network management responsibilities but operate on a fixed scope and/or period contract to meet the specific needs of the work/project requirements.

1.1.8 System, process and data management and innovation

Our information systems are used to record, develop, maintain and operate our business. Systems and information flows are shown in figure 2-8a.

Our website is logically divided into two distinct areas. One focuses on the delivery of information to our customers and the other is a services portal that manages third party access to a range of services.

The majority of our primary asset information is held in our asset database and GIS system. Due to improved asset management plans, regulatory compliance and better risk identification and management, information accuracy has improved. This enables the ability to locate, identify and confirm ownership and attributes of assets through our records.

We have started the implementation of a Distribution Power Flow (DPF) real-time modelling module within our PowerOn Network Management system. DPF will leverage the network model in our Network Management System to evaluate the outcomes of what-if scenarios and assess the performance of the network in different configurations.

1.1.9 Assumptions

We assume no major changes in the regulatory framework, asset base through merger, changes of ownership and/or requirements of stakeholders. We forecast a relatively small budget for the acquisition of remaining Transpower spur assets in our region.

We have based our service level targets on customers' views about the quality of service that they prefer. Extensive consultation over many years tells us that customers want us to deliver network resilience and reliability and keep prices down.

We have assumed no significant purchase/sale of network assets or forced disconnection of uneconomic supplies other than those discussed in the development of our network (section 5).

Our development plans acknowledge the reduced demand associated with the development of the Central Plains Water scheme and also the increased energy efficiency of businesses and households.

With assumptions regarding management of risk, although we have processes and resources to ensure business continuity as a result of a major event or equipment failure, we have not included the actual timing and financial consequences of a forecast/ hypothetical major event in our AMP forecasts.

The key assumptions for our cost forecasts are discussed in section 8.1 where all dollars are in FY19 terms and no allowance has been made for CPI adjustments, changes in foreign exchanges rates, or local labour, plant and material market rate changes. Refer to appendices for the expenditure schedules in nominal (inflation-adjusted) terms.

Potential uncertainties in our key assumptions include:

- regulation
- the city's rebuild
- changing customer demand
- high growth scenario
- resourcing of skilled contractors and staff due to demand.

Factors that may lead to material differences between our forecast and actual outcomes are discussed in section 2.9.5.

1.2 Service levels

1.2.1 Introduction to service levels

We endeavour to provide a level of service that meets the expectations of our customers in the long term. This is consistent with our vision, values and statement of intent (SOI). Our SOI contains specific service level targets for reliability (SAIDI, SAIFI) and other aspects of our business, some of which are outside the scope of this AMP.

In setting our service level targets we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and customer expectations.

1.2.2 Customer consultation

Customers are our most important stakeholders. We recognise that their individual expectations will differ and we endeavour to ensure that, as far as practicable, all are satisfied with the level of service we provide in the long term and that no one party is unfairly advantaged or disadvantaged. Keeping our network operating sustainably is about knowing our customers, what their needs and aspirations are, and ensuring we remain relevant in their lives.

We do that by actively consulting with them, and getting to know them better. We seek out our customers' views on possible future investment, our customer service and how they see emerging technologies offering new ways to manage their energy consumption. To determine customer expectations with regard to the level of service that we provide, we utilise six main methods of consultation. We detail information on these consultation methods in section 3.2.

Orion is committed to putting our customers at the centre of all we do, and we continue to work hard to better understand the needs of our customers and give them a voice in our decision making.

1.2.3 Service level measures

All of our consultation methods show that, almost without exception, a reliable supply of electricity at a reasonable price is our customers' fundamental requirement of us. We measure our performance against this primary customer requirement in a number of ways as shown in section 3.3.1.

Our primary service level measure is network reliability. Measures are applied as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These measures are:

- SAIDI, system average interruption duration index, measures the average number of minutes per annum that a customer is without electricity
- SAIFI system average interruption frequency index, measures the average number of times per annum that a customer is without electricity.

Extreme environmental events can have a major impact on the reliability of an electricity network. To moderate this impact, the current regulatory regime calculates a daily boundary value to cap the number of customer-minutes lost in the case of extreme events.

Other service levels we measure or monitor are:

- network restoration time
- network capacity
- network efficiency (utilisation, load factor, energy loss)
- power quality
- safety
- customer service
- environmental
- economic efficiency
- Resiliency.

1.2.4 Service level targets

Our targets are set inline with Orion's asset management strategy for the measures discussed previously.

Our primary reliability targets for SAIDI and SAIFI for FY19 are <81 and <0.92 respectively.

All our targets for FY19 and future years are shown in tables 3.4.1 and 3.4.2.

1.3 Lifecycle asset management

1.3.1 Network overview

Asset description

We own and operate the electricity distribution network in central Canterbury. Our network covers 8,000 square kilometres across central Canterbury between the Waimakariri and Rakaia rivers and from the Canterbury coast to the Main Divide at Arthur's Pass. For maps of network see figures 4-1a and 4-1b.

Table 1-3a **Orion's electricity network asset quantities**

Category	Description	31 March 2017
Subtransmission lines/cables (km)	66kV and 33kV	651
Distribution lines/cables (km)	11kV	5,811
	400V	4,778
Zone substations	66kV	27
	33kV	19
	11kV	7
Distribution/Network substations	Buildings	468
	Ground mounted	4,724
	Pole mounted	6,397
Customer connections		198,242

Customers

Customer densities range from five customers per km in rural areas to 26 in urban areas. Approximately 88% of our customers are located in the urban area of Christchurch with 12% in the rural area.

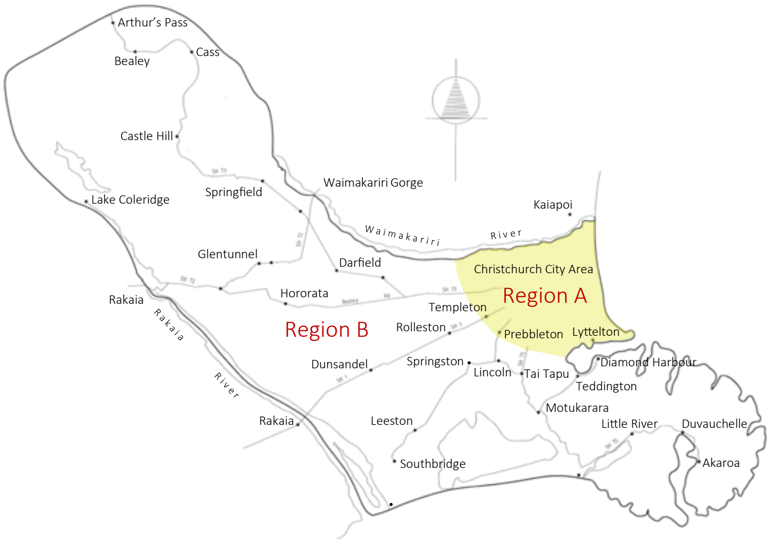
The Canterbury area and business sectors are largely service and/or agricultural based. This is reflected in the mix of approximately 325 major business customers connected to our network with loads ranging from 0.3MW to 11MW. The largest single load in this category is less than 2% of our total maximum demand.

Currently we have 17 customers that have an anytime maximum demand of greater than 2MVA. Each of these major customers is charged on a 'major customer connection' delivery charge basis. We individually discuss their security and reliability of supply requirements in relation to our normal network performance levels at the time of connection or upgrade.

Generally our operating regimes and asset management practices do not specifically provide enhanced levels of service for these customers. Many major customers run generators in response to our pricing signals and we have specific arrangements to run generators at approximately 40 connections at other times when it is beneficial for our delivery service.

As part of obligations under the Civil Defence and Emergency Management Act we have on-going discussions with life-line services such as the hospitals, seaport and airport to ensure appropriate levels of service are provided for in our future planning.

Figure 1-3a **Orion's electricity network area**



1.3.2 Asset management

Lifecycle asset management is the balance of cost, performance and risk over the whole of an asset's life (cradle to grave).

Through this process we must balance our shareholders' and customers' needs today, and in the future. Lifecycle asset management means taking a long term view to make informed and rational investment decisions to deliver our service levels at an appropriate cost and time.

Benefits of a whole of life approach are:

- minimised safety risks and future legacy issues through safety in design
- understanding capex/opex trade-offs
- establishing forecasts for operational and replacement expenditure, thus avoiding surprises
- minimised total cost of ownership while meeting accepted standards of performance/reliability.

Maintenance plan

We undertake lifecycle management and asset maintenance planning using whole-of-life cost analysis, reliability centred maintenance (RCM), condition based maintenance and risk management (CBRM) techniques. These techniques are used to inform our decision making and improve our performance.

Generally assets are not replaced on age alone, but are kept in service until their continued maintenance is uneconomic or until they have the potential to pose a health and safety, environmental or reliability risk. Reliability performance is measured and used to identify areas where further maintenance is needed to improve our delivery service or where maintenance may be reduced without affecting service levels. Our total network Opex forecast for FY19 is $29m (see table 4-3b).

Replacement plan

Traditionally asset replacement programmes were based on the age of assets. We identified very early on that this was not the most effective approach and have been using other factors such as condition and risk to help develop our replacement programmes. We have adopted an "asset class" condition based risk management (CBRM) approach for the replacement of our network assets. This approach utilises asset information, engineering knowledge and experience to define, justify and target asset replacements. Our total network replacement Capex forecast for FY19 is $27.8m (see table 4-3c).

Asset performance

Our asset management practices are used to reduce interruptions in both frequency and duration for customers. An in-depth reliability review was conducted in FY17 and FY18. This was a two stage project. Stage 1 looked at our current performance in areas of the network in direct response to feedback from our customers. This resulted in a number of initiatives with improved reliability for those customers. Stage 2 involved detailed analysis across all asset classes, throughout the network, to assess if further improvement could be or should be achieved.

Our analysis indicates the emerging reliability impact of some aging overhead assets that are further stressed from earthquake vibration and compounded by severe weather events. There has also been an external influence from increased construction activity in post earthquake Chistchurch.

1.4 Network development

1.4.1 Introduction

Developing our network to meet future demand growth requires significant capital expenditure. Before spending capital on our network, we consider a number of options including those available in Customer Demand Management and distributed generation. We also take account of the uncertainty arising from various scenarios related to solar PV, battery storage and electric vehicle uptake. The amount we spend on our network is influenced by existing and forecast customer demand for electricity and the number of new customer connections to our network.

The growth rate in overall maximum network system demand (measured in megawatts) traditionally drives our capital investment and is strongly influenced in the short-term by climatic variations. For FY18 the peak total supplied through Transpower's GXPs was 623MW, when there was 37% load shedding due to hot water cylinder management. For planning we look for the peak injection with maximum load shedding. For the few hours of higher load that sometimes occurs, we plan to encroach on the N-1 contingency capacity rather than build more network. For FY18 this peak was 605MW with 94% shedding. This was supplemented by export from distributed generators of 10.8MW. The maximum export recorded from embedded generators during the year was 12.7MW on the evening of 12 August 2017.

Our urban 66kV subtransmission and 11kV network architecture reviews have resulted in refinement of our subtransmission strategy as described in section 5.6.3. The construction of our post earthquake northern 66kV urban subtransmission link was completed in 2016. Our load forecasts have been updated with April 2017 post-quake population forecasts–the forecast also takes account of Christchurch City Council vacant industrial land uptake data to June 2017. The central city rebuild is forecast to add 12MVA to peak demand over the next five years.

1.4.2 Network architecture

Our network is supplied from seven GXP substations as shown in figure 5-2. The three remote GXPs at Coleridge, Arthurs Pass and Castle Hill have a single transformer and a much lower throughput of energy (together less than 1% of Orion's load). With the exception of Hororata and Kimberley all the GXPs peak in winter. Approximately 65% of our customers are supplied through the Islington GXP 220/66kV interconnection made up of two 200/266MVA transformers and one 250/310MVA transformer.

As detailed in section 4 we have a number of 66/11kV, 33/11kV and 11kV (with no transformer) zone substations. This AMP envisages one new region A (urban) zone substation and a capacity increase of transformers at two substations in the next 10 years. In our region B (rural) area we have a number of 66/33/11kV, 66/11kV and 33/11kV zone substations. This AMP envisages one new zone substation, a capacity increase of transformers at two and the partial conversion of one zone substation from 33kV to 66kV in the next 10 years.

1.4.3 Planning criteria

The first stage of planning a distribution network is to ensure that existing network loads are monitored and tested against existing network capacity. The capacity test involves checking adequacy during contingencies defined in our Security Standard and also predefined utilisation thresholds. When network inadequacy is identified, the process of developing solutions begins. Each potential solution is assessed for compliance with our design standards. Sections 5.3.1 to 5.3.5 discuss the main planning criteria considered when solutions are developed.

We monitor loads on our major zone substation 11kV feeder cables at half hour intervals. This information is used to prepare an annual reinforcement programme for our network. Reinforcements recommended in this plan are generally based on winter loading for metropolitan areas and on summer loading for farming areas.

When a capacity or security gap is identified on the network we consider different solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense.

We discuss our approach to increased capacity in our documents NW70.60.16 - Network Architecture Review: Subtransmission, NW70.60.06 - Urban 11kV Network Architecture Review, and NW70.50.05 - Network design and overview.

Prioritisation of network solution projects for capacity and constraints is a relatively complex process that involves multiple factors that are both external and internal to Orion.

The primary factors to be considered when prioritising projects, in decreasing order of significance, are:

- coordination with NZ Transport Authority and local authority civil projects
- satisfying individual or collective customer expectations
- managing contractor resource constraints
- coordination with Transpower
- our asset replacement programme
- our asset maintenance programme.

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we consider the following alternatives:

- customer demand management (ripple control, interruptible load, power factor correction)

- distributed generation
- uneconomic connections.

See section 5.3.5 for details of non-network solutions.

As well as controlling hot water cylinder load to manage peaks on our own network we also coordinate control of hot-water cylinders on other distributors networks to manage peaks on Transpower's Upper South Island network.

1.4.4 Energy, demand and growth

To effectively plan the future of our network, we need to estimate the size and location of future loads. However any load forecasting is an approximation. We know there is some uncertainty due to the drop in peak demand and energy consumption from a population decrease (particularly in the east of the city), increasing immigration and timing of the commercial rebuild in central Christchurch. Furthermore, a range of emerging technology uptake scenarios creates additional uncertainty.

Network development is driven by growth in peak demand not energy. In general, two factors affect load growth; population increases and changes in behaviour. At a national level it is reasonably easy to forecast population growth but when broken down to a regional level the accuracy is less, but still useful in predicting future demand.

Our Customer Demand Management strategies discussed in section 5.3.5 impact on our peak load forecast. Our forecast assumes that 2MW of diesel generation will be added to our network each year. This is commensurate with growth in diesel generation over the last five years. Because it is difficult to predict the location of new diesel generation, we have not attempted to apply the growth in diesel generation to the zone substation load forecasts. Instead we attempt to encourage diesel generation in constrained areas on our network by publishing the area specific network deferral value of Customer Demand Management initiatives (see section 5.6.11).

Energy throughput (GWh)

Network energy throughput for FY17 was 3,227GWh (including export from distributed generation of about 7.4GWh), down 2.1% on the previous year. The 20-year pre-earthquake history shows an average steady growth rate of about 1.7% each year. For the six years post earthquakes, energy growth was lower than the long term average at 1.0%. Environment Canterbury's Clean Air Plan has had only a modest impact on energy use, as surveys suggest that the high conversion rates of solid fuel burners to heat pumps has been balanced in part by other customers switching from resistive heating to higher efficiency heat pumps.

We have observed a downward step change in energy demand as a result of the February 2011 earthquake. For several years recovery was limited by demolition work in the Central City and in the east. We expect the new business and residential buildings will be more energy efficient than the older buildings they replace, and the Ōtākaro Central City Recovery plan also implies fewer, much smaller rebuilds. The increase from the Central City rebuild started having an impact in 2016. However this is offset by the Central Plains Water Scheme which is reducing energy use. See figure 5-4d for the projection of pre–quake and post-quake growth rates.

Maximum demand (MW)

Maximum demand is the major driver of investment in our network. This measure is very volatile and normally varies by up to 10% depending on winter weather. Because our network demand peaks during the winter, we can publish the FY17 peak in this AMP. Our network maximum half hour demand for FY17 was 605MW (the peak that occurred on 12 July 2017), up 18MW from the previous year.

Forecasting peak demand has challenges (on top of the earthquakes) including uncertainties with the global economy and the uptake of battery storage and electric vehicles. Prior to the earthquakes, the long and short term trends show a demand growth rate of just under 1% per annum. It appears this rate may have slowed recently, however this is not clear. In the short term the Central City rebuild is forecast to add 12MW to demand. Historic and forecast network demand is shown in figure 5-4e.

Load duration

With constantly changing load on our network, the peak demands that determine network capacity generally only occur for very short periods in the year. Figure 5-4h shows that Customer Demand Management has been successful in flattening the load curve in recent years. Control of the dominant winter maximum demand depends heavily on suitable price signals, and customers' response to them. If this is to continue to be effective then it is important that electricity retailers continue to support Customer Demand Management initiatives. Of particular importance is the promotion of night-rate tariffs and load control via the on-going installation and maintenance of ripple receivers.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions that may last for only a few hours. Generation at peak times can help to delay the need for increases in Transpower's network capacity. Generation may also be used to reduce Transpower's charges. If used for this purpose, longer hours of operation might be needed, especially to avoid reductions in water heating service levels.

Region B load growth

In contrast to region A, growth rates for our summer peaking region B (rural) have been high over the last 10 years. Since FY02, customer applications to connect new load to region B have been reasonably consistent (with an increase in Rolleston and Lincoln in the post quake period).

Despite growth in the townships which contributes to winter demand, region B is still dominated by the summer peaking rural customers. Stage 1 of the Central Plains Water Scheme (CPW) came online for summer 2015/16. The Sheffield scheme is planned for summer 2017/18, and Stage 2+ for summer 2018/9. Within the CPW area, conversion of existing ground water pumps to the pressurised CPW scheme is forecast to continue to substantially reduce summer load on two zone substations. See figure 5-4h for recent summer load growth in region B.

Load growth forecasting

Our network feeds both high density Christchurch City loads and diverse rural loads on the Canterbury plains and Banks Peninsula. Growth in electricity consumption can occur from an increase in population and also the introduction of new end use applications. Growth in electricity consumption in the city and on Banks Peninsula has historically matched growth in population (holiday population for Banks Peninsula). Conversely, electricity growth on the Canterbury plains has not matched population growth but has been driven by changes in land use and hence changes in electricity use.

Winter peak demand on our network is mainly driven by growth in the city and townships and is anticipated to increase by approximately 80MW (13%) over the next 10 years. Our region B network peaks in the summer and it is anticipated to increase by approximately 15MW (12%) in the next 10 years, with most of this in the next couple of years.

The network development projects listed in this ten year plan seek to ensure that capacity and security of supply can be maintained for the growth rates described above. Actual growth rates are monitored on an annual basis and any change would be reflected in next year's development plan.

1.4.5 Network gap analysis

On an annual basis, our network planning group updates contingency plans for all valid subtransmission (220kV, 66kV, 33kV) and 11kV contingencies. In some cases the Security Standard criteria for 'no interruption' or 'restoration time' of load cannot be economically met. In general, network security gaps fall into one or more of the following categories:

- solution is currently uneconomic and an economic solution is not anticipated in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but future network expansion in adjacent areas is expected to provide a security improvement
- solution requires co-ordination with Transpower's asset replacement programme and/or is subject to Transpower/Commerce Commission approval.

The economic analysis for each network gap determines the value of lost load (VOLL) when a defined contingency occurs and then utilises probability theory to determine the annual VOLL.

The network gaps identified in the tables in section 5.5 arise because the cost of reinforcing the network to the performance level identified in our Security Standard would be economically prohibitive.

1.4.6 Network development proposals

The network development projects proposed in this AMP are driven mainly by the need to meet the capacity and security requirements of load growth. Where economic, project solutions have been designed to meet our security of supply standard requirements.

This ensures that our network configuration and capacity is constructed in a consistent way and the impact on our supply service levels will be predictable. It should be noted that reliability of supply service levels are a function of many inputs and, while network configuration and capacity is a major input, it is not the only factor. Project solutions also need to consider our safety, power quality, environmental and efficiency targets.

Overview of projects

Projects for the current year can be considered firm. Those planned for the following four years will be reviewed annually, and may not proceed as currently envisaged. Projects for the remainder of the period are indicative only because of uncertainties as to the nature and magnitude of future loads. For details of projects see section 5.6.

A summary of the options for the major projects has been provided. Because most of the projects beyond the current year are still subject to a final review and refinement, it is possible that actual implementation may differ from that proposed if new information becomes available before the need to start detailed design. For projects beyond the current year, the value per kW of deferral has been tabled in section 5.6.9 to provide a guide to potential Customer Demand Management providers.

Although GXP alterations are not carried out directly by us, they are included here to provide a greater understanding of the capacity and security issues we face. Transpower is to undertake the GXP projects to improve the capacity, security and quality of supply to our customers. They will meet the initial capital cost and then charge us an annualised amount for the use of the additional assets. Transpower costs are essentially passed through to us to be recovered from our customers.

Urban 66kV subtransmission review

From FY08 - FY12 we met growth within region A without the need to invest significantly in the subtransmission network. Following the earthquake we anticipated that new zone substation capacity would be required towards the north of Christchurch City at Waimakiriri and Marshland. The capacity of our pre-earthquake 66kV subtransmission network in the area was not sufficient to supply any proposed new zone substations. Permanent damage sustained to our 66kV network from the earthquake meant our network capacity was further reduced.

In FY14 we started to invest significantly to replace capacity in the east and meet the electrical needs of northern Christchurch customers. These investments significantly shaped the long term security and reliability of supply outcomes for the northern part of Christchurch City.

In an environment where our standard of living and health is so heavily dependent on a reliable electricity supply it has become increasingly important that our network is resilient to a wide range of factors. The earthquakes prompted the need to review the architecture of our network and our network security of supply standard and a reconsideration of the Christchurch subtransmission network was carried out in FY12. This review is described in our Network Architecture Review - Subtransmission (NW70.60.16).

Transpower spur assets

Transpower owned or owns a number of 66kV, 33kV and 11kV assets in our network area (see figure 5-6a). Many of these assets do not form part of Transpower's core grid and deliver electricity solely to our network. We call these assets 'spur assets' to Transpower's grid and they fundamentally serve the same purpose as our own 66kV, 33kV and 11kV distribution network assets. In recent years, we have also entered into New Investment Agreements (and other small agreements) with Transpower for the upgrade of Transpower spur assets at some of these GXPs.

Although the spur asset purchases included in this AMP reflect the most likely outcome, they are subject to Orion and Transpower board approval.

In addition to the purchase costs tabled, the ownership of Transpower spur assets will also require an increase in our budgets for reinforcement, replacement, maintenance and operations. Additional capital expenditure as a result of the spur asset purchases associated with growth, reinforcement and replacement has been incorporated into this AMP.

1.5 Business support

1.5.1 People

This section describes our forecast opex to plan, operate and administer our network operations. It does not include opex on our network assets, consistent with the Commission's required expenditure breakdowns and definitions.

Our most significant opex in these categories is remuneration for our employees who undertake these tasks.

1.5.2 System operations and network support

This category covers operational expenditure where the primary driver is the management of the network and includes expenditure relating to control centre and office-based system operations. Approximately 75% of our employees are in this category. Our forecast for employee FTEs at the start of FY19 is 151. Non-network opex for FY19 is $19.2m.

The primary functions of this group are:

- Network asset management
- Lifecycle management
    - Asset data systems
    - Contract delivery
    - Lifecycle
- Network operations
    - Control centre
    - Release planning
    - Field response
    - Operations services
    - Network access
- Contact centre
- Engineering support
- Network growth and planning
- Quality, health, safety and environment
- Infrastructure management.

1.5.3 Business support

This category covers opex, other than that included in system operations and network support. Around 25% of our employees are in this category. Our forecast for employee FTEs at the start of FY19 is 50. Non-network opex for FY19 is $15.4m.

The primary functions of this group are:

- People and strategy
- Finance
- Information solutions and technology
- Commercial, regulatory, communications and engagement
- Corporate, governance and risk

- Board
- Insurance
- Property
- Fleet.

1.5.4 Buildings

We carry out regular inspections of our buildings to ensure that they do not deteriorate further as a result of the seismic activity that the area has experienced. Several databases are used to assist us with the management process such as our asset register and our works management system. We also use a 'fault incident report' database to collect any faults or safety issues with our corporate properties. For any instances where further expertise is sought we employ an external consultant to offer an independent judgement to assist in the decision making process for any maintenance or repair programmes.

We currently have no plans to dispose of any corporate property.

Administration building

As a lifelines utility (under the Civil Defence Emergency Management Act 2002) providing essential services to the community, we are required to be operational after a significant event. Our administration building was built in FY14 to Importance Level 4 (IL4) standard. This means that the building is designed to remain operational following a 1 in 500 year seismic event. The building is also equipped with a standby generator with 500 litre diesel tank.

Waterloo depot

The Waterloo depot has been purpose built by Orion to provide a fit for purpose and resilient depot for Connetics. Orion will retain ownership of the site with Connetics entering a long-term 'arms-length' lease arrangement. The building was completed and Connetics relocated in early 2018.

Rental Properties

We own nine rental properties of which four are residential properties adjacent to zone substations. Some of these were acquired as part of a package when substation land was purchased. Others have been strategically purchased to allow the substation to expand if necessary. We receive income from these properties in line with the local rental market.

1.5.5 IT Corporate

Our corporate business information systems and productivity software support cross-organisational processes within Orion. They include financial systems, employee management systems (e.g. human resources, payroll, health and safety) and personal productivity software (desktop applications, email, web and document management). Our supporting computer infrastructure hosts, connects and provides the physical tools for access to our information systems.

In most cases we manage our computer infrastructure rather than outsource to third parties because of the critical nature of some of our information systems and the need for them to be continuously connected in real time to equipment on the electricity network. In some cases however it is more appropriate to deliver services on a system hosted by a third party, such as our payroll system and parts of our website.

All systems are supported directly by the Orion information solutions group with vendor agreements for third tier support where appropriate. We employ a standard change management approach to all software and hardware systems. Major changes to all corporate business information systems will follow the predefined steps of project proposal / concept socialisation, business case and approval, business requirements and implementation via a project. All project costs are capitalised.

Our budgeted replacement costs are shown in section 8.2.2 – Capex - Non network.

1.5.6 Vehicles

We own 97 vehicles to enable us to operate and maintain our electricity network and to respond to any events. Of these vehicles 11 are either electric powered or petrol/electric hybrids.

Our vehicles are relatively new and regularly maintained and as a result they are in good condition. All vehicles within their warranty period are serviced according to the manufacturers' recommended service schedule by the manufacturers' agent. For vehicles outside of their warranty the servicing requirements are also maintained in accordance with the manufacturers' specifications by a contracted service agent. Our budgeted maintenance costs are in section 8.2.1 – Opex - non network.

Our fleet replacement plan aims to replace vehicles on a like-for-like basis, where applicable, when the vehicle reaches its designated age or distance covered. Where possible we purchase vehicles that better fit our purpose and where there is a demonstrable gain in safety, efficiency, reliability and value for money. Vehicles are typically disposed of via auction. Our budgeted replacement costs are in section 8.2.2 – Capex - non network/vehicles and mobile plant.

1.6 Risk management

1.6.1 Introduction

We aim for proportionate risk management and continuous improvement. Proportionate means that we aim to identify and treat our key risks in cost-effective and practicable ways that prevent harm to person or property.

Our risk management objectives are based on the international risk management standard ISO31000-2009. Our risk management policy document (OR00.00.28) outlines our objectives.

Our risk management processes aim to control the potential for uncertainty and negative events that prevent the achievement of our objectives, and to identify opportunities to enhance the achievement of our objectives.

We monitor and review our processes to ensure that new information and context are understood and incorporated. Our communicate-and-result loop helps to ensure that we follow our processes and learn and continually improve our risk management.

1.6.2 Our risk management context

As a lifelines utility, section 60 of the Civil Defence Emergency Management (CDEM) Act requires us to ensure that we are '*able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency*'.

Our service area of Christchurch and central Canterbury is in an earthquake zone and near the Alpine fault. It is dependent on a resilient and reliable supply of electricity due to cold winters, no reticulated natural gas and restrictions on the use of solid fuel heating systems.

Our industry is rapidly evolving, with new technologies changing the way in which our customers consume, produce and store energy, potentially impacting the use of our network assets and the business model. Our business is regulated and we have statutory obligations that we must uphold.

In making risk management decisions we seek to properly understand how risks if realised would affect our objectives and the interests of our stakeholders, and we develop mitigating responses that are proportionate and in the long-term interests of our customers.

1.6.3 Our overall risk appetite

Given our risk management context that we outline in section 7.2 above, we have a cautious (relatively risk-averse) risk appetite for our network asset management approach.

Our caution risk appetite is consistent with our statement of intent (SOI) objective to act in the long-term interests of our customers, our community and our shareholders.

1.6.4 Our risk management responsibilities

Our risk management responsibilities begin with risk identification in all areas of our business, within the context of our objectives and operating environment. These risks are recorded in our risk registers. Our board oversees risks that have the greatest potential to adversely affect the achievement of our objectives. Management regularly reports to the board on those key risks. Our everyday risk management is mostly handled by line managers as part of their normal duties.

High impact low probability (HILP) events such as natural disasters, pandemics or cyber-attacks necessitate situation specific reporting and responsibility structures – and a plan-to-plan approach. Each HILP event will be different and so it is not possible or desirable to fully prescribe detailed procedures before such events. The CDEM Act requires us to function during and after an emergency (and have plans to support this), participate in CDEM planning at national and regional level if requested and provide technical advice on CDEM issues where required.

We have aligned our disaster and crisis risk responsibilities using the Civil Defence 'four R's' approach to resilience planning—reduction, readiness, response and recovery. Our summary of other key service organizations' lifeline interdependencies in our network region is shown in table 7-5f.

1.6.5 Our risk management process

Our ongoing risk assessments mostly follow the international standard. We approach our network resilience planning from two perspectives:

- first, we aim to reduce the impacts of future significant events by how we design, construct and operate our network
- second, we aim to ensure that we have a fit for purpose respond and recover capability.

We have a number of key network resilience documents and contingency plans that address risks to our network from asset failure, natural disaster, transmission grid emergencies and access by unauthorised persons. Additional to these network plans we also have plans for communication to our stakeholders and general business continuity.

1.6.6 Our key risks

The key risks to our electricity delivery service are shown in table 7-5b for a natural disaster and table 7-5c for asset failure.

We believe that our greatest natural disaster risk is a major earthquake – most likely the Alpine Fault, which is currently rated at a 30% chance of an 8.0 magnitude event in the next 50 years. We rate this as a medium to high risk, one with potentially major consequences for our network and for our wider community. Now that we have substantively completed our post-quake network recovery projects, we believe that our network and our operational preparedness are in good shape.

Legacy network assets that do not meet our current standards and potentially pose an unacceptable risk are inevitable with long -life network assets. As we become aware of them, we assess the risks and decide on our priorities and timeframes to eliminate or mitigate those risks. Our actions may include replacement over time or interim mitigations until full replacement can be practicably achieved. Our legacy asset treatments are described and forecast as lifecycle opex and capex.

Our electricity distribution network spans diverse terrain and ever-changing environmental conditions. Electricity is potentially harmful and our network has hundreds of thousands of individual components of many different types that have been installed over many years. These factors are typical of electricity distribution networks and they are important context – electricity distribution networks are inherently potentially hazardous to our employees, our contractors and the public. So we take all reasonably practicable steps to minimise harm to person and property.

We take all practicable steps to prevent undue harm to the environment. We have a documented environmental policy and we maintain an environmental risk register (NW70.10.06).

For our approach to insurance and other comments about our risks and risk management see section 7.6.

1.7 Financial forecasts

1.7.1 Network Opex and Capex

Our forecasts are based on our network opex and capex programmes and projects as detailed in sections 4 and 5. These forecasts are based on the best information available regarding the timing and extent of the post earthquake key recovery projects. Whether or not these projects will proceed, and the timing of them, is determined by Government and local Authorities and/or Developers. A summary of our forecast expenditure is shown in the following:

Table 1.7a Summary of forecast network expenditure – $000

Budget	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Opex - Network	29,035	28,540	27,640	27,595	27,410	27,410	27,510	27,460	27,460	27,460	**277,520**
Capex - Network	61,007	60,617	57,022	60,167	60,732	57,717	68,305	68,463	70,958	54,132	619,120

1.7.2 Changes from our previous forecasts

Changes described in these budgets are referenced to our last published AMP (for the period from 1 April 2017 to 31 March 2027). All forecasts are now in FY19 dollar terms (previously in FY18 dollar terms).

Opex - Network

Details of our maintenance plans are described by asset type in section 4 – Lifecycle asset management.

Our opex forecasts are generally consistent with last year's forecasts.

Capex - Network

ASSET REPLACEMENT

Our asset replacement plans are described by asset type in section 4 – Lifecycle and asset management.

Our replacement programme is broadly consistent with last years forecast with the significant exceptions of:

- increasing our Pole replacement programme (see section 4.8.6 & 4.9.6)
- a new programme introduced from FY24 onward for the replacement of our 66kV oil filled cables (see section 4.10.6).

CUSTOMER CONNECTIONS AND NETWORK EXTENSIONS

Our load demand forecasts are detailed in section 5 – Network development. Our network extensions and customer connection cost forecasts are based on our current and forecast business and residential growth forecasts. We are expecting one further year of strong household connection numbers. Thereafter falling to 2,500 pa in the medium term and 2,000 pa in the last five years of the AMP period. The Christchurch CBD will continue to have growth replacement buildings and developments occurring over the next 10 years.

ASSET RELOCATIONS

Underground conversions are carried out predominantly with road works, at the direction of Selwyn District Council (SDC), Christchurch City Council (CCC) and/or the New Zealand Transport Agency (NZTA). Costs associated with these works can vary depending on council or roading authority demands. Currently the CCC has indicated they will not be carrying out undergrounding within the next few years. SDC is continuing with its on-going programme. Undergrounding associated with NZTA projects has currently provided works that have compensated for the reduction by CCC. We estimate that activity will decrease after the major Roads of National Significance (RONS) Programme is completed by NZTA over the next few years.

REINFORCEMENT

Our 11kV reinforcement forecasts remain constant at $3.5M per annum. Our reinforcement forecasts are in section 5 – Network development.

MAJOR PROJECTS

Our major projects have a long term focus to meet forecast growth while delivering our resilience, reliability and security of supply objectives. They typically include new 66kV subtransmission lines or cables and/or new 66/11kV zone substations.

Our overall major project ten year budget forecast is relatively stable but there have been a number of timing changes. The following changes mainly reflect changes to customer plans:

- Steels Rd - deferral of substation and line from FY19 to FY20
- Dunsandel - deferral of transformer upgrade from FY19 to FY20
- Railway Rd - deferral of 11kV substation from FY20 to FY21
- Shands Rd - deferral of land acquisition for switchyard from FY19 to FY20
- Hawthornden - bring forward of tee-off from FY23 to FY22
- Porters Village—deferral from FY19 to FY22
- Hills Rd - deferral of substation upgrade from FY19 to FY21.

1.8 Evaluation of performance

1.8.1 Introduction

In this section we review our performance against targets stated in our previous AMP. These targets may be actual values as stated in section 3 or a declaration to carry out a particular maintenance or reduce risk. We also include whether or not budgets were met and explain any variances. Also included is a discussion on some current and future initiatives along with a reliability gap analysis.

Table 9-2a **Orion network reliability results for FY17 and last five year average**

Category	FY17 target	FY17 result**	FY13-FY17 average	FY16 CPP reliability limit
SAIDI	< 91	78	177	91
SAIFI	< 1.15	0.77	1.1	1.16
Faults restored within 3 hours (%)	> 60	63	61	
Subtransmission lines faults per 100km*	-	1.7	-	
Subtransmission cables faults per 100km*	-	0.8	-	
Distribution lines faults per 100km*	-	17.6	-	
Distribution cables faults per 100km*	-	2.4	-	
Subtransmission other faults*	-	1	-	
Distribution other faults*	-	99	-	

* As per Disclosure schedule 10(v).

** Major event daily limits applied in accordance with CPP.

1.8.2 Review of customer service

As shown in table 9-2a our customer service reliability results for FY17 SAIDI and SAIFI were consistent with our targets and under the Commerce Commission's CPP reliability limit. The year was free of any major weather events.

When compared with other New Zealand line companies, the reliability of our urban network (when not subjected to earthquakes) appears to be above average, while our rural network (when there are no storms) is slightly below average.

Our network performs well in terms of voltage and quality. We receive a number of voltage complaints every year but only approximately 30% of complaints are due to a problem in our network. Both our targets for voltage and harmonics complaints were met in FY17. See table 9-2b.

1.8.3 Works expenditure in FY17

The AMP figures shown here are from our AMP 1 April 2016 to 31 March 2026 period.

Maintenance

Our maintenance costs for FY17 were $26.2m, compared with our budget forecast of $29.5m. The under-expenditure was largely due to deferred works due to the uncertain requirements around earthquake recovery, third-party works and constrained resources. Contractor resources have prioritised the large amount of road works, infrastructure rebuild projects, and customer connection works. The key areas of under expenditure are in emergency and scheduled maintenance works. Variances from budget are as follows:

Emergency works -$0.3m

We observed a lower than expected number of wind/weather events that impacted on the network.

Scheduled maintenance -$2.3m

Areas of significant under-expenditure were:

- Overhead and underground feeder maintenance (-$1.0m)

  We had issues coordinating contractor resources to undertake works. Connection and relocation works were given a higher priority.

- Substation removal (Red Zone) (-$0.4m)

  Decisions regarding the removal of substations in the red zone area have been deferred until land/area use has been decided.

- Generators (-$0.2m)

  Expected use of our connected generators less than expected hence reduced fuel and maintenance costs.

- Load Management, Communications and SCADA (-$0.6m 5m)

  The costs associated with communications and SCADA have reduced due to the introduction of new technology and work practices.

Non Scheduled maintenance -$0.6m

- Road works (-$0.7m)

  Significant roadworks required replacement of infrastructure rather than relocation.

Capex

Customer connections and extensions

Our customer connection and extension costs for FY17 were $20.8m, compared with our previous budget forecast of $13.7m. Customer connection demand remained higher than expected in subdivision, in-fill development and large commercial connections.

Reinforcement

Our reinforcement costs for FY17 were $3.3m, compared with our budget forecast of $3.5m.

Relocation

Our relocation costs for FY17 were $11.6m, compared with our previous budget forecast of $9.5m.

This expenditure is dependent on project timing associated with the needs of the Road Controlling Authorities, Christchurch City Council, Selwyn District Council, NZTA and developer requirements.

The over-expenditure was largely driven by significant works being undertaken by the NZTA.

Major projects

Major project costs for FY17 were $7.4m, compared with our previous budget forecast of $10m. The under-expenditure was largely due to delays in projects that will be completed in the next financial year.

Replacement

Our replacement costs for FY17 were $19.2m, compared with our previous budget forecast of $17.4m. The over-expenditure is largely due to the following factors:

- our revised suspect pole inspection procedures and education program resulted in an increased number of replacements (+$0.7M)
- we accelerated our customer LV supply fuse replacement program (+$1.5M).

Project completion

All our current projects were completed except for two. For our project completion status see table 9-4a.

1.8.4 Safety

We report all employee injury incidents via Vault and collect similar statistical incident data from our contractors. These contractor statistics, our own statistical data and our incident investigations, enable us to provide staff and contractors with indicators of potential harm.

Table 9-5a **Personal safety – performance results**

Key asset management driver	Measure	Target	Achieved FY17	Performance measure	Measurement procedure
Personal safety	Safety of employees	0	0	Notifiable injury, incident or illness.	Accident/incident reports
	Safety of our contractors	0	1		
	Safety of public	0	1	Number of accidents involving members of the public (excluding car v pole accidents)	

1.8.5 Environment

All our service providers are required to adhere to our environmental management manual and procedures.

No significant environmental incidents occurred on our network in FY17.

1.8.6 Improvement initiatives

Subtransmission network

We have identified a need to improve security and performance in the upper network (higher voltage), since this asset affects the largest number of customers. Initiatives taken in relation to this asset include:

Underground

- Completed the northern 66kV loop which allows for better resilience to the eastern suburbs, as was shown from the two isolated incidents since its completion.
- carried out thermal engineering checks to determine/confirm the current rating of cables
- specified trench backfill to provide the required thermal and mechanical support
- replaced the 66kV oil-filled cable joints and 33kV oil-filled cables to counter thermo-mechanical effects.

Overhead

- replaced insulators and installed vibration dampers
- re-rated conductor for 75^{0}C operating temperature and applied dynamic ratings
- assessed condition of tower foundations and repaired where required.

Substations

- increased reliability at Addington by splitting the 66kV bus and rearranged existing 11kV supplies
- constructed a 66kV bus at Springston
- installed a 66kV bus zone scheme at Bromley.

Transpower GXP

- major alterations at Islington GXP to increase capacity and alter vector grouping along with replacing half of the 33kV outdoor switchgear with indoor equipment.

Distribution overhead lines

Historically our rural 11kV overhead network experienced around 12 faults per 100km per year. Since the Canterbury earthquakes in FY11 this has increased to approximately 19 faults per 100km per year. This increase can be attributed to the failure of insulators exposed to seismic shock, a number of strong weather events and changes to how our network is switched during outages. We are actively targeting any areas of poor performance with the aim of returning to a lower rate of around 12 faults per 100km per year.

As the reliability of our rural network is driven by the fault rate on overhead lines, improving performance can either attempt to reduce the overhead line fault rate or minimise its impact. We initially improved our reliability performance by reducing the fault rate. More recent improvements have come from minimising the impact of line faults. In the five years from FY00-FY04 we installed 29 additional line circuit breakers in our rural network – the first significant installation of line circuit breakers in approximately 15 years. See section 9.8.2 for more detail of opportunities for further improvement.

Substations

We have instigated several initiatives to reduce problems with switchgear, primary transformers and their terminations. These include:

Metal-clad switchgear

- standardise equipment types and improve installation drawings
- engage internationally recognised consultants to evaluate switchgear in the network
- establish partial discharge testing as ongoing preventive maintenance
- locate and replace older air terminations using tape insulation with heat shrink
- remove dual cable terminations with insufficient clearances and ventilate air termination cable boxes
- increase levels of training for jointers working on this equipment
- modify older circuit breakers to enable more reliable operation.

Primary transformers

- carry out half-life maintenance programme and replace/refurbish on-load tapchangers
- replace pressure relief glass bursting diaphragms with pressure relief valves
- conduct tests to establish on-site overload ratings and install extra cooling as required
- install dynamic controllers at key locations
- perform dissolved gas analysis of transformers.

Power quality project

We have now completed our three year project to install power quality measurement instruments at 30 locations within our distribution network. These instruments collect power quality trend data as well as triggered transient event information. As part of analysis of the data the from the project we have discovered very high harmonic levels on the network supplied from Hororata GXP. These findings have assisted Transpower to analyse the effect of transposing 220kV lines as part of a project to reduce voltage imbalance.

At Darfield, total harmonic voltage distortion exceeded 8% at times during the summer of FY09. During the summer of FY10 after the transformers were changed and despite an increase of 50% in the VSD load, the total harmonic voltage decreased to approximately half that of the previous summer.

We also use the power quality instruments and PQView to discover and monitor the increasing harmonic distortion caused by everyday domestic customer electronic equipment and we continue to look at other strategic sites to locate power quality instruments such as major customers and new zone substations.

Emergency stock

Our emergency stock holdings valued at approximately $4m have been reviewed by looking at the reliability statistics of each asset, and systematically identifying the benefits of components that make up that asset. It was necessary to set a reasonable level of risk to ensure that we balanced the need for carrying emergency spares with the costs of holding these items. For our overhead line asset we set this level at about a one-in-50 year event. As risk assessment of individual network components is further refined some items may be released or additional critical items will be held.

1.8.7 Gap analysis

Asset management processes

The Commerce Commission released new Information Disclosure (ID) requirements in 2012. As part of these requirements EDBs must provide an overview of asset management documentation, controls and review processes using an instrument known as the Asset Management Maturity Assessment Tool (AMMAT).

AMMAT reviews are usually self-assessment. However we engaged EA Technology Ltd to undertake an independent assessment. They found that we comply with the requirements in a number of important, high impact areas and that we are making steady improvement. For scores see section 9.9.1.

Reliability

We have compiled detailed reliability statistics for the past 26 years. Statistics from the first few years indicate that most interruptions occurred in the rural area and were due to trees on lines, vehicles hitting poles and equipment failure to a lesser extent. Since then we have made considerable effort to control tree growth and instigate various maintenance programmes on our rural 11kV lines. A project to install reflectors on roadside poles to reduce the incidence of vehicles hitting poles has also been completed.

Our plant failure statistics show that as loads increase in parts of our network, we have to work harder to keep aging equipment performing satisfactorily. We use a UV corona imaging camera that utilises the latest technology in an effort to identify potential problems before they cause an interruption.

We have also completed a project to shorten the interrupted portions of our feeders by installing additional line circuit breakers. Circuit breakers are relocated to more appropriate locations as the network is altered and total 50 in our rural network.

We have installed and put into service 23 Ground Fault Neutralisers (GFN). These units are equipped with 5th harmonic residual current compensation and are starting to contribute to an improvement in rural network reliability and safety.

We are currently targeting feeders with poor performance and there is a programme in place for FY18 and FY19 to identify and replace seismically damaged insulators.

Security standard

Our security standard provides a useful benchmark to identify areas on our network that may not currently receive the high level of security that the majority of our network has. Any gaps against our security standard are discussed in section 5.5 – Network gap analysis.

Business Context

2

List of figures and tables in this section

2.1 Purpose of AMP

Our AMP sets out our asset management practices for our electricity distribution business. We update and publish our 10 year AMP in March each year.

This AMP looks ahead for the 10 years from 1 April 2018. Our main focus is on the first three to five years, with the highest level of certainty in the first year. Beyond three to five years our forecasts are necessarily more indicative as we respond to the changing needs of our customers and community.

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. These requirements include:

- a summary
- background and objectives
- target service levels
- details of assets covered and lifecycle management plans
- load forecasts, development and maintenance plans
- risk management, including policies, assessment and mitigation
- performance measurement, evaluation and improvement initiatives.

Our cross reference of how our AMP meets the detailed regulatory information disclosure requirements is shown in Appendix B.

Our AMP goes beyond regulatory requirements. We aim to demonstrate responsible stewardship of our electricity distribution network — in the long term interests of our customers, shareholders, electricity retailers, government agencies, contractors, financial institutions and the general public.

We aim to optimise the long term lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet target service levels and future demand. Each year we aim to improve our AMP to take advantage of new information and new technology. These innovations help us to remain one of the most resilient, reliable and efficient electricity networks in the country.

2.2 Business strategy

2.2.1 Relationship of our AMP to our SOI and business plans

Our AMP supports our aim to work collaboratively with our customers to achieve the most successful outcomes.

Other key documents that are part of our annual business planning process are:

1. **Statement of intent (SOI):** In accordance with section 39 of the Energy Companies Act, we submit a draft SOI to our shareholders prior to each financial year. After carefully considering shareholders comments on the draft, the Orion board approves our final SOI. Our approved SOI is then sent to our shareholders and is placed on our website.

   Our SOI sets out our overall strategic/corporate objectives, intentions and performance targets for the next three financial years.

   Our SOI notes that section 36 of the Energy Companies Act stipulates that our principal objective shall be to operate as a successful business.

   Our SOI has a number of performance targets each year related to:

   - network development
   - network reliability
   - environment
   - community and employment
   - financial**.**

   Our AMP targets are consistent with and support our SOI targets, although the scope of our SOI targets are wider than in our AMP.

2. **Business plan:** Our AMP is consistent with and supports our business plan, although the scope of our business plan is wider than our AMP.

3. **Financial forecasts:** Our AMP supports our business financial forecasts, although the scope of our business financial forecasts are wider than our AMP forecasts.

The following figure shows how our business plans and processes interact with each other.

Figure 2-2a **Interaction of plans and processes**

2.2.2 Our AMP supports our business strategy and vision

Our Business Strategy:

Our strategy is focused on:

- as our key priority, our core electricity distribution business (core)
- the opportunities and challenges of emerging technologies and their integration into our core business
- profitable non-regulated activities – including through our subsidiary, Connetics
- opportunities for collaboration and efficiencies with other industry players.

We'll continue to strive to be an industry leader with strong credibility.

Our company strategy creates value by maintaining the relevance and value of our core network investment through a deep understanding of customer technology trends and embedding emerging technology within our core business activity. This is complemented by opportunities in profitable non-regulated activity and industry collaboration. Various initiatives support these aims and are grouped under four objectives:

- close to customers
- identify opportunities
- operational excellence
- stakeholder engagement.

The following strategy framework, figure 2-2b, summarises this approach.

Figure 2-2b **Strategy framework**

Context for this strategy includes:

- the company's post-quake recovery and the wider rebuild
- the regulatory regime – principally the price-quality control regime
- increasing opportunities for collaboration, and creating opportunities with other electricity networks
- emerging technologies.

Our vision:

Connecting communities, igniting innovation.

In order to achieve our vision, our core network business objective is to deliver a safe, secure and cost effective electricity distribution service to our customers. This means we want a business that:

- connects communities (to ensure they thrive)
- connects with communities (builds relationships, understands customers requirements, negotiates outcomes with customers, connects and collaborates with other networks and other businesses)
- ignites innovation (focuses on innovative solutions, builds on our current capability to be more effective and efficient, works with others to generate innovative outcomes, supports the innovation of others, collaborates to create innovation).

Our values:

We will	Meaning
Connect	We build real relationships with our customers and stakeholders so we can better power, energise and connect our communities
Create	We are big picture thinkers and our innovation and agility enable us to identify opportunities, exercise sound judgment and learn continuously
Collaborate	We work together, building on our strengths, our initiative and our commitment to ensure our communities trust us, our business is successful and our people and environment are valued

2.3 Asset management strategy and initiatives

2.3.1 Introduction

Community use of electricity and expectations of the network that delivers electricity is changing. Electricity has always been an essential service but community dependence on electricity is increasing with the adoption of emerging technology, electrification of the transport system and global movement to a low carbon economy. The relationship between lifelines organisations[1] such as telecommunications, transportation and energy delivery are increasingly interdependent and underpinned by provision of electricity supply and delivery. Our asset management strategy reflects these externalities.

Our asset management strategy describes the principles that guide us in making our day to day investment and operational decisions. It ensures that our decisions, plans and actions are consistent with our vision and values, and that our actions work efficiently and effectively towards achieving our business plan. This strategy describes our asset management framework, our asset management focus areas and asset management objectives. It also describes the strategic initiatives, over and above our business as usual activities necessary for us to respond to change and continually improve our performance for the long-term benefit of customers and our stakeholders.

2.3.2 Context

We own and operate the electricity distribution infrastructure powering our customers and the community in Christchurch and central Canterbury. Our network is both rural and urban and covers 8,000 square kilometres across central Canterbury between the Waimakariri and Rakaia rivers from the Canterbury coast to Arthur's Pass. We deliver electricity to over 200,000 homes and businesses.

Electricity distribution is an essential service that underpins regional, community and economic welfare. We pride ourselves on our stewardship of our assets for the long term benefit of customers.

We will transition from our customised price-quality path (CPP), to a one-year default price-quality path (DPP) in FY20. We will then be subject to a five-year DPP reset for FY21 to FY25. For our FY21 to FY25 reset, we will submit our network reliability assessment criteria, along with our AMP.

Rapidly changing technologies are providing opportunities for our customers to produce, store, and consume electrical energy rather than primarily consuming it. This change has the potential to alter the demands on and for our network assets and the services that our customers require. Our assessment is that while requirements will change, our customers will continue to rely upon our network services for the foreseeable future.

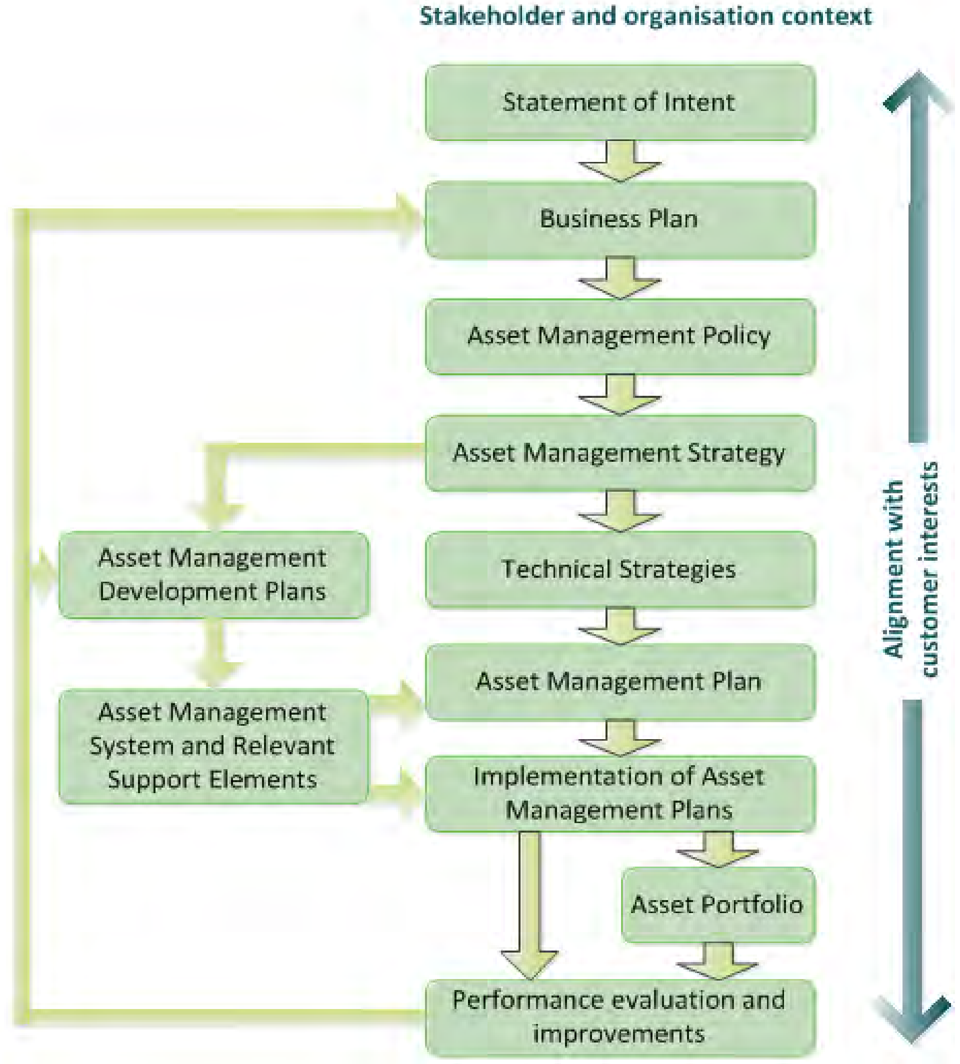
2.3.3 Our asset management framework

Our asset management framework provides structure and process that ensures that our decisions, plans, and actions are in alignment with our vision, values, and corporate goals. It also provides structure and process to ensure that we deliver our services with the required level of dependability to meet our service obligations, and resilience to respond to high impact events.

Our vision

Our asset management framework is a hierarchy of documents and processes that provide for clarity of purpose and alignment from our corporate statement of intent and business plan, to our investment and operational decisions and actions. Our asset management framework is depicted in Figure 2-3a.

Figure 2-3a Our asset management framework



An output of this asset strategy is a suite of technical strategies that define our technical approach for developing actionable projects and plans. Examples include our network architecture review which defines our approach for developing the network and asset management reports which define our approach to managing the lifecycle of existing assets. A further output of this asset management strategy is an asset management development plan which defines how we will continually improve and evolve our capability to meet the needs of our customers.

2.3.4 Our asset management policy

Our asset management policy sets the scene for our asset management strategy focus areas. Our policy objectives aim to:

- provide a resilient, reliable and cost effective electricity distribution network service
- meet the long-term interests of our customers and shareholders
- embed safe working practices- for our employees, contractors and the public
- provide excellent customer service
- identify and manage risk in a cost-effective manner
- identify and evaluate relevant information in a cost-effective and timely manner
- recruit, develop and retain competent and motivated people
- build effective relationships with relevant stakeholders- including customers
- comply with relevant regulatory requirements.

Figure 2-3b Our areas of asset management focus

Being close to our customers by providing services that they value and maintaining the trust necessary to retain our social license to deliver our services

Continually improving our activities associated with planning, operating, maintaining and constructing the network

Keeping the public, our contractors and employees free from serious harm due to our activities

Supporting sustainability by using resources wisely and actively seeking to reduce waste and the release of pollutants.

Continually developing our capability as effective asset managers, skilful at utilising our assets to achieve our corporate vision and objectives and meet the expectations of stakeholders

Being an enabler and embracing the significant technological change that is affecting the way that energy is being produced, stored and utilised

2.3.5 Our asset management focus areas

Our asset management objectives are based around six focus areas as shown and described in Figure 2-3b. These focus areas group our asset management objectives, the principles that guide our decisions and the supporting initiatives we have identified as necessary to achieve our objectives.

2.3.6 Customers

Our purpose is to connect our customers by providing safe, reliable, resilient and efficient services focusing on the long-term interests of our customers and community. We will do this by:

- achieving our performance targets as set out in the corporate statement of intent
- actively seeking to understand and meet our customers' needs now and in the future
- continually improving our customer engagement and our customer service
- being socially responsible in our actions.

To achieve these goals, we have set corresponding asset management objectives, principles and supporting initiatives.

Objective	Guiding principle
Work with our customers to obtain mutually beneficial outcomes in their long term interest.	We will identify and implement ways to improve customer experience, and streamline the delivery of our services.
Provide services that our customers value.	We will regularly engage with our customers to understand how they value our services. We will tailor our price service level offering to meet our customers' expectations.
Meet customer expectations for levels of service.	We will manage our assets and operations to meet both regulatory requirements and customer expectations.
Seek to understand and predict future customer requirements and trends.	We are in a time of rapid technological change that is affecting how our customers consume and produce energy. These changes will alter the services that our customers require and the assets we must provide to support this need. We will seek to understand and to the extent possible predict and respond to future customer requirements and trends.
Provide cost reflective and service based pricing for network access.	In the future, customers will interact with our distribution asset in new ways. Our pricing may need to evolve to reflect this while recovering prudent and efficient income sufficient to manage the asset sustainably.

Initiatives to support focus area

- complete a review of our customer facing business processes and implement improvements to enhance customer experience and operating efficiency
- develop and implement a formalised stakeholder and customer engagement plan
- complete our reliability management and forecasting strategy and implement actions
- monitor and regularly report on emerging customer energy production, storage, and consumption trends
- develop a network pricing roadmap and seek industry and customer engagement.

2.3.7 Safe, reliable, resilient system

A safe, reliable and resilient system means delivering our services effectively and efficiently and making decisions that are in the long-term interests of our customers, while maintaining a financially sustainable business. We will do this by prudently and efficiently:

- innovating and continually improving the efficiency and effectiveness of our operations and service delivery
- investing in and setting target levels for the safety, reliability and resilience of our electricity distribution network through our network design and operation
- recovering our costs, including an appropriate return on investment
- identifying and managing our key risks including safety
- complying with relevant legislation, regulation, and planning requirements.

To achieve these goals, we have set the following asset management objectives, principles and supporting initiatives.

Initiatives to support focus area

- continue to restore resilience in the network and ensure that the network architecture provides sufficient resiliency and flexibility alongside other needs
- continue to improve use of condition and risk management tools for planning maintenance and renewal investments
- monitor technology developments in terms of capability and lifecycle costs. Where promising, conduct trials with a view to developing standardised solutions for implementation.

Objective	Guiding principle
Develop the network to provide capability, flexibility, and resilience at optimal life cycle cost.	The future network must provide required capability while retaining flexibility to respond to changing customer requirements and resilience to cope with network events or natural disasters.
Apply a balanced risk vs cost approach to making asset maintenance and renewal decisions.	Maintenance and renewal activities manage risk arising from asset deterioration and ensure continuing fitness for purpose and legal compliance. We will treat asset maintenance and renewal activities as an investment that is justified through risk assessment and by benefits to customers and community as measured by risk.
Develop the network using a suite of standardised asset building blocks.	Standardisation of network equipment and designs provides lifecycle benefits arising from volume and consistency. Benefits include reduced procurement costs, minimisation of installation defects, reduced operation risk and the development of organisational experience to effectively manage the asset over its lifecycle.
Network innovation.	We apply 'best practice principles' in our network design and operation. This includes adopting and harnessing advances in technology where this can cost effectively improve our service performance in both our network and its supporting systems.
Maintain sufficient competent resources to deliver programs and respond to network events.	The availability of sufficient and competent resources is essential to both the delivery of our planned programs and our ability to respond to network events and natural disasters. We will proactively assess the levels of resources necessary to deliver our objectives and to the extent that is practicable and economically justified, we will plan our activities to incentivise our commercial partners to grow and maintain the delivery resources that we need.

2.3.8 Future network

Rapidly changing technologies are providing our customers with opportunities to produce, store and consume electrical energy in new ways. They provide opportunities for innovative network services. These new technologies may however create technical and business challenges, as they alter the required capabilities the network must deliver as well as the existing charging model for services. We welcome these opportunities and will be an enabler for our customers to realise the economic and environmental benefits of adopting these new technologies.

To facilitate the adoption of emerging energy technologies we have set the following asset management objectives, principles and supporting initiatives.

Initiatives to support focus area

- develop a roadmap to provide Distribution System Operator capability, providing a new platform for demand side management
- undertake a LV system and communications architecture review to accommodate requirements for emerging technologies
- explore the application, benefits and risks of using dynamic and/or cyclic and seasonal ratings to determine asset capacity.

Objective	Guiding principles
Facilitate customer adoption of emerging technologies.	We will facilitate the introduction of emerging energy technologies in a coordinated, efficient and cost reflective manner (via open access) that advances the wider interests of our customers and community.
Enhance understanding of low voltage network capability.	Customer adoption of new technology, such as photovoltaics and battery storage, on the demand side (i.e. in their homes and businesses) will interact directly with our low voltage network introducing technical requirements not anticipated when these networks were designed and built. We will improve our understanding of the technical capability of this asset and how it must evolve to meet future customer needs.
Implement no regrets actions that align with credible future scenarios.	Future customer requirements are uncertain and could evolve towards divergent scenarios. We will assess investment decisions against agreed scenarios, favouring options that provide flexibility and least regrets.
Release latent capacity of network assets.	Many network assets are thermally rated using conservative continuous ratings. Opportunities may exist to release latent asset capacity by using dynamic or cyclic ratings that take into consideration actual service conditions.

2.3.9 Health, safety and wellbeing

We aim to have safe worksites and a safe network for our employees, contractors, visitors, customers, and the public. We take a risk based approach to health and safety and balance the potential for harm with the value that our services provide to our customers and the community.

To achieve this goal we have set the following asset management objectives, principles and supporting initiatives.

Initiatives to support focus area

- enhance our risk management framework to provide consistent management of risks and risk mitigation measures
- embed safety by design principles into our business as usual decision making including, network architecture, design, procurement, construction, maintenance and operation
- complete safe work practice reviews of construction and maintenance activities
- active wellness programme.

Objectives	Guiding principles
Keep all our communities and people healthy and safe.	Providing electricity to the community by its nature presents hazards that could cause harm to the public, our contractors, and staff. This potential for harm is balanced by the benefits that electricity provides to our community both economic and in terms of people welfare. We will proactively identify and understand risk and optimise opportunities to reduce the potential for harm while retaining and enhancing the benefit of our service to society.

2.3.10 Environment

We are committed to environmental sustainability, and supporting the New Zealand Government in achieving their commitment to reduce carbon emissions via the 2016 Paris Agreement. We will support sustainability by using resources wisely and actively seek to reduce waste and the release of pollutants. Over 90% of our carbon footprint comes from network losses and the carbon embedded in our network assets. By reducing system peaks through effective customer demand side management, we can reduce network losses and the need to acquire more assets. We will also adopt and enable use of electric vehicles to reduce the carbon emissions associated with transport.

To achieve these goals, we have set the following asset management objectives, principles and supporting initiatives.

Initiatives to support focus area

- maintain the viability of our customer demand side management capability – see DSO initiative under the future network focus area
- continue to collaborate with partners to install public electric vehicle chargers around our region
- continue to seek opportunities to promote the adoption of electric vehicles, and ensure that our network is ready for charging loads
- develop distributed generation connection guidelines to facilitate the connection of embedded low carbon generation.

Objective	**Guiding principles**
Avoid unnecessary environmental harm due to our activities.	We will manage our activities, with the aim of causing no lasting harm to the environment. We will select assets, adopt work practices, and maintain the condition of our network to minimise waste, the release of pollutants and disruption to the natural environment.
Facilitate a low carbon future.	We will facilitate a low carbon future by being a facilitator of new energy technology. We will continue to reduce our carbon footprint by taking account of electrical losses when we design and operate our network. We will value the role that customer demand side management plays in reducing the capacity needs of our network.
Manage risk of SF_6	We recognise the environmental risks of SF_6 and will consider alternative equipment solutions wherever reasonably practicable.

2.3.11 Capability

We will continually improve our capability so that we can deliver our services effectively and efficiently, and with the required degree of dependability and resilience. We recognise the role that systems such as those defined by ISO 55000 can play in providing assurance and managing risk. While we do not seek formal accreditation to this standard now, we will adopt good practice principles and align our processes wherever this adds value for our customers.

We have set the following asset management objectives, principles and supporting initiatives to enhance our asset management capability.

Initiatives to support focus area

- produce an asset management system development roadmap for improving business processes, systems, and documentation to reach or exceed compliant levels in all areas of the Commerce Commission AMMAT framework
- formalise and embed a corporate risk management framework in alignment with AS/NZS 31000
- identify mutually beneficial opportunities to collaborate with peer utilities for the benefit of customers and stakeholders.

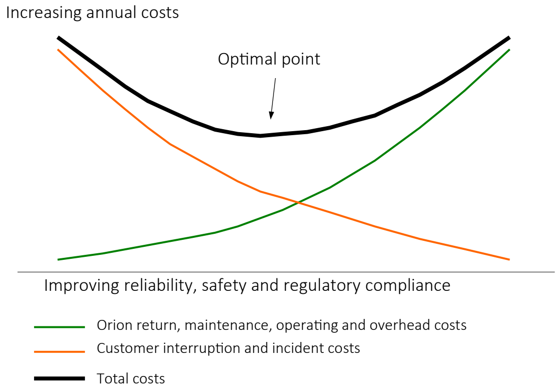
Objective	Guiding principles
Develop asset management system in alignment with ISO 55000.	An asset management system embodies the processes, IT systems and documentation to assure that asset management activities are aligned with objectives. Our asset management system has been developed in alignment with industry practices consistent with the scale and scope of our operations. We will continue to develop our asset management system and processes in alignment with the international standard for asset management ISO 55000 where this cost effectively provides operational benefits.
Accurate and timely asset information to support processes and decisions.	Accurate and timely asset information is a critical input to operational processes and longer term decision making. We will develop and maintain our asset information systems to balance the benefits of information against the cost to collect and maintain.
Identify and manage key risks	The ability to transparently and consistently identify, rate and manage key risks is important for long term balanced decision making. We will implement a corporate wide risk management framework that ensures that key risks are visible to decision makers and acted upon proportionately.
Collaborate with industry peers for win/win outcomes.	New Zealand electricity distribution companies are small by international standards, with limited in house research and development potential. The projected rate of change is such that there will be benefits in collaborating with peers to develop solutions to optimise new opportunities.
Our asset management strategy objectives are implemented in a timely manner.	The asset management strategy captures the key areas of asset management focus, including business as usual, new, and enhanced asset management objectives. We will prioritise, resource and proactively manage the implementation of these objectives to ensure that we address our risks and opportunities in an appropriate timeframe.

2.4 Asset management drivers

2.4.1 Investment principle

When we extend, replace, maintain and operate our network we consider the balance between cost and the quality and safety of supply provided. The optimum point of investment in the network is achieved when the value of further expenditure would have exceeded the value of benefits to our customers. This concept is illustrated in the following Figure 2-4a.

Figure 2-4a **Optimal cost versus quality principle**



Put simply, we need to find the right balance between cost, and health and safety and the quality of our electricity delivery service. We seek to achieve this optimal point by whole-of-life economic analysis when we develop and review our asset management practices.

To achieve optimal outcomes, we also commit significant resources to participate actively in the consultation phase of national rules and regulations. It is important that rules and regulations that affect our industry are well-informed, principled and practical.

The speed at which new asset and systems technologies become available has increased in the last decade. We welcome these new initiatives and are committed to keeping up-to-date with technological advancements.

In line with our 'optimal point' approach above, we introduce new technology only when it results in an economic balance of cost and network performance. We then modify our standards and specifications to include the initiative.

More detail on technology initiatives is discussed in context within the various sections of our AMP.

2.5 Asset management process

2.5.1 Introduction

We undertake lifecycle management and asset maintenance planning using whole-of-life cost analysis, reliability-centred maintenance, condition based maintenance and risk management techniques. The techniques are based on performance and reliability targets. The high level targets are discussed in section 3.

Reliability-centred maintenance

Our network maintenance philosophy is reliability-centred and based on retaining asset function. To do this we ask the following questions:

- what is the functional requirement of this asset?
- what is it that may fail and prevent this function?
- what can we do to retain the asset function?

Cost and benefit are considered and the results are monitored to gauge the effectiveness of any significant changes. This works well for overhead line assets that have a higher failure rate, providing sufficient information to make meaningful decisions. However, when applying reliability-centred maintenance to assets with much lower failure rates, such as switchgear, information has to be obtained from a wide range of equipment before we decide on cost-effective actions.

Condition based risk management

Condition based maintenance is an extension of reliability-centred maintenance. Where appropriate, maintenance is performed based on the condition of the asset and the consequence of its failure (see 7.1), rather than on the traditional time-based approach.

We engaged EA Technology Limited to develop condition based risk management (CBRM) models for the majority of our network assets. These models utilise asset information, engineering knowledge and experience to define, justify and target asset renewal. They provide a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts. We are currently integrating this practice into our business processes and have used the CBRM models to develop a number of our replacement programmes.

The CBRM models calculate the health index (HI) and probability of failure (PoF) of each individual asset. This effectively gives the asset a ranking which can be used to help prioritise replacement strategies. Note, the models utilise some averaging/ generalising of asset information to calculate the asset ranking so the asset managers are still relied upon to prioritise the replacement schedule and make judgements on refinement.

2.5.2 Planning priorities

Recent changes in regulations and industry codes of practice have highlighted a greater need to mitigate safety risks for the public, employees and contractors. Therefore we:

- continue to remove or modify high-risk equipment
- increase security around substations and equipment
- tighten controls on equipment access.

In recent years we have focused our ability to meet the growth needs of the community while ensuring appropriate reliability and security. Network security can be compromised during times of change when capital or maintenance works are carried out.

To mitigate risk associated with reduced security during these periods of change we:

- endeavour to plan work methods and contingencies to minimise any impact on the network
- use programmes that allow for contingency events
- programme works in a manner that provides consistent work for the skilled resources available
- are proactive in the development and retention of skilled resources for the future.

2.5.3 Construction standards and working practices

Safety in design

A Safety in Design standard is used by Orion and its approved designers and contractors to identify hazards that could exist throughout the complete lifecycle of assets from concept to disposal via construction and maintenance. The standard includes a hazard identification and risk assessment process which, when applied by designers and other key participants such as those who construct and operate the assets, allows for proposed elimination and control of each identified hazard to a level so far as is reasonably practicable. The Safety in Design process can be applied at any stage of asset lifecycle and can also be applied to non network assets such as vehicles and tools. The Safety in Design process aligns with industry best practice and ensures that designers carry out duties in line with the Health and Safety at Work Act 2015.

Design standards

In order to manage the health and safety, cost, efficiency and quality aspects of our network we seek to standardise network design and work practices. To achieve this consistency we have developed design standards and drawings that are available to approved designers/contractors. Normally we only accept designs that conform to these standards. However, this should not be construed as a desire on our part to limit innovation. Design proposals that differ from normal are considered if they offer significant economic, environmental and operational advantages.

Technical specifications

These specifications are intended for authorised contractors working on the construction and maintenance of our network and refer to the relevant codes of practice and industry standards as appropriate. Specifications are listed in section 4 against the asset group they relate to.

Equipment specifications

We also seek to standardise equipment used to construct components of our network. To this end we have developed specifications that detail accepted performance criteria for significant equipment in our network. Usually new equipment must conform to these specifications. However, this should not be construed as a desire on our part to limit innovation. Equipment that differs from normal is considered if it offers significant economic, environmental and operational advantages. See following section 2.5.4 – Process to introduce new equipment.

Asset management reports

We have a report for each of the asset groups set out in section 4. They detail the criteria and asset management practices we use to obtain effective performance and acceptable levels of service from our assets. The CBRM results and the maintenance/replacement budgets for the asset group are detailed here.

Equipment operating instructions

To ensure the wide variety of equipment on our network is operated safely with minimum impact on our customers, we have developed operating instructions that cover each different type of equipment on our network. We create a new operating instruction each time any new equipment is introduced. See following section 2.5.4 – Process to introduce new equipment.

Operating standards

To ensure our network is operated safely we have developed standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

Document control process

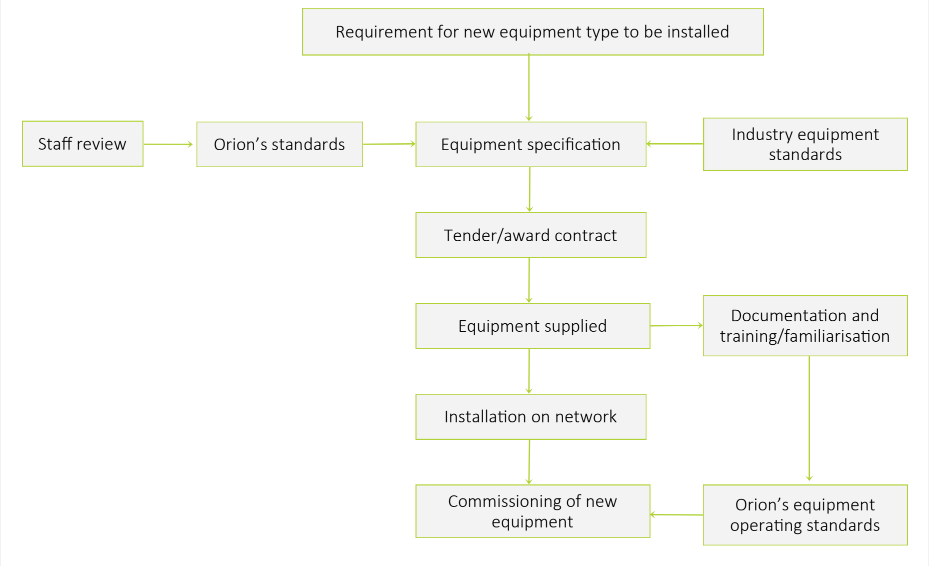
To ensure that all these documents and drawings are maintained as accurately as possible, each is ’owned’ by one person who is responsible for any modifications to it. Our Asset Data Manager is responsible for processing these controlled documents using a process set out in our document control standard.

Email and a restricted-access area on our website are used to make documents and drawings accessible to approved contractors and designers.

2.5.4 Introduction of new equipment types

New equipment types are reviewed to carefully establish any benefits they may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost effective utilisation to support our supply security requirements.

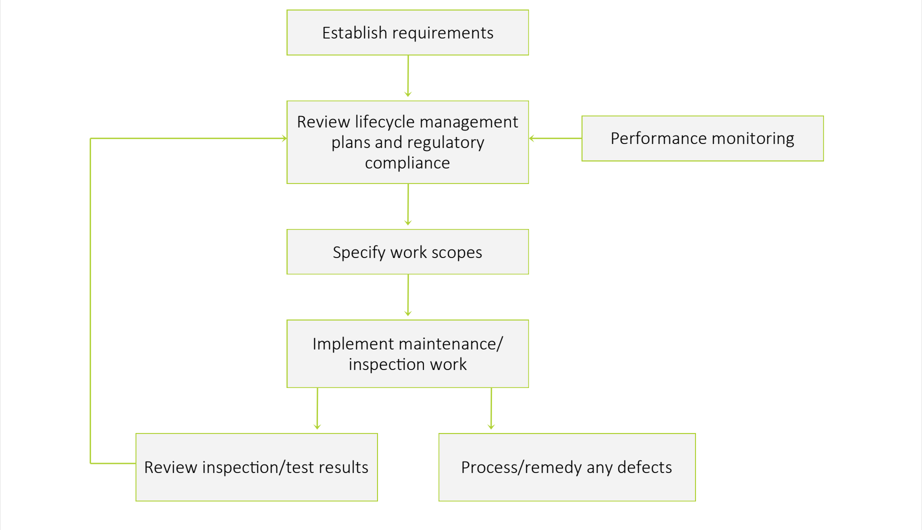
Figure 2-5a **Process to introduce new equipment**



2.5.5 Routine asset inspection and maintenance

The main function of our routine asset inspection and maintenance process is to ensure that optimal levels of asset performance allow us to meet our service level objectives.

Figure 2-5b **Process for routine asset inspection and maintenance**



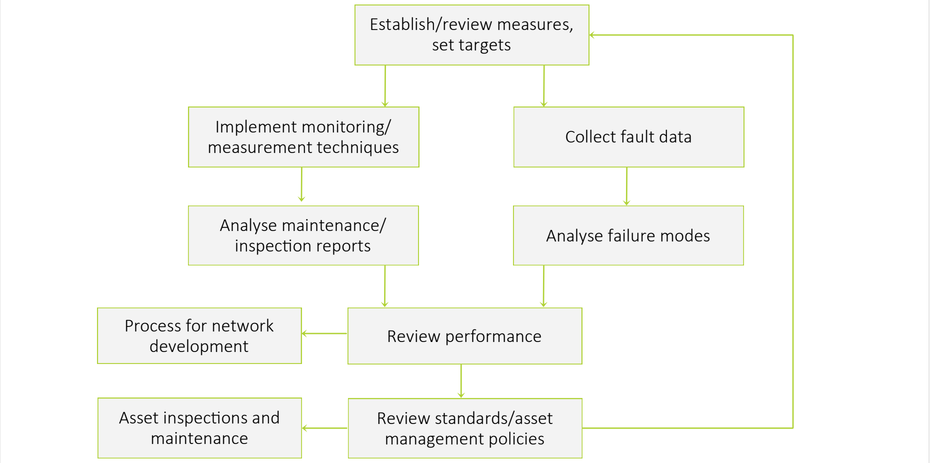
2.5.6 Performance measurement

The main function of our performance measurement process is to maintain levels of network performance. This allows us to set optimal asset/network management standards to meet customer and regulatory requirements.

We currently collect network performance data and rigorously review all network outages logged in our control centre. This process is independently audited on an annual basis and has been automated with the introduction of our network management system that utilises SCADA information and a real-time network model.

SAIDI and SAIFI figures are monitored and reported on a monthly basis to allow appropriate management of the network. A more detailed internal documented review of network performance is undertaken on an annual basis.

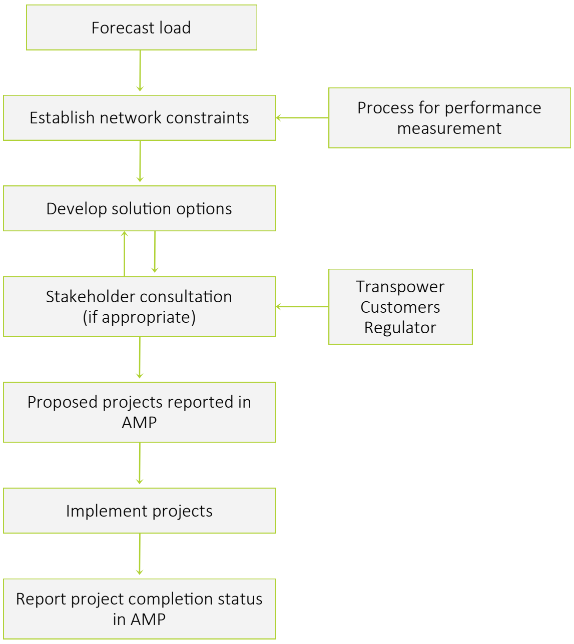
Figure 2-5c **Process for performance measurement**



2.5.7 Network development

The main function of our network development process is to meet the capacity and security requirements of load growth. See section 5.6 for a description of network development at Orion.

Figure 2-5d **Process for network development**



2.6 Stakeholder interests

Our key stakeholders are:

- shareholders: Christchurch City Council Holdings Limited and Selwyn District Council
- customers (includes all end users of electricity)
- community
- energy retailers
- employees
- Transpower
- government agencies - the Commerce Commission and Electricity Authority
- contractors and suppliers
- financial institutions.

We have identified our key stakeholder interests through the following forums:

- customer surveys, meetings and informal discussions
- major customer forums and industry seminars
- reviews of major events (storms)
- quality of supply studies
- employee engagement surveys
- specific project consultations
- supplier technical assessment meetings
- contract performance reviews
- consultation papers and submissions.

The interests of our key stakeholders can be summarised as:

- Shareholders:
    i. a fair return on investment commensurate with the risk of that investment
    ii. efficiency
    iii. long term value
    iv. prudent financial management and planning
    v. security of supply.
- Community, Customers and Retailers:
    i. a reliable electricity supply
    ii. value for money
    iii. efficient fault restoration with good communication during events
    iv. consistency with the Commerce Act Part 4A purpose to “provide services at a quality that reflects customer demands”.
- Employees:
    i. a safe and healthy work environment
    ii. clear direction, responsibilities, accountability and productivity
    iii. job satisfaction.
- Transpower:
    i. load forecasts
    ii. security of supply
    iii. technical connection issues
    iv. new investment.
- Government agencies:
    i. economic efficiency
    ii. compliance.
- Contractors and suppliers:
    i. fair access to business
    ii. consistent terms
    iii. clear specifications

    iv. clear information to assist efficient resource planning
    v. support.

- Financial institutions:
    i. prudent financial management and planning
    ii. capacity to repay debts as they fall due
    iii. timely and accurate information
    iv. transparent key forecast assumptions
    v. access to senior management.

We support these stakeholder interests in our asset management practices through:

- customer demand forecasts
- security of supply standards
- safety plans, auditing and compliance programmes
- coherent network planning, standards and procedures
- capability of our employees
- clear contracts with counterparties
- risk management
- use of professional judgment and experience
- key resource management principles (e.g. managing a sustainable pool of competent network contractors)
- use of independent experts
- prudent financial management and planning.

We manage any conflicting stakeholder interests by:

- considering the needs of stakeholders as part of our high level planning
- balancing the cost of non-supply and the investment to provide the security desired
- cost/benefit analyses
- our principal objective pursuant to section 36 of the Energies Company Act being to operate *"...as a successful business"*.

Each year, our updated AMP is made publicly available on our website within a week of it being approved by our board. This is usually at the end of March. We welcome comments and suggestions on our AMP from stakeholders and interested parties at any time.

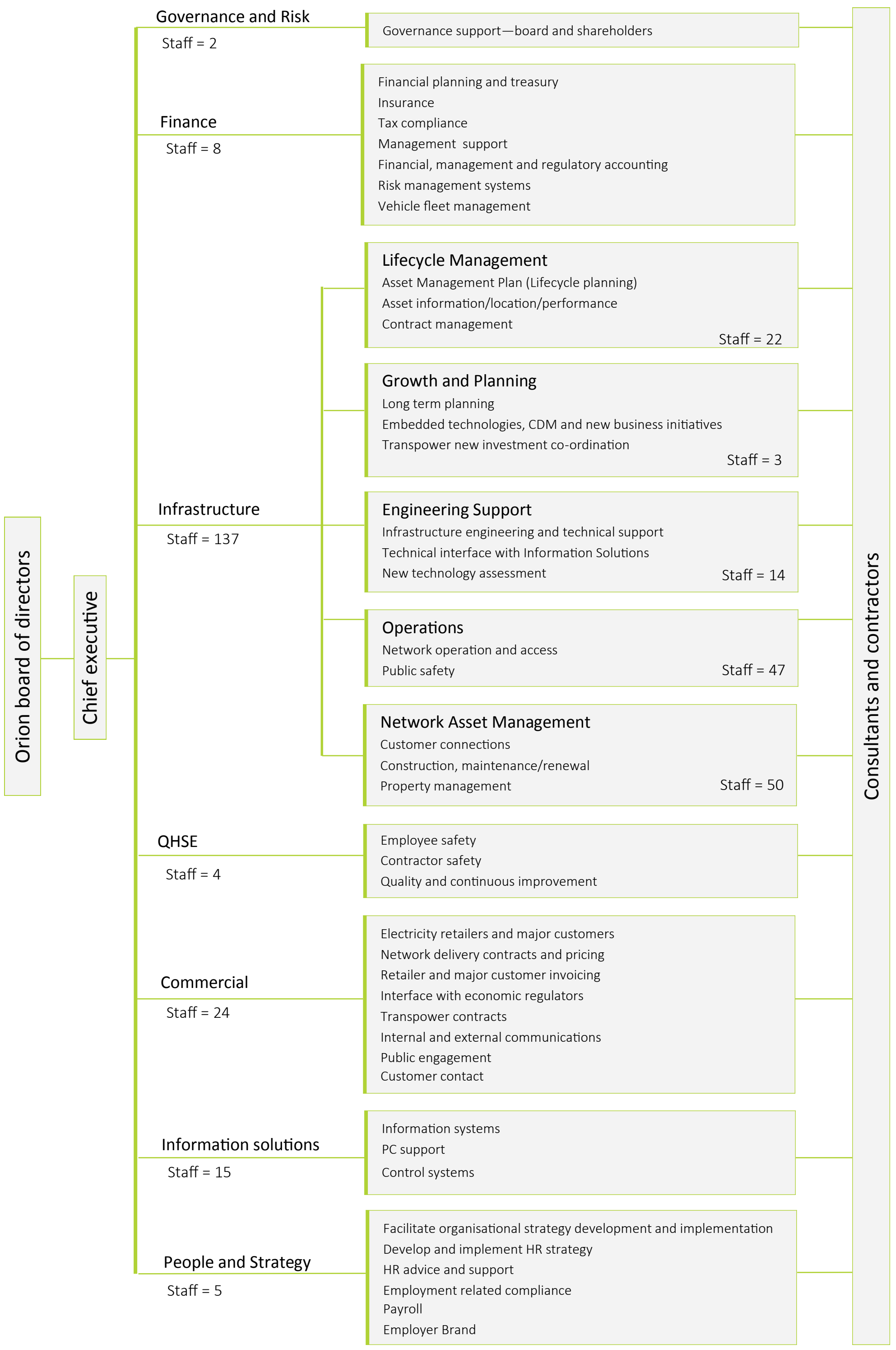
Customer research is covered further in section 3 – Service levels.

2.7 Accountabilities and responsibilities

2.7.1 Asset management structure

Our network is managed and operated from our Christchurch office at 565 Wairakei Rd. Our governance/management structure is as follows:

Figure 2-7a Asset management structure



2.7.2 Board and executive governance

Orion's directors are appointed by its shareholders to govern and direct Orion's activities. The board of directors is the overall and final body responsible for all decision-making within the company.

The board is responsible for the direction and control of the company including commercial performance, business plans, policies, budgets and compliance with the law. The board reviews and approves our revised 10 year AMP prior to the start of each financial year (1 April).

The board also formally reviews and approves our key company policies each year, including delegated authorities and spending authorities. Each corporate manager is responsible for their budget and operating within their delegated authorities.

The board usually meets monthly and receives formal updates from management of progress against objectives, legislative compliance and risk management and performance against targets.

We summarise the main responsibilities of each of our corporate groups below.

2.7.3 Finance

Our finance group supports the other corporate groups in areas such as:

- governance support for the board and shareholders
- reporting to the board and shareholders, including regulatory and statutory requirements
- financial planning and treasury management
- insurance
- debtors and creditors
- financial, management and regulatory accounting
- financial management information systems (FMIS)
- tax compliance
- risk management
- vehicle fleet management.

2.7.4 People and strategy

Orion's people and strategy function is responsible for:

- facilitation of organisational strategy development and implementation
- HR strategy development and implementation
- HR advice and support
- employment-related compliance
- payroll
- employee health and well being
- manage employee brand.

2.7.5 Infrastructure

We maintain in-house technical and administrative competence within our infrastructure group to:

- keep the public and our staff/contractors safe and healthy
- manage safety and environmental compliance systems
- manage risk to our assets as well as operational and environmental risk
- manage and develop asset and network policies along with design and construction standards
- scope network extension and maintenance work and prepare budgets
- manage projects/contracts and interact with contractors
- maintain strategic asset records and reliability statistics
- manage and monitor the network
- manage corporate property
- assess new network technologies

- monitor asset emergency spares and supply systems
- analyse and forecast load, asset capability monitoring and contingency planning etc.
- interface with Transpower over technical connection issues and national grid capacity
- investigate the potential and impact of embedded generation.

2.7.6 Health and safety

Orion's quality, health safety and environment group is responsible for:

- supporting the business in the management of health and safety outcomes
- fit for purpose systems and tools
- championing quality and continuous improvement.

2.7.7 Commercial

Orion's commercial group is responsible for:

- pricing, billing and contracts with retailers
- relationships with economic regulators (such as the Electricity Authority and Commerce Commission)
- compliance with the industry rule-book
- commercial contracts with Transpower
- advice to retailers and major customers
- communications planning and implementation
- consultation and engagement on substantial projects
- customer engagement and consistency of customer experience
- managing Orion's brand
- 24/7 Contact Centre.

2.7.8 Information solutions

Orion's information solutions group is responsible for:

- procurement, delivery and management of our information systems infrastructure
- the provision, support and enhancement of information systems that support our business processes
- managing our control systems.

2.7.9 Consultants and contractors

We have a number of consultants, contractors and independent experts that work with us to meet our asset management objectives. They do not have direct network management responsibilities but operate on a fixed scope and/or period contract to meet the specific needs of the work/project requirements.

It's our responsibility to identify our capital works and maintenance programmes as detailed in sections 4 and 5 of this AMP, subsequently approved in an annual budget. We then specify the work to be done by competent and appropriate consultants or contractors.

All network maintenance and construction work (where practicable) is competitively tendered to selected contractors. Contract works are tendered, processed and managed by the Infrastructure group.

The scope of out-sourced works to consultants and contractors can be outlined as:

Consultants

- expert advice
- detailed design.

Field services

- emergency response services
- spares and major plant services
- some specialist asset inspections and non-invasive/non-destruction testing
- maintenance of existing network infrastructure
- installation and replacement of new or existing network infrastructure.

2.8 System, process and data management and innovation

2.8.1 Systems

Our information systems are used to record, develop, maintain and operate our business. Systems and information flows are shown in Figure 2-8a on the following page. A description of the function of the main systems is detailed below:

1. Geographic asset information

Our geographic information system (GIS) records our network assets according to their location and electrical connectivity. It is one of a number of integrated asset management systems.

Full access to the GIS is available to staff at all times through both local and remote viewing tools. Tailored views of GIS data are also available to authorised third parties via a secure web site.

Information stored in our GIS includes:

- land-base
- aerial photography
- detailed plant locations for both cable and overhead systems
- a model of our electricity network from the Transpower GXPs to the customer connection
- conductor size and age.

See section 4 for more specific detail of information held on each asset group.

Our GIS mapping team updates and maintains the GIS data. Data integrity checks between our asset register and the GIS are automatically run every week.

Systems are in place to facilitate and manage GIS business development in-house.

2. Asset database

Our asset database is our central repository for details of the non-spatial network assets. Schedules extracted from this database are used for preventative maintenance contracts and network valuation purposes.

Information held includes details of:

- substation land (title/tenure etc.)
- transformers
- switchgear and ancillary equipment
- test/inspection results for site earths, poles and underground distribution assets
- transformer maximum demand readings
- protection relays
- substation inspection/maintenance rounds
- poles and attached circuits
- valuation schedule codes and modern equivalent asset (MEA) class
- field SCADA and communication system
- links to documentation and photographs.

See section 4 for more specific detail of information held on each asset group.

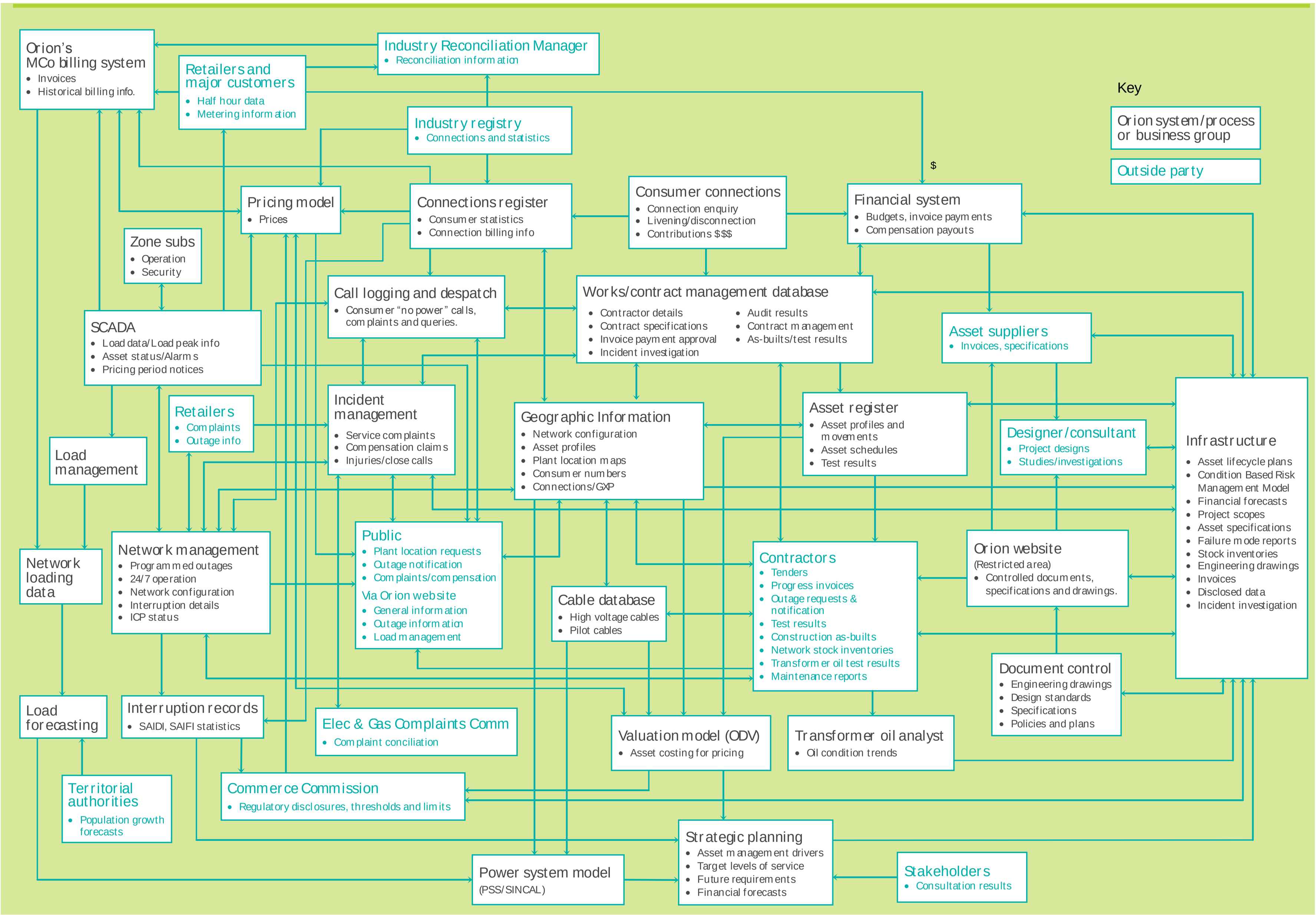
3. Works management system

All works activities are managed using an in house application. There is integration with our financial management system that allows works orders to be raised directly in Works management.

Information held in Works management includes:

- contractor/tendering details
- contract specifications and drawings
- management of customer connection requests
- auditing outcomes
- contract management documentation
- financial tracking
- job as-built documentation.

Figure 2-8a Management systems and information flows



4. Connections-related service requests

A web portal allows contractors and the public to lodge requests for new and modified network connections. There is integration between the Connections and Works Management systems.

5. Connections register

Our Connections register (which links to the Industry Registry) holds details of all installation control points (ICP) on our electrical network. There is an interface with our GIS systems that enables accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are routinely traced within PowerOn (for the high voltage network) and the GIS (for the low voltage network) using the in-built connectivity model. Accurate information about the number of customers and interruption duration are recorded and posted overnight to the Electricity Authority's registry.

6. Financial management information system (FMIS)

Our FMIS (Microsoft NAV) delivers our core accounting functions. It includes the general ledger, debtors, creditors, job costing, fixed assets and tax registers. Detailed network asset information is not held in the FMIS.

There is an interface between the Works management system and the financial system to link project activities to jobs.

7. Network monitoring system (SCADA)

The electricity distribution system is monitored and controlled in real time by the SCADA system. SCADA is installed at all zone substations and line circuit breakers. We are also progressively installing SCADA at network substations throughout the urban area as old switchgear is replaced. See section 4.22 for more detail.

Half hour network feeder loading data is retrieved from the SCADA historical storage system. This data is analysed to derive and maintain maximum demands for all feeders monitored by the SCADA system. Loading data is also archived for future analysis.

8. Network management system (NMS)

The NMS is a real-time software model of our high voltage distribution network that sits above the SCADA system. It allows interaction in real time with indication and control devices to provide better information on network configuration. This gives us the ability to decide on how to respond to network outages (especially big events such as storms) and manage planned maintenance outages to minimise the impact on customers. The system also allows us to automate some functions and improve response times in network emergencies.

9. Outage management system (OMS)

The OMS is the third component (along with the SCADA and NMS functions) of a comprehensive "Smart" Distribution Management System that drives much of our operational activity. Outages are inferred from SCADA 'trippings' or from customer call patterns and are tracked through their lifecycle. Key performance statistics are automatically calculated and an audit trail of HV switching activity is logged.

Integrated into the NMS and OMS is a mobile extension which delivers switching instructions to field operators in real time, and returns the actions they have taken. It also delivers fault jobs to field workers and tracks the progress of the job as it is worked on. Jobs requiring further work by an emergency contractor are automatically dispatched to the contractors' administration centre. Contractors enter completion information directly into a web-based application, and the job details automatically flow through into the works database.

10. Outage reporting

A web-based application is used to display details of planned, current and past outages both internally and to the public via the Internet. Currently this is updated manually, but is about to be replaced by a version that extracts its information directly out of the PowerOn OMS-to allow accurate real-time reporting of customer numbers affected by an outage. We also provide a web-based real-time Outages map for the public.

11. Demolition management

Demolition jobs are dispatched to the field and demolition details returned electronically.

We are currently further streamlining this process.

12. Interruption statistics

We automatically post outage information from the PowerOn OMS into a regulatory reporting database. After checking, the data is summarised along with cause and location in an interruptions register. Reports from this register provide all relevant statistical information to calculate our network reliability statistics (such as SAIDI and SAIFI) and analyse individual feeder and asset performance.

13. Load Management

A high-availability Load Management system is used to perform load shedding to reduce the magnitude of our peak load and to respond to Transpower constraints.

We also run an “umbrella” Load Management system that co-ordinates the load management systems of each of the seven distributors in Transpower’s Upper South Island region. This co-operative venture provides a number of significant benefits both to Transpower and to each of the participating distributors.

14. Incident management

Incidents are recorded, managed and reported in our Vault safety management system. This enables incidents and injuries to be captured using a desktop client or in the field using a phone based application. Vault also manages non-staff related incidents (e.g. incidents affecting our network) and customer complaints.

15. Valuation model

The purpose of the valuation model is to determine the regulatory optimised deprival value (ODV) of our electricity network assets. The valuation follows the methodology prescribed in the Commerce Commission’s ODV Handbook. Some key valuation handbook data is held against assets in our asset register and GIS, and additions and removals of assets from the network are captured in our works management system. This raw data is extracted and imported into a purpose-built valuation model developed using desktop application tools.

16. Pricing model

We maintain a financial pricing model that supports our derivation of delivery charges. We assign connections to several connection categories (depending on size and load characteristics) and use the model to allocate assets and costs to each category. We then establish a set of cost-reflective prices to collect the allocated costs. Asset, asset valuation and loading information are key inputs to a purpose-built pricing model developed using desktop application tools.

17. Orion’s NZX billing system

We have contracted NZX, a leading data services and market place support company, to provide our delivery billing system. The system receives connection and loading information, calculates delivery charges and produces our monthly invoices to electricity retailers and directly contracted major customers.

18. Network asset loading history

A database of well over 100 million half-hour loading values is available for trend analysis at a wide range of monitoring points in our network. The database also includes Transpower grid injection point load history and major customer load history. Several tens of thousands of new data point observations are being added daily.

19. Power system modeling software

An integral part of planning for existing and future power-system alterations is the ability to analyse and simulate its’ impact off-line using computer power-flow simulation. We use a power-flow simulation software package called PSS/Sincal, and have the ability to model our network from the Transpower connection points down to the customer LV terminals if required. An automated interface developed in-house is used to enable power-flow models to be systematically created for PSS/Sincal. These models are created by utilising spatial data from our GIS, and linkages to conductor information in our as-laid cables database and customer information in our connection database records.

Because of harmonic problems encountered on the network supplied from Hororata GXP, we have also purchased the PSS/Sincal harmonics module to allow us to model the network harmonics. We are studying the feasibility of implementing the online power flow analysis package as part of our new network management system.

20. Cable databases

The Basix database is used to hold information on 66, 33 and 11kV underground cables and pilot/communication cables. Cable lengths, joint and termination details are held and linked to our GIS by a unique cable reference number.

21. Transformer oil analyst

Transformer oil analysis (Perception) software provides a centralised database for new and past oil test results for all primary transformers. Perception provides dissolved gas diagnostics, the trending of key oil performance indicators and reporting capabilities. Reports from the Perception software are reviewed annually for all primary transformers .

22. Document control

Our engineering drawings and standard documents are controlled using a custom built system. This system is used to process the release of CAD drawings to outsourced contractors and return them as “as-built” drawings at the completion of works contracts. Standards and policies maintained in-house are also controlled using this system. Standard drawings and documents are then posted directly on our ‘restricted’ website and the relevant contractors/designers are advised via an automated email process.

23. Orion website

Our website is logically divided into two distinct areas. One focuses on the delivery of information to our customers and the other on interactions with third parties.

The customer facing portion of the web site provides the following information:

- power outages, planned and unplanned, advised to street level
- load management, with near real-time network loadings, peak pricing periods and hot water control
- pricing
- publications, regulatory disclosures and media releases
- public safety and tree information.

The interactive section of our website is a services portal that manages third party access to a range of services.

Services include:

- annual work plan
- standard drawings, design standards, operating standards, specifications
- network location map requests
- close approach consents
- new and modified connection requests.

2.8.2 Asset data

The majority of our primary asset information is held in our asset database, GIS system and cable database. We hold information about our network equipment from GXP connections down to individual LV poles with a high level of accuracy. The data has become more complete and more accurate over time.

Due to improved asset management plans, regulatory compliance and better risk identification and management, information accuracy has improved. This has ensured that we have the ability to locate, identify and confirm ownership of assets through our records.

Although there will inevitably be some minor errors and improved information will always be required, we believe that our information for the majority of the network is accurate. Some information for older assets installed more than 25 years ago has been estimated based on best available data. Examples of this include:

- the conductor age for some lines older than circa 1990
- timber poles that went into service prior to the use of identification discs
- older 11kV air break switches and cut-out fuses.

Refinement of data is an ongoing process. Compliance inspections and maintenance regimes are the main source from which to confirm or update data. As we replace aging assets with new assets over time all estimated data will be superseded.

Currently the only area identified where information needs to be improved is associated with determining accurate connection assets of individual LV customers. This information is not easily accessible as it requires manual searches through archived information. The requirement for this information is not deemed high priority and information will be sourced associated with other inspection programmes over the next five years.

Details of current data, compliance inspections and maintenance regimes for each asset group are shown in section 4 – Lifecycle asset management – (*relevant asset*) – Standards and asset data.

2.8.3 Short term developments

Asset database

In a major life cycle upgrade our asset database (WASP) has been upgraded to the most current version of the software from vendor EMS. The new product, Basix, provides benefits not only in the area of vendor support but it also has an improved user interface and improved capabilities for the collection of data from the field.

Distribution power flow analysis

We have started the implementation of a Distribution Power Flow (DPF) real-time modelling module within our PowerOn Network Management system. DPF will leverage the network model in our Network Management System to evaluate the outcomes of what-if scenarios and assess the performance of the network in different configurations. There are benefits to the business in the preparation of network release schedules for planned outages, for assessing alternative switching responses to network emergencies and also for understanding how proposed changes to the network will affect performance and capacity. The project will take approximately a year.

2.9 Assumptions

2.9.1 Significant assumptions

Business structure and management drivers

We assume no major changes in the regulatory framework, asset base through merger, changes of ownership and/or requirements of stakeholders. We forecast a relatively small budget for the acquisition of remaining Transpower spur assets in our region.

Service level targets

We have based our service level targets on customers' views about the quality of service that they prefer. Extensive consultation over many years tells us that customers want us to deliver network resilience and reliability and keep prices down. To meet this expectation we look for the right balance between costs for customers and network investment. See section 3.2 for a summary of our recent consultation.

Any spur assets purchased or newly developed distribution assets are expected to perform within their parameters~~.~~ We continue to assess the latent condition of assets that may have been damaged by the earthquakes.

We are currently reviewing our reliability targets to test the appropriateness in a changing technical and operational environment (e.g. asset technology enhancements and increased safety requirements).

Lifecycle management of our assets

We have assumed no significant purchase/sale of network assets or forced disconnection of uneconomic supplies other than those discussed in the development of our network (section 5).

The planned maintenance and replacement of our assets is largely condition and risk based. This assumes prudent risk management practices associated with good industry practise to achieve the outcomes in line with our targeted service levels. Our risk assessments are based on the context of no significant changes to design standards, regulatory obligations and also our other business drivers and assumptions discussed in this section.

Network development

Section 5 of this AMP outlines projects that will ensure that our network will continue to meet our customers' expectations of supply. Our plans acknowledge the reduced demand associated with the development of the Central Plains Water scheme and also the increased energy efficiency of businesses and households.

Our network pricing aims to promote active participation from customers (for example, many of our major customers respond to our price signals and reduce their demand when our network is running at peak demand) and we have assumed this participation will continue. We envisage that the uptake of new technology such as electric vehicles, batteries and solar panels will accelerate but will have only modest low voltage network impacts in the 10 year time frame. We have assumed that industry rules will ensure that generation connections will not be subsidised by other industry participants (including us) or customers.

Risk management

The assumptions regarding management of risk are largely discussed in section 7. Although we have planned for processes and resources to ensure business continuity as a result of a major event or equipment failure, we have not included the actual consequences of a forecast/hypothetical major event in our AMP forecasts.

2.9.2 Changes to our existing business

No changes are proposed to the existing business of Orion. All forecasts in this AMP have been prepared consistent with the existing Orion business ownership and structure.

2.9.3 Sources of uncertainty

Potential uncertainties in our key assumptions include:

- Regulation. Future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure for ensuring cost effective delivery of network services. We believe that the structure of our network pricing and our management processes encourage the economic development of the network and the chances of adverse significant changes in the regulatory framework in this regard are low
- The city's rebuild. The pace of the CBD and 'red zone' recovery is influenced by The Crown, Ōtākaro/CCDU and local roading authorities. It's also influenced by private developers. There is uncertainty regarding the timing and extent of some key recovery projects as the cost of the rebuild escalates
- Changing customer demand. The uptake of emerging technologies such as electric vehicles, photovoltaic generation and battery storage is forecast to increase. We anticipate that this will start to impact the network towards the end of the 10 year AMP period. These forecasts are uncertain and we are researching the impact of these technologies for different uptake scenarios

- High growth scenario. Growth scenarios form a relatively narrow range. Our peak demand forecasts include a range of scenarios to test the impact of new technologies. The high growth scenarios do not cause a material uplift in network constraints and hence a material uplift in network investment or contractor resource requirements. Large capacity customer requests such as Fonterra and Synlait create manageable uncertainty
- Resourcing of skilled contractors and staff due to demand. Powerco have applied to the Commerce Commission for a CPP and Aurora are likely to follow. This will put further upward pressure on labour rates in the next period.

2.9.4 Cost inflation

The key assumptions for our cost forecasts are discussed in section 8.1 where all dollars are in FY19 terms and no allowance has been made for CPI adjustments, changes in foreign exchanges rates, or local labour, plant and material market rate changes. Refer to appendices for the expenditure schedules in nominal (inflation-adjusted) terms.

2.9.5 Potential differences between our forecast and actual outcomes

Factors that may lead to material differences include:

- regulatory requirements may change
- customer demand may change and/or the requirement for network resilience/reliability could change. This could be driven by economic and/or technology changes. This could lead to different levels of network investment
- changes in demand and/or connection growth could lead us to change the timing of our network projects
- one or more large energy customers/generators may connect to our network requiring specific network development projects
- major equipment failure and/or a major natural disaster may impact on our network requiring significant response and recovery work. This may delay some planned projects during the period until the network is fully restored
- input costs and exchange rates and the cost of borrowing may vary influencing the economics associated with some projects. If higher costs are anticipated, some projects may be abandoned, delayed or substituted
- changes to industry standards, inspection equipment technologies and understanding of equipment failure mechanisms may lead to changing asset service specifications
- requirements for us to facilitate the rollout of a third party communications network on our overhead network could lead to substantial make ready work ensuring the network is capable of meeting required regulatory and safety standards. This could lead to resource issues and short-medium term increases in labour costs.

Service levels

3

List of figures and tables in this section

3.1 Introduction to service levels

This section of our plan outlines our performance targets. It deals with customer-related service requirements and other requirements relating to our asset management drivers as defined in section 2.6. Those drivers are:

- customer service
- safety
- environmental responsibility
- investment principles
- efficiency
- legislation.

We aim to meet the expectations of our customers and other stakeholders. This is consistent with our vision and values and statement of intent (SOI). Our SOI contains specific service level targets for reliability (SAIDI, SAIFI) and other aspects of our business, some of which are outside the scope of this AMP.

Our service level targets are based on a balance of:

- customer and stakeholder consultation
- health and safety considerations
- regulatory requirements
- international best practice
- past practice.

We endeavour to provide a level of service that meets the expectations of our customers' in the long term. We also recognise their differing requirements and endeavour to ensure that, as far as practicable, all customers are satisfied with the level of service we provide and that no one party is unfairly advantaged or disadvantaged.

Keeping abreast of changing customer expectations is fundamental to optimal asset investment and asset management practices. To determine customer expectations with regard to the level of service that we provide, we utilise six main methods of consultation. We detail information on these consultation methods in section 3.2.

In summary, we:

- involve customers in setting our security of supply standard
- undertake customer surveys, workshops and focus groups
- engage with customers via retailers
- obtain direct customer feedback
- consult customers on selected major projects
- consult with a customer advisory panel that was formed in late 2017.

In FY19 we are looking to establish a 'standing' customer advisory panel to enable us to obtain customer feedback. The group is to be made up of a cross section of community representatives.

In setting our service level targets we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and customer expectations.

For a review of service level performance against our targets, see section 9 – Evaluation of performance.

3.2 Customer consultation

Every moment of every day, 200,000 customers rely on electricity delivered by Orion's network across Christchurch and the Selwyn District.

Keeping this vital infrastructure operating safely and sustainably all day, every day is our top priority.

As well as maintaining our physical infrastructure, keeping our network operating sustainably is also about knowing our customers, what their needs and aspirations are, and ensuring we remain relevant to their lives.

We do that by actively consulting with our customers and getting to know them better. We seek out our customer's views on possible future investments, our customer service and how they see emerging technologies offering new ways to manage their energy consumption at home, in the workplace and on the road.

This has never been more important than it is today.

It's an exciting time in the electricity industry in an era of transformation, driven by new technology and shifting customer expectations. Our customers are changing and they want more control over where their energy comes from, and how they consume it. With lifestyles that are becoming increasingly diverse, customers are looking for flexibility and more choice. It's vital we adapt our business to respond to customer driven demands.

Orion is committed to putting our customers at the centre of all we do, and we continue to work hard to better understand the needs of our customers, and give them a voice in our decision making, as we power a vibrant and energised region now and into the future.

We have taken significant steps to listen more closely to our customers now and even better in the future.

Major customer engagement

All of our major customers are invited to at least two seminars a year where we take the opportunity to engage with them on key matters. These are people who run intensive power dependent businesses, from schools, supermarkets and malls to dairy processing plant and printing machines.

We regularly meet with key stakeholders and key influencers in the business community, our shareholders, Community Boards and local MPs to seek their views on our performance, future direction, and options we are considering.

Customer consultation over major projects

We have also responded to increasing expectations on the part of the community to be consulted on decisions affecting their lives including how and when we programme our work.

Where major projects have a significant impact on the community, we consult with the affected parties including Community Boards, local MPs, businesses and directly with residents.

Following the successful pilot of a new communications and engagement model for a significant project in the Lyttelton community in 2017, we have undertaken a review of our planned outage communications process and established new protocols.

"Always-on" Contact Centre

We operate a 24/7 Customer Contact Centre which means we talk with our customers on a daily basis about the service they receive. Through more than 3,000 calls per month we gain a rich understanding of what's important to our customers which enables us to continuously improve our service, and identify any prevalent concerns or opportunities to respond to.

We are taking what we learn in these conversations into our future planning.

Keeping the public informed

Mass communication channels, tradeshows, public exhibitions and social media are utilised to provide public safety messages and advice on power outages, along with an invitation to provide us with feedback. These include:

- media releases
- media briefings and interviews
- newspaper and radio advertising
- magazine advertising
- stands at tradeshows for the farming community
- information updates on our website
- Twitter updates.

Annual general customer survey

Each year we commission an independent research company to conduct a survey of 800 urban and rural residential customers. This gives us valuable insight into their expectations and levels of satisfaction with our service, views on network reliability and awareness of, and interest in, new technologies.

Key findings from that research in 2016 are:

- 84% agree that Orion carries out its duties very well
- 82% agree that Orion is capable and effective
- 70% agree that Orion acts in the interests of local residents
- 74% say power outages have no or minor impacts
- 85% say restoration met or exceeded their expectations
- 82% overall satisfaction with communications
- Orion achieved a +22 Net Promoter Score – compared to the industry average of -8%.

While we are encouraged by this generally positive result, the research also identified areas for improvement in customer experience and perceptions. These areas, in particular improving our planned outage communications, and a focus on improving network reliability and communications with the Lyttelton community are being given priority.

Perceptions of reliability are created by the timing and impact of the most recent outage:

Last outage **more than 6 months** ago:

98% reliable

1% unreliable

Last outage **less than 6 months** ago; **no or minor impact**:

83% reliable

6% unreliable

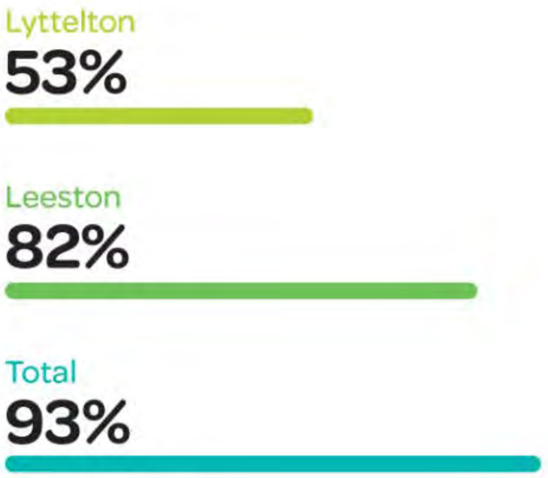
Last outage **less than 6 months** ago; **some, moderate or major impact**:

48% reliable

29% unreliable

Lyttelton residents are much less satisfied than the total, while Leeston residents are not as affected:

Satisfied with reliability:



The future: new roles, increased focus

Increasing our commitment to meaningful dialogue with our customers, we have sought to drive an increased focus on community engagement and consultation throughout Orion. We are concentrating our attention on exploring the impacts of new technologies from the customer's perspective through our Communications and Engagement Manager and creating a new position of Opportunities and Developments Manager.

Working with other key managers throughout the business, these roles spearhead a virtual team formed to drive Orion's Customer Engagement Strategy. This team has established Orion's Customer Engagement Framework and commenced our Insights Programme that utilises a range of existing and new ways to stimulate conversations with our customers.

The three pillars of our Engagement Framework are:

PRICE vs QUALITY	IMPROVE CUSTOMER EXPERIENCE	FUTURE CUSTOMER
Are we delivering the quality and price customers are comfortable with?	*Do we understand our customer's needs and expectations?*	*What do our customers want and need for the future?*

New engagement initiatives

The most effective way to engage with customers is meeting with them to talk in person. This allows us to speak to different types of customers and get in-depth information about what they expect and want from the network.

In 2017 we initiated a number of new ways to get to know our customers better, by talking with them in person:

"Powerful conversations" workshops where groups of 15 to 20 customers debate their thinking on price/quality trade-off around a range of network maintenance and upgrade proposals forming our Asset Management Plan, and attitudes to future technology options. Theses workshops allowed us to inform participants and discuss options with them. We presented information about Orion, its planning and its challenges, and then facilitated a participatory workshop that elicited concerns and captured the thinking of target groups. We ran **three** "**Powerful conversations**" one each for rural customers, urban customers and small-to-medium enterprises.

We are seeking to establish a **Customer Advisory Panel** to host lively and informative discussions quarterly on a range of topics.

A series of **Focus Groups** led by an independent researcher helped us elicit customers' views on our 15c per day fixed price proposal and proposed new forms of communications.

3.3 Service level measures

This section details the measures used to monitor our performance as an asset management business. All our consultation methods show that, almost without exception, a reliable supply of electricity at a reasonable price is our customers' greatest requirement of us. We measure our performance against this primary customer requirement in a number of ways as shown in section 3.3.1.

Other service measures such as efficiency, safety, environmental and legislative compliance reflect a range of performance measures that we monitor. Our performance in these areas often provides advance notice about where Orion's performance is heading prior to any change being noticed in our primary reliability targets.

For some of these other service measures we have not set a specific target value. In those cases we explain our position as to why we believe doing so would be counter productive. All our targets are set out in table 3-4a. Our performance against the targets shown in this section are in section 9 - Evaluation of Performance.

3.3.1 Network reliability

Network reliability is measured by the frequency and duration of interruptions to the supply of electricity to our customers. Our goal is to ensure that our reliability performance meets our regulatory requirements and our customers' expectations as ascertained by the means discussed in the previous section.

Our primary network reliability measures are applied as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These measures are:

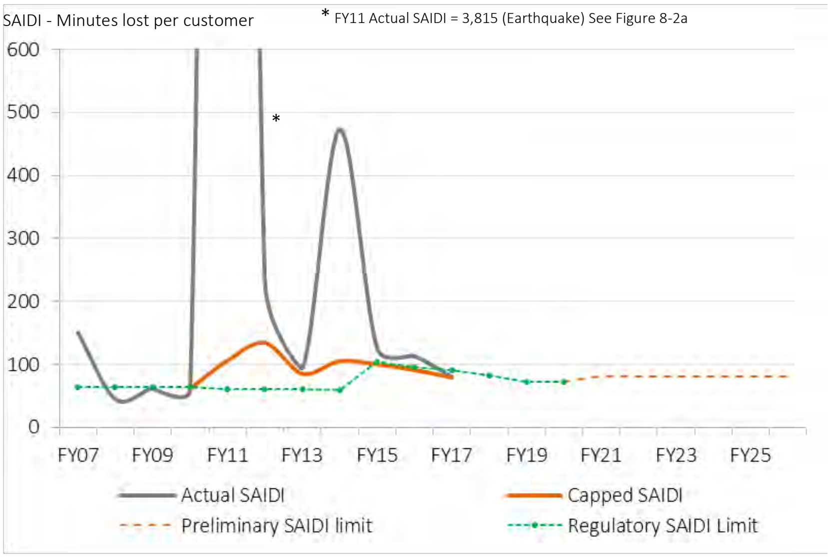
- SAIDI, system average interruption duration index, measures the average number of minutes per annum that a customer is without electricity
- SAIFI, system average interruption frequency index, measures the average number of times per annum that a customer is without electricity.

Both the SAIDI and SAIFI measures consider planned and unplanned interruptions of a duration longer than one minute on our subtransmission and high voltage distribution system. Low voltage interruptions and those that originate in Transpower's transmission system are not included. Planned interruptions to carry out work on our network would normally account for approximately 15% of our SAIDI minutes and 5% of our SAIFI.

Extreme environmental events can have a major impact on the reliability of an electricity network (this can be seen in the actual SAIDI values in figure 3-3a). To moderate this impact, the current regulatory regime calculates a daily boundary value to cap the number of customer-minutes lost in the case of extreme events. Our annual network reliability limits and daily boundary values are currently set by the Commerce Commission under the Customised Price-quality Path (CPP) regime determined for Orion after the earthquakes of FY11. These limits will run from FY15 through to FY19. Our FY20 limits will be the same as FY19 as stated in the Commerce Commission's Electricity Distribution Services DPP Determination 2015. FY20 is the final year of the DPP disclosure period of the other non-exempt EDBs. We have called it the "Transitional Year" between our current CPP and the next regulatory reset. Orion's SAIDI and SAIFI targets are set in relation to the same calculation methodology and daily boundary values.

We have recently completed an 18 months project focusing on quality. As part of the project, we've applied the Commerce Commission's latest Inpout Methodology to eight years of historical reliability data. The calculated limits are only preliminary since actual data for FY18 and FY19 is not yet available. The limits are calculated for the period of FY21-FY25 and extended out to FY28 as shown in Figure 3-3a and Table 3-4b.

Figure 3-3a **Orion SAIDI – 10 year history and 10 year target**



NOTES.

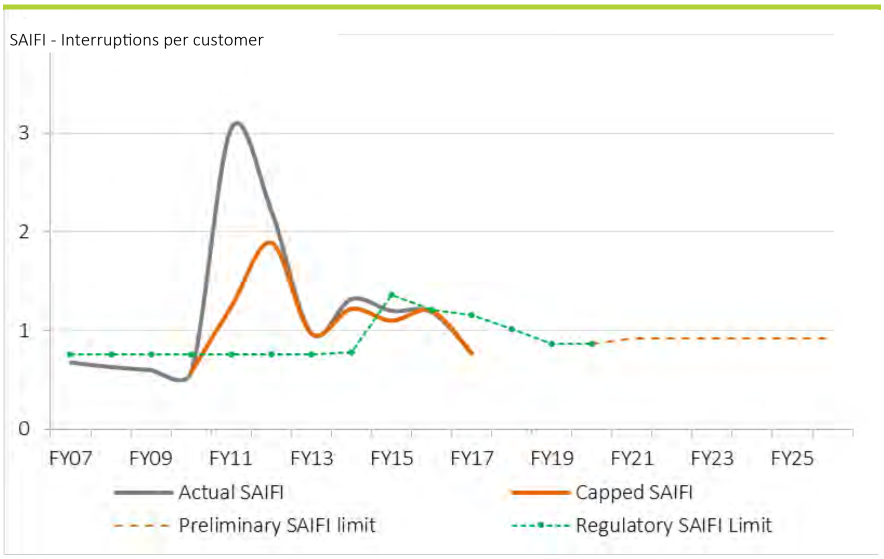
Actual SAIDI
SAIDI value without any daily boundary values applied.

Capped SAIDI
SAIDI value capped to daily boundary values for any extreme event days as per CPP requirements.

Preliminary SAIDI limit
Limit calculated using Input Methodology

Regulatory SAIDI limit
Regulatory annual limit value, with daily limit applied to cap extreme events as per CPP requirements.

Figure 3-3b **Orion SAIFI – 10 year history and 10 year target**



It is not realistic to expect that we can continually improve network reliability as there comes a point where the added costs outweigh the added benefits, particularly in a predominately overhead rural network. For example, a major improvement in rural reliability would require a large capital investment and a correspondingly large increase in line charges.

Customers have indicated across our various consultation methods that they are generally satisfied with our present level of network reliability and that they have concerns in regard to price increases. In practical terms this means that we do not believe our customers wish to see increasing levels of reliability beyond current levels if it means higher prices.

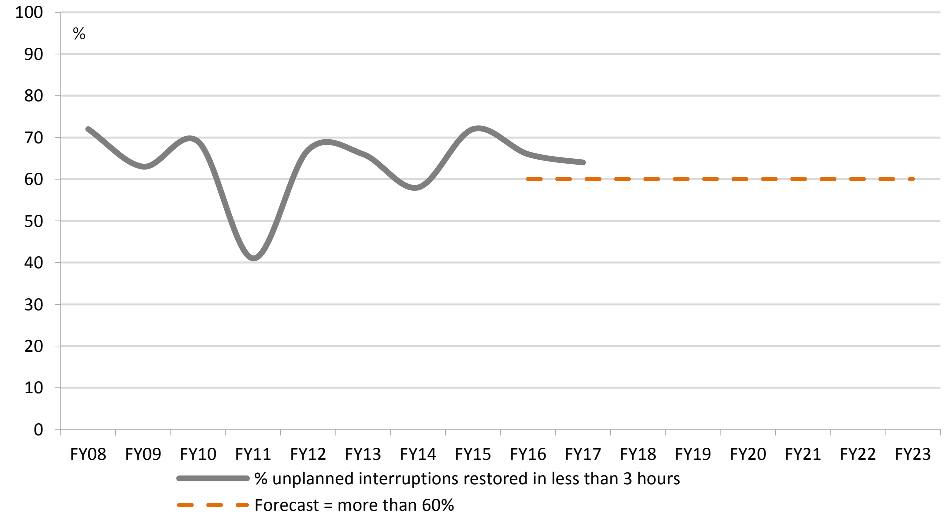
3.3.2 Network restoration

Customer consultation has told us that if a power failure does occur, then rapid restoration of power is the most important concern. Surveys show that 83% to 90% of customers consider this important following a power failure. Consequently our customer focused measure is the percentage of unplanned interruptions restored within three hours.

Customers across our various consultation methods say they are generally satisfied with our present level of service and that they are concerned about increased electricity prices. In practical terms this means that we do not believe our customers wish to see increased levels of service beyond current levels if this would mean higher prices. Our percentage of unplanned interruptions restored within three hours is based on providing a reasonable level of service at a reasonable cost.

We have engaged an emergency contractor to manage our distribution asset spares and provide adequate response to any event on our network. Reasonable response times to effect a repair have been established and enshrined in a contract between us and our emergency contractor.

Figure 3-3c **Unplanned interruptions - % restored in under three hours**



3.3.3 Network capacity

Orion has a security standard that was developed in consultation with external advisors and adopted in 1998. It is based on the United Kingdom's P2/6 which is the regulated standard for distribution supply security in the UK.

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. Note that security of supply differs from reliability. Reliability is a measure of how the network performs and is measured in terms of things such as the number of times supply to customers is interrupted.

During 2007 we reviewed our security standard to ensure it takes into account customer preferences for the quality and price of service that we provide . As a result of our review and customer consultation, our security standard was improved to better reflect the needs of our customers. Our revised security standard may result in slightly lower reliability for our outer-urban customers but will also reduce the need for future price rises.

These kinds of trade-offs between price and electricity supply reliability are a constant focus for us. Generally, the more we spend, the more reliable our community's electricity supply becomes. However, the trade-off is that the more we spend the higher our prices become, as we need to recover our costs. We are committed to seeking our customers' views on the price/ quality trade-off and we want to ensure that our network investment decisions reflect customer preferences.

The demand group thresholds in our security of supply standard tend to err on the side of caution and generally provide a level of security that is slightly above the requirements of the average customer connection. Our analysis has also shown that it is appropriate to provide a slightly higher level of network security for the Christchurch CBD.

This approach ensures that customers who place a high value on security of supply are reasonably represented in areas where a mix of customer types exists.

Our security standard is detailed along with proposed improvement work in section 5 – Network development.

3.3.4 Power quality

Power quality is defined by a group of performance attributes of the electricity power supply. Two of the most common and important power quality attributes that are mostly under our control are:

- the steady state level of voltage supplied to customers
- the level of harmonics or distortion of voltage of the power supply.

The reason why these attributes are only 'mostly' under our control is because the power quality that is supplied to us by Transpower (and to it by the generators) provides a baseline level of performance that we can only pass on to customers. We contract with Transpower to provide a suitable level of power quality performance at the GXPs.

We have installed power quality measurement instruments throughout our distribution network as part of a long-term survey to determine the performance of our distribution network and how it changes over time. The 33 measurement sites represent the average and worst performing parts of our network over a variety of customer types.

Steady state voltage

The range of steady state voltage supplied to customers is mandated by regulation, as 230 volts ± 6%. We design and operate our network to meet this requirement. However, despite our efforts and usually due to unanticipated changes in customer loads, some customers will experience voltages outside these limits for short periods of time. When a complaint is made, we will investigate. If the complaint is proven (i.e. the investigation shows that the non-complying voltage or harmonic originated in our network) we will upgrade our network to rectify the problem.

The level at which we have set our target for steady state voltage non-compliance (proven) is a pragmatic customer-focused ratio of no more than one case per 2,500 customers per year.

Harmonics/distortion

The allowable level of harmonics or distortion of the power supply provided to customers is also covered by regulation. In most cases the customers themselves have distorted their power supply, for example, by the use of electronic equipment. We provide an initial investigation service to measure the levels of harmonics or distortion and will determine whether other customers are affected. If others are affected, the customer must rectify the problem. If no other customers are affected, we will suggest suitable consultants who can offer a solution to the problems, but will leave the customer to rectify at their cost.

We use harmonic allocation methods defined in joint International Electrotechnical Commission (IEC)/Australian/New Zealand standards to determine acceptable customer levels of harmonic injection. These allow each customer to inject a certain acceptable amount of harmonic distortion depending on the strength of the power supply at their premises.

The level at which we have set our target for proven harmonics/distortion complaints is no more than one per 50,000 customers per year. This target is based on historical Orion and international data.

3.3.5 Safety

Operating and maintaining an electrical network involves hazardous situations that cannot be eliminated entirely. We are committed to consultation and co-operation between management and employees to provide a safe reliable network and a healthy work environment – we take all practical steps to minimise the risk of harm to the public, our contractors and staff. Maintaining a safe healthy work environment benefits everyone and is achieved through co-operative effort.

Our objectives are to:

- keep the public and our staff/contractors safe
- provide safe plant and systems to ensure worker and public safety
- ensure compliance with legislative requirements and current industry standards
- provide safety information, instruction, training and supervision to employees and contractors
- provide support and assistance to employees
- set annual goals and objectives, and review the effectiveness of policies and procedures
- take all practicable steps to identify and then either eliminate, isolate or minimise hazards.

Further information on these objectives is available in our statement of intent and our performance against them is detailed in our annual report. Our target of no serious safety events or accidents is the only prudent target we could have for this measure.

3.3.6 Customer service

Customers consider it important to get a quick response from us following an interruption to their electricity supply, and to get accurate information on when it will be restored. Of the 3% of urban customers and 20% of rural customers who try to contact us following a power cut, around 75% state that it is important to get through quickly if they call. In relation to the ability to call Orion, we operate a 24/7 contact centre from our head office.

We aim to answer calls promptly and typically 92% of calls to our contact centre are answered within 20 seconds, with an average wait time of about 11 seconds. However, our focus in call management is not on call answering times, or call duration, but rather providing information quickly, accurately and politely.

3.3.7 Environmental

We are committed to being environmentally responsible. This fits within our principal objective, which is to operate as a successful business and be financially sustainable. We have established a number of environmental sustainability policies that are published on our website. These policies are reviewed annually. Further information on each of these policies is available in our statement of intent which is also on our website.

The environmental measures related to the operation of our network are:

- the amount of SF_6 gas lost into the atmosphere (as a percentage of the total volume in use on our network)
- the number of oil spills that are not contained by our oil containment facilities or mitigation procedures.

Our target for loss to the atmosphere of the insulating gas SF_6 is based on a percentage of the total volume of the gas in use on our network. The level is set by an undertaking we have signed with the Ministry of the Environment to comply with the "Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF_6) to the Atmosphere". In addition to this we have a policy not to purchase equipment containing SF_6 gas if a technically and economically acceptable alternative exists.

In respect to oil spills, we operate oil containment facilities and have implemented oil spill mitigation procedures and training. Our target of zero uncontained oil spills is the only prudent target we could have for this measure.

In FY08 we undertook a study, in conjunction with international consulting firm MWH, to map our key impact on the environment and identify where we can improve our environmental performance. This 'mapping' exercise was very wide ranging and went beyond the factors normally considered in carbon footprint exercises. As a result of MWH's report we identified the following activities to focus on (five have been accomplished and the others are on-going; date completed shown in brackets):

- incorporate the cost of carbon into our network investment decisions (June 2009)
- assess the feasibility and desirability of becoming carbon neutral (September 2009)
- work with Community Energy Action to insulate at least 500 low income homes in Christchurch (March 2010)
- undertake a safety and efficiency driving course for all Orion and Connetics employees who regularly drive operational vehicles (March 2011)
- consider the potential to replace operational vehicles with more fuel efficient models. Then work with other contractors servicing the Orion network to encourage them to run their vehicle fleet as efficiently as possible (March 2011)
- convert Orion vehicles to EV hybrid (23% complete at 2017)
- continue to undertake and encourage customer demand management (on-going)
- reduce and where practical eliminate the installation of new network cables containing lead (on-going)
- continue our support for and sponsorship of CEA (on-going)
- support the Christchurch City Council's sustainable energy strategy (on-going).

Other aspects of our operations that support our environmental commitment are that we:

- facilitate the easy connection of renewable low-carbon generation (for example wind and PV) to our network
- signal load peaks in our network pricing to encourage the efficient use of our network
- maintain and operate an efficient water cylinder load control system so that significant loads can be shifted away from peak times to less expensive off peak times – at minimal inconvenience to customers
- are looking at possible wind generation sites in our network area.

3.3.8 Efficiency

Economic efficiency

Economic efficiency reflects the level of asset investment required to provide network services to customers, and the operational costs associated with operating, maintaining and managing the assets.

We have adopted the following measures of economic efficiency:

- capital expenditure per annum per MWh of electricity supplied to customers
- operating expenditure per annum per MWh of electricity supplied to customers
- operating expenditure per annum per year end number of ICPs (connection points).

Our target is to perform better than the New Zealand industry average.

Capacity utilisation ratio

This ratio measures the utilisation of transformers installed on our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network.

Our management process aims to ensure maximum economic efficiency by ensuring good design and lifecycle management practices. If we specifically target levels of capacity utilisation, there could be an incentive to design inefficiently, for example to install long lengths of low voltage distribution or uneconomically replace transformers early in their lifecycle due to shifts in area load profiles.

Although we monitor this ratio, we do not have a specific target.

Load factor

The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year. We always seek to optimise load factor as this indicates better utilisation of capacity in the network.

Our forecast load factor band is shown in section 5.4.2.

Energy loss

All electricity networks have energy losses caused mainly by heating of lines, cables and transformers. Electrical losses are natural phenomena that cannot be avoided completely and consequently retailers have to purchase more energy than is delivered to their customers.

Electrical losses are the difference between energy volumes entering our network (mainly at Transpower GXPs) and the energy volumes leaving our network at customer connections. We estimate that these losses are around 5% with a margin of error of +/- one percentage point. Significant deviations from this value exist in some parts of our network, for example, when we compare urban areas against rural areas.

When considering losses in network design and asset purchase, we do not aim for a target percentage of loss. Instead the lifetime annual cost of losses is converted to a net present capital value which can be added to the capital value of the asset concerned. We implement the least cost overall (asset cost + capitalised loss cost) solution. This approach provides the optimal economic level of losses.

See section 9.3.4 for a more detailed evaluation of our approach to network losses.

3.3.9 Resiliency

Resilience is the ability of our network, our people and systems to respond to rare but major events such as earthquakes and wind and snow storms. Reliability is a measure of our day to day performance and is characterised by the number and duration of power outages to customers. A more resilient network will limit the number of customers affected during major events and will enable faster than otherwise restoration of power for those customers experiencing outages.

We will seek to develop methods for setting and measuring resiliency standards/targets that capture the preparedness and response of our people, systems and network.

3.4 Service level targets

This section describes our targets set in line with Orion's asset management strategy for all the measures discussed in the previous section 3.3.

Our targets for FY19 and future years are shown in the following tables.

3.4.1 Targets for current year

Table 3-4a **Service descriptions, targets and measures for current year (FY19)**

Service class	Service measure	FY19 targets	Performance measure	Measurement procedure
Network reliability	SAIDI - system average interruption duration index	< 81	Orion network– average minutes lost per customer per annum for all interruptions (planned and unplanned). Orion network only.	Tracking of all interruptions to our network (process audited annually). All 400V faults are excluded and HV faults <1min in duration are excluded. Capped to daily boundary values for any extreme event days as per CPP requirements (see section 3.3.1).
	SAIFI - system average interruption frequency index	< 0.92	Orion network- average number of times a customer's supply is interrupted per annum for all interruptions (planned and unplanned). Orion network only,	
Network restoration	Unplanned interruptions restored within 3 hours	> 60%	% of total number of unplanned interruptions where the last customer is restored in three hours or less. Orion network only, See section 3.3.2.	
Network capacity	Delivering reasonable levels of network security	To meet our security standard	Any gaps identified against our security standard. See section 5.5	
Power quality	Steady state level of voltage	< 70	Voltage complaints (proven). See section 3.3.4	Tracking of all enquiries
	Level of harmonics or distortion	< 4	Harmonics (wave form) complaints (proven). See section 3.3.4	Checks performed using an harmonic analyser
Safety	Safety of employees and contractors	Zero	Serious safety events. See section 3.3.5.	Accident/incident reports
	Safety of public	Zero	Number of accidents involving members of the public (excluding car v pole accidents) See section 3.3.5.	Accident/incident reports
Environment	SF_6 gas lost	< 1% loss	Gas lost expressed as a % of the total contained in our network equipment. See section 3.3.7.	Set out in Orion Procedure NW70.10.01
	Oil spilt	Zero	Oil spills not contained. See section 3.3.7.	Set out in Orion Procedure NW70.10.02

3.4.2 Targets for future years

Table 3-4b **Service descriptions, targets and measures for future years**

Service class	Service measure	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Network reliability	SAIDI – system average interruption duration index	< 73	81	81	81	81	81	81	81	81
	SAIFI – system average interruption frequency index	< 0.85	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Network restoration	Unplanned interruptions restored within three hours	> 60% →								
Capacity	Delivering reasonable levels of network security	To meet our security standard								
Power quality	Steady state level of voltage	< 70 →								
	Level of harmonics or distortion	< 4 →								
Safety	Safety of employees and contractors	Zero →								
	Safety of public	Zero →								
Customer service	Prompt response to enquiries									
Environment	SF_6 gas lost	< 1% loss →								
	Oil spilt	Zero spills →								

Lifecycle asset management

Orion

4

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4.1 Network overview

4.1.1 Asset description

We own and operate the electricity distribution network in central Canterbury. Our network covers 8,000 square kilometres across central Canterbury between the Waimakariri and Rakaia rivers and from the Canterbury coast to Arthur's Pass. Customer densities range from five customers per km in rural areas to 26 in urban areas. Approximately 88% of our customers are located in the urban area of Christchurch with 12% in the rural area.

Traditionally our subtransmission network was described as urban and rural but changes in customer demographics (e.g. the growth of Rolleston and Lincoln townships) necessitate recognition of a range of customer types in the rural area and a range of resulting network architectures. The area previously known as urban is now region A and what was rural is now region B.

4.1.2 Region A

Our network consists of both a 66kV and a 33kV subtransmission system. Our 66kV system supplies 18 zone substations in and around Christchurch city and is supplied from Transpower's 66kV GXPs at Bromley and Islington. Our 33kV system supplies another six zone substations in the western part of Christchurch and is supplied from Transpower's Islington 33kV GXP. Both systems consist of overhead line and cable in the quantities shown in table 4-1a. A further six zone substations in the area take supply at 11kV from our 66kV zone substations.

The zone substations supply a network of 11kV cables connected to 201 network substations. These network substations in turn supply over 4,000 distribution substations on a secondary 11kV cable network. The low voltage (400V) system to which most of our customers are connected is supplied from these distribution substations. The reasons for the structure of our network are further discussed in section 4.2.

4.1.3 Region B

Our network consists of both a 66kV and a 33kV subtransmission system that supplies 22 zone substations from Transpower's Islington, Hororata and Kimberley GXPs. The distribution system primarily consists of 11kV overhead radial feeders from our zone substations and three small Transpower GXPs at Coleridge, Castle Hill and Arthur's Pass.

Table 4-1a **Orion's electricity network asset quantities**

Category	Description	31 March 2017
Total network	Lines and cables (km)	15,623
	Zone substations	53
	Distribution substations	11,361
Overhead lines (km)	66kV	246
	33kV	279
	11kV	3,209
	400V	1,804
	Street lighting	917
Underground cables (km)	66kV	89
	33kV	37
	11kV	2,602
	400V	2,974
	Street lighting	2,434
	Communication	1,031
	Total cables	9,168
Zone substations	66kV	27
	33kV	19
	11kV	7
Distribution substations	Building	468
	Ground mounted	4,724
	Pole mounted	6,397
Embedded generation	Greater than 1MW	10 Customer-owned sites
Major business customers	Loads between 0.3MW and 11MW	325

Figure 4-1a 66kV, 33kV and 11kV subtransmission network – Region A

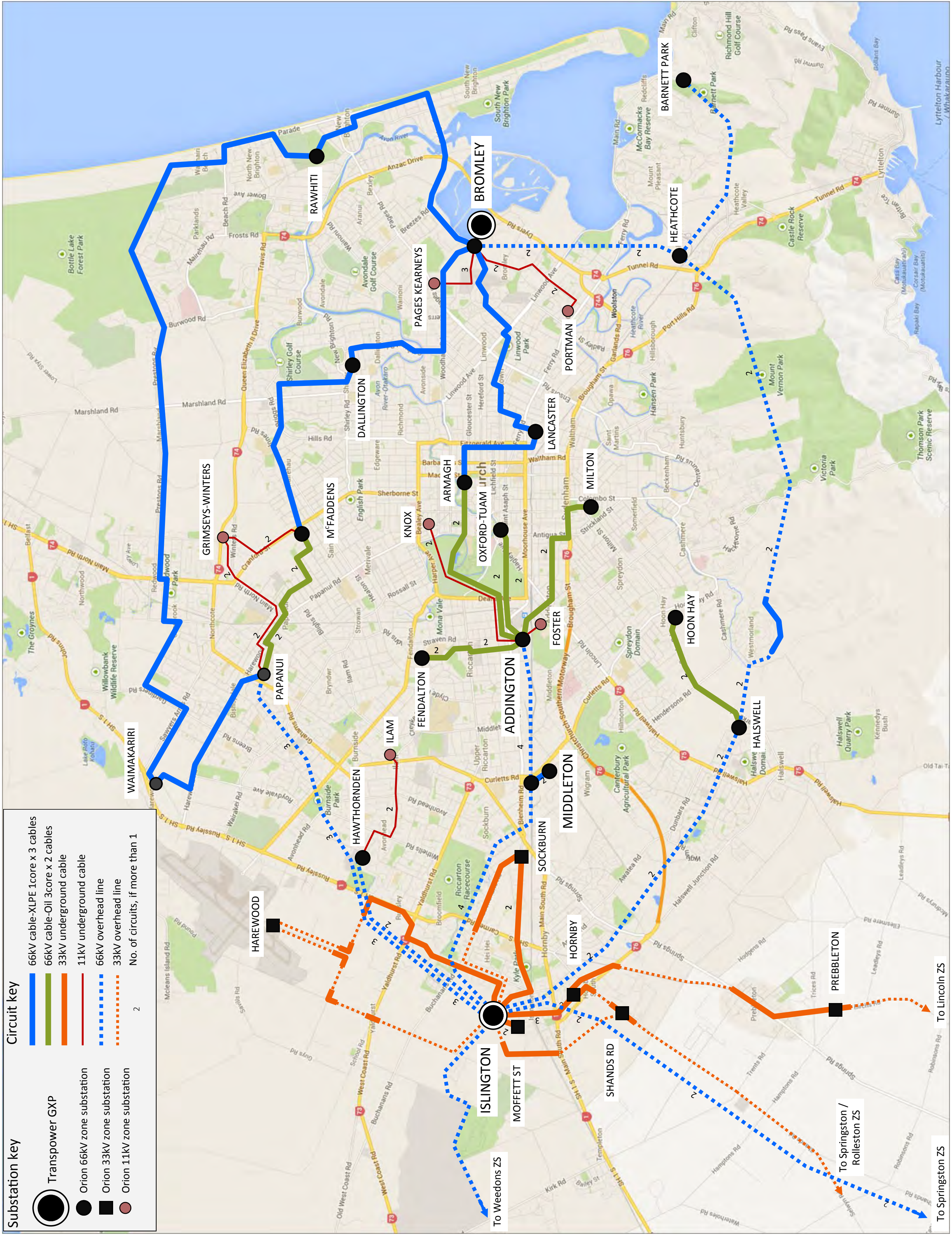


Figure 4-1b 66kV and 33kV subtransmission network – Region B

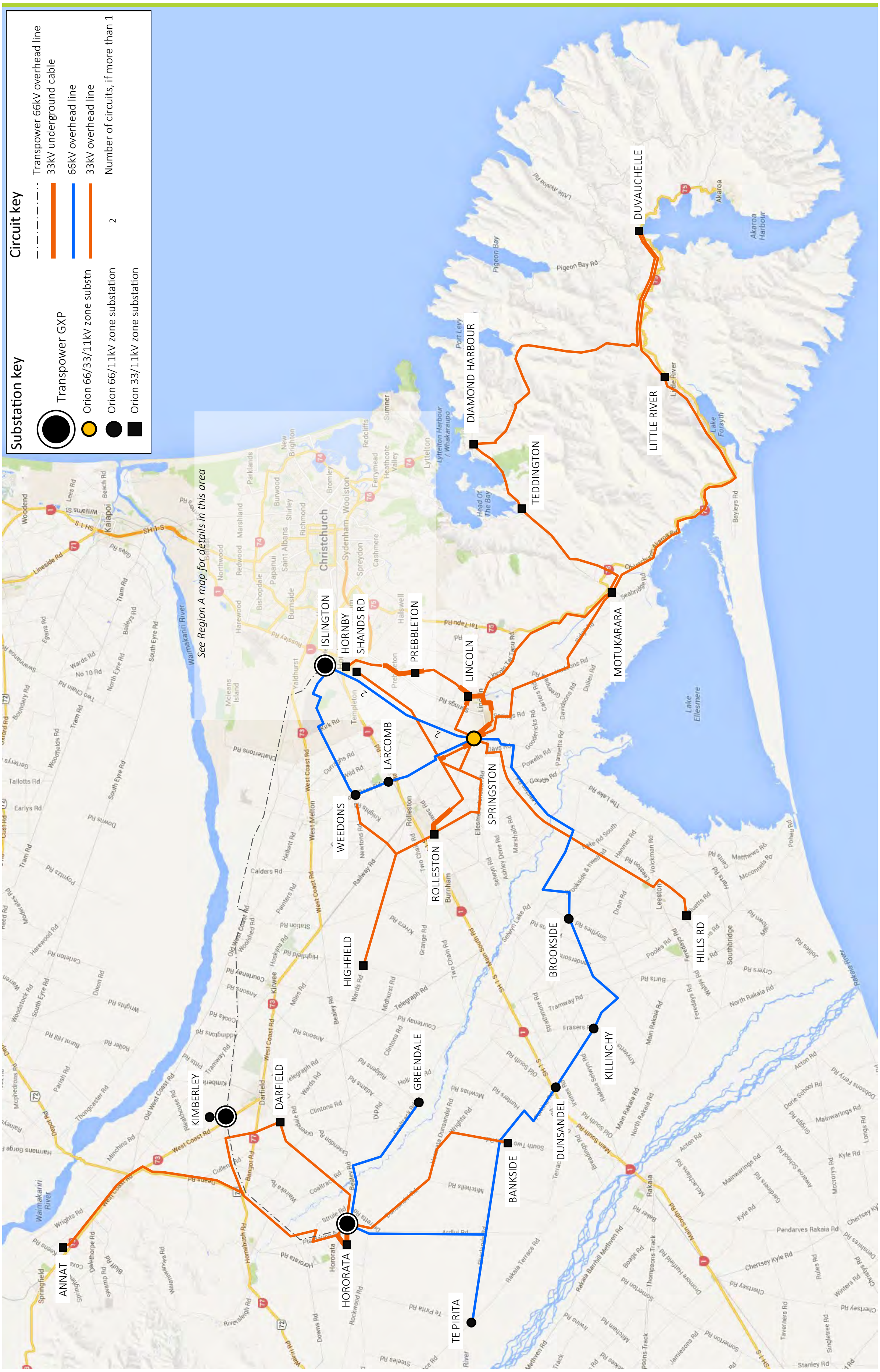
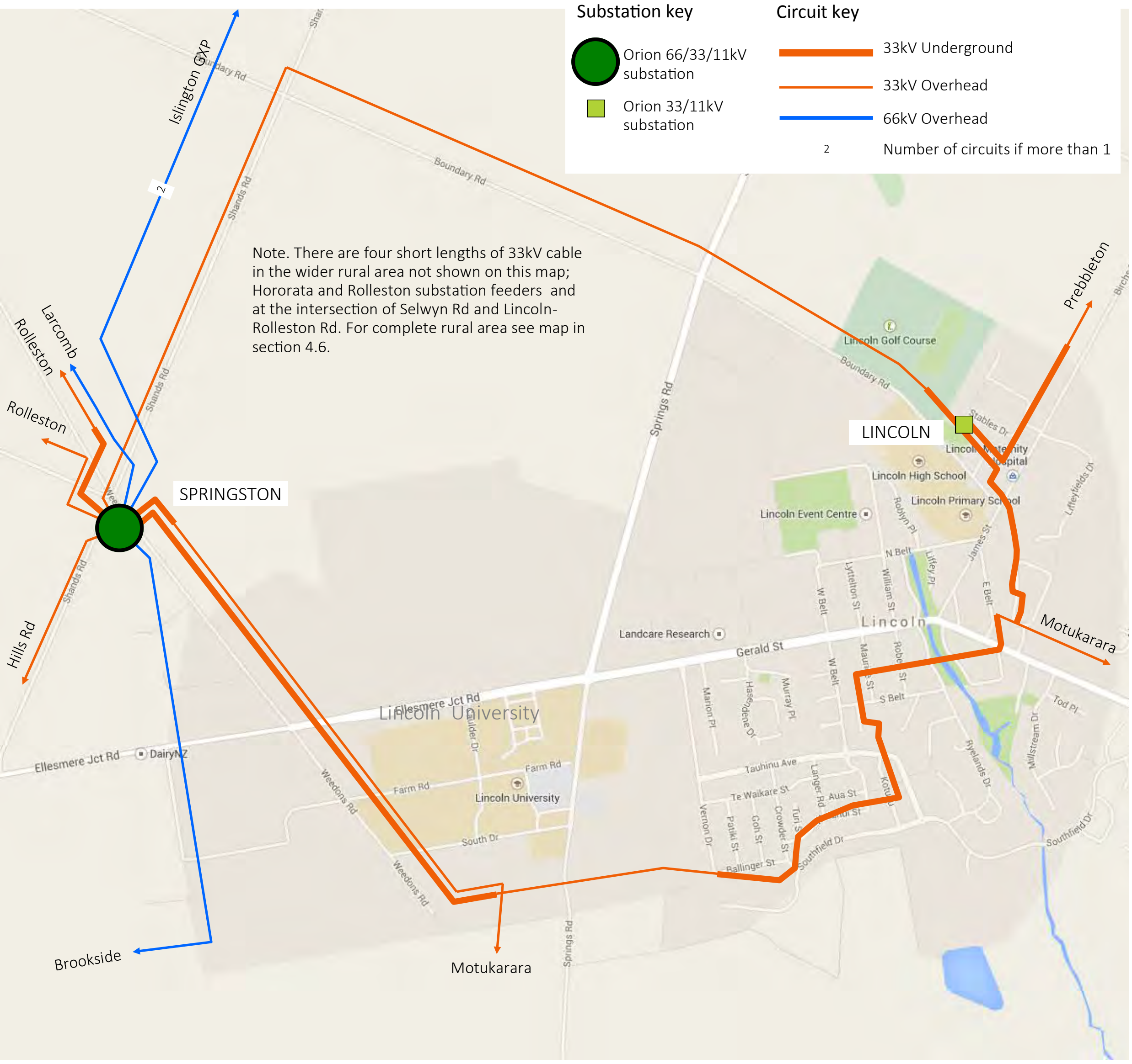
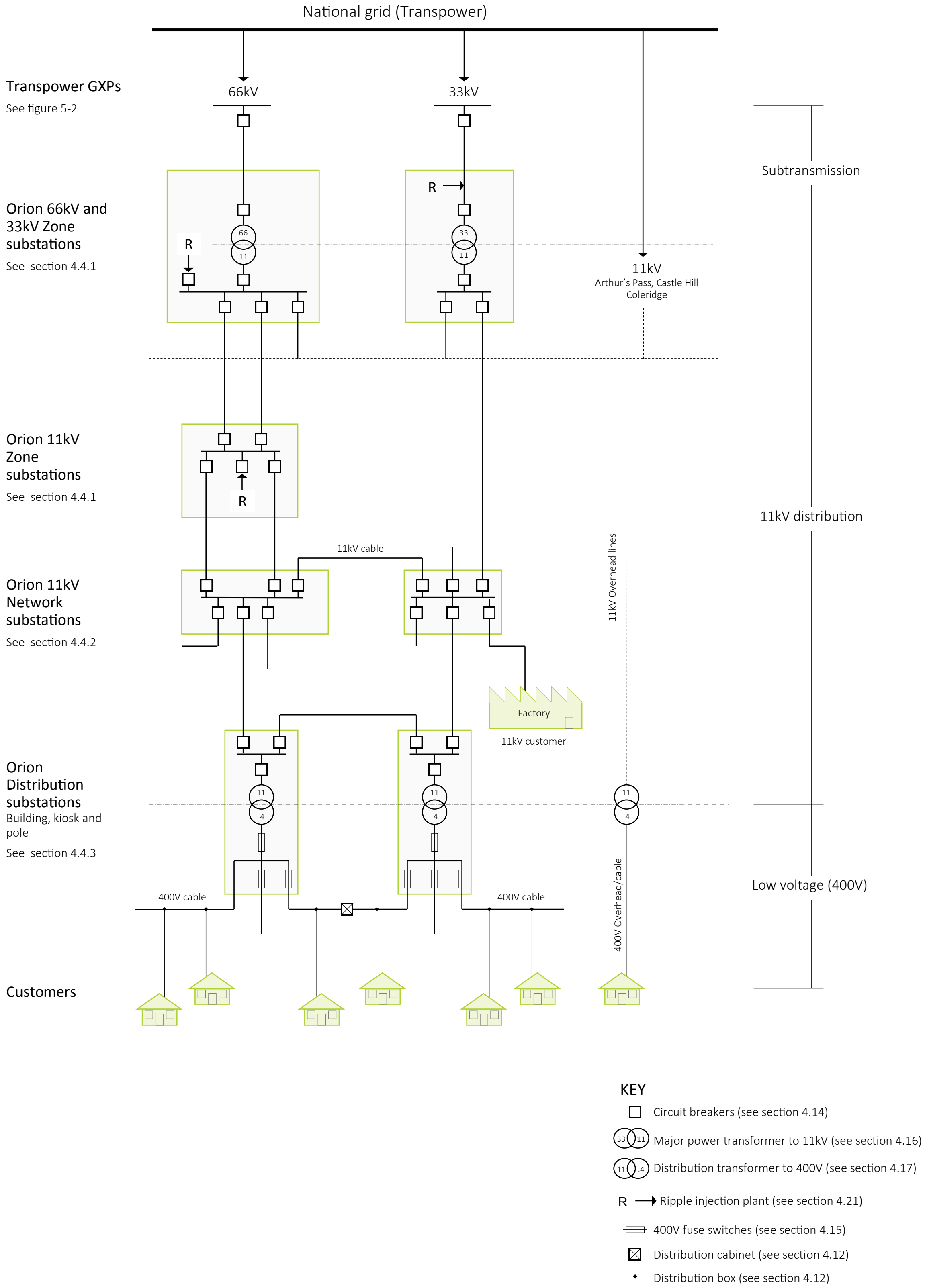


Figure 4-1c **Subtransmission – Lincoln and Springston area**



Note. There are four short lengths of 33kV cable in the wider rural area not shown on this map; Hororata and Rolleston substation feeders and at the intersection of Selwyn Rd and Lincoln-Rolleston Rd. For complete rural area see map in section 4.6.

Figure 4-1d **Network voltage level/asset relationships**



4.2 Network justification

4.2.1 Introduction

Our electricity network serves high-density urban areas, medium density rural countryside and remote rural locations. Approximately 88% of our customers are located in the urban area of Christchurch with the remaining 12% in the rural portion of our network.

The first electricity customer in Christchurch was connected in 1903. In 1912 11kV was adopted as the primary distribution voltage. Construction of the Coleridge power station around 1918 significantly shaped the initial network, with the introduction of low cost hydropower and a 66kV transmission system that is still in service today.

In the early 1920s, development in rural areas was based on overhead power lines serving rural communities in very diverse geographical locations such as Banks Peninsula, the Canterbury plains and the high country of Canterbury.

4.2.2 Region A-system design

The first electricity distribution systems in Christchurch were a mix of underground cable and overhead lines originating from the Government's Addington substation. Additional 11kV grid connection points evolved at Bromley and Papanui, providing quite large capacity at high fault levels. A comprehensive underground cable network based on electrical districts then grew from these three main grid connection points.

This network served the city until the rapid development period of the 1960s, when demand grew by 7% per year. Increased demand was met by building 66/11kV zone substations. These substations are the backbone of the present urban system. The initial design of our 66kV system was radial in nature with the installation of short, duplicated 66kV oil-filled feeder cables directly connected to transformers without 66kV switching facilities. The exception to this approach was the double circuit 66kV line around the Port Hills which was built in 1957 as a radial feed to Bromley but later became an interconnection between Bromley and Islington GXPs. During the 1990s and subsequent decade we saw continued load growth and New Zealand/worldwide system blackout events. We reviewed our network risks and introduced security standards. This resulted in changes to our network design philosophies which meant increased investment in interconnected 66kV sub-transmission and zone substations. In 2000 a new underground 66kV interconnection cable was laid from Bromley to the CBD to provide a second connection between Islington and Bromley GXPs. A further review of our 66kV network design/architecture was undertaken in 2012 following the series of Christchurch earthquakes which caused significant damage to our northeast 66KV subtransmission network. The review provided confirmation of our recent approach to increase the interconnection of our 66kV network. Consequently is was decided to rebuild our northeast 66kV network with two links between Islington and Bromley GXPs. The combined effect of four 66kV links and our cable and line route diversity provides a secure and resilient 66kV subtransmission network and also reduces the reliance on our 11kV network to transport power over large distances. This design proved itself during the 2017 Port Hills fire when Transpower lost supply to Bromley GXP. We were able to re-route supply using the newly completed 66kV link from Islington and therefore negating a potential significant loss of customer minutes.

The original 11kV distribution system, supplied by a small number of large grid connection points, led to the design philosophy of a primary 11kV cable network, capable of handling relatively large amounts of power (at high fault levels) over long distances around the city. Local 11kV distribution circuits of smaller size cables were laid to supply substations that convert the voltage to 230/400 volts for customer use. To allow even greater power density to be serviced 66/11kV transformers were introduced, while fault levels could be controlled through suitable choice of transformer impedance. This evolutionary process resulted in a network of primary 'closed' rings of 11kV distribution cables which connect network substations to zone substations. From each network substation, radial 11kV cables provide an interconnected 11kV secondary distribution network which services kiosk substations around the city. A review of our 11kV architecture in 2006 led to a change in our approach and the era of building new primary rings and associated network substations came to an end. Our new approach recognises the change to a stronger 66kV subtransmission network which enables a simpler radial approach to our 11kV network. The primary ring network is well established in our urban network and the conversion to a radial approach will take many decades to complete in an economic fashion as aging infrastructure is replaced over time.

Similar to the primary ring network, the new radial 11kV feeder network will continue to have strong interconnections between feeders and zone substations. The interconnected nature of the secondary network means that supply can be switched, allowing restoration of power to most customers within a relatively short time. Interconnection at the low voltage (400V) network level is also generally available, and enables us to restore power supply quickly when local distribution substations (transformers or switchgear) are damaged by faults. This high degree of network interconnection allows us to carry out routine maintenance and repair faults with minimal disruption to customer supply – it contributes significantly to our overall system reliability performance.

4.2.3 Region B system design

The earliest rural electricity distribution networks in Orion's area were based on 3.3kV and 6.6kV systems supplied from connection points off the Coleridge transmission lines, mainly at Hororata and Addington. These systems were simple radial lines, and were up-rated to 11kV over time to service increasing demand.

Load growth required the introduction of 33kV subtransmission in the mid 1960s. The 33kV was used to supply an increasing number of 'zone' substations, usually consisting of a 7.5MVA transformer with 11kV radial feeders interconnected to adjacent substations. Subtransmission of 33kV was always needed to get power to Duvauchelle in Banks Peninsula, because of the long distance from the old GXP at Motukarara.

This 33kV subtransmission/11kV distribution system was eventually extended over most of the rural area, and into the western fringes of Christchurch city, including the international airport.

The 'urban' part of this otherwise largely rural network evolved into a high load density area, with strong growth and higher reliability requirements. Therefore, the system is now a number of 20MVA firm capacity substations with two transformers, 11kV distribution feeders and a paralleled 33kV cable/line subtransmission network.

Overhead radial 11kV feeders have gradually been replaced with underground 11kV cables on this urban 33/11kV network.

In recent years, very high growth in irrigation loads has meant the rural 33kV subtransmission system has approached its design capacity. We decided the most economical reinforcement method was to build additional 66/11kV zone substations equipped with 7.5/10MVA transformers within the existing 11kV distribution network, while retaining (and converting to 66kV over time) the existing 33/11kV zone substations and 33kV lines. This methodology retains our existing network investment while shortening 11kV feeder lengths, resulting in improved system reliability.

As growth continues in the rural townships, and specific larger customers are connected, single transformer substations become unsuitable to meet future demand. Our rural network design now incorporates dual transformer substations with firm capacity of 10MVA (Lincoln and Rolleston) with new substations around Rolleston and its developing industrial park, supported by dual transformer substations with a firm capacity of 23MVA, similar to our western urban network.

4.2.4 Large customers

The Canterbury area and business sectors are largely service and/or agricultural based. This is reflected in the mix of approximately 325 major business customers connected to our network with loads ranging from 0.3MW to 11MW. The largest single load in this category is less than 2% of our total maximum demand.

Currently we have 17 customers that have an anytime maximum demand of greater than 2MVA. These customers are represented in the following activities:

• food processing	6
• industrial	3
• hospital	2
• university	2
• airport/seaport	2
• shopping mall	2

Each of these major customers is charged on a 'major customer connection' delivery charge basis. We individually discuss their security and reliability of supply requirements in relation to our normal network performance levels at the time of connection or upgrade. Generally our operating regimes and asset management practices do not specifically provide enhanced levels of service for these customers. We run six monthly seminars to update our major customers and provide them with a forum for open discussion. Typically we discuss asset management priorities, enhancement projects and current industry issues. We explain and promote pricing options (demand side management, power quality etc.).

If major customers require enhanced network performance, we work with them to achieve their requirements by either enhanced connection or on-site generation options. Our delivery pricing allows charges for dedicated equipment for enhanced supply to be made, or incentives to run embedded generation if it benefits our network.

Many major customers run generators in response to our pricing signals and we have specific arrangements to run generators at approximately 40 connections at other times when it is beneficial for our delivery service (see section 5.3.5 for details of our DSM initiatives). Connected generation at customer sites can vary from just a few kilowatts to as much as 2.5MW. We have 20 connections with more than 1MVA installed capacity.

Although there are issues to be co-ordinated when sites with generation are established, there is minimal impact on the operation and asset management of the local area networks. Most of these sites have installed generators for security reasons and running of the generators generally only reduces or off-sets their established load requirements. A small number of sites have the ability to export surplus energy into the network with metering and protection systems appropriately installed. The largest net energy export into the Orion network is 1.2MW.

As part of obligations under the Civil Defence and Emergency Management Act we have on-going discussions with life-line services such as the hospitals, seaport and airport to ensure appropriate levels of service are provided for in our future planning.

Two rural milk processing plants have a significant impact on our network operations or asset management priorities. The Synlait plant located at Dunsandel was commissioned during 2008. Its load including the predicted expansion was significant in the context of our rural network design in that area. The installation required a new zone substation at Dunsandel providing enhanced security. Similarly, the Fonterra plant commissioned during 2012 also required a new zone substation (Kimberley) to provide enhanced security. This has required us to revisit proposed current and future rural network design in Darfield and the surrounding area. Both connections are part of a ‘large capacity connection’ category to accurately reflect the cost of supply to this type of connection. The on-going delivery charges reflect an appropriate return on the assets needed to supply electricity to these customers.

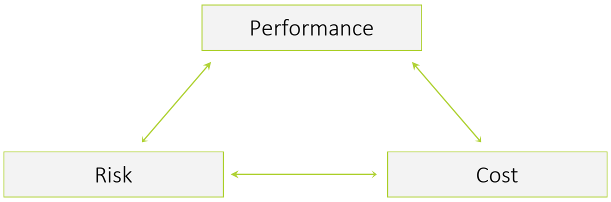
Irrigators (agricultural and dairy) are one customer group that significantly impacts on the operation and asset management of our network in the rural area. Irrigation growth over the last 20 years has required substantial reinforcement of our network. In discussions with this customer group, we were able to determine that as a group they could endure a slightly reduced level of security of supply. To reduce our investment in the rural network, we were able to offer an appropriate pricing scheme for irrigation connections that allows us to control their irrigation use during network emergencies. For further details refer to section 5.3.5

Irrigation connections are also impacting on our rural network power quality. We observed excessive harmonic levels generated by non-linear control devices (variable speed drives) associated with the irrigation pumps. This led to the introduction of new requirements for limiting harmonics generated from new connections.

4.3 Asset management approach

4.3.1 Lifecycle management

Lifecycle asset management is the balance of cost, performance and risk over the whole of an asset's life (cradle to grave).



Through this process we must balance our shareholders' and customers' needs today, and in the future. Lifecycle asset management means taking a long term view to make informed and rational investment decisions to deliver our service levels at an appropriate cost.

Benefits of a whole of life approach as shown in the diagram below are:

- minimising safety risks and future legacy issues through safety in design
- understanding capex/opex trade-offs
- establishing forecasts for operational and replacement expenditure, thus avoiding surprises
- minimising the total cost of ownership while meeting accepted standards of performance.

4.3.2 Management planning

We undertake lifecycle management and asset maintenance planning using whole-of-life cost analysis, reliability centred maintenance (RCM), condition based maintenance and risk management (CBRM) techniques. These techniques are used to improve our performance to enable us to meet out network reliability limits.

Generally assets are not replaced on age alone, but are kept in service until their continued maintenance is uneconomic or until they have the potential to pose a health and safety, environmental or reliability risk. Reliability performance is measured and used to identify areas where further maintenance is needed to improve our delivery service or where maintenance may be reduced without affecting service levels.

We develop our maintenance and replacement programmes in-house and use a competitive tender process to contract out all works. Our asset management planning process involves the creation of:

- Maintenance Plan

  We have a baseline of work we need to do to ensure our network remains in good order. These works include inspection rounds and asset specific testing to determine condition.

  We also have targeted works for improvements and to maintain functionality e.g. line retightening, partial discharge testing of switchgear.

  We maintain our network assets to ensure:

  i. the safety of the public, contractors and our staff is maintained
  ii. reliable, cost effective electricity for our customers
  iii. we prevent premature deterioration or failure of the network.

We have specific maintenance programmes for each of our asset classes however all works roughly fall into the following categories:

i. Scheduled Maintenance – work carried out to a predetermined schedule and allocated budget
ii. Non-scheduled Maintenance – work that must be performed outside the predetermined schedule, but does not constitute emergency work
iii. Emergency Maintenance – work that must be carried out on a portion of the network that requires immediate repair.

These are the categories we use when forecasting our expenditure. The categories stipulated in the Commerce Commission determination are slightly different, in this document we use the Commerce Commission categories for consistency. Table 4-3a shows a high level translation between categories.

Table 4-3a **Expenditure category translation**

Commerce Commission	Orion
Service interruptions and emergencies	Emergency works
Vegetation management	Scheduled maintenance
Routine and corrective maintenance and inspections	Scheduled and non-scheduled maintenance
Asset replacement and renewal	Scheduled maintenance

Table 4-3b **Total network Opex forecast (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	8,975	8,675	8,675	8,675	8,675	8,675	8,675	8,675	8,675	8,675	**87,050**
Vegetation management	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	**35,600**
Routine and corrective maintenance and inspections	13,150	13,125	12,775	12,730	12,545	12,545	12,545	12,495	12,495	12,495	**126,900**
Asset replacement and renewal	3,350	3,180	2,630	2,630	2,630	2,630	2,730	2,730	2,730	2,730	**27,970**
Total	**29,035**	**28,540**	**27,640**	**27,595**	**27,410**	**27,410**	**27,510**	**27,460**	**27,460**	**27,460**	**277,520**

- ## Replacement Plan

Traditionally asset replacement programmes were based on the age of the assets. We identified very early on that this was not the most effective approach and have been using other factors such as condition, safety risk, reliability and performance to help develop our replacement programmes. We have adopted a condition based risk management (CBRM) approach for the replacement of our network assets. This framework utilises asset information, engineering knowledge and experience to define, justify and target asset replacements.

We develop our replacement programming on an "asset class" basis. The tables in this section reflect the Commerce Commission determination categories.

Table 4-3c **Total network replacement Capex forecast (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Subtransmission	990	3,140	640	3,140	640	4,640	4,640	4,640	4,640	4,640	**31,750**
Zone substation	4,925	4,090	5,480	2,315	3,050	4,145	840	3,075	1,815	2,160	**31,895**
Distribution and LV lines	3,480	3,975	3,805	4,750	6,900	7,250	8,800	9,150	11,500	11,940	**71,550**
Distribution and LV cables	420	420	420	420	420	420	420	420	420	420	**4,200**
Distribution substations and transformers	3,605	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	**35,060**
Distribution Switchgear	4,445	5,030	6,110	7,435	7,370	6,695	8,575	6,515	8,195	6,630	**67,000**
Other network assets	9,970	10,905	12,380	11,960	10,685	10,315	11,170	10,745	10,725	4,040	**102,895**
Total	**27,835**	**31,055**	**32,330**	**33,515**	**32,560**	**36,960**	**37,940**	**38,040**	**40,790**	**33,325**	**344,350**

4.4 Asset performance

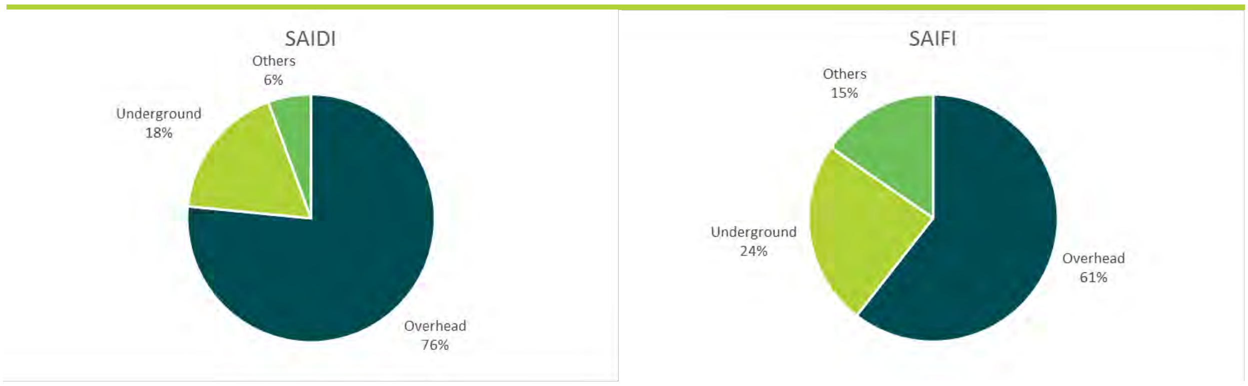
Our asset management practices are used to reduce interruptions in both frequency and duration for customers. An in-depth reliability review was conducted in FY17 and FY18. This was a two stage project. Stage one looked at our current performance in areas of the network in direct response to feedback from our customers. This resulted in a number of initiatives with improved reliability for those customers. Stage two involved detailed analysis across all asset classes, throughout the network, to assess if further improvement could be or should be achieved.

Our analysis indicates the emerging reliability impact of some aging overhead assets that are further stressed from earthquake vibration and compounded by severe weather events. There has also been an external influence from construction activity. The factors are summarised as:

- asset lifecycle – some insulators and fuses are coming to the end of their useful life and targeted replacement is required. Details are covered in this section
- weather events – historical wind/snow events are few and far between. However, in recent years, it is not unusual to have a weather event nearly every year and that has a significant effect on our network reliability
- construction activity – over the last five years, higher than normal demolition, excavation and house removal work has occurred as part of the city is rebuild post quake and this has resulted in an increase in third party related events
- earthquake – intense vibration during earthquakes and aftershocks caused stress on cables and insulators.

These contributing factors have predominantly affected overhead and underground assets and this shows in our reliability graphs (below). The 'Others' segment includes all of our other asset categories.

Figure 4.4a **Reliability Graphs—3 year average**



4.5 Format of asset sections

The following sections (4.7 to 4.25) describe Orion's existing assets by category. All references to years such as FY19, are to be taken as the financial year ending that year i.e. 31 March 2019. For each category the asset and its management approach are discussed under the following headings:

Asset description

A brief description giving an idea of the type, function and location of each asset group.

Asset capacity/performance

Design capacity and utilisation with any constraints, failure modes and deterioration specific to this asset.

Note: The definition of asset failure as shown in the graph of failures per 100km for an asset is any interruption to supply caused by a plant failure. This excludes being damaged by a third party or environmental event.

We have used a three year average for these events. We were exposed to a 'severe' windstorm that affected large parts of Canterbury in FY14. This windstorm has been excluded as a statistical outlier.

Asset condition

A summary of the asset's current condition is described, including an age profile and health index profile. CBRM models calculate the health index (HI) and probability of failure (PoF) of each individual asset. This effectively gives the asset a ranking which can be used to help prioritise replacement strategies. Note, the criticality of the asset is also considered when prioritising the replacement schedule.

The health index scoring is different to the Commerce Commission grading system set out in Schedule 12a of the information disclosure requirements. The following table shows the method used to convert our CBRM scores to those required in Schedule 12a.

Table 4-5a Condition score conversion table - CBRM to Commerce Commission schedule 12a

Condition	HI Range	Probability of Failure	Health Index	Schedule 12a Grade	Definition
Unknown				Grade unknown	Condition unknown or not yet assessed
Bad	10	High	10 + (9 - 10)	Grade 1	End of serviceable life, immediate intervention required
Poor		Medium	(8 - 9) (7 - 8)	Grade 2	Material deterioration but asset condition still within serviceable life parameters. Intervention likely to be required within 1 to 3 years
Fair		Low	(6 - 7) (5 - 6) (4 - 5)	Grade 3	Normal deterioration requiring regular monitoring
Good	0	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Grade 4	Good or as new condition

Design standards and asset data

A list of design standards and technical specifications pertaining to the asset. These may be industry or our own standards. Also discusses asset data completeness, improvement sources and the system where the data is held (see section 2 for systems used at Orion).

Maintenance plan

The ongoing day to day work plans required to keep the asset serviceable and prevent premature deterioration or failure.

Replacement plan

These are major work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity.

Creation/acquisition plan

This is capital work that creates a new asset or improves an existing asset beyond its existing capacity.

Disposal plan

This is any of the activities associated with disposal of a decommissioned asset.

4.6 Substations overview

A 'substation' encompasses buildings, switchgear, transformers, protection and control equipment used for the transformation and distribution of electricity. Our network structure has three identified levels of substations – zone, network and distribution (see figure 4-1c). The lifecycle asset management plans for assets making up a substation are discussed in the relevant parts of section 4. A substation is not described as an asset in its own right.

4.6.1 Zone substations

A zone substation is a building substation usually with a high voltage structure that has been identified as a zone substation because of its importance in our network. Orion has 53 zone substations and, in general, they include a site where one of the following takes place: voltage transformation of 66kV or 33kV to 11kV, two or more incoming 11kV feeders are redistributed or a ripple injection plant is installed. Zone substations are inspected every two months and given an infra-red scan every two years.

66/11kV zone substations

We have 26 66/11kV zone substations and one 66/33/11kV zone substation at Springston. Eighteen of them are in the Christchurch urban area. Twelve of the urban substations have an exposed bus structure. The Armagh, Dallington, Lancaster, McFaddens and Waimakariri structures are inside a building. Going forward we will continue to assess the cost-benefit trade-off of building our 66kV substations indoors.

Construction dates for the urban structures are:

• Addington	1962	• Halswell	1974	• Middleton	2008
• Armagh	2001	• Hawthornden	2004	• Papanui	1968
• Barnett Park	1981	• Heathcote	1968	• Rawhiti	2011
• Bromley	1973	• Lancaster	2000	• Waimakariri	2014
• Dallington	2013	• McFaddens	2012		

Most of the urban zone substations are supplied by two cables connected to a pair of 66/11kV transformers. Each cable and associated transformer has an emergency rating equivalent to the full load of the zone substation (traditionally 40 MVA) and can maintain supply should the other cable or transformer fail. The rating of the transformer and cable are currently limited by the thermal capacity of the 66kV cables. The transformers supply 11kV switchgear housed in two, three or four fire and explosion resistant rooms. This switchgear may supply up to 20 feeder cables and can be sectioned using bus-couplers between the rooms.

Our rural Springston 66/33/11kV zone substation is supplied by tower line from Transpower's Islington GXP. It has an outdoor structure with two 66/33kV 60/70MVA transformers and one 33/11kV 7.5MVA transformer.

The eight rural 66/11kV zone substations at Brookside, Dunsandel, Killinchy, Larcomb, Kimberley, Greendale, Te Pirita and Weedons are supplied by overhead lines and have 7.5/10 or 11.5/23MVA transformers. All have outdoor structures. The indoor 11kV switchgear may supply up to five feeder cables.

Four other substations at Annat, Bankside, Little River and Highfield have 66kV structures but are currently operating at 33kV. See section 5.6.7 for details of the projects to convert them to operate at 66kV.

Armagh zone substation, with its neon 'Nebula Orion' artwork, contains an 'outdoor' 66kV structure.

Weedons 66kV rural zone substation

33/11kV zone substations

Orion has 19 33/11kV zone substations, mainly in the Canterbury rural area and on the western fringe of Christchurch city. Most have some form of outdoor structure and bus-work. Where economically viable we are replacing outdoor 33kV switchgear with an indoor type, negating the need for outdoor structures. Capacity of these substations is split into three groups as follows:

1. Larger urban substations have two or three independent dual rated transformers. These have separate supplies, with each transformer and supply rated to carry the full substation load. The 11kV switchgear may supply up to 11 feeder cables and is housed in two or more switch-rooms linked by a bus-coupler.
2. Smaller urban and larger rural substations have a pair of single rated transformers of 7.5MVA.
3. Smaller rural substations have one single rated transformer of 7.5 or 2.5MVA. Single transformer zone substations (largely in rural areas) rely on back-up capacity from adjacent single transformer substations to provide firm capacity.

11kV zone substations

We have six of these substations, all in the Christchurch city urban area. They are directly supplied by either three or four radial 11kV cables and do not have power transformers. The cables have usually been laid along the same route and have sufficient capacity to supply the full zone substation load. The 11kV switchgear may supply up to 12 feeder cables and is housed in either two or three switch-rooms linked by bus-couplers.

None of the 11kV zone substations have any form of outdoor structure or bus-work.

We have had the opportunity to decommission some 11kV zone substations rather than replace them due to the changing load profile in certain parts of the network and in conjunction with specific changes to our 11kV distribution network architecture.

Table 4-6a Zone substation equipment schedule

Zone substation	Circuit breakers			Power transformers			
	66kV	33kV	11kV	66/33kV	66/11kV	33/11kV	Rating (MVA)[1]
Addington	14		35		4		29/34 x2 and 20/40 x2
Annat		1[2]	4			1	2.5
Armagh	5		33		2		20/40
Bankside		1[2]	5			1	7.5/10
Barnett Park			12		1		11.5/23
Bromley	11		24		3		30/37
Brookside	3		10		1		7.5/10
Dallington	3		26		2		20/40
Darfield		2	6			1	7.5/10
Diamond Harbour		3	4			1	7.5
Dunsandel	4		10		2		7.5/10
Duvauchelle		5	9			2	7.5
Fendalton			20		2		20/40
Foster			20				
Greendale	1		6		1		7.5/10
Grimseys Winters			18				
Halswell	8		11		2		11.5/23
Harewood		2	9			2	7.5
Hawthornden			28		4		20/40 x2 and 11.5/23 x2
Heathcote	8		26		2		20/40
Highfield		1[2]	6			1	7.5
Hills Rd		1	5			1	7.5
Hoon Hay			26		2		20/40
Hornby		10	11			2	10/20
Hororata		3	5			1	7.5
Ilam			13				
Killinchy	3		6		1		7.5/10
Kimberley	3		11		2		11.5/23
Knox			21				
Lancaster	3		24		2		20/40
Larcomb	3		9		2		11.5/23
Lincoln		3	9			2	7.5
Little River		2	3			1	2.5
McFaddens	5		24		2		20/40
Middleton	2		19		2		20/40
Milton			23		2		20/40
Moffett St		3	14			2	11.5/23
Motukarara		6	6			2	2.5 and 7.5
Oxford-Tuam			24		2		20/40
Pages Kearneys			16				
Papanui	11		36		2		20/40
Portman			18				
Prebbleton		2	8			1	11.5/23
Rawhiti	3		16		2		20/40
Rolleston		2	9			2	7.5
Shands Rd		4	12			2	11.5/23
Sockburn			18			3	10/20 x2 and 11.5/23 x1
Springston	7	14	6	2		1	60/70 x2 and 7.5 x1
Te Pirita	1		6		1		7.5/10
Teddington		1	3			1	2.5
Waimakariri	3		18		1		20/40
Weedons	5		9		2		11.5/23
Totals 52	**106**	**66**	**750**	**2**	**51**	**30**	

NOTES:

1. Dual rated transformers have been installed with a design nominal rating/emergency rating.
2. 66kV CB operating at 33kV.

4.6.2 Network substations

There are 201 network substations in our 11kV network, all within the Christchurch urban area. They contain at least one 11kV circuit breaker per connected primary cable and one or more circuit breakers for radial distribution feeders. They may also contain secondary 11kV switchgear, one or more distribution transformers and a 400V distribution panel with fuse assemblies using high rupturing current (HRC) links.

Network substations have historically been installed whenever the load on radial feeders exceeded the design limit of cable capacity and when primary cables with adequate spare capacity were available nearby. The original policy was that no radial secondary loads were to be supplied from zone substations and all such loads were to be supplied from network substations. In recent years this policy has been modified so that if suitable spare switchgear is available at a zone substation, and it is more economical to do so, secondary cables may be laid from the zone substation to reinforce overloaded cables. This avoids the need for additional network substations.

Due to changes in the location of load during their lifetime, network substations may become under-utilised. In these cases, and when it is economical to do so, the primary cables supplying the substation may be through-jointed and the secondary load transferred to other feeders and the network substation decommissioned.

Network substations are inspected every six months. This involves a complete visual component inspection and the reading of any transformer loading maximum demand indicators (MDIs). Any minor maintenance is also done at this time and any larger maintenance work is reported back to the relevant asset manager.

A network substation design from the late 1930s.

Network substation refurbished as a standalone building after being part of a larger customer building that was demolished due to earthquake damage.

4.6.3 Distribution substations

A distribution substation can take the form of any of the types shown in the following table. They take supply at 11kV from either a zone substation, a network substation or from another distribution substation. In respect of the building substations, in many situations the building that houses our electrical equipment will be owned by the customer.

The types of substation that make up the total 11,361 substations in this asset category are shown in the following table.

Table 4-6b **Distribution substation types**

Type	Quantity in service	Description
Building	240	These are similar to network substations in all aspects except for their status in the network. The substation buildings vary in size and construction and 70% are customer owned. All substations usually contain at least one transformer, up to 1500kVA, with an 11kV 400A Magnefix switch unit (MSU) and 400V distribution panel containing fuse assemblies using high rupturing current (HRC) links.
Kiosk	3,190	Full kiosks vary in size and construction but usually contain a transformer, up to 500kVA, with an 11kV 400A Magnefix switch unit (MSU) and a 400V distribution panel containing fuse assemblies using HRC (high rupturing current) links. For details of kiosk types in service see section 4.26.1.
Outdoor	741	These vary in configuration, but usually consist of a half-kiosk with 11kV switchgear and a 400V local distribution panel as per a full kiosk. An outdoor transformer is mounted on a concrete pad at the rear or to the side of the kiosk. This design allows the installation of a transformer up to 1500kVA.
Pole	6,397	Single pole mounted substations usually with 11kV fusing and a transformer rated from 7.5kVA to 200kVA.
Pad transformer	793	These are a transformer only, mounted on a concrete pad and supplied by high voltage cable from switchgear at another site. Transformers are generally uncovered.

We inspect our distribution substations every six months with the exception of pole mounted substations. This visual inspection is of all the components and includes recording any transformer loading maximum demand indicator (MDI) values. Any minor maintenance work is also done at this time and any larger maintenance work is reported back to Orion's asset manager.

Substation earthing

A risk based approach has been taken for the inspecting and testing of our site earths. In general, earth systems in our rural area are subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems. Between 2,000 and 2,600 sites are tested in any year and those sites requiring repairs are scheduled for remedial work in the following year.

A recently developed kiosk with precast concrete sides, designed to be embedded into a hillside.

4.6.4 Substations expenditure

Our total budgeted maintenance costs are shown in section 8.1.1 - Opex budgets - Network: Substations. A detailed breakdown of substations opex, is shown in table 4-6c.

Table 4-6c **Substations opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	75	75	75	75	75	75	75	75	75	75	**750**
Routine and corrective maintenance and inspections	480	480	480	480	480	480	480	480	480	480	**4,800**
Total	**555**	**555**	**555**	**555**	**555**	**555**	**555**	**555**	**555**	**555**	**5,550**

The forecast operational expenditure covers our substation monitoring and inspection programmes. The details of these inspections programmes are covered in more detail under the relevant asset section.

Our total budgeted replacement costs are shown in section 8.1.13 - Replacement budgets - Substations. A detailed breakdown of substations replacement is shown in table 4-6d.

Table 4-6d **Substations replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Zone substations	30	30	30	30	30	30	30	30	30	30	**300**
Distribution substations and transformers	225	225	225	225	225	225	225	225	225	225	**2,250**
Other network assets	125	125	125	125	125	125	125	125	125	125	**1,250**
Total	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**3,800**

The forecast capital expenditure above covers the ongoing replacement of our substation ancillary equipment such as battery banks and battery chargers. We continue to replace any two pole platform substations with a single pole substation, or a kiosk if the line is likely to be removed. This is done to satisfy issues of safety and seismic risk.

4.7 Overhead lines – subtransmission

4.7.1 Asset description

This section describes our 66kV and 33kV overhead line assets. This comprises of towers, poles, conductors, and associated hardware. For a map of these assets see Figure 4-1a and Figure 4-1b. We have 6,227 support structures and 524km of sub-transmission overhead conductor as summarised in Table 4-7a and Table 4-7b.

Table 4-7a **Support structure type - subtransmission**

Type	66kV	33kV	Total
Hardwood	967	2,136	3,103
Softwood	24	565	589
Concrete	16	2,109	2,125
Steel pole	13	2	15
Steel Tower	395		395
Total	1,415	4,812	6,227

Table 4-7b **OH conductor type - subtransmission**

	Length (km)		
Type	66kV	33kV	Total(km)
Aluminium conductor steel reinforced (ACSR)	245	233	478
Copper		46	46
Total	**245**	**279**	**524**

Our 66kV subtransmission pole lines consist of 105km of single circuit on mainly timber poles, some of which also carry 11kV distribution lines. The lines run from Transpower's Hororata, and Islington GXPs to our 66/11kV zone substations Te Pirita, Springston, Dunsandel, Killinchy, Greendale, Brookside, Larcomb and Weedons.

The 33kV subtransmission pole lines are 279km in length. These take supply from Transpower's Islington, and Hororata 33kV GXPs to form a network of interconnecting lines in the rural area of central Canterbury, Banks Peninsula and into the western edge of Christchurch city. These lines are built using timber and concrete poles, some of which also carry 11kV distribution lines.

Our 66kV subtransmission tower lines consist of 75km of double circuit. These tower lines provide important security to the Christchurch city subtransmission network by providing limited alternative connection between Transpower's Islington and Bromley GXPs.

We have recently purchased three tower lines from Transpower (Islington GXP to Addington, Papanui and Springston) which increases our tower population from 144 to 395.

Table 4-7c **66kV tower line circuits**

Circuit	Kilometres	Towers	Poles[1]	Circuits
Bromley-Heathcote	4.2	22	0	2
Halswell-Heathcote	9.5	30	4	2
Heathcote-Barnett Park	4.1	19	0	2[2]
Islington-Addington A	7.2	57	0	2
Islington-Addington B	7.2	57	0	2
Islington-Halswell	7.8	35	6	2
Islington-Hawthornden	4.7	30	1	2
Islington-Papanui A	8.9	56	1	2
Islington-Papanui B	8.9	56	1	2
Islington-Springston	13	33	2	2
Total	75	395	15	20

Notes:

1 These monopoles replaced towers relocated to allow land subdivision or roadworks to proceed.

2 One of these circuits is operating at 11kV.

4.7.2 Asset performance

Conductors

The subtransmission overhead line network is exposed to the environment. Our design standards were developed specifically for Canterbury's high wind and snow loadings. As a result the network has performed well overall. It has withstood several snow/wind[1] storms in recent years. The resulting major damage was due to trees bringing down lines rather than deficiencies in design or installation.

Poles

The number of pole failures and suspect poles are shown in Figure 4-7a.

- failure — when the pole is no longer capable of supporting its static load
- suspect — when a pole requires furthering investigation to ensure its suitable to remain on the network. These poles will be replaced in a timely manner before they progress to a 'failure'.

Events recorded as 'failure' exclude any poles identified during our normal asset management practices (e.g. Visual Inspection process) unless that pole is only being supported by lines or other structures. Also excluded are events known as assisted failure, such as vehicle impacts, trees falling etc.

Those poles recorded as suspect have been identified during our normal asset management practices and have been replaced before progressing to a 'Pole Failure'.

The subtransmission pole population is 5,832. There has been one failure and two suspect poles for 33kV over the last 5 years with no 66kV failures.

Figure 4-7a **33kV pole failures**

Pole top hardware

We have identified some older types of insulator (predominantly 33kV) that have seen an increase in failure rates. We believe a contributing factor has been the mechanical stress from earthquakes. These are being addressed in our maintenance programmes.

Smaller conductors and older type insulators in exposed areas of Banks Peninsula have resulted in higher failure rates in FY14 and FY15. The conductors have since been upgraded and insulators replaced. The on-going practice of replacing hand binders with distribution ties has reduced the incidence of 33kV conductors coming off insulators. Apart from age, another contributing factor is the high altitude environment the feeders are located where they often experience extreme wind speeds. We are targeting these insulators in conjunction with other maintenance works. Older (non-type tested) concrete and hardwood poles may be replaced in conjunction with the insulators identified above.

The number of failures per 100km is shown in Figure 4-7b. The failures includes all subtransmission overhead assets; poles, conductors and pole top hardware. Failures on the subtransmission overhead contributes to 3% of the total network SAIDI and SAIFI. We believe this is an acceptable level of performance.

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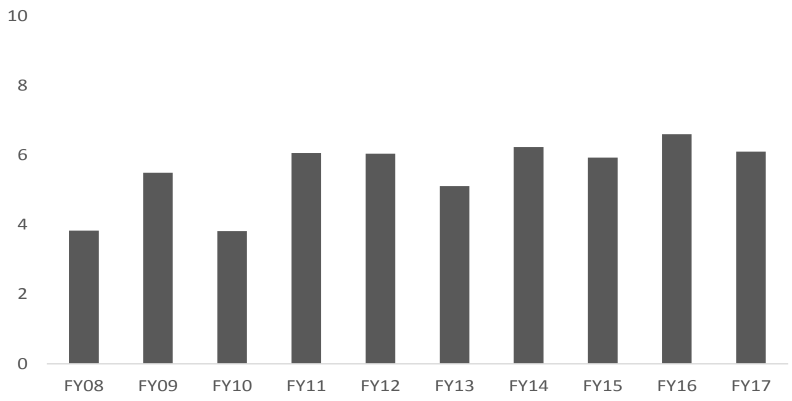
[1] The lines are designed to a minimum wind speed of 145km/h and a maximum wind speed of 160km/h.

Figure 4-7b **Subtransmission overhead lines – asset failures/100km**

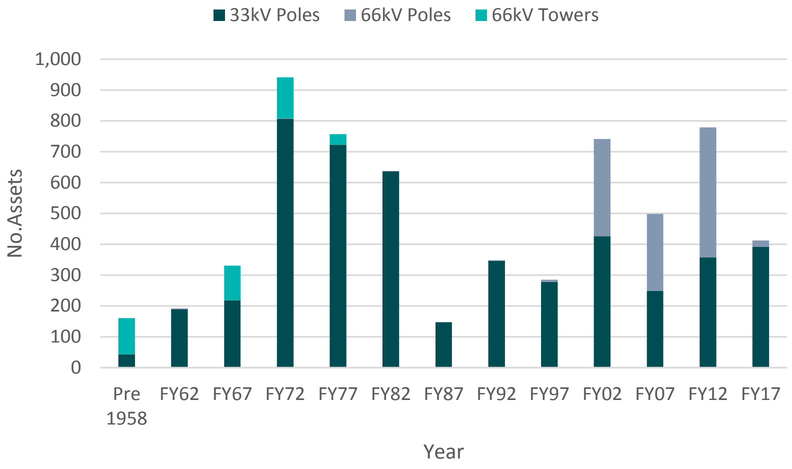


4.7.3 Asset condition

Towers and poles

The age profile of our subtransmission structures is shown below in Figure 4-7c.

Figure 4-7c - Subtransmission pole and tower - age profile



The overall condition of our steel towers is good. The towers purchased from Transpower between Addington and Islington had no additional paint protection. Assessments of tower corrosion have been undertaken and a prioritised programme of tower painting has been implemented.

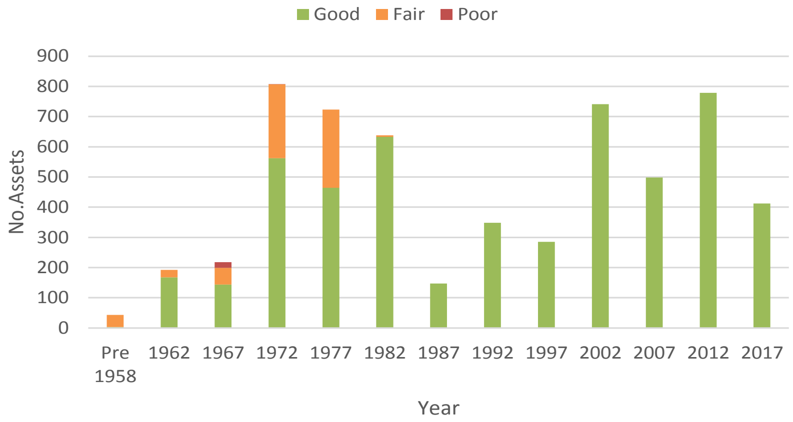
The tower foundations are a mixture of concrete footings and grillage. Our investigations have indicated that the worst corrosion on buried foundation steel is between 300 and 600mm below ground level, with little or no corrosion below that point.

A refurbishment programme to extend the life expectancy of steel tower legs/foundations has seen most of the grillage foundations completed. The remaining sites have access issues but we anticipate completing them within the AMP period.

The overall condition of the 66kV poles is good. More than 95% of the 66kV poles are less than 15 years old and therefore have no historical issues. We have a large population of 33kV poles. The life expectancy of these poles is 35 to 55 years for wooden poles and 50 to 70 years for concrete poles. Improved treatment procedures mean that we expect new poles will last longer than this in future.

The condition of the subtransmission poles has been quantified using the process of Condition Based Risk Management (CBRM). Figure 4-7d below shows the current age and condition profile for our overhead subtransmisson poles. It can be seen that the pole population is predominantly in good condition. Our replacement program will prioritise poles in fair and poor condition as the majority were installed in the 60s and 70s.

Figure 4-7d- Subtransmission pole - age/condition profile

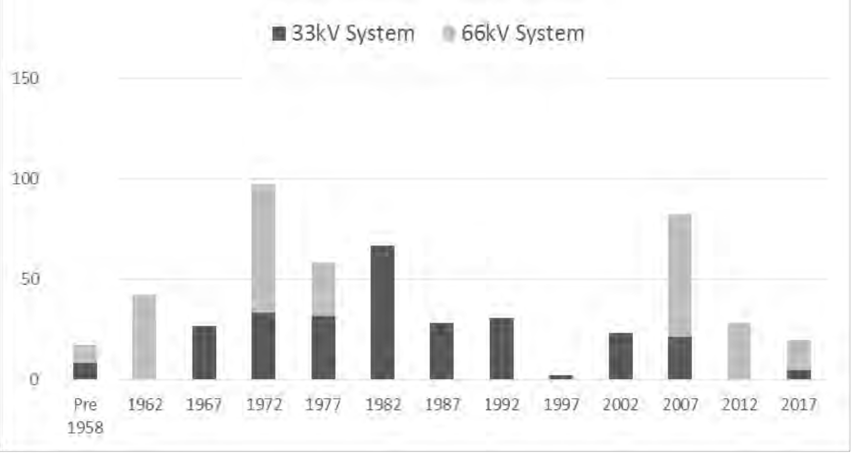


Conductor

The age of our 66kV overhead conductor is in two distinct eras as shown in Figure 4.7e. Our oldest circuits were constructed in 1959 using ACSR Wolf conductor. These make up about one third of our total 66kV OH transmission lines. Inspections and tests have shown signs of deterioration, with corrosion more prominent on our older circuits nearest the coast. We have focused on developing a replacement programme for these circuits first and it is likely to be like for like. i.e. no conversion to UG Cables.

Some of our oldest 33kV copper conductors are showing signs of deterioration. In the next 12 months we plan to investigate further to determine a suitable plan going forward. Note: the conductor discussed above is predominately found in rural areas.

Figure 4-7e - Subtransmission conductor - age profile



4.7.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.26 – Overhead lines - subtransmission.

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design standard.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.21.03 – Retightening of components
- NW72.21.05 – Tower painting
- NW72.21.06 – Tower maintenance painting
- NW72.21.11 – Overhead line inspection and assessment
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.21.18 – Standard construction drawing set – overhead lines
- NW72.21.19 – Tower inspections
- NW72.24.01 – Vegetation work adjacent to overhead lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.08 – Poles – hardwood
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers
- tower/pole age, type and condition assessment score
- conductor size, age and phasing (the age of some conductors is estimated)
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the asset and the fittings/attachments.

4.7.5 Maintenance plan

The condition of this asset is monitored by:

- visual inspection including a check for clearance violations in the urban area
- corona/thermal imaging scans every two years

  The use of a Corona Imaging Camera enables the detection of corona, partial discharge and arcing. The camera provides the ability to visually detect partial discharge occurring on equipment e.g. cracked insulators and defective components at early stages of degradation thus minimising unscheduled outages.
- lifting inspection of tower suspension assemblies every 10 years to check for wear and corrosion
- tower foundation inspections/refurbishment in corrosive soil zones
- paint and steelwork condition assessment.

The maintenance work planned is as follows:

- suspension hardware assemblies will be assessed for corrosion damage
- tower foundation grillage refurbishment
- line retightening of pole line components within 18 months of installation and every 10 years thereafter
- ongoing vegetation management (in conjunction with 11kV lines).

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Subtransmission overhead lines. A detailed breakdown of overhead subtransmission opex, in Commerce Commission categories, is shown in Table 4.7d.

The flat opex forecast is due to the consistent maintenance and inspections programmes in place. We believe this reflects the best balance of cost, performance and condition. Our tower painting programme accounts for the largest portion of opex.

Our vegetation management is captured in section 4.8 11kV overhead lines as this aligns with how we manage the contract.

Table 4-7d **Subtransmission overhead lines opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Service interruptions and emergencies	110	110	110	110	110	110	110	110	110	110	**1,100**
Routine and corrective maintenance & inspections	1,440	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	**13,185**
Asset replacement and renewal	100	250	250	250	250	250	250	250	250	250	**2,350**
Total	**1,650**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**16,635**

4.7.6 Replacement plan

A detailed breakdown of subtransmission capex, in Commerce Commission categories, is shown in table 4.7e.

Table 4-7e **Subtransmission overhead lines replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Subtransmission	990	3,140	640	3,140	640	640	640	640	640	640	**11,750**
Total	**990**	**3,140**	**640**	**3,140**	**640**	**640**	**640**	**640**	**640**	**640**	**11,750**

Tower lines

We have undertaken tests on conductor samples from our ISL-BRM 66kV overhead line to determine end of life. We are currently assessing these results and intend to replace portions of these overhead lines with new conductor within the disclosure period. This is identified in our budgeted replacement costs shown below.

Our tower replacement programme is based on our condition assessments. We do not have any towers scheduled for replacement due to their condition.

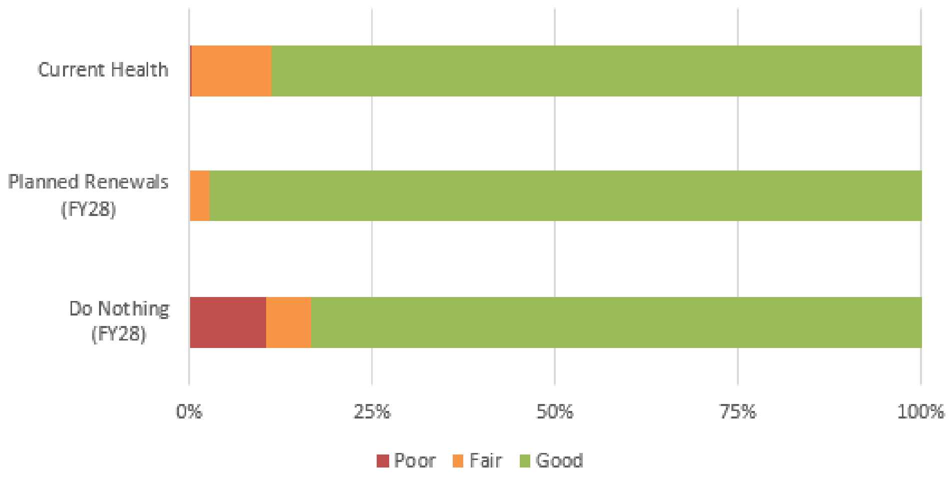
Poles lines

Poles, crossarms and insulators are replaced as required and driven from our inspection survey or CBRM models.

CBRM has been used to determine the replacement requirements for subtransmission poles. We started a review of our pole replacement programme in July 2016 and recalibrated our CBRM models. We plan to continue replacing our 33kV poles at a steady rate. The figure below compares the projected asset health based on our planned replacement rates with the “do nothing” scenario. The replacement rates have been projected with consideration for cost vs benefit and constraints on resource requirements. We continue to monitor our performance and safety to ensure the optimum levels of replacement are delivered.

Note: 33kV poles that are replaced are built to our 66kV standard design as this is more cost effective overall.

Figure 4-7f **Subtransmission poles projected 10 year asset health**



4.7.7 Creation/acquisition plan

For a list of projects containing this asset see section 5.6 – Network development proposals.

4.7.8 Disposal plan

We have no plans to dispose of any of the subtransmission overhead line asset.

4.8 Overhead lines – distribution 11kV

4.8.1 Asset description

Our 11kV distribution overhead system is 3,231km circuit length of lines in the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. Supply is taken from zone substations as feeder lines which form a network to supply distribution transformers. These lines are built using approximately 52,000 timber and concrete poles, some of which also support subtransmission and 400V conductors. The 11kV system includes 11kV lines on private property that serve individual customers.

Single wire earth return (SWER) lines on Banks Peninsula total 100km circuit length in 10 separate systems. These lines supply power to remote areas, and at times are exposed to severe weather conditions.

Our 11kV lines are supplied from the zone substations shown on the 66kV and 33kV subtransmission network maps in the previous sections. Supply is also taken directly at 11kV from the GXPs at Coleridge, Castle Hill and Arthur's Pass.

4.8.2 Asset capacity/performance

Conductors

To improve the performance of smaller conductors, we are using smooth body Flounder ACSR conductor more in the rural areas when new conductor is required. The use of Flounder conductor should reduce breakages in lines exposed to snow and high winds.

The Port of Lyttelton depends on a secure power supply and could be critical to Christchurch after any natural disaster. A double circuit line is currently the only supply to the Port. The status of this line has been raised to that of the subtransmission system. This means a higher level of maintenance and more regular inspections are undertaken than for other 11kV lines. The poles were replaced in 1999 and the phasing has been aligned with our standard. Increased clearances now allow maintenance on this line to be performed with the line alive, causing no interruption in supply to Lyttelton. In FY18 further work has been undertaken on the Lyttelton end to mitigate the risk of land slips.

There have been issues in the past with bi-metallic joints corroding on our 11kV overhead network. These joints continue to be replaced in conjunction with our re-tightening programme or when they are found during other scheduled works.

Poles

In the September 2010 earthquake we had a small number of poles fail, with the majority of failures attributed to pole foundations succumbing to liquefaction or land subsidence. The number of pole failures and suspect poles over the last five years is shown in Figure 4-8a.

Failure — when the pole is no longer capable of supporting its static load

Suspect — when a pole requires furthering investigation to ensure its suitable to remain on the network. These poles will be replaced in a timely manner before they progress to a 'failure'.

Events recorded as 'failure' exclude any poles identified during our normal asset management practices (e.g. Visual Inspection process) unless that pole is only being supported by lines or other structures. Also excluded are events known as assisted failure, such as vehicle impacts, trees falling etc.

Figure 4-8a - Number of suspect poles and pole failures

Having observed a gradual increase in the number of pole failures and suspect poles being identified, in FY17 a revised process for tagging poles was initiated to ensure the risk to public safety is reduced. As a result, the more generic 'Danger – Do not climb' tags used previously have been replaced with a Red or Orange tag and aligned with a stricter replacement timeframe. Any pole considered incapable of supporting structural design loads will require replacement within three months, and any pole at risk of failure under normal structural loads will require immediate replacement.

As a result of the revised process, a significant increase has been observed in the number of suspect poles being identified and replaced before they progress to a 'Pole Failure'. We expect this process to reduce the number of failures going forward.

Insulators

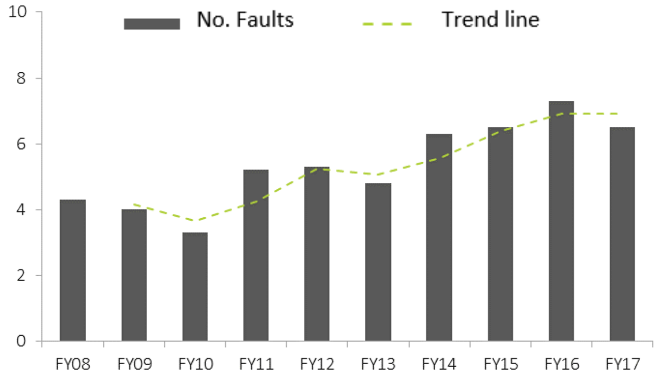
We have seen an increase in 11kV insulator failures in recent years which we attribute to severe weather events and residual faults from the earthquakes. For example, the significant earthquake on February 14th 2016 stressed the insulators on the network causing them to crack.

Cracked insulators cause intermittent outages that are difficult to detect by visual inspection from the ground. When we suspect such outages may be occurring we conduct a corona camera inspection of the feeder. The camera enables us to identify faulty insulators that are otherwise difficult to detect.

In FY17 we started a programme to replace older type insulators as part of our existing line retightening programme. Since then we have started seeing a small improvement in performance.

The overall asset failure trend is shown in Figure 4-8b. Failures on the 11kV overhead lines contributes to 9% of the overall SAIDI and SAIFI. It has the second biggest impact on reliability for asset failures followed by 11kV cable.

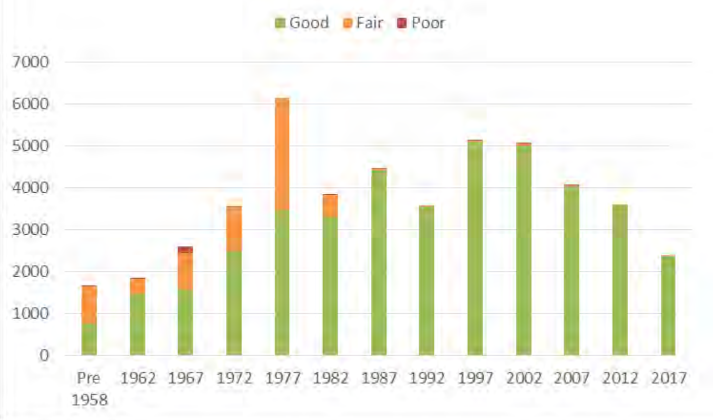
Figure 4-8b **Overhead lines 11kV – asset failures/100km**



4.8.3 Asset condition

The condition of the 11kV network has been quantified using the process of CBRM. Figure 4-8c below shows the current age and condition profile for our overhead 11kV poles. It can be seen that the pole population is predominantly in good condition. Our replacement program will prioritise poles in fair and poor condition as the majority were installed in the 60s and 70s.

Figure 4-8c **Overhead lines 11kV poles – age/condition profile**



4.8.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.27 - Overhead lines - 11kV.

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design standard
- NW70.51.02 – Overhead line design manual
- NW70.51.03 – Overhead line design – worked examples.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Overhead line work
- NW72.21.03 – Retightening of components
- NW72.21.11 – Overhead line Inspection and Assessment
- NW72.21.10 – Thermographic survey of high voltage lines
- NW72.21.18 – Standard construction drawing set – overhead
- NW72.24.01 – Vegetation Work Adjacent to Overhead Lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.06 – Poles – softwood
- NW74.23.08 – Poles – hardwood
- NW74.23.10 – Insulators – high voltage
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers
- pole age, type and condition score
- conductor size, age and phasing (the age of some conductors is estimated)
- pole and fittings condition assessments
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan, as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition and the fittings/attachments on our poles. This data is used to manage our condition monitoring and assist our maintenance and replacement programmes.

4.8.5 Maintenance plan

Our maintenance plan is driven by a combination of time based inspections and maintenance, and reliability centred maintenance. Recently we have been focusing on reliability improvement for rural townships by targeting feeders through a combination of insulator replacements and installation of automated line switches (more details in section 4.15). The older type insulators and bi-metal joints in other parts of the network will also be replaced as indicated by the reliability review.

The condition of our 11kV overhead lines is monitored, following the guidelines of NZCEP 34, by:

- a visual inspection at least every five years
- UV corona imaging inspection carried out every two years
- a thermal imaging scan (selected areas as required)
- an inspection of poles within the Christchurch urban area
- an inspection of poles in the rural area.

Maintenance work planned is as follows:

- to cut trees (in conjunction with 66/33kV lines)
- to re-tighten components, replace problematic insulators and bi-metal joints
- do other work that results from inspections.

The overhead network is exposed to the environment and is therefore susceptible to major weather events. During these events windblown debris and vegetation come into contact with conductors and impact on our network performance. We have a proactive programme in place to trim trees within the corridor stated in the tree regulations. We also consult with land owners with trees that pose a risk to our assets, but are outside the trim corridor. Vegetation management accounts for approximately half of our Opex spend on 11kV overhead lines.

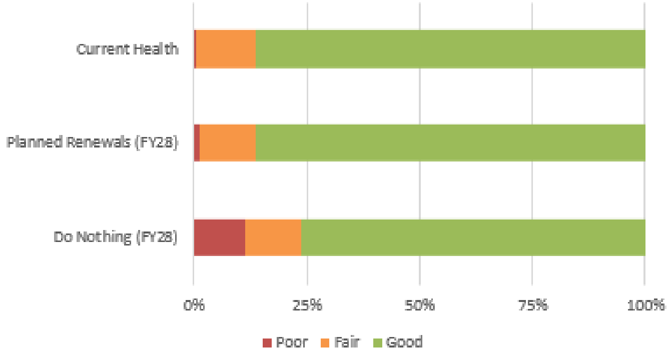
Our total budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: 11kV overhead lines.

A detailed breakdown of 11kV overhead opex is shown in table 4.8a. The emergency works contract contains resiliency criteria that requires our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these resilience issues have been apportioned across each of the asset classes including 11kV overhead lines, and are captured under 'service interruptions and emergencies'.

Table 4-8a **11kV overhead opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	1,925	1,880	1,880	1,880	1,880	1,880	1,880	1,880	1,880	1,880	18,845
Vegetation management	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	27,750
Routine and corrective maintenance and inspections	835	835	835	375	375	835	835	835	375	375	6,510
Asset replacement and renewal	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	10,250
Total	6,560	6,515	6,515	6,055	6,055	6,515	6,515	6,515	6,055	6,055	63,355

Figure 4-8d **Percentage of 11kV conductor by HI category**



4.8.6 Replacement plan

Our replacement programme is based on a multi faceted approach. This includes a CBRM approach, and by implementing findings from our reliability improvement studies. We are planning to replace approximately 2.5% of our overhead network annually for the next few years as we look to remove the remaining sections of smaller steel and copper conductor. This will be in done in conjunction with a ramping up of our 11kV pole replacement programme.

We started a review of our pole replacement programme in July 2016 and recalibrated our CBRM models. This approach aligns with the recommendations from an independent review of Orion's pole asset management practices completed in May 2017. As a result we plan to increase our current rate of replacement of mainly wooden poles, ramping up through to FY25 and then levelling off. This steady increase is necessary to maintain our current risk profile due to the aging pole population, but also to build and retain the contracting resource that is already in demand nationwide.

Our total budgeted replacement costs are shown in section 8.1.13 - Replacement budgets: 11kV overhead lines. A detailed breakdown of 11kV overhead replacement is shown in table 4.8b.

Forward forecasts of asset health are shown in figure 4-8b. The chart shows a representation of the health index profile now, the forecast based on current expenditure levels and in 10 years in the future for a do nothing scenario. The planned renewal profile suggests that the current projected expenditure level is sufficient to maintain the asset health profile to its current level.

Table 4-8b - **11kV overhead replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Distribution and LV lines	2,465	2,610	2,090	2,685	4,485	4,485	5,685	5,685	7,685	7,775	**45,650**
Distribution Switchgear	540	540	540	540	220	220	220	220	220	220	**3,480**
Total	**3,005**	**3,150**	**2,630**	**3,225**	**4,705**	**4,705**	**5,905**	**5,905**	**7,905**	**7,995**	**49,130**

4.8.7 Creation/acquisition plan

We now only build 11kV lines in rural areas as they are prohibited in urban areas by planning requirements.

Additional 11kV lines are constructed as a result of the following:

- reinforcement plans (refer to section 5.6 – Network development proposals)
- new connections and subdivision developments.

4.8.8 Disposal plan

We dispose of lines to meet customer requirements or to implement city/district council underground conversion projects.

4.9 Overhead lines – distribution 400V

4.9.1 Asset description

Our 400V distribution overhead system is 2,721km circuit length of lines, mainly within the Christchurch urban area. This length includes 917km of street lighting circuit. The urban 400V network is a multiple earthed neutral system operating at 400 volts between phases and 230 volts to earth. In the city the network can be interconnected with adjacent substations by installing ties at various normally open points. We have a mixture of both timber and concrete poles.

Lines on private property

Owners are responsible for the safety of lines that they own. We provide a maintenance service to our customers for lines that they own, and the cost of this service forms part of our line charge.

4.9.2 Asset capacity/performance

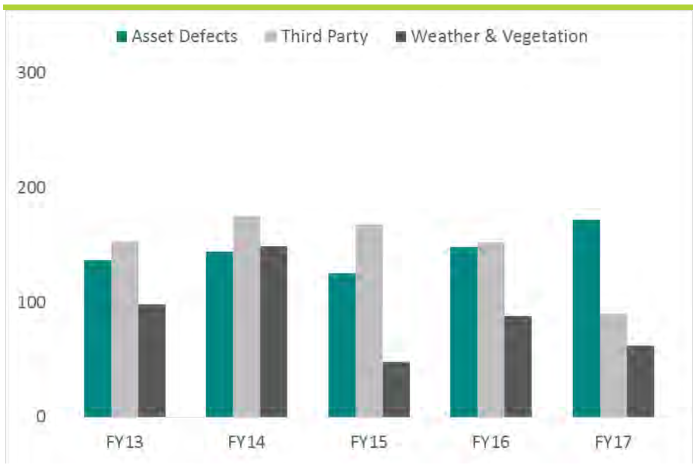
The standard 400V polyvinyl-chloride (PVC) covered conductors are itemised in the table below. Ratings are based on 20°C ambient and 30°C conductor rise.

Table 4-9a **Standard 400V conductors**

Conductor (Aluminium)	Rating (Amps)	Conductor (Copper)	Rating (Amps)
Weke AAC	299	37/0.083 HD	395
Rango AAC	221	19/0.083 HD	265
Namu AAC	114	19/0.064 HD	195
		7/0.083 HD	144
		7/0.064 HD	106

We are not required to record SAIDI/SAIFI for our LV networks. However to ensure prudent asset management and good stewardship we collect performance data on our LV system. The graph below shows a record of 400V defects over the last five years including conductors, poles and pole top hardware. These are defects that require more than an operator to repair under an emergency job.

Figure 4-9a **Overhead lines 400V – number of defects**



As with all overhead assets, the LV network is exposed to the environment and susceptible to weather events and vegetation. These factors have caused a fluctuation in performance in recent years. (FY13 snow, FY14 severe wind storm and FY16 snow).

The reduction of third party related incidents can be attributed to a slow down in the Christchurch rebuild work.

The number of asset defects has increased due to a higher number of suspect poles being identified under the enhanced visual inspection and education processes which were rolled out in FY16. As a result of this process, operators and external contractors have been more vigilant in identifying suspect poles and replacing them under emergency jobs to reduce risk to the public.

For this reason, the number of suspect poles has increased as shown in Figure 4-9b.

Failure — when the pole is no longer capable of supporting its static load

Suspect — when a pole requires furthering investigation to ensure its suitable to remain on the network. These poles will be assessed and replaced as appropriate before progressing to a 'pole failure'.

Figure 4-9b - **Number of 400V pole failures and suspect poles**

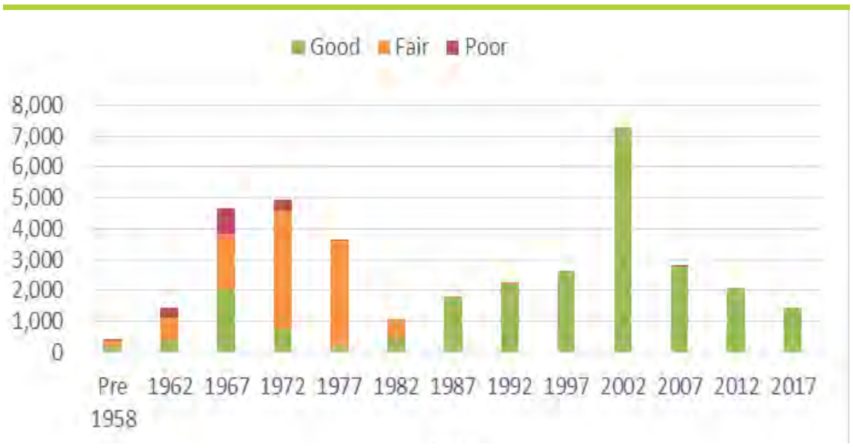
Note: we have 36,378 LV poles in our network.

4.9.3 Asset condition

Poles

The life expectancy of wooden poles is 35 to 55 years and 50 to 70 years for concrete poles. Improved treatment procedures mean that we expect new poles will last longer than this in future. However, wooden poles in areas exposed to harsh environmental conditions will have a reduced nominal service life. The age profile of our 400V poles is shown in the following figure.

Figure 4-9c - **400V pole - age/health profile**

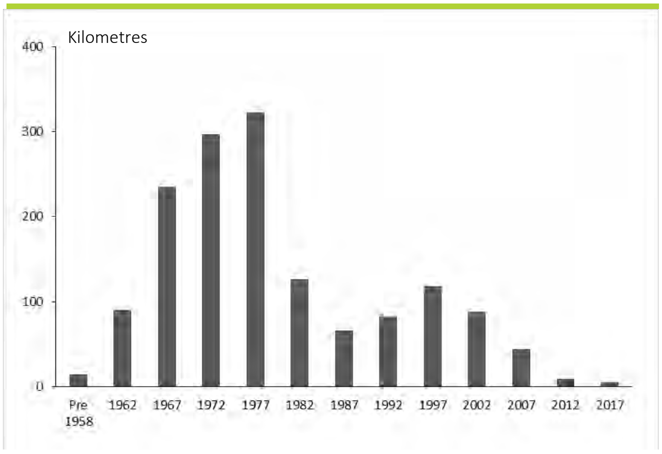


Conductor

We are still developing our CBRM models for our LV conductor however the condition of our overhead lines is generally good. The 400V network conductors are predominantly PVC covered, but in some older areas triple braid (TB), that has poor insulation properties, is still in use. Conductors with this type of insulation are replaced during scheduled pole replacement work.

Figure 4-9d shows our 400V conductor age profile by kilometres of line. The profile highlights the growth that occurred in the region in the late 60s and 70s.

Figure 4-9d - **400V conductors—age profile**



4.9.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.25 - Overhead lines - 400V.

Design standards developed and in use for this asset are:

- NW70.51.01 – Overhead line design standard
- NW70.51.02 – Overhead line design manual.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.21.01 – Overhead line work
- NW72.21.03 – Retightening of components
- NW72.21.11 – Overhead line Inspection and Assessment
- NW72.21.18 – Standard construction drawing set – overhead
- NW72.24.01 – Vegetation Work Adjacent to Overhead Lines.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.06 – Poles – softwood
- NW74.23.08 – Poles – hardwood
- NW74.23.17 – Conductor – overhead lines
- NW74.23.19 – Cross-arms.

Asset Data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- pole identification numbers (urban poles not physically labelled)
- pole age, type and condition score
- Conductor size and age (the age of some conductors is estimated)
- Pole and fittings condition assessments
- construction and as built drawings for renewals and extensions.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition and the fitting/attachments on our poles.

4.9.5 Maintenance plan

Maintenance is primarily based on a periodic pole inspection cycle. We continue to focus on clearing trees from 400V lines to comply with the Tree Regulations. Other maintenance work is on an as-required basis. Requests from lighting authorities to install various outreach street lighting arms on existing poles requires some poles to be changed to meet the additional load. Our total budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: 400V overhead lines. A detailed breakdown of opex is shown in table 4.9b.

Table 4-9b - **400V overhead opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	1,245	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	**12,045**
Vegetation management	785	785	785	785	785	785	785	785	785	785	**7,850**
Routine and corrective maintenance and inspections	1,265	1,265	1,265	1,725	1,725	1,265	1,265	1,265	1,725	1,725	**14,490**
Asset replacement and renewal	135	135	135	135	135	135	135	135	135	135	**1,350**
Total	3,430	3,385	3,385	3,845	3,845	3,385	3,385	3,385	3,845	3,845	35,735

4.9.6 Replacement plan

The condition of our overhead lines is generally good. Our pole replacement programme is derived from a condition assessment survey. This is an on-going process and any poles deemed not satisfactory are replaced. Our total budgeted replacement costs are shown in section 8.1.13 - Replacement budgets: 400V overhead lines. A detailed breakdown of replacement is shown in table 4.9c.

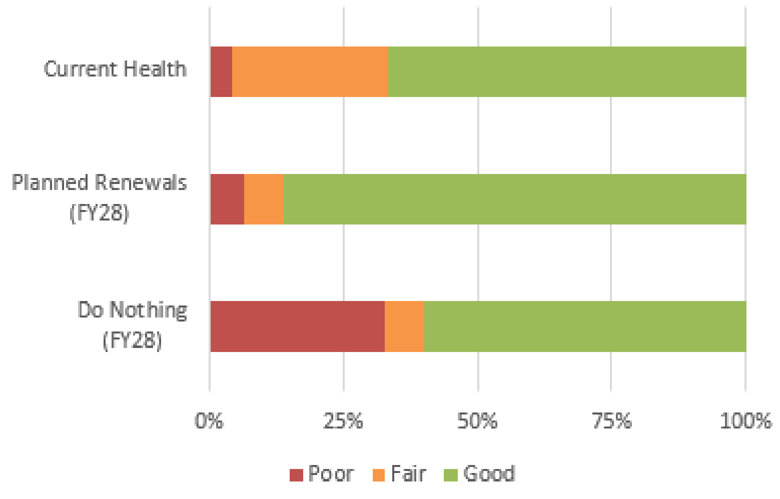
Table 4-9c - **400V overhead replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Distribution and LV Lines	1,015	1,365	1,715	2,065	2,415	2,765	3,115	3,465	3,815	4,165	**25,900**
Other network assets	100	100	100	100	100	100	100	100	100	100	**1,000**
Total	1,115	1,465	1,815	2,165	2,515	2,865	3,215	3,565	3,915	4,265	26,900

We started a review of our pole replacement programme in July 2016 and recalibrated our CBRM models. Our current levels of replacement are not sufficient to maintain our current levels of performance and risk into the future. To maintain our current risk levels we plan to gradually increase our rate of replacement for the next several years. This programme is desirable as it provides a consistent and sustainable workflow for our contractors, enabling them to maintain competency levels, and minimising the risk of inadvertently creating a scenario where work loads become unsustainable in the future.

Figure 4-9e provides information on our pole health and the effect of our planned renewals programme.

Figure 4-9e **Pole health index**



4.9.7 Creation/acquisition plan

We now only create 400V distribution lines in our rural area as they are prohibited in urban areas by city/district plan requirements. They are generally constructed in response to customer connection requirements only and predominantly use timber poles.

4.9.8 Disposal plan

We dispose of overhead lines to meet customer requirements or to implement city/district councils underground conversion projects.

4.10 Underground cables – subtransmission

4.10.1 Asset description

Our subtransmission underground cable network is a combination of 66kV and 33kV. With a total length of 107km its primary purpose is to deliver electricity from Transpower's GXPs to the various substations in the Christchurch urban area (Region A).

For a map of this asset see Figure 4-1a and Figure 4-1b.

66kV cables

Our 66kV underground cable asset is 89km in circuit length. Originally, pairs of 66kV three core aluminum, oil filled cables were installed to our 66/11kV zone substations. There is 40km of circuit length of this aluminum cable. Each cable has an emergency rating equivalent to the full load of the zone substation (nominally 40MVA). These cables have an outer cover of semi-conducting plastic sheath over the aluminum. They are installed either encased in weak mix concrete and capped by a 50mm layer of hard concrete dyed red or supported on a reinforced concrete strip footing. For each zone substation the two cables have been laid in a common trench spaced 300mm apart.

Since FY00 48km of single core XLPE cables have been installed in a weak mix of thermally stabilised concrete and capped with a 50mm layer of stronger concrete dyed red. Two fibre optic cables have been installed with these XLPE cables, one of which is strapped to the 66kV cable to facilitate monitoring of thermal performance. The second fibre optic cable is part of the cable protection system. See table 4-10a for individual cable details.

Additionally, short lengths of 66kV single core cable are located within the zone substations to link primary equipment. These cables are shown in the circuit listing (table 4-9a), along with the main cables.

As a result of the Canterbury earthquakes we undertook a review of how our subtransmission cables have been installed. One of the key findings was that while we had good current carrying capacity between zone substations the fact we had dual circuits in the same trench meant we experienced common mode failures due to lateral spread. To mitigate this we have increased the interconnectivity of our 66kV cable network and used more route diversity for recent installations.

The Alpine fault rupturing remains a credible event that will have a major impact on our network. Network resilience remains critical for us. Our 66kV oil-filled cables and joints are vulnerable to seismic events and are likely to fail. We will initiate a replacement programme for our 66kV oil-filled cables within the disclosure period. See section 4.10.6 for further details.

Table 4-10a **66kV cable circuits**

Cable circuit	Install year	Cable type	Size	Rating (A)* summer/winter	Length (m)
Addington 66-Armagh No.1	1981	3c Oil	300 Al	343/370	4,280
Addington 126-Armagh No.2	1981	3c Oil	300 Al	343/370	4,416
Addington 66-Fendalton T1	1978	3c Oil	300 Al	345/393	2,464
Addington 176A-Fendalton T2	1978	3c Oil	300 Al	345/393	2,345
Addington 46-Milton T1	1979	3c Oil	300 Al	330/384	3,990
Addington 176B-Milton T2	1979	3c Oil	300 Al	330/384	4,089
Addington 146-Oxford Tuam T1	1975	3c Oil	0.45 Al	330/350	2,661
Addington 46-Oxford Tuam T2	1975	3c Oil	0.45 Al	330/350	2,562
Bromley-Lancaster	2000	3x1c XLPE	1,600 Cu	1,400/1,400	4,884
Bromley-Dallington	2014	3x1c XLPE	1,600 Cu	1,400/1,400	4,804
Bromley-Rawhiti	2015	3x1c XLPE	1,600 Cu	1,400/1,400	6,552
Dallington-McFaddens	2013	3x1c XLPE	1,000 Cu	1,050/1,050	5,410
Halswell 196-Hoon Hay T1	1969	3c Oil	0.45 Al	289/356	2,644
Halswell 136-Hoon Hay T2	1969	3c Oil	0.45 Al	289/356	2,647
Halswell-Heathcote 1 (Westmorland)	2015	3x1c XLPE	630 Cu	700/700	1,055
Halswell-Heathcote 2 (Westmorland)	2015	3x1c XLPE	630 Cu	700/700	1,055
Middleton T1	2008	3x1c XLPE	300 Cu		375
Middleton T2	2008	3x1c XLPE	300 Cu		365
Papanui 136-McFaddens T1	1972	3c Oil	0.45 Al	348/396	4,163
Papanui 206-McFaddens T2	1972	3c Oil	0.45 Al	348/396	4,091
Papanui - Waimakariri	2015	3x1c XLPE	1,000 Cu	1,050/1,050	4,016
Waimakariri - Rawhiti	2016	3x1c XLPE	1,000 Cu	1,050/1,050	17,500
Barnett Park	1987	3 core Oil	300 Al	330/350	120
Lancaster-Armagh	2002	3x1c XLPE	1,600 Cu	1,400/1,400	2,363
Armagh (T1/T2)	2001	3x1c XLPE	300 Cu		75

* Ratings are single cable contingency, that is second parallel cable is out of service (assumes that condition of cables and joints are capable of design rating).

33kV cables

Our 33kV cable asset is 37km of circuit length of underground cable, buried directly in the ground. It is mostly situated in the western part of Christchurch city, with sections of cable in Rolleston, Lincoln, Prebbleton and Springston, and is made up approximately as follows:

PILCA	3km	installed 1978-1988
XLPE	33km	installed 1992-2014

In recent years there has been an increasing amount of 33kV overhead line replaced by underground cables as land has been developed and road controlling authorities have requested removal for road upgrades.

We replaced all of our 33kV oil-filled cables a number of years ago. See 4.10.6 replacement plan for further details.

Table 4-10b **33kV cable circuit listing**

Cable circuit	Length (m)	Type	Size	Winter rating (A)
Islington 2102 - Harewood 234	690	XLPE	300 Al	475*
Islington 1036 - Moffett St 334	151	XLPE	300 Cu	
Islington 2092 - Moffett St 344	122	XLPE	300 Cu	
Islington 936 - Sockburn T1	2,019	XLPE	300 Al	475*
Islington 2062 - Sockburn T2	3,513	XLPE	300 Al/630Cu	372
Islington 976 - Sockburn T3	3,486	XLPE	300 Al	319
Islington 886 - Harewood 224	4,507	PILCA /XLPE	300 Al	319
Islington 966 - Hornby 572-582	1,848	XLPE	300 Al	306*
Islington 2072 - Hornby 532-542	1,852	XLPE	300 Al	338*
Springston 1206 - Shands Rd 436	67	PILCA	300 Al	365*
Hornby 502-512 - Shands Rd 454	830	PILCA/XLPE	300 Al	365*
Hornby 562-572–Prebbleton 4832	3,474	XLPE	300 Al	365*
Prebbleton 4842 - Lincoln 3434	781	XLPE	300 Al	365*
Hororata 1226 - Hororata 924	95	PILCA	.3 Al	280*
Hororata 1206 - Annat 1106/Kimberley 4926	181	PILCA	.3 Al	280*
Springston 1206 - Rolleston 3234	2,945	XLPE	300 Al	475*
Springston 1146 - Springston 3554	74	PILCA	.3 Al	280*
Springston 1186 - Springston 3544	80	PILCA	185 Cu	355*
Springston 1176 - Motukarara 3612/3622	5,027	XLPE	300 Al	
Springston 1196 - Rolleston 3206/Highfield 4216	363	PILCA/XLPE	300 Al/185 Cu	365*
Springston 1226 - Lincoln 3432	177	XLPE	300 Al	
Springston 3532 - Motukarara 3632/3642	154	PILCA/XLPE	300 Al/185 Cu	355*
Motukarara 3642/3652 - Little River 3812	79	XLPE	300 Al	
Motukarara 3602/3612 - Teddington 3704	105	XLPE	300 Al	
Islington 1026 - Hornby 512-522	1,836	XLPE	300 Al	
Islington 2082 - Shands Rd 444	2,400	XLPE	300 Al/150 Cu	
Hornby zone substation	151	XLPE	300 Al/630 Cu	
Motukarara zone substation	70	XLPE	300 Al	
Duvauchelle - Diamond Harb	246	XLPE	300 Al	
Lincoln zone substation	62	XLPE	300 Al	
Shands Rd zone substation	12	XLPE	300 Al	
Prebbleton zone substation	19	XLPE	300 Al	

Note: Some of these circuits may have an overhead line component that will affect overall circuit rating.
*Nominal rating – investigation to determine full rating to be completed.

4.10.2 Asset capacity/performance

66kV cables

The older 66kV underground cables are predominantly paper insulated, oil filled/aluminum sheathed with the newer cables being XLPE/lead or aluminium sheathed. Ratings are shown in Table 4-10a.

Failure modes have predominately been related to termination oil leaks and third party damage. We are proactively addressing these issues.

Oil filled cables are particularly vulnerable to damage from:

- unrelated work, for example other services trenching
- differential ground settlement that can occur as a result of poorly compacted fill material or naturally soft ground for example organic clays and peat
- movement as a result of seismic activity.

The cable routes have been assessed to ascertain the vulnerability of the cables to a seismic event.

The 66kV cables have been reliable prior to the earthquakes and in recent years. The performance of the cables are based on benchmarks such as SAIDI, SAIFI and defect incident records. An example of a minor defect would be termination issues such as oil leaks which are repaired under an emergency job.

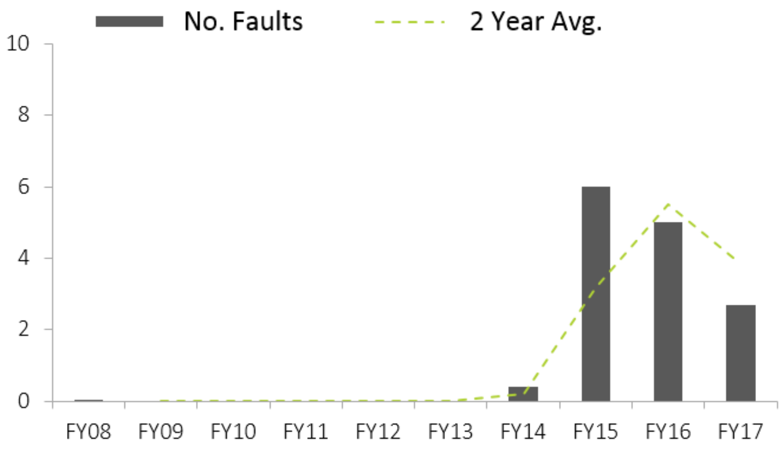
33kV cables

The cable sizes are as shown in the circuit listing (Table 4-10b) and are solid insulation with a nominal rating of 425A or 24MVA.

For XLPE cables we have seen failures of joints and terminations due to incorrect installation practices. These issues have been addressed by introducing new joint/termination kits and improved training.

We are pro-active with contractors and council staff to maintain awareness of the location of subtransmission cables.

Figure 4-10a **Underground cables 33/66kV – asset failures/100km**



33kV cable failures contribute to 3% of the overall SAIDI and SAIFI. There have been five joint failures since FY14. Three of these failures were due to the incorrect compression technique used on the compression connector during the installation of the joint. The other two failures were due to incorrect jointing practices being carried out. We have since significantly improved our 33kV joints by using mechanical shear bolt connectors instead of the old compression type as well as improving the overall design of the joint.

4.10.3 Asset condition

66kV cables

Our 66kV cables have a low average age, with the oldest cables being laid in 1967. The cables to date have been operated conservatively and therefore not been subject to electrical aging mechanisms. We monitor the cables to ensure the integrity of the mechanical protection of the cables is maintained.

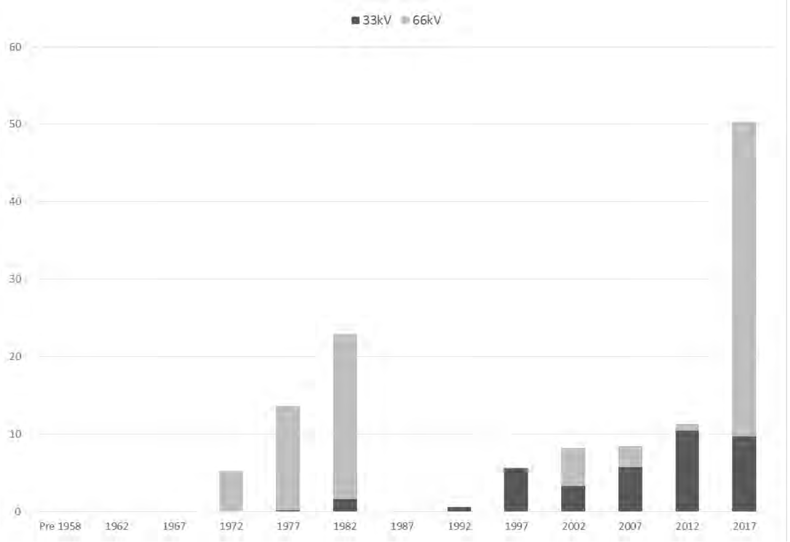
During the FY11 earthquakes there was significant ground movement in areas around the Avon River where our Brighton and Dallington 66kV cables traversed. An inspection was carried out on the Dallington cables after the September 2010 earthquake and while there was some minor damage the cables were returned to service with a lower load rating. The M6.3 earthquake in February 2011 caused further significant damage to these cables and other 66kV cables in our urban network. The cables to Brighton and Dallington zone substations could not be made serviceable and have been replaced.

All the joints that indicated excessive movement of conductors have now been replaced. We continue to inspect the joints that have shown no signs of damage or buckling as part of an ongoing maintenance plan.

33kV cables

These cables are relatively new and are in good condition.

Figure 4-10b **Underground cables 33/66kV – age profile**



4.10.4 Standards and asset data

Standards and specifications

Cables are installed to manufacturers' specifications and to specific design on a case-by-case basis by suitably qualified engineering consultants. Any design includes thermal modelling of soil and ground conditions for the cable to achieve the required level of service.

Asset management report:

- NW70.00.31 - Underground cables - 33kV
- NW70.00.32 - Underground cables - 66kV.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.14 – Cable - Subtransmission - 33kV
- NW74.23.30 – Cable - Subtransmission - 66kV - 300mm^2 Cu XLPE
- NW74.23.31 – Cable - Subtransmission - 66kV - 1,600mm^2 Cu XLPE
- NW74.23.35 – Cable - Subtransmission - 66kV - 1,000mm^2 Cu XLPE.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.22.01 – Cable installation and maintenance
- NW72.22.02 – Excavation, backfilling and restoration of surfaces
- NW72.23.24 – Cable testing

- NW71.12.03 – Cabling and network asset recording.

Risks associated with alternative standards include operating cables at temperatures above the recommended levels. This could reduce the service life of the cables concerned.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- circuit ratings
- sheath test results
- cable type, size and age
- joint age, type and condition
- seismic risk assessments and profile drawings of cable routes.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the asset.

4.10.5 Maintenance plan

66kV cables

The condition of our 66kV underground cables is monitored by:

- an annual inspection and sheath test of all cables with any planned repairs completed the next year
- alarms fitted to give early warning of low oil pressure and oil level via the SCADA system. Immediate investigation and rectification of the problem follows any oil alarm. To give better monitoring and analysis we install pressure transducers at the ends of cables in conjunction with joint upgrading
- continuous temperature monitoring at a potential ‘hot spot’ on the Addington-Armagh T1 cable – this also reports via the SCADA system
- other cables are currently being identified for further monitoring work.

The following maintenance work is planned:

- ensure contractors with suitable skills are available for oil filled cable jointing
- review the thermal properties of backfill material where tests indicate that the cable’s rating is compromised
- continue inspecting joints for signs of thermal-mechanical damage.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Subtransmission UG cables.

33kV cables

The condition of this asset is monitored by an inspection and sheath test, where practicable, every year.

A detailed breakdown of opex is shown in table 4.10c. This includes opex for 66kV and 33kV assets.

Table 4-10c - **Subtransmission underground opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	105	105	105	105	105	105	105	105	105	105	**1,050**
Routine and corrective maintenance and inspections	325	325	325	325	325	325	325	325	325	325	**3,250**
Asset replacement and renewal	420	420	420	420	420	420	420	420	420	420	**4,200**
Total	**850**	**850**	**850**	**850**	**850**	**850**	**850**	**850**	**850**	**850**	**8,500**

4.10.6 Replacement plan

Our 66kV oil filled cables and joints have a medium to high risk of multiple faults occurring when the Alpine fault ruptures (30% chance in the next 50 years). Being an ageing technology, oil filled cables have some disadvantages. Namely, longer duration of repairs compared to modern XLPE cable, difficulty in sourcing trained and skilled resources and the risk of oil escaping to the environment.

Another issue is the mechanical strength of the cable joints. While these joints are suitable for the mechanical stress caused by cyclic loading they will fail during a long duration Alpine fault event.

To minimise the risk of failure and to continue investing in the network to provide a resilient electricity supply for our community and customers we will initiate a replacement programme for our oil filled 66kV cables. We have approximately 40km of 66kV oil filled cables. Our replacement forecast is based on a 10 year programme starting in FY24. We have learned from the earthquakes that dual circuits in the same trench can lead to common mode failure. To ensure resiliency, any new installation will follow our 'ringed' substransmission architecture.

In the next 12 - 18 months we will undertake a review to:

- identify which circuits are most vulnerable
- analyse historic test results to identify the highest risk cable
- identify suitable routes to support the 66kV architecture
- identify what other works at our zone substations may be required as part of this programme.

Once completed we will refine our expenditure forecast to better reflect the findings and recommendations of the review.

Table 4-10d - **Subtransmission underground replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Subtransmission	0	0	0	0	0	4,000	4,000	4,000	4,000	4,000	**20,000**
Total	**0**	**0**	**0**	**0**	**0**	**4,000**	**4,000**	**4,000**	**4,000**	**4,000**	**20,000**

4.10.7 Creation/acquisition plan

Cables are laid in the city to conform with the requirements of the Christchurch city plan. Cables are also installed as a result of customer driven work from developers requiring the undergrounding of our overhead subtransmission lines.

For details of projects to reinforce our subtransmission cable network see section 5.6 – Network development proposals.

4.10.8 Disposal plan

We have no plans to dispose of any subtransmission cable assets.

4.11 Underground cables – 11kV

4.11.1 Asset description

Our 11kV cable network is 2,602km of circuit length of underground cable and is largely (approximately 90% of total length) concentrated in the urban area of Christchurch (Region A).

These cables are classed as subtransmission (feeder and primary) and distribution (secondary) cables as follows:

- feeder cables that supply our 11kV zone substations (see table 4-11a)
- primary cables which supply network substations from zone substations
- secondary cables which supply distribution substations from network substations.

The reason for having these classes is largely historical and is explained further in section 4.2.2 – Urban System Design.

The 11kV cable is predominantly of the paper lead variety with an expected life of 70 to 80 years.

Table 4-11a **11kV feeder cable circuit listing**

Cable circuit	Install year	Type	Size	Rating (A)** summer/winter	Length (m)
Addington 1/2722-Foster 12 (2 cables)	1950/93	PILCA	0.5 Al and 300 Al	700*	160
Addington 1/2662-Foster 6 (2 cables)	1993	PILCA	2x 300 Al	700*	160
Addington 1/2802-Foster 19 (2 cables)	1950/93	PILCA	0.3 Cu and 300 Al	700*	150
Addington 2/13/Foster 4-Knox 13	1965/2001	PILCA	0.5 Cu and 400 Cu	273/324**	2,960
Addington 2/4-Knox 3	1965	PILCA	0.5 Cu	273/324**	3,185
Addington 2/14-Knox 17	1965	PILCA	0.5 Cu	273/324**	3,175
Bromley 5-Pages Kearneys 4	1966/73	PILCA	0.5 Cu	375/466	1,560
Bromley 6-Pages Kearneys 10	1966	PILCA	0.5 Cu	375/466	1,560
Bromley 7-Pages Kearneys 16	1966	PILCA	0.5 Cu	375/466	1,560
Hawthornden 31-Ilam 2	2005	XLPE	400 Cu	220*	2,849
Hawthornden 32-Ilam 14	2005	XLPE	400 Cu	220*	2,849

* Nominal rating - investigation to determine full rating to be completed.

** Rating when one cable is out of service.

4.11.2 Asset capacity/performance

The September 2010 and February 2011 earthquakes caused a number of 11kV cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale. These areas contain approximately 90km of cable. The majority of cables that failed were PILCA as this was the predominant type installed in the area that experienced the most land movement. These cables were typically 40-50 years old, however age was not a factor in the damage suffered. Some of these cables had multiple faults. The failure modes were either joints (typically older pitch filled types) pulled apart or significant movement of the cables causing failure of the cables' outer sheath and subsequently the paper insulation.

11kV feeder system

These cables mainly supply our 11kV zone substations. The rating of each cable has been assessed based on the thermal resistivity of the cable bedding material. These assessments have shown the present loading requirements of the substations do not exceed the cable capability. We manage the development and operation of the network to ensure the cable ratings are not exceeded during contingency events.

Primary 11kV system

This system is designed to be run in single or multiple closed rings. Each ring usually starts at a zone substation bus and includes one or more network substations before returning via a different route to the starting zone substation. To provide additional 11kV tie capacity, primary circuits may also be provided in some cases to alternative zone substations. A primary ring consists of dedicated runs of cable between a zone substation bus and a network substation or between network substations. Each end of a primary cable is protected with a circuit breaker using differential protection. No distribution substation load is supplied directly from the primary cable system. The primary system is designed to be loaded up to the point where, in the event of a single cable fault contingency, no primary cables will become overloaded and no loss of supply will result. The standard conductor is 300mm^2 Al/0.25in^2 Cu PILCA giving each circuit a rating of 365A or 7MVA. As per the 2006 11kV architecture review findings, the primary 11kV system will be changed over time. As assets come up for replacement, the associated network will be converted to a secondary system and therefore peak loads will tend to be around 50% of the cable capacity.

Secondary 11kV system

This system consists of radial feeders, most of which are supplied from network substations, however, as we transition our 11kV system to the new architecture, more 11kV feeders will be supplied directly from the zone substation bus. Depending on the area and load supplied, secondary feeders have nominal ratings ranging between 2 and 7MVA. Secondary feeders are loaded to the extent that, in the event of a single fault contingency, it should be possible to split the faulty feeder so that the healthy portions can be supplied from adjacent feeders without overloading those feeders. Historically this would mean that, under normal circumstances, any individual feeder should not be loaded above 70% of cable rating. The new architecture requires that the size of the 11kV feeders is sufficient to provide the full load of adjacent feeders.

The age of the cables making up this asset covers a wide range. The cable failure modes are monitored to ensure the high reliability of cables. To date the majority of failure modes have included:

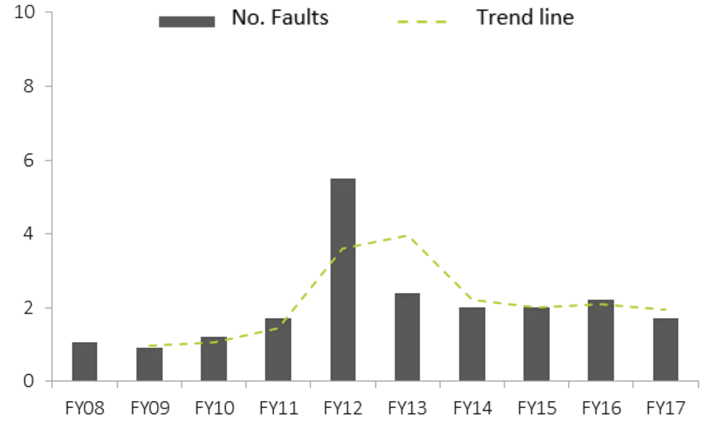
- third party damage
- damage of cable during installation or other disturbance
- failure of terminations.

To manage these issues the following actions are taken:

- proactive promotion to contractors of cable maps and locating services
- free training (including a DVD) on working safely around cables, including reading cable location maps
- extensive safety advertising in the media
- inspection of contractors during the laying of cables
- ultrasonic and partial discharge monitoring of terminations in zone and network substations
- new cables installed with an orange coloured sheath to allow easier identification.

We are starting to see a reduction in third party cable strikes and other failure modes in general. This is due to a combination of improved excavation compliance from third party contractors, earthquake damage being completed and the proactive maintenance of susceptible cable terminations.

Figure 4-11a **Underground cables 11kV – asset failures/100km**



4.11.3 Asset condition

The condition of these cables is largely assessed by monitoring any failures. Condition testing of a sample of varying cable types and ages has been undertaken using the partial discharge mapping technique. A limited amount of partial discharge was noticeable in a few joints. However, there were no major areas of concern. This indicates that cables are in good condition.

A programme has been developed to test 11kV (and other) cables in areas that were subjected to significant earthquake damage to determine if the cables were adversely affected.

11kV cable failures contribute 12% to the overall SAIDI and SAIFI. The peak in FY12 are failures of cables that were stressed by the earthquakes in 2010 and 2011. In recent years, the majority of failures have occurred in a joint section of the cable and half of these are located in/near the red zone[1]. The termination maintenance programmes have been effective in keeping the failure numbers low.

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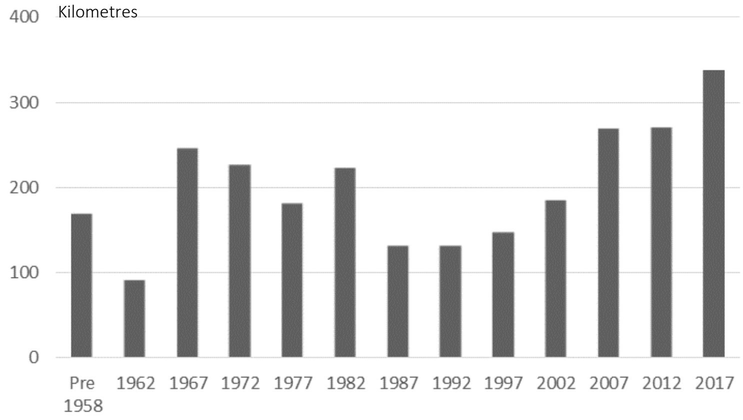
[1] Red zone—areas of land adversely affected by the FY11 earthquakes which is unlikely to be built on in the medium to short term.

Figure 4-11b **Underground cables 11kV – age profile**



4.11.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.30 - Underground cables - 11kV

Design standards developed and in use for this asset are:

- NW70.52.01 – Underground cable design.

Technical specifications:

- NW72.22.01 – Cable installation and maintenance
- NW72.22.02 – Excavation, backfilling and restoration of surfaces.
- NW72.23.24 – Cable testing
- NW71.12.03 – Cabling and network asset recording.

Equipment standards:

- NW74.23.04 – Distribution cable 11kV
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- circuit ratings
- cable type, size and age
- joint age and type.

Data improvement is ongoing but there are limited opportunities to improve what we already know about this asset group. We closely monitor the cause of any failures to see if any trends develop with a particular cable/joint type.

4.11.5 Maintenance plan

We have programmes in place to address identified failure modes of cables. These failure modes have been predominately related to the terminations. An inspection and maintenance programme has been implemented. Although failure rates are beginning to decrease, emergency work expenditure is remaining static due to a rise in contractor costs.

Our total budgeted maintenance costs are shown in section 7.1.1 – Opex budgets - Network: 11kV underground cables. A detailed breakdown of opex is shown in table 4-11b.

Table 4-11b **11kV underground opex (real)- $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	2,555	2,450	2,450	2,450	2,450	2,450	2,450	2,450	2,450	2,450	**24,605**
Routine and corrective maintenance and inspections	600	600	600	600	505	505	505	505	505	505	**5,430**
Asset replacement and renewal	290	355	255	255	255	255	255	255	255	255	**2,685**
Total	**3,445**	**3,405**	**3,305**	**3,305**	**3,210**	**3,210**	**3,210**	**3,210**	**3,210**	**3,210**	**32,720**

4.11.6 Replacement plan

We currently do not have a specific replacement programme for this asset. Any significant replacements will be undertaken as part of other works such as a reinforcement/switchgear replacement project or a local authority driven underground conversion project.

Some expenditure is forecast annually to allow for the replacement of short sections (<100m) of 11kV underground cable identified as being unreliable. These sections are predominantly in earthquake damaged areas.
Our total budgeted replacement costs are shown in section 8.1.13 - Replacement budgets: 11kV underground cables. A detailed breakdown of replacement is shown in table 4-11c.

Table 4-11c **11kV underground replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Distribution and LV Cables	100	100	100	100	100	100	100	100	100	100	**1,000**
Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**1,000**

4.11.7 Creation/acquisition plan

Additional 11kV cables are installed as a result of the following:

- reinforcement plans (refer to section 5.6 – Network development proposals)
- conversion from overhead to underground as directed by Christchurch City and Selwyn District Councils
- developments as a result of new connections and subdivisions.

4.11.8 Disposal plan

We have no plans to dispose of any of this asset, other than minor disposal associated with changes and rearrangements in the network. No decision has been made as to the fate of assets in the ‘red zone’.

Overhead line 11kV cable termination with surge arrestors fitted

4.12 Underground cables – distribution 400V

4.12.1 Asset description

Our 400V cable network is 2,974km of circuit length and is largely concentrated in the urban area of Christchurch. The earlier cables are of paper/lead construction. PVC insulation was introduced in 1966 to replace some paper/lead cables. XLPE insulation was introduced in 1974, mainly because it has better thermal properties than PVC.

We have some 6,200 distribution cabinets installed on our 400V cable network. Sufficient cabinets are needed to allow the system to be reconfigured (that is, each radial feeder must be capable of supplying or being supplied from the feeder adjacent to it) in the event of component failure or other requirements. Distribution cabinets are all above ground. Older ones are generally steel and the later ones are a PVC cover on a steel frame.

We have approximately 42,000 distribution boxes in our 400V cable network. These are generally installed on alternate boundaries on both sides of the street. Several types of distribution box are in service. All are above ground. The majority are a PVC cover on a steel base frame, although some older types are concrete or steel.

Street-lighting cables are also included in this asset group. The street-lighting cable network consists of 2,434km circuit length of underground cable and is largely concentrated in the urban area of Christchurch. Approximately 60% of this cable is included as a fifth core in the 400V distribution cables.

4.12.2 Asset capacity/performance

Many system configurations are used for 400V cable distribution, depending on the area to be supplied, but generally it is a two-sided system with cables on both sides of a street. These cables are fed from a kiosk distribution substation via multiple feeders, each with a rating of around 250A. The cables are buried directly in the ground. Jointing methods have been changed to improve performance. Historically many customer service cables were connected directly to the underground network cables by way of a tee joint with the customer protection fuses in their meter-box. For increased safety we have introduced a supply fuse relocation program where these fuses are moved to newly installed distribution boxes on the property boundary.

The earthquakes in FY11 caused a number of 400V cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale.

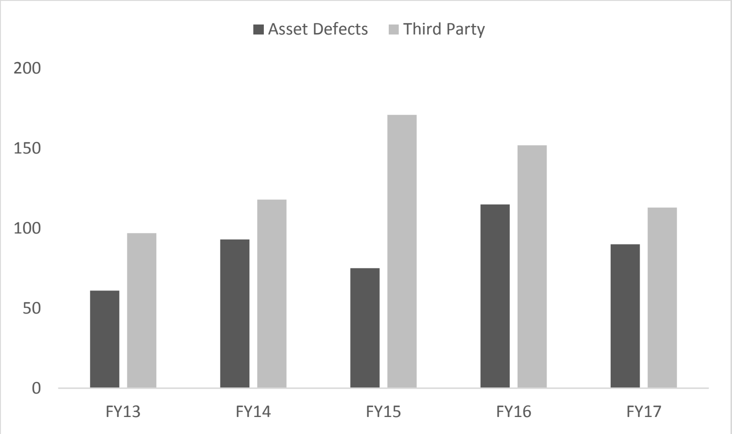
We are not required to record SAIDI/SAIFI for our LV networks. However to ensure prudent asset management and good stewardship we collect performance data on our LV system. These are defects that require more than an operator to repair under an emergency job.

The number of failures over the last five years can be seen in Figure 4-12a where the majority of failures relates to third party damage and service/network cable failures. The increase in the number of third party hits is due to the effect of the Christchurch rebuild.

To manage these issues the following actions are taken:

- proactive promotion to contractors of cable maps and locating services
- free training on working safely around cables, including map reading and a DVD
- extensive safety advertising in the media
- inspection of contractors during the laying of cables
- new cable is now required to be installed with an orange coloured sheath to allow easier identification.

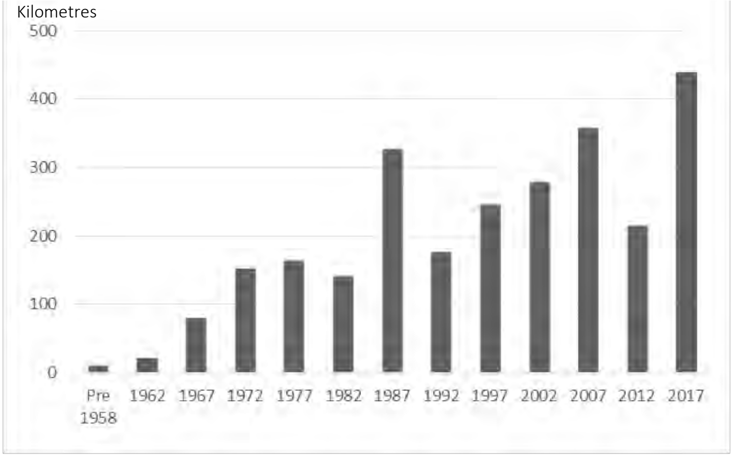
Figure 4-12a **Underground cables 400V – number of faults**



4.12.3 Asset condition

Cable laying has been performed to a good standard and we are not exposed to any great extent from external damage or faulty joints. We anticipate cables that have been subjected to earthquake stress will have higher failure rates as faults develop in sheaths and insulation. A programme has been developed to run over the next few years to test the 400V and other cables in areas that were subjected to significant earthquake damage to determine whether maintenance or replacement is required. The distribution cabinets and boxes are in reasonable condition. We inspect them every five years, with any defects remedied in a subsequent contract.

Figure 4-12b **Underground cables 400V – age profile**



4.12.4 Standards and asset data

Asset management report:

- NW70.00.29 - LV underground cables and hardware.

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.52.01 - Underground cable design.

Technical specifications:

- NW72.22.01 - Cable installation and maintenance
- NW72.22.02 - Excavation, backfilling and restoration of surfaces
- NW72.23.24 - Cable testing
- NW72.22.03 - Distribution enclosure installation
- NW71.12.03 - Cabling and network asset recording
- NW72.21.12 - Network inspection.

Equipment standards:

- NW74.23.11 - Distribution cable LV
- NW74.23.20 - Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- cable type, size and age
- distribution box types/condition.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan, as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the visible portion of the asset. We also closely monitor the cause of any failures to see if trends develop with a particular cable/joint type.

4.12.5 Maintenance plan

The condition of this asset is monitored through:

- a five-yearly visual inspection programme of the above-ground equipment and terminations.

Maintenance work planned is as follows:

- upgrade insulation on cable to overhead terminations, where insulation is degraded due to the effects of UV light
- replace old cast iron cable termination boxes with heat shrink to remedy safety issues
- install Perspex covers over all exposed LV equipment to provide an extra barrier of protection for the general public, see section 7.5.3 – Risk management-legacy assets.

Our total budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: 400V underground cables. A detailed breakdown of opex, in Commerce Commission categories, is shown in table 4-12a.

Table 4-12a - **400V underground opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	1,860	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	**17,655**
Routine and corrective maintenance and inspections	1,375	1,390	1,400	1,295	1,295	1,295	1,295	1,295	1,295	1,295	**13,230**
Asset replacement and renewal	160	160	160	160	160	160	160	160	160	160	**1,600**
Total	**3,395**	**3,305**	**3,315**	**3,210**	**3,210**	**3,210**	**3,210**	**3,210**	**3,210**	**3,210**	**32,485**

4.12.6 Replacement plan

We have made an allowance for 400V cables that may need replacement due to damage caused by the earthquakes.

We are also upgrading our existing distribution cabinets to a more secure design.

We have developed a programme to install distribution boxes on the supply cable where the service fuse is currently in the customer's meter box. This project is programmed to be complete in 2028.

Our total budgeted replacement costs are shown in section 8.1.13 - Replacement budgets: 400V underground cables. A detailed breakdown of Replacement is shown in table 4-12b.

Table 4-12b - **400V underground replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Distribution and LV Lines	320	320	320	320	320	320	320	320	320	320	**3,200**
Other network assets	5,000	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,160		**54,910**
Total	**5,320**	**6,570**	**6,570**	**6,570**	**6,570**	**6,570**	**6,570**	**6,570**	**6,480**	320	**58,110**

4.12.7 Creation/acquisition plan

We will install additional 400V cables as a result of the following:

- conversion of reticulation from overhead to underground as directed by the city and district councils
- developments as a result of new connections and subdivisions.

Electric vehicle chargers

The uptake of electric vehicles (EV), including plug in hybrid electric vehicles, has been steadily increasing. New Zealand's mostly renewable energy generation means that EVs offer the greatest opportunity to reduce transport emissions (the country's second biggest source of emissions). One of the biggest barriers to uptake commonly cited is range anxiety - drivers fear that they will run out of battery charge before reaching the destination. To help drivers overcome this anxiety, and encourage others to adopt this technology, we have installed a number of EV chargers at strategic locations throughout our network. These chargers are available for public use and provide a platform for our community to easily connect with New Zealand's renewable energy source. We have had positive feedback from both drivers and community leaders.

There is still some uncertainty regarding the continuing uptake rate of EVs and how businesses such as cafés, service stations, super-markets, etc. will impact the number of charging stations available for the public to use. As time passes and more information is gathered, our understanding of the communities adoption/use of EVs and their charging habits will improve.

4.12.8 Disposal plan

We have no plans to dispose of any of this asset, other than minor disposals associated with changes and rearrangements in the network.

No decision has been made as to the fate of assets in the residential 'red zone'.

4.13 Communication cables

4.13.1 Asset description

Our 1,031km of communication cables are predominantly located in Christchurch. Most are armoured construction. They are laid to most building substations and are used for SCADA, telephone, data services, ripple control, metering and many other purposes in addition to their original function of providing unit (pilot wire) protection communications.

We have recently negotiated with Transpower to share their existing fibre-network ducts. This will provide us with fibre routes between our main office at 565 Wairakei Rd and our zone substations at Papanui, Hawthornden, Middleton, Addington and Islington GXP. These fibre routes provide protection signaling for the Waimakariri/Papanui/Islington 66kV circuits and in the future Hawthornden/Islington.

Unit protection system

The distribution network in the urban area is predominantly underground cable made up of primary and secondary 11kV systems. The primary system is operated in closed rings with the secondary system operated radially from network substations on the primary system. Because of the low electrical impedance of cables at 11kV, there is very little variation in fault level throughout the distribution network and thus little opportunity for application of inverse-time based protection co-ordination. To obtain protection co-ordination in the 11kV network it has thus been necessary to use differential or unit protection on all but the last radial sections of the network.

The most common and effective differential protection uses common twisted-pair communication cables for end-to-end measurement of electrical parameters on the protected section of cable. Therefore as new lengths of primary network cable are laid, a communication cable is laid with the electrical power cable. In general it is uneconomic to lay single pair communication cables, as required only for the unit protection, and thus multi-pair cables are installed.

It is not possible to use a dedicated communications provider's network for unit protection. The unit protection signal levels are incompatible with normal commercial communications and, in addition, it is not possible to obtain the very high reliability levels provided by a dedicated end-to-end cable laid with the power cable.

4.13.2 Asset capacity/performance

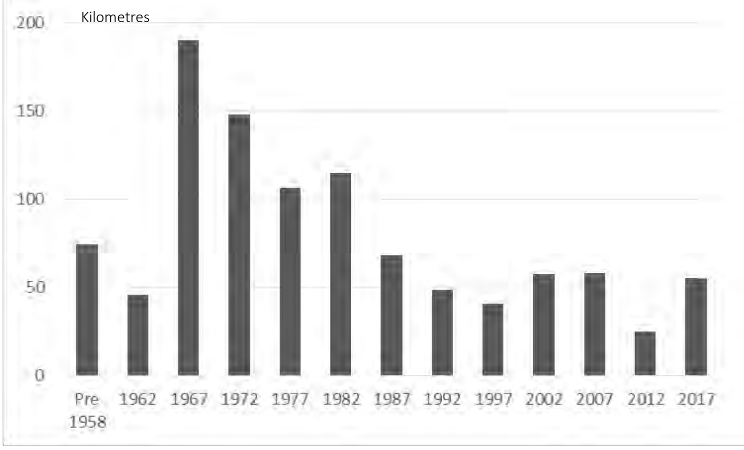
The standard cables laid are 0.9mm^2 Cu. These are reasonably heavy cables in communication terms, but this large conductor size is required for the unit protection communications over longer cable routes. The common failure point for these cables is the joints. Epoxy filled joints do not stop the ingress of moisture.

Two separate types of optical-fibre cable, each containing multiple fibres have been laid with new 66kV cables, multi-mode for cable temperature measurement and single mode for communications purposes. The protection equipment for the 66kV cables use single mode fibres.

4.13.3 Asset condition

These communication cables are in very good condition, with the steel wire armoured variety being the most robust. Some older unarmoured cables of the 2core/2pair type are prone to failure. Where condition is proven to be poor, these cables are replaced or bypassed when additional power cables are installed during system reinforcement. Other options include the use of radio communication channels or the use of dedicated communication providers for services other than power system protection.

Figure 4-13a Communication cables – age profile



4.13.4 Standards and asset data

Standards and specifications

Asset management report:

- NW70.00.28 - Underground cables - communication.

Design standards developed and in use for this asset are:

- NW70.52.01 – Underground cable design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.22.01 – Cable installation and maintenance
- NW72.23.24 – Cable testing
- NW72.22.02 – Excavation, backfilling and restoration of surfaces
- NW71.12.03 – Cabling and network asset recording
- NW72.27.01 - Unit protection maintenance.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.11 – Distribution cable LV
- NW74.23.20 – Earthing equipment and application.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS)
- cable type, size and age
- distribution box types/condition
- database of the cables and their connections.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan, as well as specific inspections carried out as required. All inspections are used to further our knowledge of the condition of the part of the asset which is above ground. We also closely monitor the cause of any failures to see if any trends develop with a particular cable/joint type.

The communication cables form a critical part of our network control system.

4.13.5 Maintenance plan

The condition of this asset is monitored by a test of the unit protection system every four years, this includes the most important of these cables. The remaining cables are generally monitored by the services using them, such as SCADA and unit protection. Communication error rates are tracked and recorded by SCADA.

Maintenance work is carried out to repair cables as required when faults occur.

Our total budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Communication cables. A detailed breakdown of opex is shown in table 4-13a.

Table 4-13a - **Communication cables opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	25	25	25	25	25	25	25	25	25	25	250
Routine and corrective maintenance and inspections	285	285	285	285	285	285	285	285	285	285	2,850
Total	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**3,100**

4.13.6 Replacement plan

An allowance has been identified for cable replacement where repair is shown to be costly.

Our total budgeted replacement costs are shown in section 8.1.13 - Replacement budgets: Communication cables. A detailed breakdown of replacement is shown in table 4-13b.

Table 4-13b - **Communication cables replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Other network assets	140	140	140	140	140	140	140	140	140	140	**1,400**
Total	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**1,400**

4.13.7 Creation/acquisition plan

New cables are installed as required to form part of new sections of the 11kV primary distribution system. Optical fibre cables are installed as part of any new 66kV or 33kV cable installation.

4.13.8 Disposal plan

We have no plans to dispose of any part of this asset, other than minor disposal associated with changes and rearrangements in the network.

4.14 High voltage circuit breakers

4.14.1 Asset description

Circuit breakers are installed to provide safe interruption of both fault and load currents during power system faults. They are strategically placed in the network for line/cable, local transformer and ripple plant protection.

66kV circuit breakers

66kV circuit breakers are installed at zone substations predominately in outdoor switchyards. The exceptions being Armagh, Dallington, McFaddens and Waimakariri zone substations where the 'outdoor design' circuit breakers have been installed indoors in specially designed buildings.

The majority of our 66kV circuit breakers use SF_6 gas as the interruption medium. We have not found a viable vacuum option for this voltage.

As part of our spur asset purchases we have recently acquired a number of bulk-oil units.

33kV circuit breakers

A mix of outdoor and indoor 33kV circuit breakers are installed in the 33kV zone substations.

Those installed pre-circa 2001 are mainly outdoor minimum oil interruption type. We are now moving from outdoor to indoor switchgear. This has the advantage of improved security and public safety.

The newer circuit breakers (shown right) at Duvauchelle, Hornby, Lincoln, Motukarara and Prebbleton zone substations are an indoor metal-clad vacuum interruption type.

As part of our spur asset purchases we have recently acquired a number of bulk-oil units.

11kV substation circuit breakers

These substation circuit breakers are installed indoors and used for the protection of primary equipment and the distribution network. The older units use oil or SF_6 gas as an interruption medium, while those installed since 1992 are a vacuum interruption type. 11kV circuit breakers are used throughout the entire rural and urban networks.

Those shown (right) are the vacuum type used in our 11kV switchgear replacement programme.

11kV line circuit breakers (Pole mounted)

Overhead line circuit breakers are pole mounted and have a reclose capability. They are installed in selected locations to improve feeder reliability by isolating a portion of the overall substation feeder. Here the circuit breaker is shown with its associated SCADA control and UHF communication equipment mounted below the circuit breaker.

Table 4-14a **Circuit breakers in service**

Location	66kV outdoor	66kV indoor	33kV outdoor	33kV indoor	11kV
Zone substations	90	16	35	28	768
Network/distribution substations					1,007
Overhead line					50

Table 4-14b **Circuit breakers by type (including spares)**

Voltage	Interruption Type	No. of Assets	% of total population
66kV	SF_6	91	4.4
	Oil	19	0.9
33kV	Vacuum	29	1.4
	Oil	35	1.7
11kV	Vacuum	781	37.5
	Oil	1,083	52.0
	SF_6	46	2.2
Total		**2,084**	

4.14.2 Asset capacity/performance

Substation circuit breakers

The rating requirements of circuit breakers are determined by the local load of the network. As a result load current and fault current interruption capabilities vary for circuit breakers of a given operating voltage.

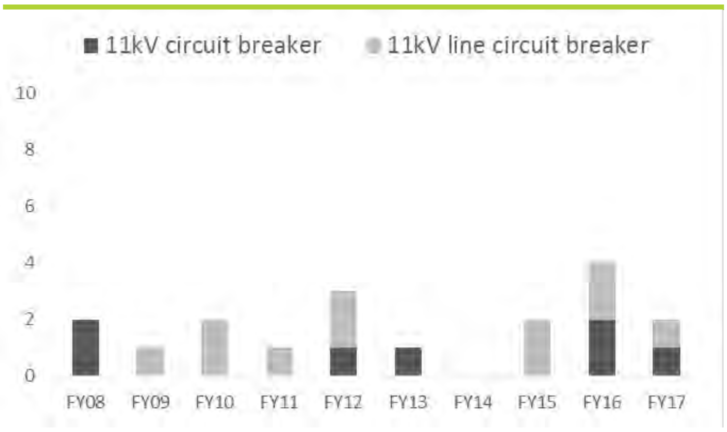
The overall performance of circuit breakers is satisfactory. Isolated cases of common mode faults have occurred in some of the older circuit breakers. As part of our spur asset purchases we have recently acquired a number of 33kV bulk-oil units.

The 33kV and 11kV indoor switchgear units are securely fixed to concrete floors. The auxiliary and voltage transformers are strapped to the switchgear frames and spare circuit breakers are also restrained. These precautions proved to be very effective in the 2010/2011 earthquakes.

Pole mounted 11kV line circuit breakers

Although line circuit breakers are performing satisfactorily, we have encountered problems with the electronic protection and control equipment on the older switches. Suitable alternatives to these units have been investigated and are now being installed in the network as part of the replacement project.

Figure 4-14a **Circuit breaker—number of outage causing faults**



There have been no 66kV or 33kV circuit breaker catastrophic or non-operating failures over the last ten years. The SAIDI and SAIFI contribution for 11kV substation circuit breakers is less than 1% of the network SAIDI and SAIFI. On average there has been one fault every two years for 11kV circuit breakers and one fault per year for 11kV line circuit breakers. For line circuit breakers, the majority of the failures are due to a faulty operating mechanism and battery corrosion.

4.14.3 Asset condition

All circuit breakers at zone substations are in satisfactory working condition. New methods of condition monitoring have enabled us to detect defects at an early stage. Older minimum-oil type units are approximately 50 years old and insulation levels are slowly deteriorating.

In FY11 EA Technology Ltd was engaged to develop a CBRM model for our high voltage circuit breakers. This model utilises asset information, engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and Capex forecasts.

We use condition based risk management models to rate our assets and give them a Health Index (or score). The results of this process show that the overall condition of our circuit breakers is good and we believe that the profiles below are appropriate for our risk appetite. The condition profile of our asset is directly linked to our network performance. If the assets were to deteriorate, thus have a poor HI profile, they would become less reliable and repairs would be longer and more costly.

Note that while the model calculates the asset ranking, engineering judgement will still be required to prioritise the replacement schedule.

Figure 4-14b HV circuit breakers - age profile

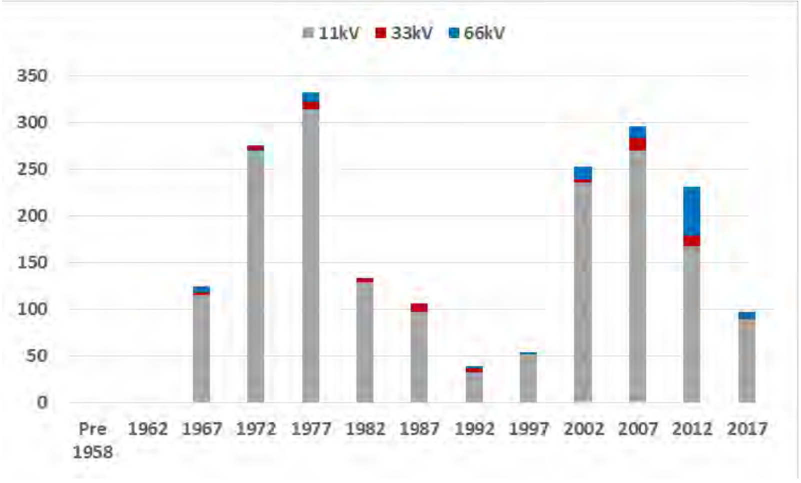


Figure 4-14c **11/33/66kV Circuit breakers - health index profile**

4.14.4 Standards and asset data

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers
- age
- circuit diagrams
- test results
- movement history.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

Standards

Asset management report:

- NW70.00.33 - Circuit breakers.

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design
- NW70.57.01 – Protection design
- NW70.59.01 – Earthing design.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.23.03 – Zone substation inspection
- NW72.23.07 – Zone substation maintenance
- NW72.23.15 – Oil circuit breaker servicing after operation under fault conditions.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.23 – Switchgear - 400V indoor
- NW74.23.25 – Circuit breaker - 66kV
- NW74.23.28 – Circuit breaker - 33kV indoor.

Operator instructions, developed in-house, are used for each different type of circuit breaker in our network.

4.14.5 Maintenance plan

We carry out regular inspection and testing to ensure safe and reliable operation of our assets. All circuit breakers are visually inspected for oil leaks and general condition. Major invasive maintenance is carried out at regular intervals as shown in table 4-14c.

Table 4-14c **Circuit breaker inspection and maintenance schedule**

Circuit breaker location	Inspection frequency (months)	Major maintenance frequency (years)
Zone substation	2	4
Network substation	6	8
Distribution substation	6	8
Outdoor ground mounted	6	4
Outdoor pole mounted circuit breaker	12	8
Outdoor pole mounted air break isolator - Load-break types	24	

As part of this maintenance we:

- inspect
- clean and lubricate
- repair or replace contacts, insulators and mechanisms
- profile the tripping function
- service or replace the oil
- thermal image outdoor equipment to identify hotspots
- monitor the levels of all SF6 we use and report any loss-to-atmosphere
- monitor partial discharge.

Partial discharge

With the age spread of the switchgear, additional testing has been introduced to detect breakdown in the insulation at an early stage. This means that targeted remedial work can be undertaken without disruption to customers.

This is achieved by partial discharge non-invasive locating and monitoring. This technology provides excellent results and has revealed potential problems at an early stage. Partial discharge checks are carried out at different intervals depending on the age and location of the switchgear:

Zone substations

- location testing – this is done six-monthly on circuit breakers over 40 years old and annually on the balance
- monitoring – is set up to continuously monitor any transient earth voltage signals. For circuit breakers more than 40 years old, it is installed on site for seven days annually. Circuit breakers less than 40 years old are monitored for three days every four years.

Network substations

- location testing – this is done annually on circuit breakers over 30 years old and every two years on the balance
- monitoring – for circuit breakers more than 40 years old, it is installed on site for three days every four years.

Line circuit breakers

The line circuit breakers have a regular maintenance procedure carried out every eight years. The exterior and control relay are inspected annually. Our SCADA provides initial indication of problems.

Network Expenditure

Our total budgeted maintenance costs are shown in section 8.1.1—Opex budgets. A total detailed breakdown of opex is shown in table 4-14.d (details our opex for all circuit breakers, HV and LV switchgear and substation disconnectors).

Table 4-14d - **Circuit breakers opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	180	180	180	180	180	180	180	180	180	180	**1,800**
Routine and corrective maintenance and inspections	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	**10,700**
Total	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**12,500**

4.14.6 Replacement plan

We have a proactive replacement programme for our HV circuit breakers and switchgear. One of the tools we use to manage our older assets are the CBRM models. Higher risk assets are replaced first. On average we expect our circuit breakers to last 50 to 55 years.

We have an ageing asset fleet therefore we have to balance replacing assets too soon with the resource availability. The objective is to smooth the works programme by deferring where we can but also by bringing replacement forward where appropriate. A risk based approach is used.

All circuit breakers have been reviewed based on a number of factors:

- safety
- performance
- condition
- maintenance issues
- operation
- logistical support
- working environment
- age.

Safety issues are given a high weighting to ensure protection of the public, employees and contractors. Performance and asset condition are considered on an individual basis and are used to develop the replacement programme. The criticality and location, i.e. zone or network substation, is also considered and factored into the programme.

Older circuit breakers are normally replaced with a modern equivalent, however in some cases they are replaced with a high voltage switch if it is deemed suitable. The replacement programme is regularly reviewed to take into account the changing requirements of the network.

Batteries

A four-year cycle of stand-by battery replacement is carried out in tandem with our switchgear inspections. Alkaline batteries previously used have been replaced with sealed lead-acid batteries with a five-year design life. Significant savings can be achieved over the previous situation where the existing alkaline batteries were maintained at a high per unit cost. Replacement lead-acid batteries can be purchased for a fraction of the previous cost.

Our budgeted replacement costs are shown in section 9.1.11—Replacement budgets—Switchgear (this includes all switchgear and circuit breakers). A total detailed breakdown of our replacement capex is shown in table 4.14.e.

Table 4-14e - **Circuit breakers replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Zone substations	3,525	3,080	1,980	1,815	2,550	2,175	360	2,715	1,335	1,680	**21,215**
Distribution switchgear	1,690	1,260	1,530	2,205	1,755	1,080	2,960	900	2,580	1,015	**16,975**
Total	**5,215**	**4,340**	**3,510**	**4,020**	**4,305**	**3,255**	**3,320**	**3,615**	**3,915**	**2,695**	**38,190**

Figure 4-14d **Circuit breakers—Health index**

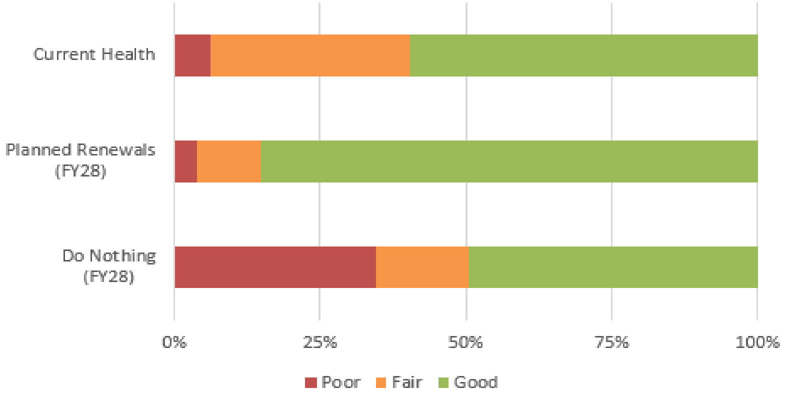


Figure 4-14d shows our current and future health index profile for planned renewals and do nothing scenarios. Our current profile is higher than our long term risk appetite, however by replacing the oil-filled circuit breakers we purchased as part of the spur asset transfer from Transpower, we will address this.

4.14.7 Creation/acquisition plan

The decision to install additional circuit breakers is generally driven by customer demand.

For a list of projects containing this asset see section 5.6 - Network development proposals.

4.14.8 Disposal plan

Circuit breakers are disposed of as part of the replacement costs.

4.15 Switchgear-high and low voltage

4.15.1 Asset description

Substation air break isolator (ABI)

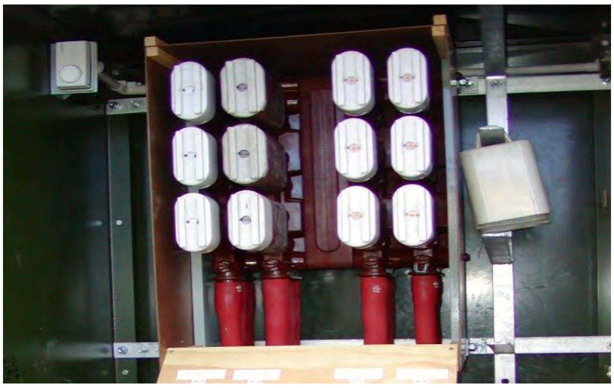
33kV and 66kV ABIs are air break switches installed in mostly outdoor bus work in zone substations. They are simple hand operated devices which are used to reconfigure the substation bus for fault restoration, or for isolating plant for maintenance . The substation 66kV and 33kV ABIs are used as isolation points in the substation structures and are mounted on support posts or hang from an overhead gantry.

Line air break isolator (ABI)

11kV and 33kV line ABIs are pole mounted in our rural overhead network.

Line switch

11kV line switches are pole mounted in our overhead network. These units are rated at 630A with a vacuum load breaking switch. They are installed to be operated on-site by hot-stick or remote operation. These switches are installed when older ABIs are due for replacement.



Magnefix ring-main unit

These switches are independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. Each phase is switched separately or three phases are operated simultaneously with a three phase bridge. These switches are the predominant type installed in our 11kV cable distribution network. They are mainly installed in distribution kiosks and as secondary switchgear in network substations. They range in configuration from a two cable unit to a five cable unit, making a total of over 13,000 individual outlets in our network.

Ring-main units (RMU)

These units are arc-contained, fully enclosed metal-clad 11kV switchgear. They combine both load-break switches and vacuum circuit breakers. With the addition of electronic protection relays they can be fully automated. They are usually installed in kiosks or as secondary switchgear in zone and network substations. They are three or four panel units.

Oil switch, fused and non-fused

These switches were installed in our 11kV cable distribution network as secondary switchgear in network and distribution building substations. They were installed before low maintenance oil-free ring-main units were proven. We no longer install these switches.

Some of the installations have locally designed bus connections that are below our current standards. Incidents and difficulties in arranging outages to carry out servicing have occurred, therefore we are gradually replacing these switches with ring-main units.

Low voltage switch

Installed generally in distribution substations, these switches form the primary connection between 11kV/400V transformers and the 400V distribution network, giving isolation points and fusing capability using high rupturing current (HRC) links. All new installations are of the DIN type (shown left).

The majority of existing older panels (approximately 3,000) are an exposed-bus (skeleton) and V-type fuse design. As accidental contact is a risk with these designs, we have a programme to replace them with the modern DIN[1] type.

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[1] DIN—a metal rail of standard type used to mount circuit breakers and control equipment of German origin.

Table 4-15a **Switchgear quantities**

Device type	Quantity
66kV Substation air break isolator	252
33kV Substation air break isolator	83
66kV Line air break isolator	0
33kV Line air break isolator	16
11kV Ring-main vacuum switch/VCB	66
11kV Magnefix ring-main unit	4,263
11kV Oil switch	55
11kV Line switch (vacuum)	72
11kV Line air break isolator	838
400V Switch	5,150

4.15.2 Asset capacity / performance

The total SAIDI and SAIFI contribution for switchgear is approximately 2%. The majority of the failures are air break isolators followed by magnefix ring-main units.

Substation air break isolator 33/66kV

Air break isolators or disconnectors are mechanical devices used to isolate primary equipment. Some disconnectors acquired in the spur asset transfer are experiencing performance issues due to mis-alignment, we are addressing this issue in our maintenance and replacement programmes. The 33kV ABIs performance level has been satisfactory with two failures over the last 10 years.

Line air break isolator (ABI)

A standard existing ABI installed on our rural network (33 and 11kV) is rated at 400A. Load-breaks have been installed on a number of isolators in key locations to increase the current rating to 600A. All newer ABIs are 600A with load-break. The substation ABIs are unable to break circuit load current.

The average number of 11kV ABI failures have slightly increased over the last 10 years. A recent reliability analysis has identified a specific ABI model reporting a high failure rate due to insulator cracking failure that will become worse with more use over time. A replacement program has been put in place for these units to be replaced over the next four years.

Figure 4-15a **11kV ABI– number of failures**

Line switch (LSW)

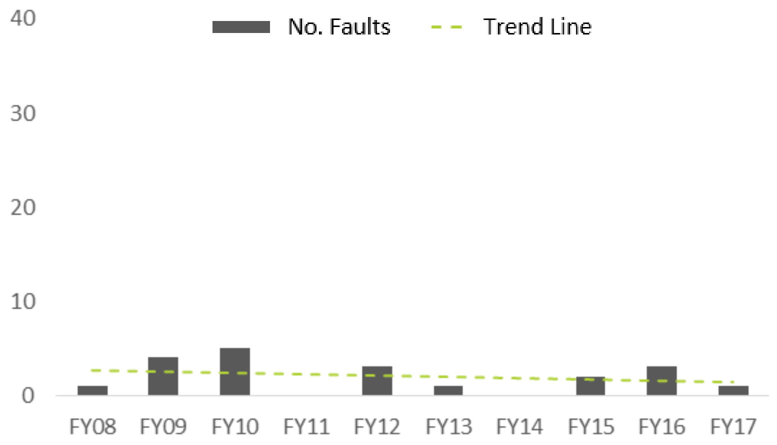
Line switches installed on the network are rated at 630A continuous, 20kA fault. These switches are new to our network and have not had any defects or failures to date.

Magnefix ring-main unit (MSU)

An MSU is a manually operated quick-make, quick-break switch design rated at 400A. Any failure is usually due to secondary factors such as a cable termination failure. These units are ageing but have performed reliably.

On average there has been two failures per year. The failure rate has decreased slightly in recent years. Reasons for failure are due to corrosion and faulty contacts.

Figure 4-15b **Magnefix - number of failures**



Ring-main unit

These units combine both 630A load-break switches and 400A or 200A vacuum circuit breakers. Any failures in these units are usually due to secondary factors such as cable terminations.

Oil switch

Oil switches are manually operated. They have caused some problems periodically due to oil leaks and jammed operating mechanisms.

Any failures in these units are usually due to secondary factors such as cable terminations. We are aware that oil switchgear has the potential to fail catastrophically as highlighted in a number of incidents in Australia and New Zealand.

Low voltage switch

The standard rating of the low voltage DIN switches is 630A, with panel busbar ratings of 800A or 1500A installed to meet distribution substation and feeder capacities.

The older ‘skeleton’ type panels and switches have good electrical performance, however, the exposed busbars create safety risks.

Some issues have become apparent with DIN type switches. These have generally been related to overheating created by the quality of connection and installation. Overheating is a more significant issue for DIN switches than for other switches, due to their enclosed construction.

4.15.3 Asset condition

33/66kV Substation air break isolator

Around 30% of the disconnectors acquired from Transpower have currently exceeded their normal life expectancy and approximately 30% will reach their end-of-life with the AHI in the next ten years.

Line air break isolator (ABI)

The condition of our line ABIs on the network is good. However, the older types are reaching the end of their economic life.

Line switch (LSW)

These switches are new to our network and their condition is good.

Magnefix ring-main unit

The condition of Magnefix units within the network is good.

Ring-main unit

The condition of the ring-main units within the network is very good.

Oil switch

Oil switches are maintained in good operational condition. Any with problematic operating mechanisms can be replaced with a ring -main unit.

Low voltage switch

The low voltage panels and switches are generally in good condition.

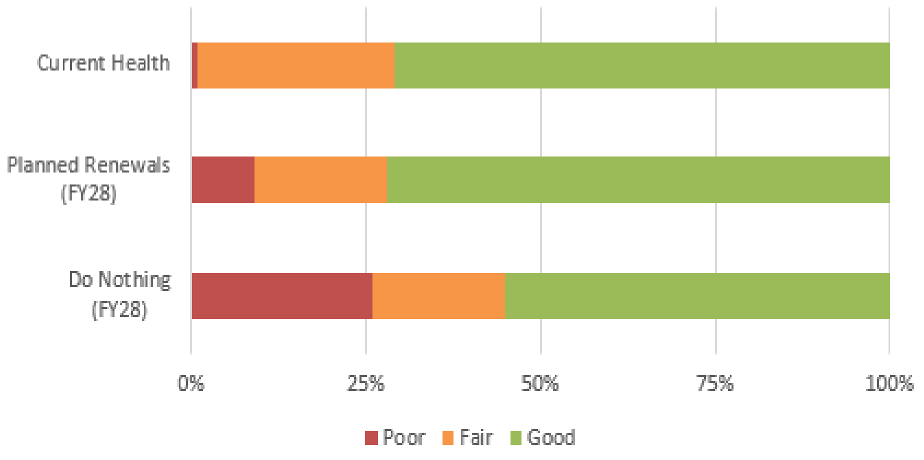
CBRM model

We use a condition based risk management (CBRM) model developed by EA Technology Ltd for our HV and LV switchgear. This model utilises asset information, engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the health index and probability of failure of each individual switch. This effectively gives the switchgear a ranking which is used when determining the replacement strategy. Note that while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

The results of this process have shown that the overall condition of our switchgear is very good and we are on target with our replacement programme. Figure 4-15c shows the health index profile of our switchgear assets.

Figure 4-15c **Total switchgear 11kV - health index profile**



4.15.4 Standards and asset data

Asset management report:

- NW70.00.24 - Switchgear HV and LV.

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.51.01 - Overhead line design
- NW70.52.01 - Underground cable design
- NW70.53.01 – Substation design
- NW70.57.01 – Protection design
- NW70.59.01 – Earthing design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.21.04 – 11kV Air break isolator maintenance
- NW72.23.04 — Network substation inspection
- NW72.23.06 — Network substation maintenance.

We have developed operator instructions for each of the different types and models of switchgear installed in our network.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type
- serial numbers (except for older ABIs)
- age (estimated for older ABIs)
- test results
- movement history (except for ABIs).

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.15.5 Maintenance plan

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Switchgear (this includes switchgear and circuit breakers). Our switchgear maintenance is captured in Figure 4.14d Circuit breakers as this aligns with how we manage the contract.

Line air break isolator (ABI)

A check on the operation of standard ABIs is included when a line retighten contract is carried out. Other maintenance work is on an as-required basis.

Line switch (LSW)

Maintenance of line switches is undertaken when a pole inspection or line retighten contract is carried out. Other maintenance work is on an as-required basis.

Magnefix ring-main unit (MSU)

11kV Magnefix switch units are virtually maintenance free, with the exception of minor dusting from time-to-time. The exceptions are those units in close proximity to the sea. They are maintained every four years.

Ring-main unit

11kV ring-main units are virtually maintenance free, with the exception of minor dusting from time-to-time. The exceptions are those units in close proximity to the sea. They are maintained every four years.

Oil switch

Oil switches in indoor situations are maintained as part of the programme of work (four or eight yearly) for the substation in which they are installed.

Low voltage switchgear

We have an inspection regime for panels and switches. Substation low voltage panels are inspected every six months. Other switches are inspected on a five yearly basis. We are over halfway through a four-year programme to install safety screens over the exposed live busbars and switches.

Table 4-15b - Switchgear opex (real) - $,000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	180	180	180	180	180	180	180	180	180	180	**1,800**
Routine and corrective maintenance and inspections	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	1,070	**10,700**
Total	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**12,500**

4.15.6 Replacement plan

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Switchgear (this includes switchgear and circuit breakers). A total detailed breakdown of replacement is shown in table 4.15c.

Substation air break isolator 33/66kV

We have an ongoing replacement programme for replacing the substation air break isolator based on their condition and criticality.

Line air break isolator (ABI)

A programme to replace older 11kV ABIs (specifically types having a high failure rate due to insulators cracking) will run through to FY22. They are being replaced by line switches as mentioned previously. They do not have operating handles and are instead operated locally by a hot-stick or remotely if so equipped.

Line switch (LSW)

These switches are new to our network and there are no plans to replace any to date. These switches are being installed as a replacement for older ABIs.

Magnefix ring-main unit (MSU)

These units have the biggest impact on the condition profiles shown in figure 4-15c, given the size of the population. We have an ongoing replacement programme for Magnefix units but it is likely that we will need to increase the rate of replacement if we are to maintain our ‘current health’ profile. More work will be done on this over the next 12 months and we will update our findings in the next AMP.

Ring-main unit

Our newer RMUs are in good condition and do not need replacing.

Oil switch

We have been proactively replacing these units and the programme is due to be completed in a few years .

Low voltage switchgear

We plan to upgrade all exposed skeleton panels with DIN type disconnects.

Table 4-15c Switchgear replacement capex (real) - $,000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Zone substation	240	750	240	240	240	210	270	150	270	270	**2,880**
Distribution switchgear	2,215	3,230	4,040	4,690	5,395	5,395	5,395	5,395	5,395	5,395	**46,545**
Total	**2,455**	**3,980**	**4,280**	**4,930**	**5,635**	**5,605**	**5,665**	**5,545**	**5,665**	**5,665**	**49,425**

4.15.7 Creation/acquisition plan

We plan to install additional switchgear during projects that improve the reliability of the network, and in works to satisfy customer demand.

4.15.8 Disposal plan

These assets are disposed of as part of replacement costs.

4.16 Power transformers and regulators

4.16.1 Asset description

Transformer

Power transformers are installed at zone substations to transform subtransmission voltages of 66 and 33kV to a distribution voltage of 11kV. The majority are fitted with on-load tapchangers and electronic management systems to maintain the required delivery voltage on the network.

The larger 40MVA transformers weigh approximately 45 tonnes. The weight of the smaller 10MVA transformers is approximately 30 tonnes. The cooling radiators can be both integral with the main tank or stand-alone.

All our transformer mounting arrangements have been upgraded to current seismic standards, and all transformers have had a bund constructed to contain any oil spill that may occur.

Table 4-16a
Power transformer quantities
(includes emergency spares)

Nameplate Rating MVA	66kV	33kV
30/60	2	
34/40	2	
30 (1Ø Banks)	7 (22)	
30/40	2	
20/40	26	
11.5/23	12	7
10/20		4
7.5/10	6	7
7.5		11
2.5		2
Totals	57	31

Table 4-16b
Regulator quantities
(includes emergency spares)

Rating MVA	11kV
20	3
4	12
1	2
0.75	2
0.65	1
Total	20

Line voltage regulator

Regulators are installed at various locations to perform two different functions:

- provide capacity (via voltage regulation) for security against the loss of a zone substation
- provide automatic voltage regulation on fixed tap transformers.

We use a wide range of ratings, from 650kVA to 20MVA, to cater for different load densities within our network. All regulators are oil filled, with automatic voltage control by an on-load tapchanger or induction. The installation designs allow for quick removal and re-installation.

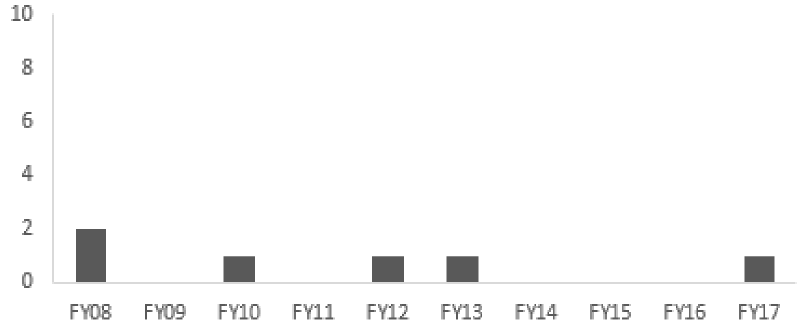
4.16.2 Asset capacity/performance

Power transformers in our network are capable of operating continuously at their rated capacity, or at a higher rating for short periods, depending on the ambient air temperature. Detailed data records of electrical loading on the transformers are compiled via the SCADA system. This data is analysed regularly.

Two distinct peak load periods affect the urban and rural networks at different times. The rural peak load occurs in summer, predominately due to irrigation. With increased development of residential subdivisions to the south and south west of the city, winter load in the rural area is increasing. However, when compared to the peak summer load, this increase is relatively low. The peak load period for the urban network occurs in winter.

We have set very high-performance standards for power transformers. This is because we design for N-1 capability in most situations and plan to attain a high level of reliability and resilience from this asset. The contribution of SAIDI from these assets is very low indicating that broadly, our current inspection, maintenance, and renewal strategies are effective. We do however continue to assess defects and failures to continually improve our maintenance practices.

Figure 4-16a **Power transformers - number of failures**



Reliability contribution is less than 1% for power transformers. On average, faults occurs once every two years, examples of failures are faulty tap changers and water ingress in the cable boxes.

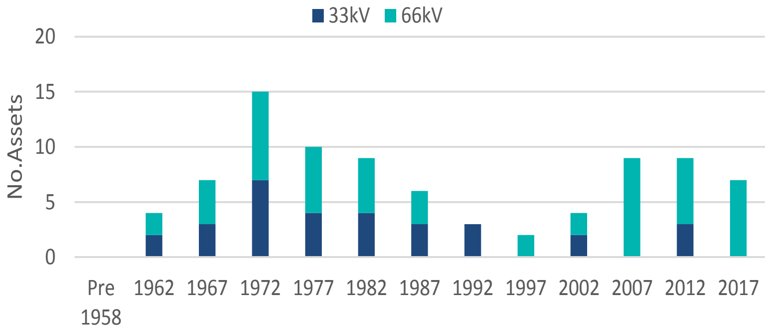
4.16.3 Asset condition

Transformers

Oil and winding insulation condition significantly impact on how a transformer performs. Through a variety of assessments, including visual inspection, insulation testing and other condition-monitoring techniques, we have determined the useful life expectancy of each transformer. The resulting CBRM health index profile for our power transformers is shown in Figure 4.16b below.

Figure 4-16b **Power transformers - age profile**

Figure 4-16c Power transformers - age profile by voltage



The health index profile shows that most assets are in good condition with health indices of less than 5.

There are a small number of assets with elevated health indices above seven. These are the ex-Transpower single phase bank transformers at Addington and Bromley substations and one transformer at Teddington. These range from 54 to 60 years of age. Our strategy to address these transformers is discussed further in section 4.16.6. There is one newer transformer (circa 2002) with a prematurely elevated health index. This is due to tap changer oil contaminating the main conservator tank. Work is planned to resolve this so we can resume reliable testing.

Voltage regulators

The three 20MVA regulators at Heathcote are an older design. The first two were refurbished before going into service with Orion and are working satisfactorily. In FY10 a third regulator was installed to provide security for the Lyttelton supply.

The condition of our other regulators is good.

4.16.4 Standards and asset data

Asset management report:

- NW70.00.23 - Power transformers.

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design
- NW70.57.01 – Protection design
- NW70.59.01 – Earthing design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.23.25 – Power transformer servicing
- NW72.23.01 – Mineral insulating oil maintenance
- NW72.23.03 – Zone substation inspection
- NW72.23.07 – Zone substation maintenance.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.07 – Major power transformer 7.5/10MVA 66/11kV
- NW74.23.15 – Voltage regulator 11kV
- NW74.23.16 – Major power transformer 11.5/23MVA 66/11kV
- NW74.23.22 – Major power transformer 2.5MVA 33/11kV
- NW74.23.24 – Major power transformer 20/40MVA 66/11kV.

Engineering drawings, as well as electrical drawings, are held for all transformers and related components.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers (transformer and tap-changer)
- age
- circuit diagrams/maintenance history
- test results/oil analysis results
- movement history.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.16.5 Maintenance plan

Our maintenance programs are based upon a combination of condition and time-based strategies. We use scheduled inspection and diagnostic tasks to assess transformer condition and identify defects for rectification. We also use time based maintenance interventions for tap changer maintenance and for some transformers oil conditioning.

Summary maintenance requirements for power transformers are shown below.

Table 4-16c - **Power transformers - Summary of maintenance requirements**

Maintenance Tasks	Strategy	Frequency
Inspection	Minor visual inspection and functionality check.	2 monthly
Shutdown service	Detailed inspection and functional check	Annually
Oil Diagnostics	DGA and oil quality tests	Annually
Oil treatment	Online oil treatment to reduce moisture levels.	2 yearly or more often as required
Tap changer maintenance	Intrusive maintenance and parts replacement as per manufacturer's instructions.	Oil - 4 yearly, Vacuum - 8 yearly
Level 1 & 2 electrical diagnostics	Polarisation index and DC insulation resistance DC Winding resistance, winding ratio test.	4 or 8 yearly

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Transformers (this includes distribution transformers). A total detailed breakdown of Opex is shown in table 4-16d.

Maintenance budgets are constant due to our practice of scheduling maintenance in a manner to level workload and costs. Our forward forecasts for emergency maintenance are also constant as we expect a broadly similar volume of defects to arise over the forecast period.

Table 4-16d - Power **transformers opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	210	210	210	210	210	210	210	210	210	210	**2,100**
Routine and corrective maintenance and inspections	415	415	415	415	415	415	415	415	415	415	**4,150**
Asset replacement and renewal	500	500	250	250	250	250	250	250	250	250	**3,000**
Total	**1,125**	**1,125**	**875**	**875**	**875**	**875**	**875**	**875**	**875**	**875**	**9,250**

Voltage regulators

Voltage regulators installed at the zone substations are included in the annual and four-yearly tap-changer maintenance programmes. The new 4MVA regulators are included in a separate section of the distribution maintenance round and are serviced on an eight-yearly cycle.

4.16.6 Replacement plan

A review of the single phase transformer banks at Addington and Bromley (recently purchased from Transpower) found that their condition does not meet our current standard. Due to their age and condition the preferred option is to replace five single -phase transformer banks with three 3 phase 20/40MVA units. This rationalisation will also include the disposal of several reactors also acquired from Transpower. We plan to carry out the work at Bromley in FY21 followed by Addington in FY24 to fit in with other works.

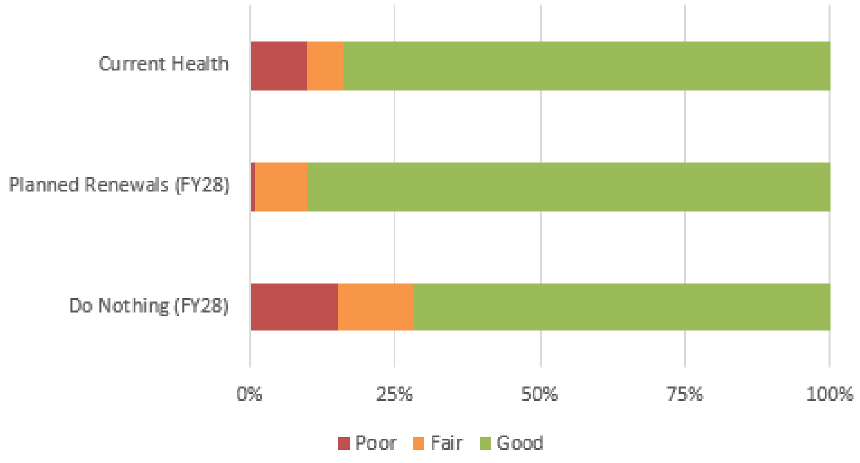
Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Transformers (this includes distribution transformers). A total detailed breakdown of Replacement is shown in table 4-16e.

Table 4-16e - **Power transformer replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Zone Substation	0	0	3,000	0	0	1,500	0	0	0	0	**4,500**
Total	**0**	**0**	**3,000**	**0**	**0**	**1,500**	**0**	**0**	**0**	**0**	**4,500**

Figure 4.16d shows the current condition and future HI profile for planned renewals and do nothing scenarios. The chart shows that the target intervention scenario improves the overall condition scores of our transformer fleet. This is largely due to the proposed retirement of the ex-Transpower single phase transformers which are nearing their end of life. Comparing with the 'do-nothing' scenario shows that the proposed program mitigates a substantial deterioration in asset condition. We consider this to be an appropriate asset fleet condition that balances asset performance and lifecycle economics.

Figure 4-16d **Power transformer - Health Index**



4.16.7 Creation/acquisition plan

Our current acquisition strategy is to procure only 3 phase transformer units, wherever practicable standardising on size and configuration to aid in future interchangeability. Where transformers could be utilised in either urban or rural configurations we specify convertible HV connections (cable box or bushings) and a reconfigurable secondary winding to provide for phase shift matching. We also specify low noise transformers to reduce environmental impact and ensure cross compatibility between urban and rural transformers.

For projects containing this asset group see section 5.6 - Network development proposals.

4.16.8 Disposal plan

The 33/11kV transformer at Springston zone substation will be removed from service and disposed as part of the larger project to install indoor 33kV switchgear.

4.17 Distribution transformers

4.17.1 Asset description

Distribution transformers are installed on our network to transform the voltage to a suitable level for customer connections. They have a ratio of 11000/400V, and range in capacity from 5kVA to 1,500kVA.

Sizes up to 200kVA can be installed in the overhead system on a single pole. The larger sizes are only ground-mounted, either outdoors or inside a building/kiosk.

Table 4-17a **Distribution transformers owned by Orion (in-service FY17)**

Rating kVA	5	7.5	10	15	25	30	50	75	100	150	200	300	500	750	1,000	1,250	1,500	**Total**
Quantity	50	270	174	1,457	340	2,046	1,193	208	727	179	1,566	1,793	899	333	210	3	15	**11,463**

Typical 300kVA transformer (Circa 1980).

4.17.2 Asset capacity / performance

Transformer utilisation is measured as the ratio of maximum demand in kVA to installed nameplate rating. For individual transformers, this ratio typically ranges from below 30% to above 130%.

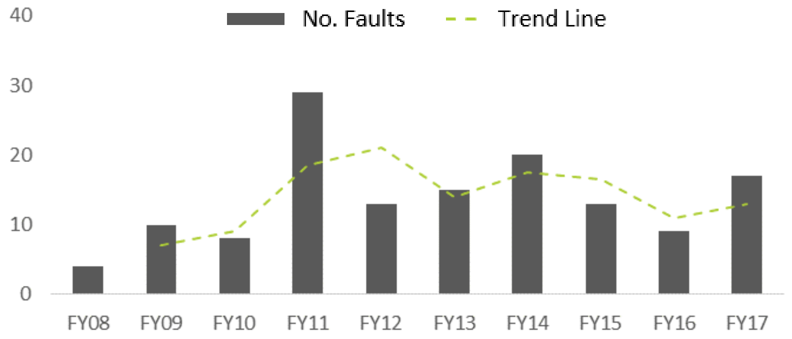
The measure of overall distribution transformer utilisation required for disclosure is the ratio of the total system demand to total distribution transformer capacity. This has fallen slowly over the last 20+ years to its present value of approximately 27.7%.

Small pole-mounted transformers usually serve only a small number of customers. Capacities are normally only reviewed when significant new load is connected. Utilisation factors are typically low.

Larger transformers are fitted with thermal maximum-demand meters which are read twice-yearly. Measured utilisation factors range up to about 140%. For typical cyclic loads, we have determined that maximum demands of about 130% of rated continuous ratings are acceptable, before upgrading action is required.

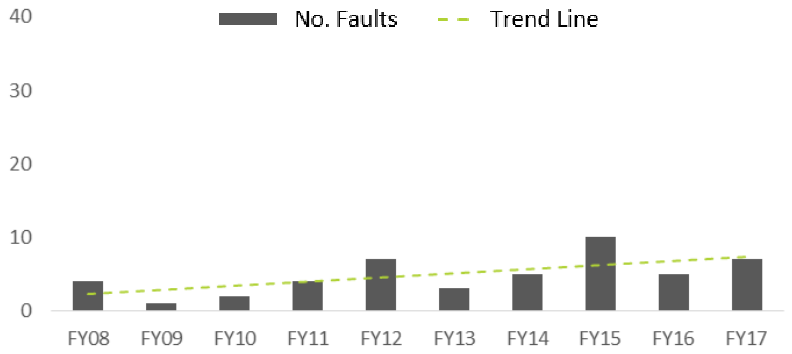
When distribution transformer maximum demand exceeds 130% of nameplate rating, a larger transformer is installed or load transferred to another substation if available. Where substation utilisation is low (<50% with no load growth predicted), the transformer will be changed or removed when this can be economically justified.

Figure 4-17a **Distribution transformers (pole) - number of faults**



Distribution transformer failures contribute 1% of SAIDI and SAIFI. Pole mount transformer failure can occur during any stage of their lifecycle and is impacted by the outdoor environment they reside in.

Figure 4-17b **Distribution transformers (ground) - number of faults**



On average there have been five ground-mounted transformer failures per year since FY08. The majority of the failures occurred in the later stage of their lifecycle.

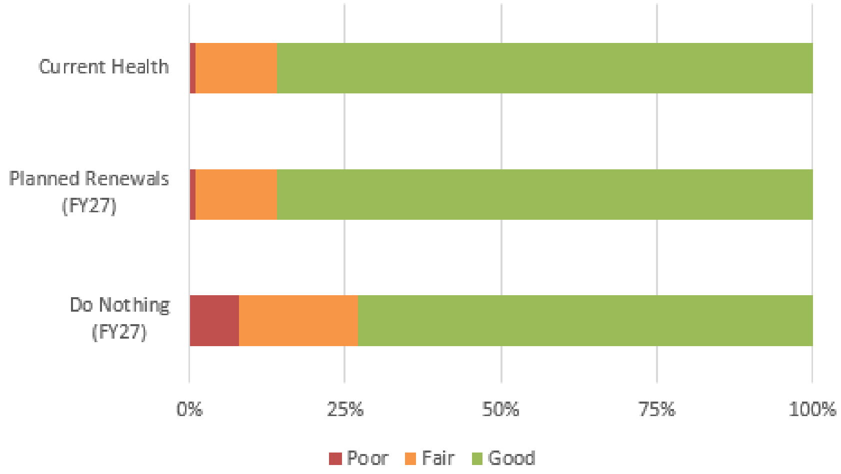
4.17.3 Asset condition

Our larger ground-mounted distribution transformers are in good condition and are inspected on site every six months. The condition of the pole-mounted transformers varies depending on their age and location. They are only maintained, if this is considered appropriate, when removed from service for other reasons.

There are five single-phase banks of transformers over 50 years of age. Manufactured between 1937 and 1950, they have iron losses that are four to six times; and copper losses that are two to three times that of a modern transformer. Most have a high oil acidity, indicating that they are nearing the end of their lives.

Figure 4-17c **Distribution transformers (all) - age/health profile**

Figure 4-17d **Distribution transformers (all) - Health Index**



4.17.4 Standards and asset data

Asset management report:

- NW70.00.40. - Distribution transformers.

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.23.16 – Transformer installation
- NW72.23.02 – Transformer maintenance (distribution).

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.05 – Transformer - distribution 200-1000kVA.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers
- age and rating
- test results
- movement and maintenance history
- maximum demand load records.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

The actual substation location is unknown for some 500 transformers, although this number is steadily reducing as works are undertaken that identify specific transformers.

4.17.5 Maintenance plan

With the exception of the network substation transformers, distribution transformers are normally maintained when they are removed from the network for loading reasons or substation works. Their condition is then assessed on a lifecycle costs basis and we decide, prior to any maintenance, whether it would be more economic to replace them. If we decide to maintain them they will be improved to a state where it can be expected the transformer will give at least another 15 to 20 years service without maintenance.

Some on-site maintenance is carried out on transformers which are readily accessible from the ground. This work mainly relates to those within building substations that require maintenance as identified during inspection programmes.

Remaining single-phase transformer banks are to receive minimal maintenance to extend their usable life until replaced.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Transformers (this includes power transformers). A total detailed breakdown of opex is shown in table 4.17b.

Table 4-17b **Transformer opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Routine and corrective maintenance and inspections	260	260	260	260	260	260	260	260	260	260	**2,600**
Total	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**2,600**

Note: Costs for service interruptions and emergencies are captured in 4.16.5 Power Transformers.

4.17.6 Replacement plan

Transformers taken out of the network due to capacity changes or faults are replaced where repair or maintenance proves uneconomic. An allowance has been made in the replacement budget to cover this.

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Transformers (this includes power transformers). A total detailed breakdown of Replacement is shown in table 4.17c.

Table 4-17c **Transformer replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Distribution substations and transformers	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	**30,700**
Total	**3,070**	**3,070**	**3,070**	**3,070**	**3,070**	**3,070**	**3,070**	**3,070**	**3,070**	**3,070**	**30,700**

4.17.7 Creation/acquisition plan

For a list of projects that contain this asset group see section 5.6 - Network development proposals.

4.17.8 Disposal plan

We dispose of transformers when they reach the end of their economic life, as detailed in the maintenance plan.

4.18 Generators

4.18.1 Asset description

Diesel generators provide a mobile source of energy to enable us to keep the power on or provide power quickly in the short term until our network is able to be restored. We have various generators which are used for different applications; mobile truck-based for use during planned work and faults, fixed for load lopping and mains failure and skid-mounted for isolated emergency response.

We have 14 medium to large diesel generators of which six are 550kVA generators that can be strategically placed throughout our urban network. They are used for emergency backup and can be switched on-line in a short time frame if there is a loss of supply. Three of them have synchronisation gear fitted.

Along with these generators we also have three truck mounted units of 330, 400 and 440kVA (mobile) and one 110kVA trailer mounted generator, which are used to restore supply at a distribution level during a fault or planned work. All are fitted with synchronisation gear, voltage kW support and reverse sync. Two have soft black start excitation. We have a further 550kVA unit attached to our main office building with synchronisation gear, two 2,500kVA 11kV generators with synchronisation gear and a 30kVA without synchronisation gear. We have recently relocated two 2,500kVA that were installed at QEII to Lyttelton.

To maintain a fuel supply for the generators we own six diesel tanks, with capacities ranging from 2,900 to 16,155 litres, and a 1,500 litre trailer mounted tank. All the diesel tanks are new and are bunded or double skinned.

Table 4-18a **Generator listing**

Description	Generator kVA	Generator kW
Mobile (truck-mounted)	440	352
Mobile (truck-mounted)	400	320
Mobile (truck-mounted)	330	264
Mobile (trailer-mounted)	110	88
Transportable (400V)	550 x 2	440 x 2
Highfield (400V)	550 x 2	440 x 2
Lyttelton (11,000V)	2,500 x 2	2000 x 2
Wairakei Rd administration building	550	440
Waterloo Connetics	550	440
Armagh	30	24
Transportable data centre (remote)	110	88
Total generating capacity	**9,720**	**7,776**

4.18.2 Asset capacity/performance

All generators are operated within their nameplate ratings.

A number of our generators were used to supply electricity to the worst affected areas in the eastern suburbs immediately after the February 2011 earthquake. These units were run continuously until our network was repaired. During this time they performed well.

4.18.3 Asset condition

All generators are checked, tested and maintained.

Most of our generator fleet is relatively new. Because they need to be ready for emergency use they are tested and maintained on a regular basis.

4.18.4 Standards and asset data

Asset management report:

- NW70.00.39 - Generators.

Operator instructions:

- NW72.13.97 – Standby generator truck – 330kVA
- NW72.13.98 – Standby generator truck – 440kVA
- NW72.13.109 – Standby generator truck – 400kVA
- NW72.13.113 – Static generator set - 2,500kVA
- NW72.13.114 – Standby generator trailer – 110kVA
- NW72.13.115 – Building generator – 550kVA.

4.18.5 Maintenance plan

These units are maintained as part of a service agreement with the suppliers.

Maintenance includes:

- inspection before use
- monthly testing
- service checks every six months
- fully serviced at 250 or 500 hour intervals depending on the engine.

Table 4-18b shows that our forecast expenditure for our generator fleet is quite flat. We are not anticipating any step changes within the disclosure period.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Generators (fixed)

Table 4-18b **Generators opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Service interruptions and emergencies	10	10	10	10	10	10	10	10	10	10	**100**
Routine and corrective maintenance and inspections	50	50	50	50	50	50	50	50	50	50	**500**
Asset replacement and renewal	0	0	0	0	0	0	0	0	0	0	**0**
Total	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**600**

4.18.6 Replacement plan

There is no renewal plan for the generator fleet. When a generator gets to the end of its economic life an analysis will be done to see if it will be replaced.

4.18.7 Creation/acquisition plan

Generators will be purchased when a need has been identified. Currently there are no plans to purchase any new generators.

4.18.8 Disposal plan

These assets are disposed of by auction when they become surplus to our requirements or they become uneconomic to operate. As seismic activity lessens, the level of risk to our network will reduce. Therefore we will continue to review our needs for the generator fleet. We have sold 5 x 550kVA units and one 375kVA truck mounted unit in FY18. We have a mutual aid agreement with the purchaser of the 550kVA units that allows us to borrow them if required.

4.19 Protection systems

4.19.1 Asset description

Protection systems are installed to provide automatic control to elements of the network and to protect the network during power system faults. These systems protect all levels of the network including the low voltage system where fuses are used.

Historically, substation protection, control and metering functions were performed with electro-mechanical equipment. This electro-mechanical equipment has been superseded firstly by analogue electronic equipment, most of which emulates the single-function approach of their predecessors and more recently, by digital electronic equipment that typically provides protection, control and metering functions integrated into a single device. The functions performed by these micro-processor based devices are so wide they have been labelled Intelligent Electronic Devices (IED).

Along with IEDs the introduction of Merging Units (Bricks) has created a paradigm shift in protection system architecture. Traditionally a dedicated protection relay, ancillary equipment and multi-core copper cabling were required for each scheme. IED’s have reduced the amount of hardware mounted on control panels but hard wired copper connections are still required between the primary plant, protection relays and station Remote Terminal Unit (RTU). This copper cabling between the primary plant and merging relay, is now replaced by fibre optic cables with the addition of merging units.

The introduction of IEDs has allowed Orion to reduce costs by improving personnel productivity and increasing system reliability and efficiency. The introduction of remote I/O reduces labour requirements, engineering design, installation and commissioning. Operation of the system is based on existing skill sets and does not require any significant changes in the organisation. With the introduction of IEDs and Bricks the skill set requirements of protection technician has also changed. Technicians must now be proficient with computer software/firmware and network systems.

Relay setting data is now held in a proprietary settings database (StationWare). This system provides a data-warehouse to store settings. Ongoing work is required to review settings as the network architecture changes with growth and alterations.

Table 4-19a **Relay types in Orion’s network**

Relay type	Number in network as % of total relays	Average age (years)
Electro-mechanical	45	31
Analogue electronic (first generation IED)	5	14
Micro-processor based (second generation IED)	50	9

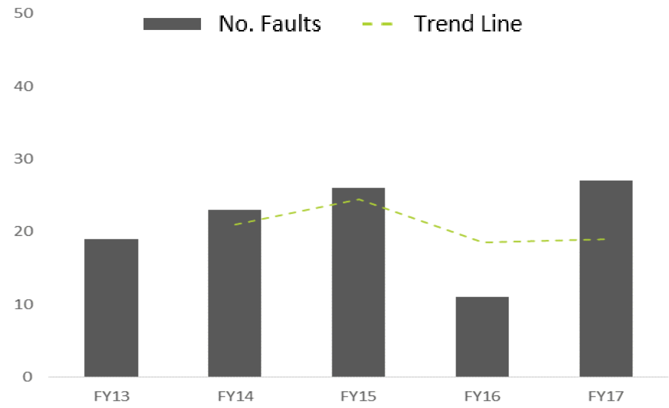
4.19.2 Asset capacity/performance

The protection system has proven to be robust and performs well. The robustness can be attributed to planned maintenance and targeted replacement along with the introduction of modern technology using simplified design to avoid “traps” which can lead to human-error incidents. Protection schemes are designed to provide the required performance with as little complexity as possible. To improve performance, older electro-mechanical and analogue electronic devices have been replaced over time. Monitoring and remote access to many IEDs has reduced site visits and improved integrity.

Early bus-zone protection schemes, core-balance and fast-bus-blocking have proven to be problematic due to complexity and difficulty to test to ensure correct generation. Some of those schemes have now been replaced and we have a programme in place to replace the rest.

Protection contributes to less than 1% of the network reliability. There has been an average of twenty defects per year in recent years and out of those , three resulted in an outage. Examples of defects are loose termination, wiring or intermittent relay faults.

Figure 4-19a **Protection systems - number of relay defects**



4.19.3 Asset condition

Our protection system plays an integral part in the provision of a safe and reliable network. As a result it is imperative that it is maintained in good condition.

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our protection relays. Prior to the introduction of the CBRM model all of our protection systems were reviewed against a number of performance criteria – failure rates, post-event diagnostic capability, manufacturer support, network suitability and age. A ranking system was created to help identify any relay types that may cause us issues. These criteria are now embedded in the data used in the CBRM model and we can now calculate a health index for individual relays rather than a generic score for relay types. The following graph shows the health index profile against age profile of our protection assets.

Figure 4-19b **Protection systems - health index profile**

4.19.4 Standards and asset data

Asset management report for this asset:

- NW70.00.22 - Protection systems.

Design standards developed and in use for this asset are:

- NW70.53.01 - Substation design
- NW70.57.01 - Protection design
- NW70.57.02 - Subtransmission protection design
- NW70.57.03 - Distribution feeder and transformer protection.

Technical specifications covering the construction and ongoing maintenance of this asset are:

- NW72.27.01 - Unit protection maintenance
- NW72.27.02 - Protection
- NW72.27.04 - Testing and commissioning of secondary equipment.

We use operator instructions developed in-house for electronic relays installed in our network.

Asset data

Data currently held in our information systems for this asset group includes:

- location (asset register)
- type and serial numbers
- age
- setting configuration
- test results
- relay movement history.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All these inspections are used to further our knowledge of the asset condition .

We keep details of all relays and their current location in our network asset register. A specialised protection database manages relay firmware and settings.

Details of the on-site installations are shown on our schematic diagrams of the substation equipment.

4.19.5 Maintenance plan

Protection systems are checked for calibration and operation as part of the substation maintenance rounds. Results are recorded and minor adjustments made if necessary. Major faults result in the system being removed from service and overhauled.

The GFNs are maintained as part of the substation maintenance rounds.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Protection. A total detailed breakdown of opex is shown in table 4.19b.

Table 4-19b Protection opex (real) - $,000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	260	260	260	260	260	260	260	260	260	260	**2,600**
Routine and corrective maintenance and inspections	510	510	510	510	510	510	510	510	510	510	**5,100**
Total	770	770	770	770	770	770	770	770	770	770	7,700

4.19.6 Replacement plan

Traditionally our protection replacement programme has been directly linked to the replacement of switchgear. Usually both asset groups were installed at the same time and had similar lifecycles. On some occasions a protection system will be upgraded due to the performance requirements of the network. With the introduction of the electronic relays (both analogue and micro-processor based) synchronisation of the lifecycles with switchgear is no longer aligned.

Protection systems with known performance issues are given a higher priority for replacement. Prior to the CBRM model being available we relied on the ranking system we developed in FY09.

We now use a combination of the CBRM model and other factors such as the upgrading/replacement of substation primary equipment or changes in the requirements of the local network to develop the protection relay replacement programme.

We will refine this process on an annual basis as we move from primarily time based replacement to one based on condition assessment and risk analysis.

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Protection. A total detailed breakdown of replacement is shown in table 4.19c.

The bulk of relay replacements still come from the switchgear replacement programme. However due to the second generation relays only having a lifecycle of 15-20 years, these relays need to be replaced more frequently in order to maintain the current health index. Earlier bus zone protection schemes, core balance and fast-bus blocking schemes have proven problematic due to complexity and difficulty in ensuring correct operation . Some of these schemes have been replaced and we have a programme in place to replace the rest.

Table 4-19c Protection replacement capex (real) - $,000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Zone substation	0	0	0	0	0	0	0	0	0	0	**0**
Distribution substation and transformer	0	0	0	0	0	0	0	0	0	0	**0**
Other network assets	2,405	2,165	2,870	3,055	3,005	2,690	3,045	2,720	3,135	2,650	**27,740**
Total	2,405	2,165	2,870	3,055	3,005	2,690	3,045	2,720	3,135	2,650	27,740

4.19.7 Creation/acquisition plan

The replacement plan and upcoming major projects determine the acquisition plan for our protection systems. For projects containing this asset group see section 5.6 - Network development proposals.

4.19.8 Disposal plan

We dispose of equipment as part of the replacement programme.

4.20 Communication systems

4.20.1 Asset description

Communication systems provide an essential ancillary service assisting with the operation of our distribution network. These systems provide both voice and data communication and allow contact with operating staff and contractors in the field, and remote indication and control of network equipment. They allow the network to be operated more efficiently with a reduced number of staff while minimising the effect of faults on customers.

4.20.2 Voice communication systems

VHF Analogue Radio

Voice radio is provided by a number of linked VHF hilltop radio repeaters. Six linked repeaters provide coverage to the greater Christchurch and surrounding rural areas of Akaroa, Banks Peninsula and upper Rakaia river areas. And a solar powered repeater provides coverage in the Arthur’s Pass area. Linking and unlinking is controlled from our control centre.

Use of the Public Cellular Networks

We make extensive use of public cellular telecommunications systems for day to day communications with staff. Orion uses both voice and data to our staff mobile phones. Cellular data is specifically used for communications to our field staff, both hand held devices and their vehicles. Cellular data is used to communicate to low priority data devices monitoring or controlling the power network.

Private Telephone Switch

This telephone switch is set up as a high availability configuration with services duplicated at two locations with the exception of voice recording and contact centre which run in a virtual environment from either location. Connections to the Telco networks are provisioned to both locations, the system can operate with a failure of either location without loss of functionality.

Figure 4-20a Radio communication network repeater sites

4.20.3 Data communication systems

SCADA Analogue UHF Radio

The SCADA analogue UHF radio system consists of two dedicated UHF repeaters sited at Roundtop and Sugarloaf, utilising licensed frequencies. The number and location of these repeaters is dictated by their coverage and the number of devices (mainly line circuit breakers) they need to communicate with. Communication from the SCADA master station to the repeaters/substations is by UHF radio.

SCADA Analogue Communication Network

Analogue modem communication with serial communications is used to RTUs in a small number of locations; data rates are typically 9.6Kbs. These modems are typically installed in dedicated pairs with one modem at the remote site connected to an RTU and its pair at a zone substation connected to the IP network via a terminal server.

SCADA and Engineering IP Network

This network provides IP based communication to all zone substations and increasing numbers of pole-top equipment sites. The system utilises a combination of Symmetric High Speed Subscriber Line (SHDSL) modems running over Orion copper communications cables, UHF IP radio and Orion fibre optic cables. The network is configured in a combination of rings and mesh topology to provide redundant paths to most zone substations.

UHF IP and Protection Signalling Radio System Utilising 64kbs and higher data speeds

The UHF IP radios use high spectral efficiency radios operating in licensed UHF bands. The radios can be used for IP traffic only in point to point or point to multipoint modes with base stations located at hilltop sites. In point to point mode the bandwidth can be shared between protection signalling and IP traffic.

Point to multipoint base stations have been established at a number of locations covering the Canterbury Plains, Banks Peninsula and the Waimakariri basin.

SHDSL IP System

Where copper communication cables are available, which is generally in the urban area, IP communications have been provided using SHDSL modems providing point-to-point IP links between substations, typically running at 1 Mb/s. The various urban links are arranged in four rings to provide full communications redundancy to each substation. This equipment is fully protected against Earth Potential Rise (EPR) voltages.

Cellular IP Systems

There are a number of 11kV regulators, diesel generators and various power quality monitors which are served by public cellular communications.

All mobile PDA devices, and data connectivity to vehicles is also provided by the public networks.

Fibre Communications Systems

To provide reliable protection signalling, we lay fibre communications ducts/cables with all new sub-transmission cables. These fibre routes also provide high speed IP communications paths serving the SCADA and engineering IP network as well as Corporate Communications requirements. We have an agreement with Transpower to share their fibre ducts between Papanui, Wairakei Rd, Hawthornden, Islington, Middleton and Addington with our own ducts from Islington to the Connetics Waterloo Park site.

4.20.4 Asset capacity/performance

As electronic control and monitoring equipment, installed in substations, has evolved to IP communications so have our communications to those locations. These provide both SCADA and engineering access over a common communications system. We provide a minimum of 64Kbs to substations and up to 64Kbs to smaller locations.

4.20.5 Asset condition

Any older hardware (typically radio hardware) that fails will be replaced by our modern IP equipment. Currently the new IP based equipment is on average no older than eight years and is in good condition.

Any technologies that are nearing end of life have replacement strategies prepared and ready to be implemented.

4.20.6 Standards and asset data

Asset management report:
- NW70.00.34 - Communication systems.

All radio equipment is licensed and complies with the relevant regulations imposed by the Ministry of Business Innovation and

Employment Radio Spectrum.

All telephone voice communications equipment complies with the standards imposed by the public telecommunications network operators in New Zealand.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GPS)
- age
- circuit diagrams.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All these inspections are used to further our knowledge of the asset condition.

4.20.7 Maintenance plan

The performance of our UHF stations used to communicate with the SCADA equipment is continually monitored.

We have maintenance contracts with several service providers to provide on-going support and fault resolution. A maintenance contract for the telephone switch is in place. Maintenance is carried out on a monthly basis. SHDSL modems, IP radios and other communications equipment are monitored with maintenance scheduled when needed.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Communication systems. A total detailed breakdown of opex is shown in table 4.20a.

Table 4-20a Communication systems opex (real) - $,000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	85	85	85	85	85	85	85	85	85	85	**850**
Routine and corrective maintenance and inspections	560	630	560	560	560	560	560	560	560	560	**5,670**
Total	**645**	**715**	**645**	**645**	**645**	**645**	**645**	**645**	**645**	**645**	**6,520**

4.20.8 Replacement plan

Because of the rapid improvement in technology, communications equipment has a relatively short life and thus equipment is not normally renewed but is replaced with more modern technologies as part of the Creation/Acquisition Plan.

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Communication systems. A total detailed breakdown of replacement is shown in table 4.20b.

Table 4-20b Communication systems replacement capex (real) - $,000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Zone substations	50	50	50	50	50	50	0	0	0	0	**300**
Other network assets	920	1,050	355	265	265	265	265	265	265	265	**4,180**
Total	**970**	**1,100**	**405**	**315**	**315**	**315**	**265**	**265**	**265**	**265**	**4,480**

4.20.9 Creation/acquisition plan

Completion of IP Network

The IP network is continually evolving. Older analogue links that are still in place will be progressively upgraded, generally when the associated network primary equipment (LCBs, switches etc.) are replaced.

As part of the installation of improved protection on the Banks Peninsula 33kV ring, additional IP radios have been installed which provide alternative communications links to the peninsula. Another link path via Birdlings Flat is being constructed.

Site Site Exit

The old data centre at our Armagh site is being decommissioned with core SCADA communications equipment being relocated to Addington zone substation.

Mobile and future 'Smart Grid' communications

Mobile data communication is currently provided using public cellular networks.

The SCADA and engineering communication systems that we have installed are suitable (possibly with the addition of more base stations) for up to the low hundreds of remote stations. So called 'smart grid' technologies will require some 1000s of remote stations which is beyond the capability of our existing infrastructure. This capability could be provided using public cellular technologies.

Experience during major events e.g. earthquakes, snowstorms etc., is that public cellular communication networks are frequently not reliable just when good communication is most essential. In addition cellular coverage for mobile data communication can be problematic in rural areas.

Technology is available to provide these communication services in-house but currently radio spectrum is not available. We are watching the allocation of spectrum for broadband services for Public Protection Disaster Recovery (PPDR) and Critical Infrastructure Operators. In an ideal situation a wide area private broadband network would reduce our reliance on public cellular providers. In the meantime we will continue to use public cellular networks for mobile data communication and 'smart grid' trials can progress using public cellular networks. We are continuously watching other emerging technologies that may support these devices/services with the intention of building a private network in the future.

Voice radios

We intend to retain basic voice radio communications and specifically not migrate to managed protocol technologies. We view our voice radio network as our "belts and braces" simple but reliable communications and always available as a backstop. Any future migration to digital technologies will be at a Tier 2 network.

Springston substation

A major rearrangement and replacement of the Springston Substation communications systems is due to take place in conjunction with the replacement of the 33 kV switchgear during FY19.

Hill Top radio facility

This facility comprises a non-guyed old wooden antenna pole and concrete block equipment building. With the expansion of both UHF radio protection linking and additional UHF Power-On communications requirements the facility is no longer fit for purpose. A replacement self-supported support structure with antenna expansion capability and weather tight equipment housing structure will be required. The work for this upgrade is due to start in FY19.

Fibre communication links

A fibre link is planned to be installed between Islington and Shands Road zone substation to support signalling for the protection upgrade on the Islington/Springston 66kV lines.

Improved external IP network security

The external IP network uses industry standard protocols and equipment and as such is exposed to cyber security threats. An industry standard centralised security access system has been installed during FY17 to control and log all access to the external IP network.

SCADA radios

The roll out or our UHF IP radio system is on-going and new radios and sites will continue to be installed until those portions of the network working on the old system have been converted. The acquisition plan has a direct correlation to the replacement plan.

4.20.10 Disposal plan

All electronic equipment is disposed of in accordance with current environmental recommendations.

4.21 Load management systems

4.21.1 Asset description

Our load management consists of two separate systems. One is used to control loads on the network—Loadman system. The second system is independent and interfaces to our Loadman system and also seven other networks (Alpine Energy, Buller Network, Ashburton, ElectroNet, MainPower, Marlborough Lines and Network Tasman) that make-up the Upper South Island (USI) load management group to coordinate the overall USI load—USI system.

Both systems exist primarily to defer or reduce energy consumption to minimise peak load using customer demand management response through load reduction and/or generation and distributor controlled load management through hot-water cylinder and interruptible irrigation control. Other uses are for distribution network and grid load management in contingent situations.

The load management system signals to customer premises by injecting an audio frequency signal into the power network that is acted upon by relays installed at the customer's connection point. There are two ripple carrier frequencies used on our system. The ripple relays are owned by the retail traders, with the exception of some 2,000 used for streetlight control. These relays are owned by us.

The load management system comprises of an USI master station, Loadman master station, and associated Loadman RTUs at each point-of-supply.

There are dedicated user human-machine-interface clients for the control and display of the load management systems, but these are general purpose desktop PCs so are not categorised as Load Management System assets.

Load management master station and RTUs

The load management master station is a SCADA system that runs independently of the network operational SCADA system. The master station consists of two redundant database servers and two communication line servers (CLS) on dedicated hardware. The load management software utilises algorithms specifically developed for Orion.

Loading information for the system is derived from RTUs located at the GXPs and zone substations. Sources of information and communication paths are duplicated where reasonably feasible.

Upper South Island load management system (USI)

The Upper South Island load management system is a dedicated SCADA system that runs independently of our load management and network operational SCADA systems. The system consists of two redundant servers that take information from Orion, Transpower and seven other Upper South Island distributors' SCADA systems, monitors the total Upper South Island system load (retrieved from Transpower) and sends commands to the various distributors' ripple control systems (including ours) to control this total load to a predefined target.

Ripple injection system - Telenerg 175 Hz

This system operates within the urban 33kV and 66kV subtransmission network and is the major ripple injecting system controlling the load of approximately 160,000 customers. It is made up of more than 25 small injection plants connected via circuit breakers to the 11kV network at individual 66/11kV zone substations and Christchurch urban 33/11kV zone substations.

These plants can operate independently with all fixed-time signaling carried out from a timetable stored in the individual plant controller. All 'anytime' signaling is controlled by the SCADA system via individual controllers in response to commands from the load management system running on the master station.

The plants are relatively small and, apart from the coupling cell itself, consist of 19" rack mounting equipment for which spares are held. A complete coupling cell is also kept as a spare. It is possible in an emergency for a single plant to signal an adjacent area.

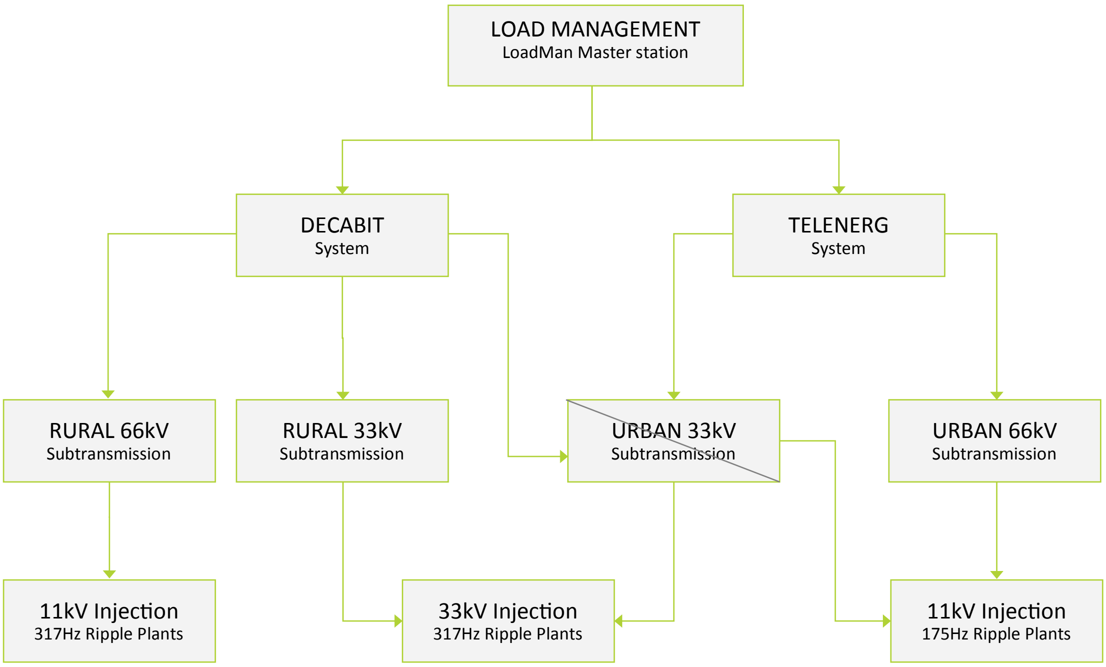
Two 66kV coupling cells act as 175Hz wave traps to absorb any signal from the 11kV plants propagating beyond the intended control areas. These coupling cells are static plants and have no controller RTU. They are installed at our Papanui and Heathcote zone substations. There is currently a review underway to see if these coupling cells are still required.

Ripple injection system - Zellweger Decabit 317Hz

The Decabit system operates within the 33kV subtransmission network and is made up of five plants connected to the 33kV system, via air break isolators and protected by circuit breakers, at Springston (two plants), Moffett, Hornby and Hororata zone substations. Back-up for the injection plants themselves is provided by pairs of plants in each 33kV supply area. Two plants are installed at Springston and the plants at Hornby and Moffett provide back-up for each other. One plant of each pair is kept as a cold standby. There is no spare plant for Hororata, however, it would be possible in an emergency to relocate one of the Springston plants to Hororata.

With the ability to transfer load between the urban 66/11kV and 33/11kV systems, 11kV Telenerg ripple plants have been installed at Hornby, Moffett, Shands, Sockburn Harewood and Prebbleton zone substations. It is anticipated that the 33kV Decabit plants will be removed from service within the next 10 years once ripple relays within the area have been re-coded

Figure 4-21a **Ripple injection system control diagram**



With the installation of the rural 66/11kV substations it has become necessary to install a 11kV Decabit ripple plant at each substation. These plants are connected to the network via indoor 11kV switchgear. Back-up for the 11kV plants is provided by the 33kV injection system.

Like the urban Telenerg system, each Decabit plant operates independently with all fixed time signaling carried out from a timetable stored in the individual plant controller. All anytime signaling is controlled by the load management system via the load management RTUs at each location in response to commands from the load management master station.

Communications

Communications between the load manager and the injection plants is via the IP communications system which provides redundant communications paths to all ripple plants.

4.21.2 Asset capacity/performance

Load management master station

The master station is a proprietary database system with full graphics running on industry standard hardware and software. It currently meets the performance requirements for the network load management.

Upper South Island load management system

The master station is a proprietary database system with full graphics running on industry standard hardware and software. It currently meets the performance requirements for the Upper South Island load management system.

Ripple injection system - urban 175Hz

The 66kV injection system was completely replaced in 2002-2004 with small individual 11kV injection plants.

Additional plants have been installed during 2005-2007 in the urban 33kV subtransmission system as 11kV interconnection capacity has been added between the urban 66 and 33kV subtransmission areas.

A larger number of smaller injection plants will significantly reduce the risk associated with a single plant failure as adjacent plants can cover for it. New 11kV plant capacity is matched to the capacity of the zone substation it is connected to. As load growth occurs, additional plants will need to be installed in conjunction with additional zone substation transformer capacity.

These plants have adequate capacity and performance for the timeframe of this plan.

Ripple injection system - rural 317Hz

The 33kV ripple injection plants have adequate capacity for the networks they are connected to, and would only have problems if GXP transformers with significantly lower impedance were installed. The existing plants have shown no sign of increased failure rates due to equipment aging and, apart from the Hororata plant, complete cold standby plants are available on both the Springston and Islington 33kV networks. Essential spares are held for the Hororata plant to enable rapid repair in the event of a fault. In a worst-case situation it would be possible to move part or all of one of the Springston plants to Hororata.

11kV, 317Hz ripple plants were commissioned because they are physically within the existing 317Hz injection area, but are supplied from the 66kV subtransmission system. These are of similar design to the 175Hz plants and were supplied under the same contract as those installed as replacements for the urban 175Hz ripple plants.

4.21.3 Asset condition

Load management master station

A “like for like” upgrade of the Foxboro load management system occurred in FY18. This included the master station hardware, operating system and underlying software, but leaves the data base and front end application largely untouched. This project was in response to the increasing risk of failure of an ageing platform and the associated difficulties of finding expert third party support if problems arise.

Upper South Island load management system

This system was installed in May 2009 . The system is maintained on a regular basis and the software is kept up to date. There is no plan to replace this system in the near future.

Ripple injection system - urban 175Hz system

The majority of the 11kV injection plants on the 66kV system were installed from FY04, and are expected to have a minimum life of 15 years. The annual maintenance programme checks for possible faults and variations in equipment performance.

Ripple injection system - rural 317Hz system

The 33kV ripple plant injection controllers were replaced in FY05 and are expected to have a minimum life of 15 years. The annual maintenance programme checks for possible faults and variations in equipment performance. The manufacturer no longer supports the SFU controller type used on the 33kV ripple plants. These units have been reliable to date, but there is a complete spare plant and controller if failures occur.

4.21.4 Standards and asset data

Standards and specifications

All building construction, methods and materials for any maintenance or replacement are to comply with the requirements of current building codes and the Resource Management Act. Orion standards will apply for all other work.

Asset management report:

- NW70.00.37 - Load management systems.

Design standards developed and in use for this asset are:

- NW70.53.01 – Substation design.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW70.26.01 - Ripple control system details
- NW72.26.02 - Ripple equipment maintenance.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.09 – Ripple control system.

Operator instructions in use:

- NW72.13.211 – 11kV Enermet ripple plant.

Operator procedures in use:

- NW21.19.20 – Upper South Island Management.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and serial numbers
- age
- circuit diagrams
- test results.

Data improvement is ongoing. Updated data comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.21.5 Maintenance plan

Following the upgrade of the load management system that occurred in FY18, the master station hardware, OS, Database and HMI is current and supported by vendor warranties and maintenance agreements.

Our ripple master maintenance programme consists of a daily operational check during the winter period and a weekly operational check during summer. This is supplemented by an annual hardware maintenance programme similar to that performed on the SCADA master stations. The complexity of the software and availability of technical support increase the difficulty and cost of maintaining the master station system.

Injection plants have a quarterly operational check as well as an annual inspection that includes measurement of installed capacitors and detailed tests on the inverter. If the plant coupling cells are found to have drifted they are retuned. Dusting and physical inspections are considered part of the annual maintenance.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Load management. A total detailed breakdown of opex is shown in table 4.21a.

Table 4-21a **Load management opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	20	20	20	20	20	20	20	20	20	20	200
Routine and corrective maintenance and inspections	275	275	275	275	275	275	275	275	275	275	2,750
Total	**295**	**295**	**295**	**295**	**295**	**295**	**295**	**295**	**295**	**295**	**2,950**

4.21.6 Replacement plan

Upper South Island load management master station

The hardware of the Upper South Island load management master station is adequate. We review the hardware requirements at appropriate intervals and upgrades are subject to available funding for the system from Transpower.

Loadman master station

There is great uncertainty at a national level on the direction of demand-side management (there is a risk of investing in a system that may not be suitable for the market conditions in years to come) and no defined timeframe on when a decision will be made, we have decided to wait-and-see. In the meantime, however, a like for like upgrade of the core application and associated infrastructure has been undertaken to ensure business continuity.

Coupling cells and controllers

These components are expected to have a life of at least 15 years and are not expected to be due for renewal for at least 10 years.

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Load management. A total detailed breakdown of replacement is shown in table 4.21b.

Table 4-21b **Load management replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Zone substation	120	120	120	120	120	120	120	120	120	120	1,200
Other network assets	120	20	1,250	1,020	70	70	550	70	70	70	3,310
Total	**240**	**140**	**1,370**	**1,140**	**190**	**190**	**670**	**190**	**190**	**190**	**4,510**

4.21.7 Creation/acquisition plan

New 11kV ripple injection plants are installed in conjunction with new zone substations or rural zone substations that move from 33kV to 66kV. One substation that is being converted is Springston; where a new 66/11 kV transformer, 11kV switchgear and 11kV 317Hz Decabit ripple plant are being commissioned this year. The existing 33kV plants will remain in service to provide ripple control to the remaining 33kV substations.

4.21.8 Disposal plan

We plan to retire the 33kV ripple injection plants at Moffett and Hornby substations in the near future. This will provide spares for the remaining plants at Springston and Hororata.

11kV injection plant at a zone substation.

4.22 Distribution management systems (DMS)

4.22.1 Asset description

A DMS is a suite of applications designed to monitor and control the distribution network and also to support decision making in the control room. Key DMS deliverables include minimisation of the duration of both planned and unplanned interruptions and maintaining of acceptable frequency and voltage levels.

SCADA (supervisory control and data acquisition) systems have been used in Orion since the early 1970s. These systems have traditionally been based on a master station (central control centre) communicating with the remote terminal units (RTU) at sites throughout the network.

A DMS integrates real time information from SCADA with a comprehensive model of the electricity network. During a network interruptions (when combined with details from customer calls) this allows us to quickly determine the point at which supply is lost and the number of customers affected. The DMS also assists network controllers to restore the power supply by automating some isolation and restoration procedures.

Remote terminal units (RTUs) are devices installed in substations that provide an interface between network equipment and SCADA.

In summary the DMS is our most important system for monitoring and operating our electricity network. Alarms notify our control room of potential or actual equipment failure allowing us to respond much more quickly than we would otherwise be able to. In a major event with wide spread effects on the network the DMS enables us to better coordinate our efforts to restore power.

CORE DMS APPLICATIONS

SCADA

A comprehensive SCADA master station is tightly integrated into the DMS and provides telemetered real-time data to the network connectivity model.

Network management system (NMS)

At the heart of the DMS is a comprehensive, fully connected network model (including all lines, cables switches and control devices, etc.) that is updated in real time with data from network equipment. The model is used to manage the network switching processes by facilitating planning, enforcing safety rules and generating associated documentation. It also maintains history in switching logs.

A full graphics ‘human machine interface’ (HMI) is used to display the network model and provide operator interaction with the system.

Outage management system (OMS)

The OMS supports the identification, management, restoration and recording of faults. It assists in determining the source of interruptions by matching individual customer locations (from fault calls) to network segments and utilising predictive algorithms.

Customer details are recorded against faults in the OMS which allows our Contact Centre to call customers back after an interruption to confirm that their power supply has been restored.

Mobile field service management

Field services operators are equipped with personal digital assistant (PDA) devices and receive switching instructions directly from the DMS. The network model is immediately updated to reflect physical changes as switching steps are completed and confirmed on the PDA.

Remote terminal unit (RTU)

The remote terminal unit is a field device that interfaces network objects in the physical world with the distribution management system SCADA master station to allow telemetry control and indication.

The communication medium and protocols used by the field network RTUs to communicate back to the SCADA master station vary, these include; Conitel over UHF radio or copper wire and DNP over UHF radio, copper wire, fibre or MimoMax radio.

ANCILLARY DMS APPLICATIONS

Historian

The Historian is a database that records time series data (binary and analogue) for future analysis. This historian has only recently been implemented, but has been capturing five minute data for the previous 18 or so months. Our historian system is currently only storing time series analogue data, but will have the capability to capture event data in-time.

The time series data stored in the historian is used by various applications throughout the organisation for planning, network equipment condition analysis and for reporting network operating performance statistics (such as reliability).

Real-time load flow analysis

The DMS has access to large amounts of real time field data and maintains a connectivity model making it possible to undertake near real time load flow calculations. Load flow analysis can be used to predict network operating conditions at locations where no telemetered data is available and can also carry out "what if" scenarios to predict the effects of modified network topologies and switching.

Information interfaces

Not all information required for operations and planning activities is available from the DMS. Linking DMS records to data from other systems greatly enhances our capabilities in both these areas.

DMS data may be presented in reports or used to populate web pages for organisational and public consumption.

4.22.2 Asset capacity/performance

DMS

The same DMS software that we use is also used at some very large electricity distribution companies overseas (greater than 500,000 connections) and is therefore not constrained by the scale of our business. We also ensure that supporting infrastructure (server, network etc.) has sufficient capacity for current and credible near future growth.

The DMS is a critical business application and runs on highly resilient infrastructure which employs multiple, mirrored and geographically separated servers. The sites in which the servers are deployed are also highly resilient, with environmental management, smoke and fire detection, un-interruptible backup power supplies and backup generators. A separate test DMS environment is used for testing all changes to the production system and for training.

There are no current issues with the capacity, performance or availability of the DMS.

RTU

We have a number of older RTUs in our network which are no longer supported by their manufacturer. We hold enough spares to cover these units for maintenance purposes and they are performing adequately. These units, namely Dataterm GPT, iQuest DS8840i and L&N C225, are progressively being replaced as other upgrades (switchgear replacement etc.) take place at their locations. The remainder of our units are performing satisfactorily and are fully supported by their vendors.

Figure 4-22a SCADA RTU - defects

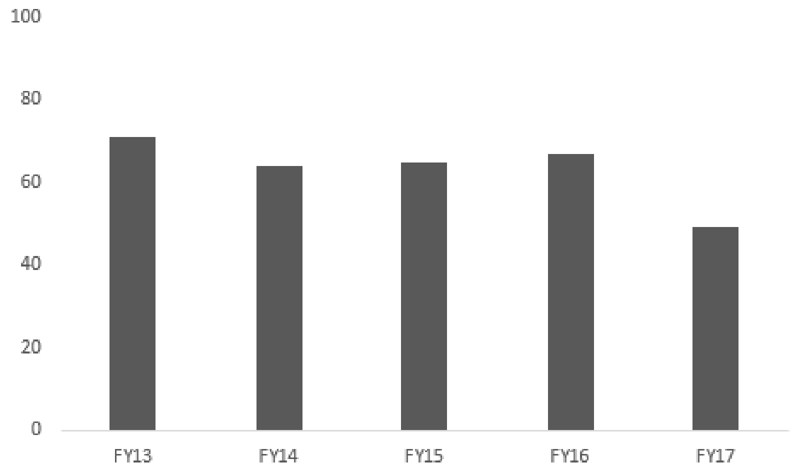
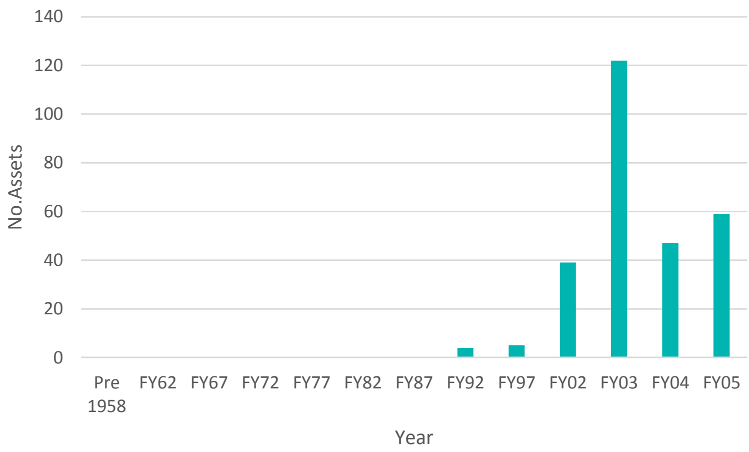


Figure 4-22a (RTU defects) is made up of faulty fibre/fibre connections, faulty serial cards or relays, modems and blown RTU power supply fuses. The RTU defects are starting to trend downwards as a result of the older units being replaced.

4.22.3 Asset condition

While some of our older RTUs no longer have manufacturer support their condition is satisfactory. Those units that do not meet our current operating criteria have been targeted for removal. The rest of this asset group is in good condition and proving reliable.

Figure 4-22b SCADA RTU - age profile



4.22.4 Standards and asset data

Asset management report:

- NW70.00.36 - Distribution management systems.

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.56.01 - SCADA functional specification for remote sites.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.26.04 - SCADA master maintenance
- NW72.26.05 - SCADA RTU maintenance.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- type and age
- circuit diagrams
- test results.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.22.5 Maintenance plan

DMS software and supporting infrastructure

The first line of support for DMS software and infrastructure is our own staff. A maintenance contract with the software vendor includes:

- a remote response capability for emergencies
- a fault logging and resolution service
- the software component of any upgrade or service patch release.

RTUs

RTUs are maintained on an as-required basis, with component availability the main criteria.

Inspections we carry out include:

- weekly general operational checks of equipment software
- annual detailed check of hardware and software systems

- annual operational check of all RTU controls and indications.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Control systems. A total detailed breakdown of opex is shown in table 4.22a.

Table 4-22a **Control systems opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Service interruptions and emergencies	65	65	65	65	65	65	65	65	65	65	**650**
Routine and corrective maintenance and inspections	505	505	505	505	505	505	505	505	505	505	**5,050**
Total	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**570**	**5,700**

4.22.6 Replacement plan

DMS and RTU hardware capabilities, age and maintainability is reviewed annually and an assessment is made of equipment that needs to be programmed for replacement/renewal.

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Control systems. A total detailed breakdown of replacement is shown in table 4.22b.

Table 4-22b **Control systems replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Zone substation	60	60	60	60	60	60	60	60	60	60	**600**
Other network assets	725	180	725	580	235	180	330	580	235	325	**4,095**
Total	**785**	**240**	**785**	**640**	**295**	**240**	**390**	**640**	**295**	**385**	**4,695**

4.22.7 Creation/acquisition plan

DMS software and supporting infrastructure

Future planning for the DMS includes the installation of more automated switchgear and on-line load-flow analysis opens the possibility to implement an Automated Power Restoration Scheme (APRS). APRS is a DMS application module that allows the NMS to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply. Various business and customer interfaces are to be developed over the next few years as resources permit.

RTUs

New network RTU's are installed when new sites with telemetry control are built.

4.22.8 Disposal plan

We dispose of equipment as part of the replacement programme.

4.23 Information systems - asset management

4.23.1 Asset description

Our asset management Systems hold information about the equipment that comprises the electricity network and support business processes that build and maintain that equipment. The majority of our primary asset information is held in our asset register, geographic information system (GIS) and cable databases. We hold information about our network equipment from GXP connections down to individual LV pole level with a high level of accuracy.

In addition to these asset registers we hold also detailed information regarding customer connections in our Connections Register and track the process of asset creation and maintenance in Works Management.

Geographic Information System (GIS) – Intergraph suites, G/Electric and GeoMedia

Our GIS records our network assets according to their location, type and electrical connectivity. It interfaces with other information systems such as substation asset attribute data stored in our asset register. GeoMedia specialises in reporting and analysing geographic data. In particular; GeoMedia easily combines core GIS and third party datasets such as aerial imagery for both Orion and contractor/consultant use.

Various GIS viewer technologies enable Orion to deliver ‘fit for purpose’ geographic asset information within Orion premises, or off site via a secure website. In areas where internet coverage is limited, GIS datasets may be stored directly on a laptop device.

Asset register – EMS Basix electricity manager

Our asset register, EMS Basix, provides a central resource management application for holding details of key asset types with their current location/status. The assets covered include land, substations and all our major equipment including HV cables with less strategic types being added over time. Schedules extracted from this database are used for preventative maintenance contracts and it archives any inspection/test data gathered during the contract. Data is also held to facilitate a valuation of our fixed network assets; the GIS holds the distributed assets (lines and cables).

Cable database (pilot/communication cables)

A separate in-house developed MS Access database is used to hold information on our pilot/communication cables. Cable lengths, joint/termination details are held and linked to our GIS by a unique cable reference number.

Works Management and Enquiry for Supply

All types of works activity are managed using purpose-built in-house developed applications which populate a single works data repository. The applications are optimised for different types of work including new connections management, general network jobs and emergency works.

When a job is created in Works Management a companion job is also automatically created in the financial system (NAV) to track job related invoices.

Connections Register

Our in-house developed Connections Register holds details of all installation control points (ICP) on our network. This is linked with the industry registry. Links with our GIS systems enable accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are now routinely traced within the GIS using the in-built connectivity model, and accurate information about the number of customers and interruption duration are recorded.

4.23.2 Asset capacity/performance

GIS – Intergraph suites, G/Electric and GeoMedia

G/Electric technology and its supporting Oracle database have the capacity to scale up and extend functionality to support business growth. Geomedia technology was upgraded in FY17 to meet the current growth in business intelligence requests and ‘access to GIS’ demands from external contractors/consultants.

The supporting physical computer infrastructure exists on a high availability Virtual Server environment, and is considered to have adequate capacity and performance for the timeframe of this plan.

Asset register – EMS Basix electricity manager

We use only a subset of the capabilities of the EMS Basix database which can be applied to Works Management as well as asset tracking. We have recently upgraded from EMS WASP.

The performance and capacity of the upgraded system is adequate for the timeframe of this plan.

Cable database (pilot/communication cables)

The cable database is an in-house application written in Microsoft Access and as such may be subject to modification as a consequence of updates to the Microsoft Office Suite. It is our intention that within the timeframe of this plan that this application will be either integrated with other databases or modified to run as in house Microsoft SQL database.

Works Management and Enquiry for Supply

Works Management and Enquiry for Supply are highly customised to support our business processes.

The performance and capacity of the database is adequate for the timeframe of this plan. This application was the subject of a FY17 systems review

Connections Register

The Connections Register has been modified significantly since its establishment in FY00, to support a range of new business processes. This system has however reached a “tipping point” and without a change to its underlying architecture, there is a high degree of risk in developing it further.

Its capacity and performance are adequate for the period of this plan if there are no further major changes required.

This application was the subject of a FY16 systems review.

4.23.3 Asset condition

GIS – Intergraph suites, G/Electric and GeoMedia

The G/Electric suite has recently been upgraded to a current release and resides on a high performance, high availability Virtual Server environment.

The upgrade included a review of customised code, which was largely replaced with standard application features, reducing the complexity of the systems from a support perspective.

Asset register – EMS Basix electricity manager

EMS WASP has been upgraded to the most current revision of the EMS Basix software.

Cable databases (high voltage and communication cables)

It is undesirable that the cables databases remain as Microsoft Access databases and they will be either integrated with other databases or modified to run as in house Microsoft SQL database.

Works Management and Enquiry for Supply

The performance and capacity of the database is adequate for the timeframe of this plan. This application was the subject of a FY17 systems review.

Connections Register

Its capacity and performance are adequate for the period of this plan if there are no further major changes required.

This application was the subject of a FY16 systems review.

4.23.4 Standards and asset data

Asset management report:

- NW70.00.48- Information Systems – Asset management.

4.23.5 Maintenance plan

General

All systems are supported directly by the Orion Information Solutions group with vendor agreements for third tier support where appropriate.

License costs are considered to provide a degree of application support but are substantially a prepayment for future upgrades. Although licenses guarantee access to future versions of software they do not pay for the labour associated with implementation. Our experience has been that significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

Software releases and patches are applied to systems as necessary and only after testing.

Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices.

Our budgeted maintenance costs are shown in section 8.2.1 – Opex budgets - Non network. A total detailed breakdown of opex, is shown in table 4.23a.

Table 4-23a **Information systems opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Routine and corrective maintenance and inspections	515	515	485	485	485	485	485	485	485	485	**4,910**
Total	515	515	485	485	485	485	485	485	485	485	4,910

GIS

The G/Electric suite and related computer infrastructure are supported directly by the Orion Information Solutions group. In addition, support hours are pre-purchased from Intergraph as part of an annual maintenance agreement.

EMS Basix electricity manager

EMS Basix and related computer infrastructure are supported directly by the Orion Information Solutions group.

Other systems

All other systems are supported directly by the Orion Information Solutions group. Some recoveries are made from salaries to capital.

4.23.6 Renewal plan

Changes to asset management information systems are typically incremental in nature and systems are replaced infrequently.

As indicated in the previous sections we employ a standard change management approach to all software systems. Renewal of an information system will follow the predefined steps of project proposal/concept socialisation, business case and approval, business requirements and implementation via a project.

Table 4-23b **Information systems replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Other network assets	40	420	170	40	170	170	40	170	170	40	**1,430**
Total	40	420	170	40	170	170	40	170	170	40	1.430

4.24 Metering

4.24.1 Asset description

High voltage (11kV) customer metering

We own current transformers (CTs) and voltage transformers (VTs) used for metering, along with associated test blocks and wiring, at approximately 75 customer sites. Retailers connect their meters to our test blocks. All Orion CTs and VTs are certified as required by the Electricity Governance Rules.

Transpower grid exit point (GXP) metering

We adopted GXP-based pricing in 1999, and most of our revenue is now derived from measurements by Transpower's GXP metering.

Orion also owns metering at Transpower GXPs. We input the data from these meters into our SCADA system. Our measurements can also help the Reconciliation Manager to estimate data if Transpower’s meters fail, or are out of service.

Transpower has dedicated meters at all metering points. The GXPs at Arthur’s Pass and Castle Hill share CTs with our metering. All VTs are shared between Orion and Transpower. Although a truly credible check metering system would have stand-alone components with their own traceable accuracy standards, this is impractical.

Power quality measurement metering

Our power quality management in the past has been mainly reactive. We have responded to customer complaints (which generally stem from the customer's own actions) while assuming that the underlying network performance is satisfactory. The general underlying qualitative power quality performance of the network, and whether it is deteriorating with time as an increasing number of non linear loads are connected to the network has been unknown. These non linear loads (which frequently reduce network power quality) are also generally more sensitive to the very power quality issues they help to create.

We installed approximately 30 permanent, standards compliant, power quality measurement instruments across a cross-section of distribution network sites which are expected to range from good (generally urban upper network) to poor (generally remote rural) power quality performance.

These instruments will continue to collect power quality data, the analysis of which will provide a long term statistical view of typical network performance across a wide range of network conditions and locations. This data can also be used to provide a view of actual network power quality performance to assist with the development of standards and regulations.

4.24.2 Asset capacity/performance

We check that our metering figures support Transpower’s data. If the two sets of data differ significantly, meter tests may be required to establish where the discrepancy has occurred.

The two sets of data will never be identical – our GXP metering cannot definitively check Transpower's half-hourly metering values because:

- some of our meters are in different locations from Transpower’s meters
- our meter-class accuracy differs from Transpower
- the error correction factors that apply to Transpower’s metering do not apply to us, as our metering uses different CTs.

4.24.3 Asset condition

All metering equipment is in good condition.

4.24.4 Standards and asset data

Asset management report:

- NW70.00.38 - Metering.

Orion historically installed metering at the asset ownership boundary to Transpower, this performed the function of check and/ or load management. Although the GXP spur asset transfer program has meant that these asset ownership boundaries are now further up the network, Orion has retained the old metering positions due to the uncertainty surrounding the future architecture and management of the load control systems, and the associated risk of stranded assets.

We manage and maintain all the Orion metering drawings and documentation, and update them as plant and equipment is altered.

4.24.5 Maintenance plan

We regularly inspect the metering sites, carry out appropriate calibration checks and witness the calibration checks on Transpower's metering.

Our meter testing contractors are required to have registered test house facilities which comply with the Electricity Governance Rules. They must also have documented evidence of up-to-date testing methods, and have competent staff to perform the work.

Our budgeted maintenance costs are shown in section 8.1.1 – Opex budgets - Network: Meters. A total detailed breakdown of opex is shown in table 4.25a.

Table 4-24a **Metering opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Routine and corrective maintenance and inspections	75	75	75	155	155	155	155	155	155	155	**1,310**
Total	**75**	**75**	**75**	**155**	**155**	**155**	**155**	**155**	**155**	**155**	**1,310**

4.24.6 Replacement plan

In recent years we have replaced all of our GXP metering in conjunction with Transpower's metering changes. We have no plans to carry out further significant replacement work at this stage.

Our budgeted replacement costs are shown in section 8.1.13 – Replacement budgets: Metering. A total detailed breakdown of replacement is shown in table 4.25b.

Table 4-24b **Metering replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Total**
Other network assets	185	245	185	245	185	185	185	185	185	185	**1,970**
Total	**185**	**245**	**185**	**245**	**185**	**185**	**185**	**185**	**185**	**185**	**1,970**

4.24.7 Creation/acquisition plan

Additional standards compliant power quality measurement instruments may be installed in the future where we connect new major customers to provide them with an assurance of the level of power quality they are being supplied with.

4.24.8 Disposal plan

We have no specific plans to dispose of any of this asset group.

4.25 Network property

4.25.1 Asset description

This section on network property covers all buildings, kiosks and land assets that form an integral part of our distribution network.

All of our zone substations, have buildings which contain switchgear and control equipment. Most of the buildings are constructed of reinforced and filled concrete block. Eleven of the substation buildings, mostly in the rural area, are of modular design constructed from a series of large rectangular reinforced concrete sections connected together to form a rectangular building.

The 205 network and 261 distribution substation buildings vary in both construction and age. We own approximately 80% of the network substation buildings and approximately 30% of the distribution buildings. Some 150 of them are incorporated in a larger building that we do not own (i.e. customer owned premises).

Our kiosks are constructed of steel to our own design. The majority fall into two categories; an older high style, and the current low style. The low style kiosk is also constructed in half (shown in photo below) and quarter versions for use where the transformer is mounted externally or at a remote location.

Table 4-25a **Distribution kiosk quantities FY17 (owned by Orion)**

Kiosk type	Low (full) steel	Low (half) steel	Low (quarter) steel	High steel	Fibreglass	Berm concrete/steel	Transformer cover	**Total**
Quantity	2,391	651	325	644	8	2	8	**4,029**

4.25.2 Asset capacity/performance

Our property assets must meet the following three performance criteria:

1. They must be secure. We are aware of increased public safety and risk management expectations surrounding our substations. A programme to run over a 10 year period to upgrade security and safety is underway. This will mainly involve access (locks and gates/doors), fencing and earthing. All ground-mounted installations in industrial and commercial locations have already been independently surveyed to gauge their susceptibility to damage. Solutions to minimise the risk of damage are being developed.
2. They must be environmentally sound to ensure that the installed equipment is not compromised. The main areas of note are the seismic strength and water-tightness of the buildings. Both these matters are being addressed.
3. They must be visually acceptable. Work such as damage repair, ground maintenance, graffiti removal and painting is on-going to achieve this outcome.

We undertook a 15 year programme to seismically strengthen our zone and network substation buildings. We completed the programme before the Canterbury earthquakes and recognised an almost immediate benefit for our community.

Outdoor substation - consisting of a half-kiosk and adjacent transformer.

4.25.3 Asset condition

Our zone substation buildings (see section 4.4.1 for examples) are well designed and mostly constructed with reinforced and filled concrete blocks. The structural integrity of all the buildings has been inspected and remedial action taken to bring all zone substations up to the latest building code and related seismic strength code. We are underway mitigating known issues with our zone substation switchyards.

Our network/distribution building substations vary in both construction and age. Those constructed prior to the early 1960s are very brittle in nature, having walls constructed entirely of non-reinforced clay brick. Those that have been constructed since the mid-1960s are of a more substantial nature, namely reinforced concrete framed masonry. A seismic assessment was undertaken on all our substations to determine those which required remedial work to bring them up to the current standard. A risk analysis of the resulting list concentrated on determining the consequences to the network of a loss of a given substation. This information was then used to develop our 'works' programme. There are a small number of distribution substations in Orion owned and customer owned buildings that have not yet had remedial works undertaken. However, it is considered that these will have a low impact on the network if lost during an abnormal event.

Our kiosks are generally in reasonable condition. Steel kiosks in the eastern suburbs nearer the sea are prone to some corrosion and it is expected that these kiosks will have to be replaced much sooner than those in the remainder of our network. They are being attended to as required.

We are currently over 85% of the way through a programme to seismic strengthen or remove our dual pole and single pole substations with large heavy transformers.

Figure 4-25a **Substation buildings (owned by Orion) - age profile**

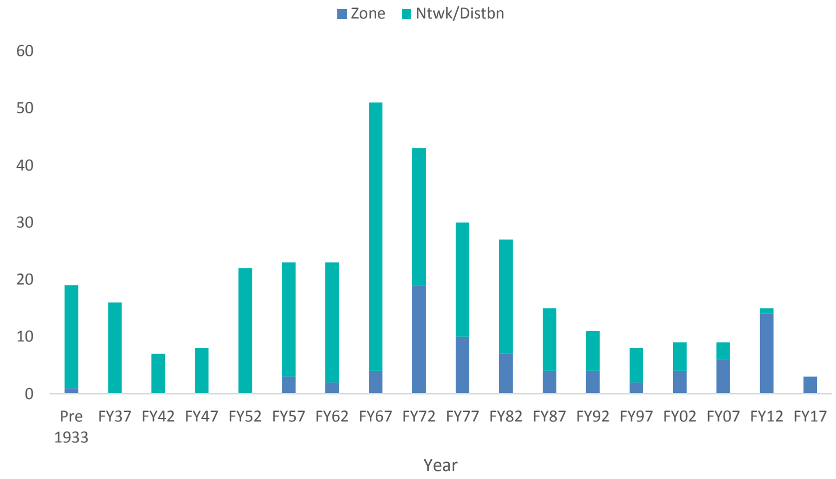


Figure 4-25b **Kiosks - age profile**

4.25.4 Standards and asset data

Asset management report:

- NW70.00.43 - Network property.

Standards and specifications

Design standards developed and in use for this asset are:

- NW70.53.01 - Substation design
- NW70.53.02 - Substation design - customer premises.

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.23.14 - Kiosk installation.

Equipment specifications covering the construction and supply of specific components of this asset group are:

- NW74.23.01 - Kiosk shell - full
- NW74.23.02 - Kiosk shell - half
- NW74.23.03 - Kiosk shell - quarter.

Asset data

Data currently held in our information systems for this asset group includes:

- location (GIS and asset register)
- construction type and age
- detail drawings
- land ownership/title details
- maintenance/improvement records.

Data improvement is ongoing. Updated data generally comes from the routine compliance inspections listed in the following maintenance plan as well as specific inspections carried out as required. All inspections are used to further our knowledge of the asset condition.

4.25.5 Maintenance plan

A five year maintenance plan to repair all of our buildings which have suffered earthquake damage is coming to an end in FY19. All our buildings and land are inspected regularly, and minor repairs are undertaken as they are identified. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis.

Property maintenance is expected to remain at a constant level, although many of the older customer owned substations will require seismic upgrading if they are retained. Customer owned substations that require maintenance or strengthening to remove risk to our equipment may present some problems in relation to who will bear the cost of this work. These will be assessed on a case by case basis.

Our substations are maintained on an as-required basis, with most general maintenance work identified during six-monthly inspections. Work such as damage repair, ground maintenance, graffiti removal, painting, signage and lock replacement is on-going.

Some of the older kiosk foundations have moved due to surrounding land movement. They need to be levelled to relieve stress on the attached cables. A small number of them are being attended to each year.

We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas. Buildings are repainted approximately every 10 years and we are now using a silicon based product to provide a waterproof membrane and protect the substation from water ingress through the blockwork.

Graffiti is an on-going problem at virtually all of our sites. We remove it as soon as possible after it is reported. We liaise with the local councils and community groups in our area to assist us with this problem. We now have a specific email set up where members of the community can report graffiti.

A new opex programme has been identified to better forecast the costs associated with decommissioning our substations. These works are mostly driven by our changing load profile.

Our budgeted maintenance costs are in section 8.1.1 – Opex budgets - Network: Buildings and enclosures. A total detailed breakdown of opex is shown in table 4.26b.

Table 4-25b **Network property opex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Routine and corrective maintenance and inspections	1,340	1,340	1,080	1,060	970	970	970	920	920	920	**10,490**
Asset replacement and renewal	720	335	135	135	135	135	235	235	235	235	**2,535**
Total	**2,060**	**1,675**	**1,215**	**1,195**	**1,105**	**1,105**	**1,205**	**1,155**	**1,155**	**1,155**	**13,025**

4.25.6 Replacement plan

We do not have a replacement plan for our building substations and will review the need for them as we undertake major works at the sites. These assets are maintained to ensure they provide the required level of performance.

To help maintain the security of our assets we have replaced all locks in our network.

There is a programme underway to replace all fibreglass kiosks as well as some steel kiosks due to rust. A number of the steel kiosks are located near the coast. We are also in the process of formulating a roof replacement programme based on a condition assessment.

Allowance has been made for upgrading security fencing and seismic requirements.

In response to a request from Transpower, we will carry out some works at our Addington zone substation to accommodate changes to their adjoining 'spares' yard. We have also identified that further works are necessary at our Papanui zone substation 'hotsite' area as part of our emergency response preparedness. Both of these projects have been scheduled for FY19

Our budgeted replacement costs are in section 8.1.13 – Replacement budgets: Buildings and enclosures. A total detailed breakdown of replacement is shown in table 4.25c.

Table 4-25c **Network property replacement capex (real) - $,000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Total
Distribution substations and transformers	310	200	200	200	200	200	200	200	200	200	**2,110**
Other network assets	210	210	210	140	140	140	140	140	140	140	**1,610**
Total	**520**	**410**	**410**	**340**	**340**	**340**	**340**	**340**	**340**	**340**	**3,720**

4.25.7 Creation/acquisition plan

We construct new buildings and kiosks to meet customer demand for supply to subdivisions or commercial ventures and when necessary to place overhead reticulation underground.

Orion are in the process of purchasing land from the CCC for the construction our Marshland zone substation to complete the 66kV ring around the North of the city

We are investigating the ownership of leased/rented sites with the view to create a more secure tenure of all network land, if required.

For a list of projects containing this asset see section 5.6 - Network development proposals.

4.26.8 Disposal plan

Equipment is disposed of as part of the replacement programme.

We are currently engaged in justifying continued ownership of (or easements over) all unused sites. We will relinquish ownership of sites deemed not required.

Network development

Orion

5

List of figures and tables in this section

5.1 Introduction

Developing our network to meet future demand growth requires significant capital expenditure. Before spending capital on our network, we consider a number of options including those available in Customer Demand Management and distributed generation (DG). We also take account of the uncertainty arising from various scenarios related to solar PV, battery storage and electric vehicle uptake.

The amount we spend on our network is influenced by existing and forecast customer demand for electricity and the number of new customer connections to our network. Other significant demands on capital include:

- meet health and safety and environmental compliance requirements
- meet and maintain our security of supply standard (see section 5.3.1)
- meet our reliability of supply targets (see section 3.4).

The growth rate in overall maximum network system demand (measured in megawatts) traditionally drives our capital investment. Maximum demand is strongly influenced in the short-term by climatic variations (specifically the severity of our winter conditions). For FY18 the peak total injection supplied through Transpower's GXPs was 623MW, when there was 37% load shedding due to hot water cylinder management. For planning we look for the peak injection with maximum load shedding. For the few hours of higher load that sometimes occurs, we plan to encroach on the N-1 contingency capacity rather than build more network. For FY18 this peak was 605MW with 94% shedding. This was supplemented by export from distributed generators of 10.8MW . The maximum export recorded from embedded generators during the year was 12.69MW on the evening of 12 August 2017.

During the winter of 2011, prior to the two snow storms, the peak half hour for the winter had been only 533MW (based on load through Transpower GXPs i.e. excluding embedded generation). The July 2011 snow led to a 7% higher half hour peak of 572MW. The August 2011 snow emphasised the effect of climatic variation when the load peaked 10% higher again at 633MW. In the medium-term it is influenced by growth factors such as underlying population trends, growth in the commercial/industrial sector and changes in rural land use. The increasing uptake of energy efficient appliances and LED lighting, together with a reduction in the cost of storage batteries is expected to put downward pressure on growth. Electric vehicle charging adds to growth. Section 5.4.2 covers various scenarios of these opposing drivers, showing the net result is forecast to be continued growth for at least five years, with growing uncertainty in the following five years.

Another factor that has influenced our network development plan is in-fill housing in existing central suburbs and new housing estates in areas such as Belfast, Halswell, Rolleston, and Lincoln. It is likely we will extend our urban 11kV network to meet these developments. CCC data forecasts over 500 new households in the central city over each of the next five years. The majority of this is in the East Frame which will mainly utilise existing 11kV cabling.

In this section we discuss our network architecture, planning criteria, energy demand and growth, network gap analysis and list our proposed projects required to address specific issues. The project list is split into major projects, 11kV reinforcement and 400V reinforcement. We also list projects undertaken by Transpower at the Orion grid exit points.

The 2010/2011 earthquakes in Canterbury caused significant damage to our network. We are proud of our pre-earthquake network architecture and engineering strategies to minimise the impact of such events and we are pleased with our operational response during the response and recovery phases. There was much to be learnt from experiencing an event of this scale and this coupled with permanent network damage led to an inevitable change to our pre-earthquake network development plans.

Our urban 66kV subtransmission and 11kV network architecture reviews have resulted in refinement of our subtransmission strategy as described in section 5.6.3. The construction of our post earthquake northern 66kV urban subtransmission link was completed in 2016. Our load forecasts have been updated with April 2017 post-earthquake population forecasts~~.~~The forecast also takes account of CCC vacant industrial land uptake data to June 2017. The central city rebuild is forecast to add 12MVA to peak demand over the next five years.

5.2 Network architecture

5.2.1 Transpower Grid Exit Points (GXPs)

Our network is supplied from seven GXP substations as shown in Figure 5-2 below. The three remote GXPs at Coleridge, Arthur's Pass and Castle Hill have a single transformer and a much lower throughput of energy. With the exception of Hororata and Kimberley all the GXPs peak in winter.

Approximately 65% of our customers are supplied through the Islington GXP 220/66kV interconnection made up of two 200/266MVA transformers and one 250/310MVA transformer.

Transpower charges users, for example Orion and Mainpower, for the costs of upgrading and maintaining the GXPs. Orion owns all the assets connected to the GXPs. We work with Transpower to plan for GXP connection asset upgrades to ensure that any capital expenditure at the GXP is cost effective.

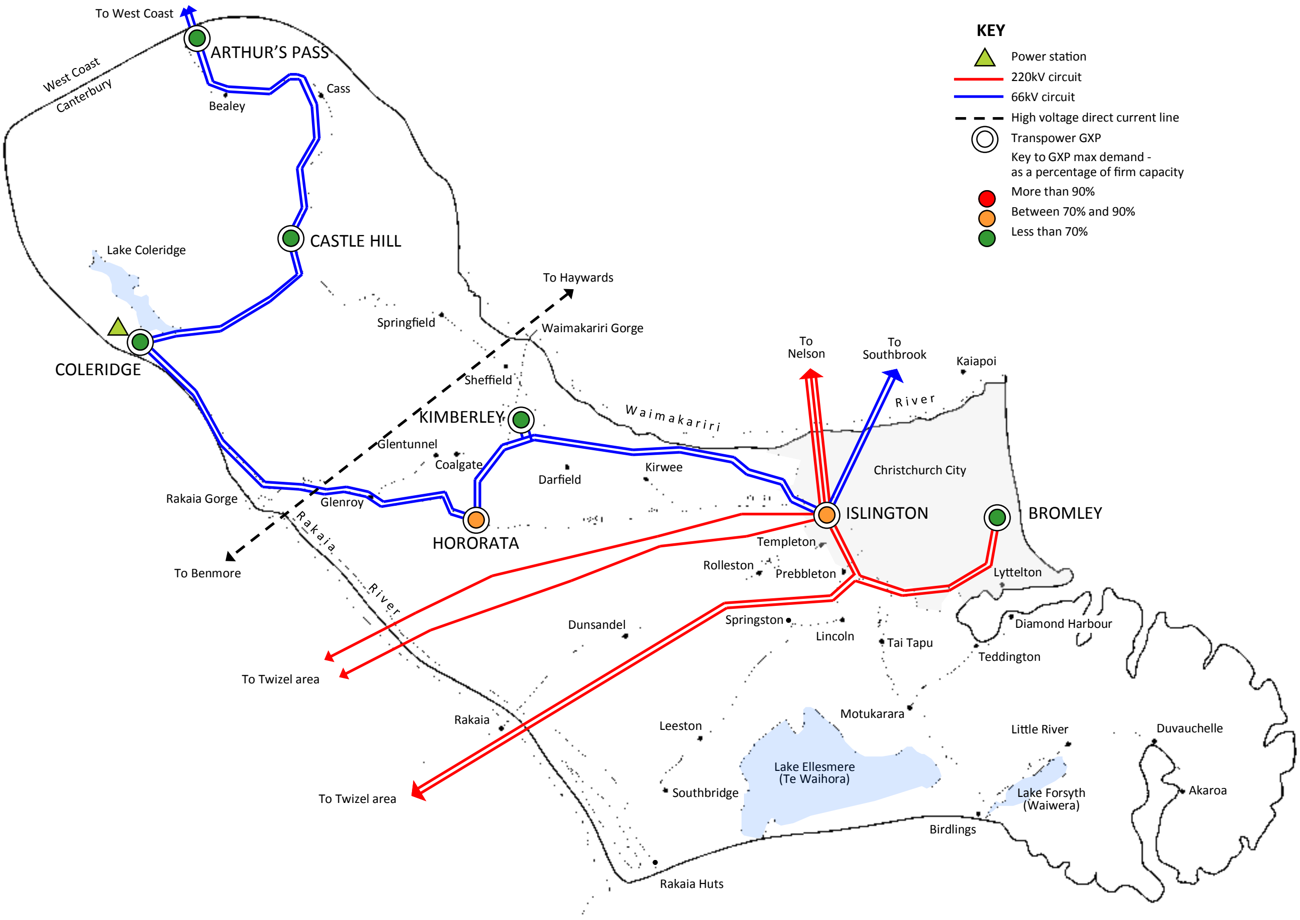
Security of supply for Orion's subtransmission network largely depends on how Transpower's assets are configured. We continue to review quality and security of supply issues (see our gap analysis in section 5.5).

As shown in section 4.1 (Network overview) we refer to our subtransmission network as region A and B. Traditionally these areas could be described as urban and rural but changes in customer demographics (e.g. the growth of Rolleston and Lincoln townships) necessitate recognition of a range of customer types in the rural area and a range of resulting network architectures.

Region A GXPs

Region A GXPs are located at Islington and Bromley which supply the CBD, Lyttelton and the Christchurch city metropolitan area. Islington has a 66kV and 33kV grid connection, while Bromley supplies a 66kV grid connection only. Islington and Bromley 220kV substations form part of Transpower's South Island grid. They interconnect between the major 220kV circuits from the southern power stations.

Figure 5-2 **Transpower system in Orion's network area**



Region B GXPs

Islington 66kV GXP also supplies a large part of the region B network including Banks Peninsula and the Rolleston and Lincoln townships. Hororata and Kimberley GXPs supply a significant proportion of the summer irrigation and milk processing area. Each GXP has a connection to the double circuit 66kV line between Islington and the West Coast with generation injection at Coleridge power station. Transpower provides a 66kV connection at Kimberley and a 66KV and 33kV connection at Hororata.

The remainder of region B is fed at 11kV from three small GXPs at Arthur's Pass, Coleridge and Castle Hill. Together these supply less than 1% of Orion's load.

5.2.2 Region A subtransmission

As detailed in section 4 we have a number of 66/11kV, 33/11kV and 11kV zone substations (with no transformer). The 11kV zone substations are being removed as the equipment comes up for replacement, as they do not fit with our current network design architecture. This AMP envisages one new region A zone substation and a capacity increase of transformers at two substations in the next 10 years. However the size, and location of this will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

We can connect most new loads to our network at short notice, as required by customers. The additional load makes use of network capacity held in reserve for contingency situations. That capacity must be replaced by capital expenditure in order to ensure that supply security continues to meet our Security Standard and the needs of our customers.

Each increment of between 20 and 40MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

5.2.3 Region B subtransmission

As detailed in section 4 in our rural area we have a number of 66/33/11kV, 66/11kV and 33/11kV zone substations. This AMP envisages one new zone substation, the capacity increase of transformers at two and the partial conversion of one zone substation from 33kV to 66kV in the next 10 years. This plan also makes provision for a new substation to connect distributed generation. However the number, size, and location of these will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

Each increment of between 5 and 20MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

The existing subtransmission network has been designed to meet strong load growth whilst optimising cost. The significant increase in load over the last 15 years has enabled a much more interconnected subtransmission network to be developed. The number of zone substations operating in radial configuration has reduced over time. Most zone substations have only one transformer, generally 7.5MVA or 7.5/10MVA, although substations serving larger townships such as Rolleston and Lincoln or a milk processing plant may have duplicated transformers up to 23MVA. Subtransmission capacity is generally limited by voltage drop considerations and hence 66kV (as opposed to 33kV) is technically and economically more attractive for new subtransmission projects.

5.3 Planning criteria

The first stage of planning a distribution network is to ensure that existing network loads are monitored and tested against existing network capacity. The capacity test involves checking adequacy during contingencies defined in our Security Standard and also predefined utilisation thresholds. More detail on our Security Standard and utilisation thresholds is described in the sections to follow.

When network inadequacy is identified, the process of developing solutions begins. Each potential solution is assessed for compliance with our design standards including safety compliance, capacity adequacy, quality, reliability, security of supply and economic consequences.

Sections 5.3.1 to 5.3.5 discuss the main planning criteria considered when solutions are developed.

5.3.1 Security Standard

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover from a fault or a series of faults.

Note that security of supply differs from reliability. Reliability is a measure of how the network actually performs and is measured in terms of things such as the number of times supply to customers is interrupted.

The basic structure of our current Security Standard was developed in consultation with external advisors and adopted by our board in 1998. It is based on the United Kingdom's P2/6 which is the regulated standard for distribution supply security in the UK. Consultation with electricity retailers and industry customer groups was also carried out. Currently there is only one industry guide published by the Electricity Engineers' Association of NZ (EEANZ) and no regulated national standard is in force. The principle is that the greater the size or economic importance of the demand served, the shorter the interruption time that can be tolerated.

During 2006 we reviewed our Security Standard to ensure it takes into account current customer preferences for the quality and price of service that we provide . As a result of our review and customer consultation, our Security Standard has been improved to better reflect the current needs of customers. Our revised Security Standard may result in slightly lower reliability for our metropolitan customers but will also reduce the need for future price rises.

These kinds of trade-offs between price and electricity supply reliability are a constant focus for us. Generally, the more we spend, the more reliable our community's electricity supply becomes. However, the trade-off is that the more we spend the higher our prices become, as we need to recover our costs. We are committed to seeking our customers' views on the price/quality trade-off and we want to ensure that our network investment decisions reflect customer preferences.

The demand group thresholds in our security of supply standard tend to err on the side of caution and generally provide a level of security that is slightly above the requirements of the average customer connection. Our analysis has also shown that it is appropriate to provide a slightly higher level of network security for the Christchurch CBD.

This approach ensures that customers who place a high value on security of supply are reasonably represented in areas where a mix of customer types exists. The Central City rebuild provided an opportunity to discuss the security and supply requirements with individual customers as they re-connect to our network. See section 3.2 for a summary of this consultation.

Given that six years had elapsed since our last Security Standard review and we had new earthquake related information to consider, we undertook a review of our urban 66kV and 11kV network architecture in 2012 which supported a continuation of our current security standard. We intend to review our rural 66kV and 11kV and urban low-voltage architectures in the future. Once these are complete they may lead to a further review of our Security Standard.

Further information, including a summary of our 2006 review, can be found on our website oriongroup.co.nz.

We made some semantic changes to our security of supply standard in 2014 to reflect the larger capacity zone substations and subtransmission feeders that we purchased from Transpower. The asset descriptions for some asset 'classes' were changed to better reflect the new asset ownership boundaries. The changes do not impact on our planned levels of security of supply.

This year (2017) we made a significant change to the format of our security of supply standard. The driver for this change was to avoid confusion around urban and rural definitions and provide greater clarity over the application of our security standard to metropolitan type loads in rural areas. That is, we apply a higher security of supply standard class to metropolitan areas such as Rolleston and Lincoln than is the case for the wider rural area. The is no change in security of supply levels on the actual network, the change was purely to provide greater clarity.

In addition to our security of supply standard, customers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We also facilitate changes to individual security of supply arrangements for existing customers.

Our largest urban customer connections are relatively small on a national level and have peak loads of approximately 4MW. Our security of supply standard caters for connections of this size and therefore the occurrence of individual security arrangements on our network is minimal. They are mainly limited to high profile services such as hospitals, Christchurch airport and public sports venues. The milk processing plants at Darfield and Dunsandel have peak demands approaching 12MW. We have put in place individual security of supply arrangements for these connections.

Table 5-3a Distribution network supply Security Standard

Class	Description of Area or Customer type	Size of load (MW)	Cable, line or transformer fault	Double cable, line or transformer fault	Bus or switchgear fault
Transpower GXPs					
A1	GXPs supplying CBD, commercial or special industrial customers	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B1	GXPs supplying predominantly metropolitan areas (suburbs or townships)	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
C1	GXPs supplying rural and semi rural areas	15-60	No interruption	Restore within 4 hours (Note 1)	No interruption for 50% and restore rest within 4 hours (Note 1)
D1	GXPs in remote areas	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Orion 66kV and 33kV subtransmission network					
A2	Supplying CBD, commercial or special industrial customers	15-200	No interruption	Restore within 1 hour	No interruption for 50% and restore rest within 2 hours
A3	Supplying CBD, commercial or special industrial customers	2-15	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
B2	Supplying predominantly metropolitan areas (suburbs or townships)	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B3	Supplying predominantly metropolitan areas (suburbs or townships)	1-15	Restore within 2 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
C2	Supplying predominantly rural and semi-rural areas	15-200	No interruption	Restore within 4 hours (Note 1)	No interruption for 50% and restore rest within 4 hours (Note 1)
C3	Supplying predominantly rural and semi-rural areas	4-15	Restore within 4 hours (Note 1)	Restore 50% within 4 hours and the rest in repair time (Note 1)	Restore within 4 hours (Note 1)
C4	Supplying predominantly rural and semi-rural areas	1-4	Restore within 4 hours (Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time (Note 1)
Orion 11kV network					
A4	Supplying CBD, commercial or special industrial customers	2-4	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
A5	Supplying CBD, commercial or special industrial customers	0.5-2	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
A6	Supplying CBD, commercial or special industrial customers	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
B4	Supplying predominantly metropolitan areas (suburbs or townships)	0.5-4	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
B5	Supplying predominantly metropolitan areas (suburbs or townships)	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
C5	Supplying predominantly rural and semi-rural areas	1-4	Restore within 4 hours (Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time (Note 1)
C6	Supplying predominantly rural and semi-rural areas	0-1	Restore in repair time	Restore in repair time	Restore in repair time

Note 1. Assumes the use of interruptible irrigation load for periods up to 48 hours.

5.3.2 Network utilisation thresholds

We monitor loads on our major zone substation 11kV feeder cables at half hour intervals. This information is used to prepare an annual reinforcement programme for our network. Reinforcements recommended in this plan are generally based on winter loading for the metropolitan areas and on summer loading for the farming areas.

Growth at the 11kV distribution level is largely dependent on individual subdivision development and customer connection upgrades. Growth in excess of the system average is not uncommon and therefore localised growth rates are applied to the region under study. Zone substations, subtransmission and distribution feeder cables are subject to four distinct types of load:

1) **Nominal load:** Is the maximum load seen on a given asset when all of the surrounding network is available for service.
2) **N-1 load:** Is the load that a given asset would be subjected to if one piece of the network was removed from service due to a fault or maintenance.
3) **N-2 load:** Is the load that a given asset would be subjected to if two pieces of the network were removed due to a fault or maintenance.
4) **Bus fault load:** Is the load that a given asset would be subjected to if a single bus was removed from service due to a fault or maintenance.

As defined in our Security Standard, the location and quantity of load supplied by a feeder has a bearing on whether all or only some of the four load categories described above should be applied to an asset for analysis.

If the nominal load reaches 70% or the N-1, N-2 or bus fault load reaches 90% then a more detailed review of the surrounding network is instigated.

5.3.3 Capacity determination for new projects

When a capacity or security gap is identified on the network it is necessary to consider different capacity options as solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder to the area. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense altogether.

When comparing different capacity solutions it is necessary to utilise the net present value (NPV) test. The NPV test is an economic mechanism that converts the value of future projects to present day dollars. NPV analysis generally supports the staged implementation of a number of smaller reinforcements. This approach also reduces the risk of over-capitalisation that ultimately results in stranded assets.

The capacity of a new zone substation and 11kV feeders is generally fixed by the desire to standardise network equipment. The capacity of a zone substation and transformer/s is based mainly on the load density of the area to be supplied and the level of the available subtransmission voltage. The expense of 66kV switchgear and underground 11kV cables, along with the high load densities in metropolitan areas facilitate large zone substations without the issues of excessive voltage drop and losses associated with equivalently sized zone substations within the farming and remote rural regions. Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair. Transformers and switchgear are more readily interchangeable and the range of spares required for emergencies can be minimised.

When underground cable capacities are exceeded, it is normally most effective to lay new cables. When overhead line capacities are exceeded, an upgrade of the current carrying conductor may be feasible. However the increased weight of a larger conductor may require that the line be rebuilt with different pole spans. In this case it may be preferable to build another line in a different location that addresses several capacity issues.

For new load it is often necessary to extend the network into new areas. As new load is connected it is necessary to reinforce the upper network. Overall a conservative approach is taken. New upper network capacity is installed only once new load growth has or is certain to occur. In the short term, unexpected or accelerated load growth is met by utilising security of supply capacity.

We discuss our approach to increased capacity in our documents NW70.60.16 - Network Architecture Review: Subtransmission, NW70.60.06 - Urban 11kV Network Architecture Review, and NW70.50.05 - Network design and overview.

The following table 5-3b provides a summary of our standard network capacities.

Table 5-3b **Standard network capacities**

Location/load density	Subtrans-mission voltage (kV)	Subtransmission capacity	Zone substation capacity (MW)	11kV feeder size (Note 1 and 2) (MW)	11kV tie or spur (Note 1) (MW)	11/400kV substation capacity (MW)	400V feeders (Note 1) (MW)
Urban high density loads	66	40MW radials (historical approach) 40-160MW for interconnected network	40	7	4	0.2-1	Up to 0.3
Urban high density loads	33	23MW radials and interconnected network	23	7	4	0.2-1	Up to 0.3
Rural low density loads	66	30MW radials 30-50MW interconnected network	10-23	6	2	0.025-1	Up to 0.3
Rural low density loads	33	15MW radials and interconnected network	7.5-10	6	2	0.025-1	Up to 0.3

Notes: 1. Network design requires 11kV and 400V feeders to deliver extra load during contingencies and therefore normal load will be approximately 50-70% of capacity.

2. 11kV feeders in the rural area are generally voltage constrained to approximately 3-4MW so the 6MW capacity only applies if a localised high load density area exists.

5.3.4 Project prioritisation

Prioritisation of network solution projects for capacity and constraints is a relatively complex process that involves multiple factors that are both external and internal to Orion.

The primary factors to be considered when prioritising projects, in decreasing order of significance, are:

1. Coordination with NZ Transport Authority and local authority civil projects:

   Where projects are known to occur in the same location, we aim to schedule our projects to coincide with the timing of key civil infrastructure projects by these two parties. This may cause us to bring forward, or even delay if possible, capital works projects to avoid major future complications and unnecessary expenditure which may arise. The most common activity of this type is coordination of planned cable works with any future road-widening or resealing programmes to avoid the need to re-lay cables or excavate and then reinstate newly laid road seal. We have worked closely with SCIRT as they rebuilt the pipes and roads of Christchurch, and we co-ordinated our Dallington to McFaddens 66kV cable installation with SCIRT's civil works in this area to allow a single trenching and resealing programme.

2. Satisfying individual or collective customer expectations:

   We consider satisfying customer expectations as very important and give priority to the constraints that are most likely to impact customer supply through extended or frequent outages, or compromised power quality.

3. Managing contractor resource constraints:

   We aim to maintain a steady work flow to contractors and ensure project diversity is preserved within a given year. This ensures that contractor personnel and equipment levels match our capital build program year-on-year at a consistent level, reducing the risk of our contractors being over or under resourced.

4. Coordination with Transpower:

   We endeavour to coordinate any major network structural changes adjacent to a GXP with Transpower's planned asset replacement programmes, and also provide direction to Transpower to ensure consistency with our sub-transmission upgrade plans.

5. Our asset replacement programme:

   We extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought to fit in with the current and long-term network development structure, for example replacement of switchgear in substations.

6. Our asset maintenance programme:

   We seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes, for example zone substation transformer half-life maintenance.

Factors 1-4 are external to the company and 5-6 are internal Orion processes. All are principally objective in nature; however, while specific issues may result in clear outcomes of customer satisfaction for the customers involved, feedback from our general customer base is less directly obtained. Sample sets of customers are surveyed on some matters, and ultimately direction is provided via the elected representatives of Orion's shareholders, the Christchurch City and Selwyn District councils.

After assessing their relative priorities, the final decision to undertake investment projects in the forthcoming year depends on urgency. Other factors also apply, such as seasonal timing (to avoid taking equipment out of service during peak loading periods - winter for projects in metropolitan areas and summer for projects in farming areas), and the necessary order of interconnected projects. Professional engineering judgements based on experience and expertise may come into these decisions.

Projects not selected for next year are provisionally assigned to a future year in the 10-year planning window. When next year's project selection process is undertaken all projects are reviewed and, depending on changes in information and priorities, either maintained in the planning schedule, advanced, deferred, modified, or deleted.

Further details of our approach is in our document NW70.60.14 - Project Prioritisation and Deliverability Process.

5.3.5 Non-network solutions

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we consider the following alternatives:

- customer demand management
- distributed generation
- uneconomic connections.

Customer Demand Management

Customer Demand Management provides an alternative to transmission and distribution network reinforcement. Originally known as demand side management the term has been refreshed to align with the value of connecting with customers instead of being on different sides.

Customer Demand Management can be defined as shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the grid and network operator.

Since legislation required electricity retailers to be separate from network operators, it has become more difficult to implement a fully integrated Customer Demand Management strategy. Electricity customers are generally no longer directly contracted to Orion. Our primary mechanism for achieving better utilisation of the assets is to signal the investment cost implications to electricity retailers in our delivery pricing structure. The derivation and application of delivery pricing is published on our website oriongroup.co.nz.

We are integrating Customer Demand Management into development of our network. Some of the gains from Customer Demand Management are:

- increased utilisation of the network
- improved utilisation of Transpower's transmission capacity
- customers benefit by becoming more efficient in the utilisation of energy and network capacity
- customer relations improve through less upward pressure on prices.

The following Customer Demand Management strategies are applied by Orion:

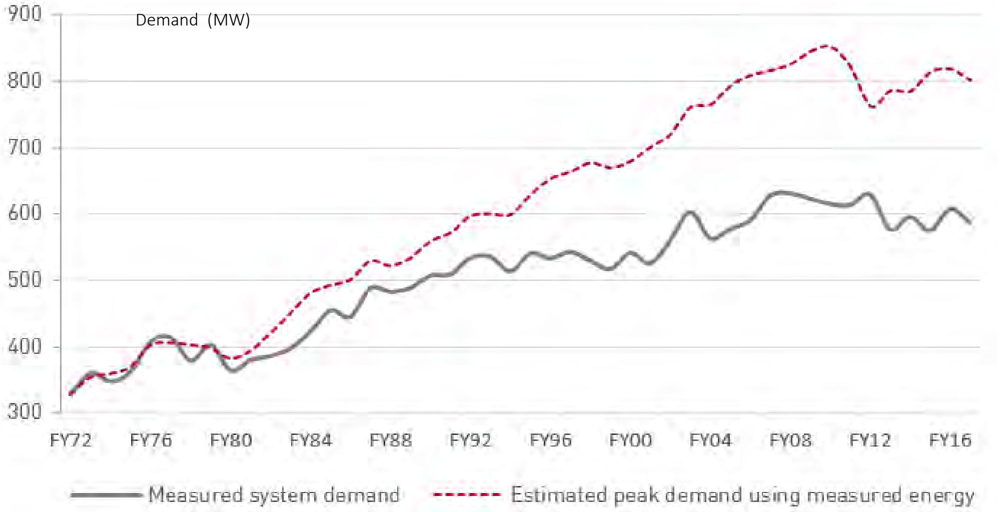
- ripple system – anytime hot water cylinder control
- ripple system – night rate price options to spread load more evenly over the day
- ripple system – major customer price signalling
- ripple system – interruptible irrigation
- ripple system - generation credits
- power factor correction rebate
- coordinated upper south island load management
- diesel fuelled generation.

The recent and forecast improvement in battery technology, and forecast drop in price is likely to create new Customer Demand Management opportunities in the short to medium term. We will continue to monitor and investigate opportunities.

For further detail on the potential of Customer Demand Management initiatives to defer or avoid investment, see section 5.6.9.

We also discuss Customer Demand Management (previously called Demand Side Management) in our network documents NW70.60.10 - Demand Side Management Stage 1 – Issues and Opportunities and NW70.60.11 - Demand Side Management Stage 2 – Potential Initiatives.

Figure 5-3 **Peak demand capping**



Ripple control

Ripple control is one of the most effective tools available for implementing Customer Demand Management. Ripple enables us to send a myriad of load control and pricing signals to our customers. Over the last 30 years, our commitment to Customer Demand Management through hot water cylinder control and peak and night rate price signalling has resulted in a dramatic difference between the growth in peak demand and energy. The previous graph shows that significant peak demand capping occurred during the 1990s as a result of our Customer Demand Management initiatives.

Since 1980 a gap of 200MW has been achieved between energy based estimated peak demand and actual peak demand. Committed utilisation of our ripple control system is thought to have been the driver for approximately 100-150MW of the 200MW gap between demand and energy. The decreased gap following the earthquakes is due to the large drop in energy delivered due to the reduction in connections supplied. There was no drop in demand for the first two years following the earthquakes due to significant snow falls in August 2011 and June 2012.

Ripple control has facilitated the implementation of the following Customer Demand Management strategies:

- hot water cylinder control – 50MW of peak load deferment
- night store heating – 125MW of night load providing an estimated 50MW peak reduction
- price signalling to major customers – 25MW (includes embedded generation)
- interruptible irrigation load groups (summer only) – 25MW during contingencies (This has reduced 3MW with the decommissioning of ground water pumps due to the uptake of the Central Plains Water Scheme).

To ensure that we can continue to achieve these results, three 66kV ripple plants have been replaced with multiple 11kV ripple plants. 11kV ripple plants avoid overloading issues caused by an increasing number of capacitors being installed on Transpower's grid and also reduce dependence on any one item of plant.

A current issue is our dependency on ripple control receivers located at customers' premises. Orion does not own these receivers and therefore has limited ability to control their installation and maintenance. In 2007 we modified our Network Code to make it mandatory to install ripple receivers that respond to an emergency signal.

We will continue to work with retailers and meter owners to ensure that the benefits of ripple control continue to be achievable as the implementation of new technology occurs.

We also recognise that new communication technologies are becoming viable and we are investigating the use of these alternatives (to ripple) technologies. A particular focus is in rural areas where the number of customers is low relative to the ripple plant investment.

Interruptible load groups – irrigation

When an interruption to supply occurs on our network, there is a cost of lost production and the inconvenience to our customers. Our targets for reliability are based on matching the cost of an interruption to the cost of preventing one. That is, there is a point where investing further in our network is not justified by the cost saving to our customers from reduced interruption times.

Not all customers are exposed to the same costs when an interruption occurs. To reduce expenditure on the network and therefore control price, it can be useful to first restore supply to customers who have a high cost of non supply, and then restore supply to those customers with a low cost of non supply when the fault is repaired. Following consultation in 2005 with irrigation customers, we have extended the possible duration of interruptions for irrigators up to 48 hours under extreme conditions. At the time of implementation, the ability to do this prevented the need to construct Ardlui zone substation ($3m) and delayed several other projects ($7m in total). The continued application of interruptible irrigation has continued to avoid and delay further network investment over the last 10 years. This has significantly reduced pressure on price rises to our customers. We will consider the impact of the Central Plains Water scheme on the effectiveness of this arrangement. The future review of our rural network architecture will also provide an opportunity to re-examine the economics and implementation of our irrigation interruption scheme.

Power factor correction rebate

If a customer's load has a poor power factor then our network and the transmission grid is required to deliver a higher peak load than is necessary. This may lead to the need for an upgrade.

Our Network Code requires all customer connections to maintain a power factor of at least 0.95. During 2010 we introduced a penalty charge for customers whose power factor falls short of the 0.95 minimum. In the Christchurch urban area where the predominately underground network is high in capacitance (which helps to improve power factor), the minimum 0.95 power factor requirement has resulted in an overall 0.99 GXP power factor at times of network peak. This is a good outcome and any further benefit from offering financial assistance to correct power factor in the urban area would be uneconomic.

However, in the rural area, the predominately overhead network is high in inductance (which reduces power factor) and we offer a financial incentive in the form of a 'power factor correction rebate' to irrigation customers with pumping loads greater than 20kW. The rebate provides an incentive for irrigators to correct their power factor to at least 0.95. The rebate is set at a level where it is economic for the customer to provide power factor correction, which is lower than the avoided network investment cost associated with power factor related network upgrades.

Coordinated Upper South Island load management

As well as controlling hot water cylinder load to manage peaks on our own network we also coordinate control of hot-water cylinders on other distributors networks to manage peaks on Transpower's Upper South Island network. We do this via a specifically designed Upper South Island load manager which communicates with Transpower and all of the Upper South Island distribution network companies. Through cooperation and the coordination of Upper South Island load control we are able to maximise the potential to reduce peaks without excessive control of hot-water cylinders.

Distributed/embedded generation

The purpose of our distribution network is to deliver bulk energy from the Transpower GXPs to customers. In certain circumstances it can be more economic for the customer to provide a source of energy themselves in the form of distributed generation (DG). DG may also reduce the need to extend network capacity.

Our policy (see our website) for DG provides a different treatment for different sizes of distributed generation.

In particular our policy for DG above 750kW gives consideration to the following issues:

- coincidence of DG with Transpower interconnection charges
- benefits of avoided or delayed network investment
- security of supply provided by generators as opposed to network solutions
- hours of operation permitted by resource consents
- priority order for calling on peak lopping alternatives, such as hot-water control versus DG.

Without the ability to store energy from Photovoltaic (PV) generation, it is unlikely that PV generation will reduce peak demand on our urban winter peaking network. Whereas diesel generation can reduce peak loads and is therefore included in our peak forecast. PV generation may offer a reduction to peak demand on our rural network which is driven by summer irrigation load. There is potential for the proliferation of PV generation to cause over-voltage problems on our low voltage network. We anticipate that we will need to either reinforce some of our low voltage network to provide for PV generation or invest in PV generation management technologies to prevent over-voltage on the worst days of the year. We have recently undertaken a study to determine the DG (mainly PV) hosting capacity of our low voltage network. New DG connection guidelines have been released through the Electricity Engineers Association and we intend to transition our DG connection process to match. The new process enables customers to make an informed choice about the level of export they propose with different technical and financial consequences associated with different choices. This should limit the amount of reinforcement needed on the network to an efficient level. See section 5.4.7 regarding the management and utilisation of our low voltage network.

In order for diesel generation to be effective we require a contract to ensure that peak lopping is reliably achieved. This is done through pricing structures that encourage users to control load at peak times. We will continue to encourage diesel generation through appropriate pricing mechanisms. Given the large investment and potentially significant network constraint deferment associated with export generators of more than 750kW, we assess them on a case-by-case basis.

We continue to proactively support the installation of diesel generation by major energy users. An incentive for major customers to generate electricity is provided through our pricing structure which includes an avoidable control period demand charge. We estimate that approximately 15MW of generation is available on control period demand signalling. The total major customer response is about 25MW and some of that is load reduction (rather than generation). There is also a significant quantity of standby generation owned by customers for their own use during an interruption.

Our peak load forecast assumes that an additional 2MW of peak diesel generation will be installed each year. The series of Christchurch earthquakes has lead to an increase in enquiries to connect diesel generation. For this to be effective in deferring network capacity, the generation capacity must be reliably available to support the network in a fault/constraint situation. In general this requires that generation be offered to operate as and when required, which in turn necessitates that fuel is able to be stored.

DG using fuel that cannot be stored does not usually substitute for network capacity unless fuel supplies are stable and reliable. Wind, PV, and run-of-river hydro are three types of generation that provide energy but do not substitute for network capacity. However, with multiple sites and diversity in fuel characteristics, some certainty of availability can be determined through analysis of historic data.

We have resource consents to install a total of 23MW of generation capacity split between sites at Bromley and Belfast. Generation at the Belfast site has potential to defer investment in new zone substations. The recent Christchurch earthquakes have resulted in significant damage to our 66kV subtransmission network feeding the Christchurch north eastern suburbs. In 2016 we completed a new 66kV subtransmission cable between Waimakariri and Rawhiti zone substations to provide a more resilient supply across the northern part of Christchurch. This increased subtransmission resiliency across the City, tactical 11kV reinforcement projects and Marshland zone substation planned for FY23 led to the two 2MW diesel generators at QE2 being decommissioned in 2016/2017.

Justification for installing generation at the Bromley site will require either an energy-firming contract with an electricity market retailer or suitable market arrangements to reward us for relieving transmission constraints between Twizel and Christchurch. Depending on the nature and duration of any contract, this generation may also provide alternative investment options for our distribution network.

Without creating an ‘at arms-length’ business, our potential involvement in large scale generation projects is limited by the Electricity Industry Act 2010 to 50MW for embedded generation within the distribution network or 250MW for grid connected generation.

Uneconomic connections policy

When an application for a new or upgraded connection (larger connections only) is submitted for review, we undertake an economic assessment of the connection. This assessment determines whether or not our standard pricing arrangements will cover the cost of utilising existing or new assets associated with the connection. If the connection is uneconomic (i.e. existing customers would be subsidising the new connection) then a connection contribution is required from the new customer.

This policy ensures that the true cost of providing supply is passed on to the appropriate customer and thereby allows them to make the right financial trade-offs. If an economic non-network alternative is available then that option can be chosen.

5.4 Energy, demand and growth

5.4.1 Introduction

To effectively plan the future of our network, we need to estimate the size and location of future loads. Long-term growth in energy consumption showed a consistent trend until the major earthquakes in FY11. This trend provides a first estimate of load growth both for the full network, and for specific areas within. However any load forecasting is an approximation—load cannot be forecast with 100% accuracy. There is some uncertainty due to the drop in peak demand and energy consumption from a population decrease (particularly in the east of the city), increasing immigration and timing of the commercial rebuild in central Christchurch. Furthermore, a range of emerging technology uptake scenarios creates additional uncertainty.

Energy and demand growth is a function of many inputs. Network development is driven by growth in peak demand (not energy); therefore we focus on demand growth rather than energy. In general, two factors affect load growth:

- population increases
- changes in population behaviour.

At a national level, it is reasonably easy to forecast population growth. When the national forecast is broken down to a regional level, the accuracy is less reliable but still useful in predicting future demand growth.

Many variables affect behavioural change. These include technological advancements, available energy options and requirements such as Environment Canterbury's Clean Air Plan. Of particular relevance is the uptake of photovoltaic generation, battery storage and electric vehicles. It is difficult to forecast these variables accurately. As well as these variables, our Customer Demand Management strategies shape our peak demand load forecast.

As a high level of accuracy is required to build an appropriate electricity distribution network, we treat load forecasts as a guide. A major 66kV or 33kV network development project takes approximately three years to plan, design and build, while smaller 11kV projects take around 18 months. A 400V solution can take several months. In this context it is prudent to apply flexibility in how we implement our network development proposals, rather than rigidly adhere to a project schedule based on an outdated forecast.

We derive our load forecast from a combination of bottom-up inputs, such as household growth forecasts by CCC using Statistics NZ 2016 projections-and historical trends in growth. These are adjusted to reflect significant inputs such as milk processing plant upgrades and Customer Demand Management initiatives.

The following sections summarise our key load forecasting inputs.

Earthquake February 2011

The February earthquake reduced energy delivery volumes by approximately 10%. Recent energy consumption suggests that energy volumes have recovered to around 4% below pre earthquake level.

The following figures show how connection numbers have been impacted by the earthquakes. The total is now 2% higher than the pre-earthquake peak.

Projecting on-going recovery post-earthquake is difficult. For post-earthquake population projections we are using the latest data

Figure 5-4a Number of active residential connections

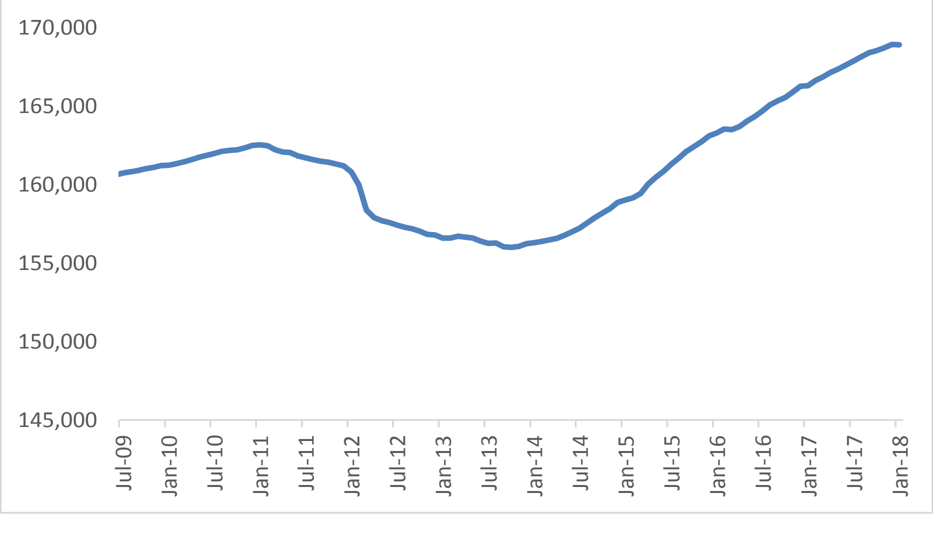
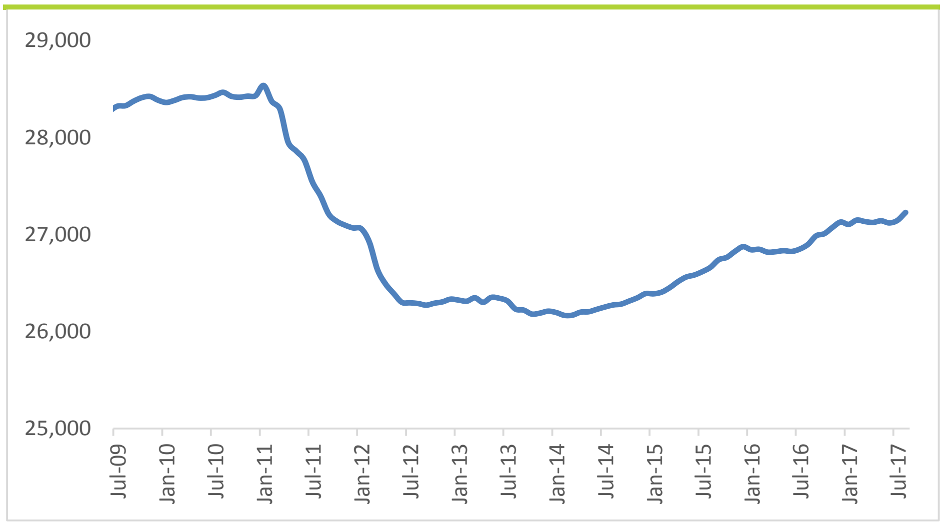
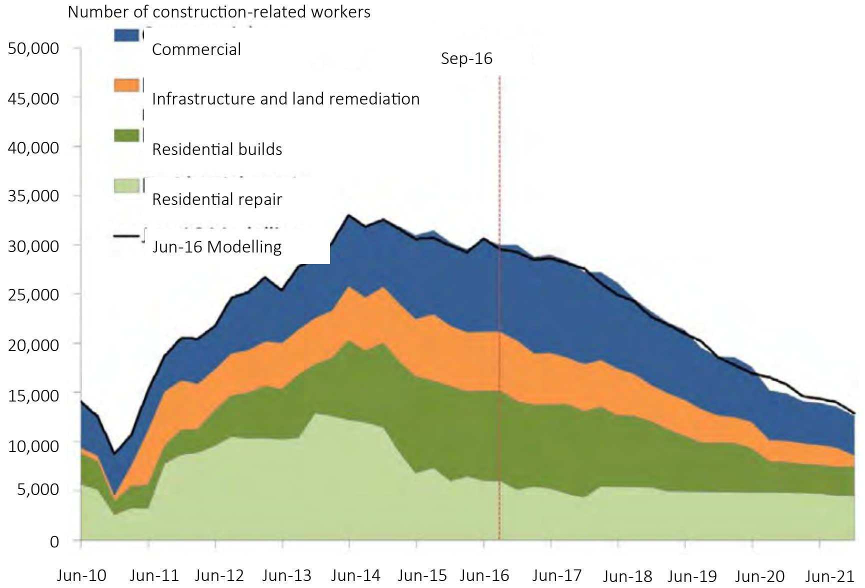


Figure 5-4b **Number of active business connections**



available at the time of drafting (CCC April 2017 and Selwyn District Council May 2016). The post-earthquake Census information increases forecast confidence, however more than usual uncertainty remains. Contributing factors are the temporary workforce associated with the rebuild and the changing household composition due to residential repairs and housing market constraints. Ministry of Business, Innovation and Employment information shown in figure 5-4c indicates the temporary workforce numbers have their peak. The reduction in load that would result from workers leaving the area is offset in part by the increase from new buildings they have finished.

Figure 5-4c **Greater Christchurch construction related employment projections**



Impact of economic downturn

Peak demand on our network varies depending on the harshness of the winter weather. Peak demand has not surpassed the high peak reached during the 2006 winter snow storm. The pre-earthquake 2010 peak was only 2% above the 2002 winter snow storm peak. The potential impact of the pre-earthquake economic downturn has been superseded by the earthquake recovery phase. Our underlying growth forecasts are linked (via the Urban Development Strategy and LURP) to Statistics New Zealand population projections. The economic environment can affect network construction costs and we monitor these costs on an annual basis to capture the impact of the economic environment on commodity prices.

Impact of Customer Demand Management on load forecast

Our Customer Demand Management strategies discussed in section 5.3.5 impact on our peak load forecast. Our network peak demand forecast assumes that 2MW of diesel generation will be added to our network each year. This is commensurate with growth in diesel generation over the last five years. Because it is difficult to predict the location of new diesel generation, we have not attempted to apply the growth in diesel generation to the zone substation load forecasts. Instead we attempt to encourage diesel generation in constrained areas on our network by publishing the area specific network deferral value of Customer Demand Management initiatives (see section 5.6.9). In reality, customer investment is usually driven by their own security of supply objectives and the benefits to our network are secondary to the overall business case.

The impact of other Customer Demand Management initiatives such as price signalling, night rate tariffs and hot water cylinder control is captured in the underlying inputs to our load forecast. For example, we monitor the after diversity maximum demand (ADMD) of new households and apply this figure to the projected number of subdivision lots for an area to determine a forecast which includes the impact of our Customer Demand Management initiatives.

A sample of 2,333 residential sites were analysed after the 2015 winter peak. At the 11kV feeder level, the ADMD for households older than five years was 2.6kW, and 3.0kW for those less than two years old. This indicates energy efficiency and insulation is offsetting peak demand impacts due to increased size of households and the increased uptake of electrical appliances and heat-pumps. This data is used in our subtransmission forecasts for both new subdivisions and urban infill (3kW per infill household). A similar process is also applied on a per hectare basis for industrial subdivisions but we recognise that specific customer requirements can cause a significant variance from the average case.

This process is described in NW70.60.12 - Long term load forecasting methodology for subtransmission and zone substations. See also section 5.4.3 - Methodology for determining GXP and zone substation load forecasts.

5.4.2 Observed and extrapolated/forecast load growth

Energy throughput (GWh)

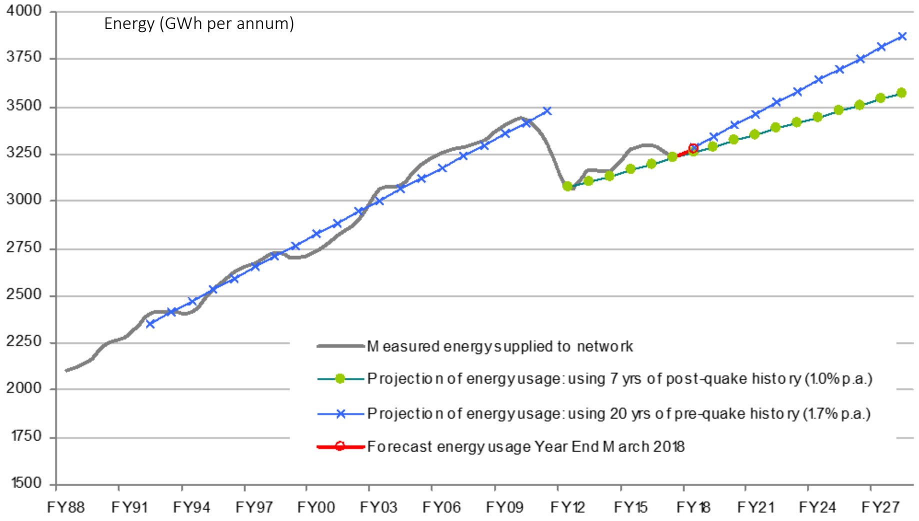
Network energy throughput for FY17 was 3,227GWh (including export from distributed generation of about 7.4GWh), down 2.1% on the previous year. The 20-year pre-earthquake history shows an average steady growth rate of about 1.7% each year. For the six years post earthquakes, energy growth was lower than the long term average at 1.0%. Environment Canterbury's Clean Air Plan has had only a modest impact on energy use, as surveys suggest that the high conversion rates of solid fuel burners to heat pumps has been balanced in part by other customers switching from resistive heating to higher efficiency heat pumps.

We have observed a downward step change in energy demand as a result of the February 2011 earthquake. For several years recovery was limited by demolition work in the Central City and in the east. We expect the new business and residential buildings will be more energy efficient than the older buildings they replace, and the Ōtākaro Central City Recovery plan also implies fewer, much smaller rebuilds. The increase from the Central City rebuild started having an impact in 2016. However this is offset by the Central Plains Water Scheme which is reducing energy use due to the transition from deep well pumping to surface supplied water. Energy volumes started trending up in 2012, then a particularly mild 2013 winter lowered usage for FY14. FY15 also had a very mild winter, but then a dry summer led to high irrigation load. FY17 was lower due to a mild 2016 winter followed by a wet spring (which lowered irrigation demand). Figure 5-4d shows the projection of pre–earthquake and post-earthquake growth rates.

Maximum demand

Maximum demand is the major driver of investment in our network. This measure is very volatile and normally varies by up to 10% depending on winter weather. In 2011 the July snowstorm increased the peak by 7%. After the August 2011 snowstorm the peak increased by a further 10%. Because our network demand peaks during the winter, we can publish the FY18 peak in this

Figure 5-4d **Orion network annual energy trends**



Financial year	Measured energy	Forecast energy
FY07	3,287	
FY08	3,325	
FY09	3,402	
FY10	3,430	
FY11	3,308	
FY12	3,070	
FY13	3,165	
FY14	3,162	
FY15	3,277	
FY16	3,296	
FY17	3,227	
FY18		3275
FY19		-

AMP.

Our network maximum half hour demand, based on load through the Transpower GXPs, for FY18 was 605MW (the peak that occurred on 12 July 2017), up 18MW-from the previous year. Note that these figures exclude excursions that show up in regulatory disclosure data which are not used for forecasting demand.

Forecasting peak demand at the moment has challenges (on top of the earthquakes) including uncertainties with the global economy and the uptake of battery storage and electric vehicles. The housing stock replacement following the earthquakes have contributed to a drop in load (relative to pre-earthquake) due to modern, better insulated replacement housing. Prior to the earthquakes, the long and short term trends showed a demand growth rate of just under 1% per annum. It appears this rate may have slowed recently, however this is not clear as the changes are much smaller than the 60MW (10%) yearly variation due to weather. In the short term the Central City rebuild is forecast to add 12MW to the maximum network demand. Longer term we consider the following scenarios:

- Electric vehicles including plug in hybrid electric vehicles

  We have used the 2015 Ministry of Transport potential uptake figures, as this aligns best with current growth. The current growth is 40% higher than the 2016 government target and this scenario assumes that growth will remain 30% higher for the next few years, and that 9% of households will have an electric vehicle by winter 2027. The high uptake recently is shown in Figure 5.4r. For zone substation forecasts, it is assumed that 20% of these vehicles will be charged at peak, which matches the behaviour of early adopters. For scenario analysis at the overall network level, the EV impact is doubled to give an indication of possible impact. The accuracy of this forecast will improve as uptake trends become clearer and behaviour around time of charging is established. Night time charging reduces the impact to the network and provides cost savings for customers. The growing potential impact of electric vehicles is shown by the blue wedge in the following figure. The small 'bump' early next decade is possibly due to the increase in new EV model options, and competition putting downwards pressure on pricing for new vehicles.

- Energy efficiency and customer response engagement

  The ongoing EECA campaigns are leading to an increase in appliance efficiency and cost reduction is increasing the uptake of LED lighting. It is also reasonably likely that we will see improvements in the efficiency of heating water using heat exchanger technology. Retailers are providing signals of high cost power or high CO_2 generation half hours to encourage temporary load reduction. These trends could continue to reduce peak demand by 0.5% annually as indicated by the pink wedge in the following figure.

- Photovoltaics and battery storage

  The rapid uptake of solar photovoltaics has no effect on the peak which occurs on a winter evening after sunset. However the reductions in the cost of battery storage are likely to lead to purchase of storage by Orion customers. The storage could be supplied by PV year round and/or supplied by cheaper night rate electricity. Modelling shows that the combined effect of 65% of connections having photovoltaic generation and 7kWh of storage could reduce the peak by up to 95MW. At this level of uptake the daily winter profile would be largely flat and the benefit of additional battery storage would only be of benefit if electric vehicles were being charged at peak. If ~50% of connections introduced battery storage to the network over the next 10 years the reduction is shown by the green wedge in the following figure.

Figure 5-4e **Likely range of impact on the Orion network**

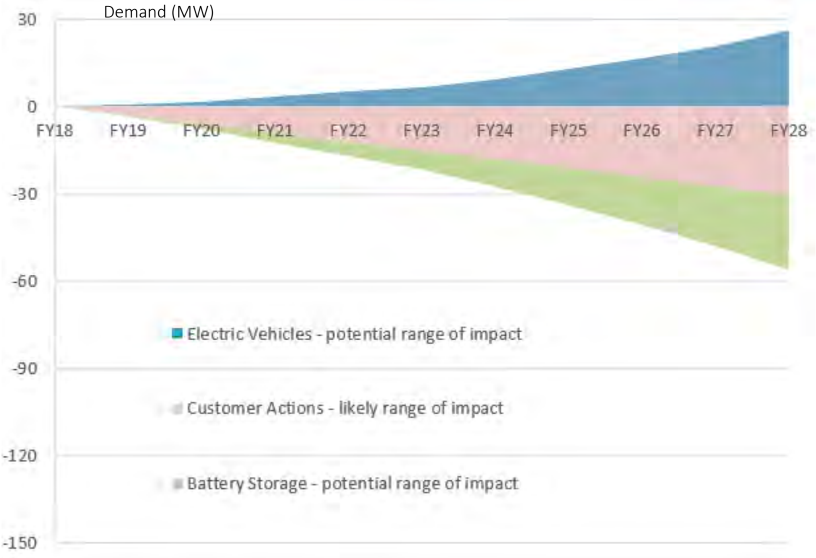


Figure 5-4f of historic network demand also includes three forecasts:

- Forecast system demand -mid scenario

  This indicates the underlying growth from new residential households , industrial uptake and commercial rebuild. It also assumes that 9% of the vehicle fleet will be electric by mid 2027 with 20% charging at peak. Energy efficiency continues to reduce peak demand by 0.5% per annum. This forecast does not include the effects of PV or batteries which have more uncertain uptake and impact. The above average increase in the short term is driven by a strong residential forecast and higher than normal number of 'in progress' commercial connection applications, e.g. Belfast water bottling plant, and central city projects (including Art Centre, Library, hotels, Justice and Emergency precinct).

  The GXP and zone substation forecasts provided later in section 5 are also based on this 'mid scenario' forecast. The peak demand forecasts in network reinforcement included in this AMP is designed to ensure that nominal and security of supply capacity is provided for in this peak demand forecast. Note however that we have the ability to respond relatively quickly (2-3 years) to actual growth and impact of emerging technologies.

- Forecast system demand high scenario

  This high scenario shows the consequences of further energy efficiency gains becoming unattainable and a doubling of the electric vehicle impact - either double the number of EVs or double the number charging at peak.

- Forecast system demand low scenario

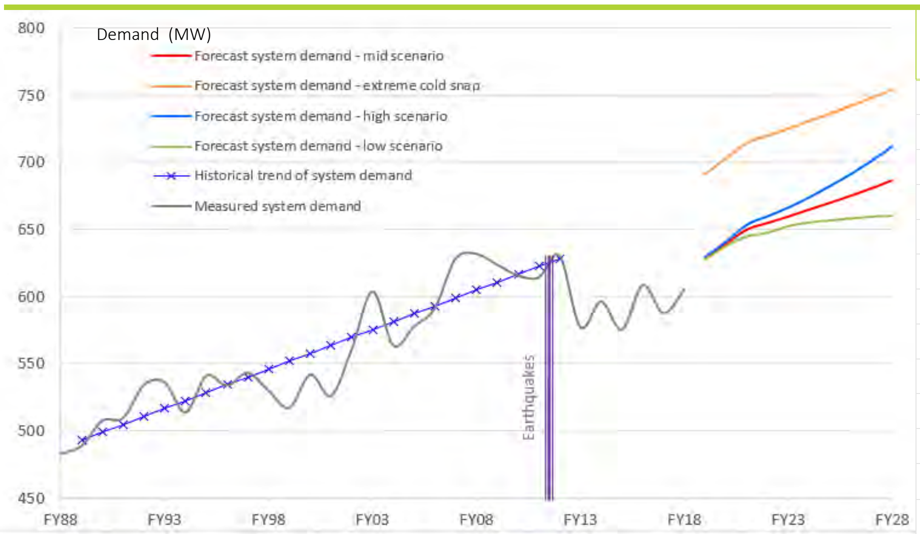
  The low scenario is based on continued energy efficiency at 0.5% per annum and battery storage (in either stationery or mobile form) being used to counter the impact of electric vehicle charging at peak - that is batteries inject power at peak to meet the charging needs of electric vehicles.

- Potential extreme cold snap peak

  This forecast is based on events similar to those in 2002 (when a severe cold-snap changed customer behaviour and we experienced a loss of diversity between customer types) and in 2011 when a substantial snowstorm on 15 August changed customer behaviour. Despite having no CBD and fewer customers in the eastern suburbs, we experienced extraordinary loads on 17 August as some schools and businesses reopened after being closed for two days while others remained closed for a third day. This led to very high loads as we experienced a loss of diversity between customer types. There was significant demand from residential customers due to some schools and businesses remaining closed, while there was also significant demand from businesses that restarted after several days without operation.

  When planning our network, it is not appropriate to install infrastructure to maintain security of supply during a peak that may occur for two or three hours once every 10 years. This forecast is therefore used to determine nominal (all assets available to supply) capacity requirements of our network only.

Figure 5-4f **Overall maximum demand trends on the Orion network**



Financial year	Measured demand	Forecast demand
FY07	628	
FY08	631	
FY09	623	
FY10	615	
FY11	614	
FY12	630	
FY13	577	
FY14	596	
FY15	575	
FY16	608	
FY17	587	
FY18	605	
FY19		629
FY20		639
FY21		650

Load factor

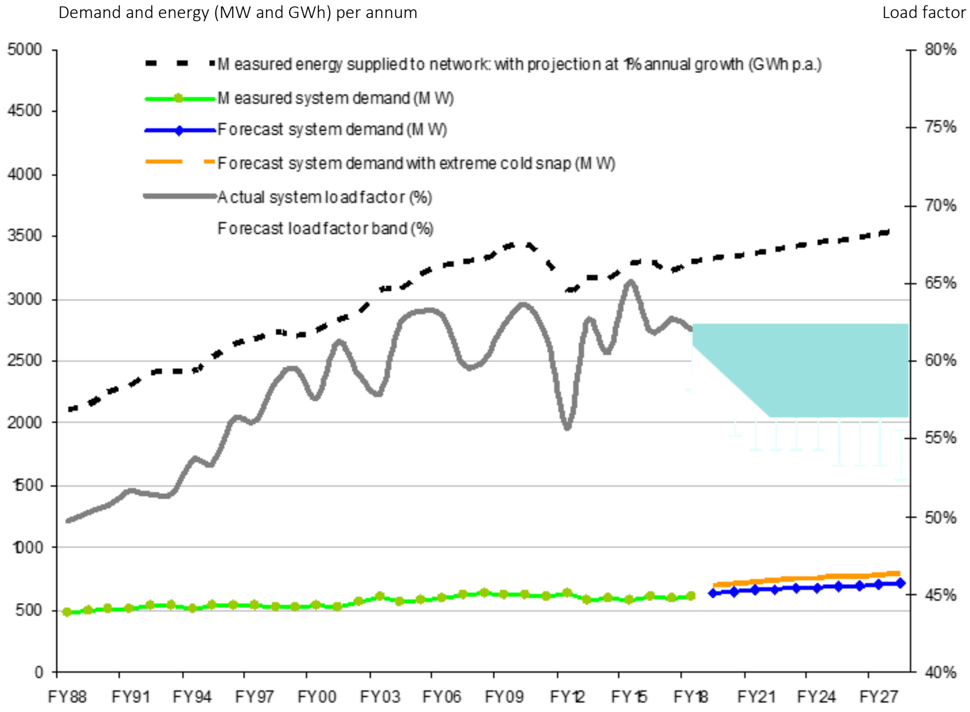
Overall system utilisation

Overall network utilisation is indicated by the system annual load factor (defined as the ratio of average to peak demand). The peak used in this calculation is based on the maximum demand which as noted in the previous section excludes temporary excursions that are not used for forecasting demand.

Orion's annual system load factor had generally improved until 2005, then plateaued (with significant variations as vagaries in our weather influenced maximum demands). Improvements in load factor had come from increased off-peak loads (irrigation, milk processing plants and summer air conditioning), combined with effective control of winter peak loads through price signalling and encouraging alternative fuel use for on-peak heating. Winters with extreme cold weather such as snow in June 2006 and August 2011 often lead to lower load factors due to the very high peak load.

The impact on load factor from the anticipated reduction of irrigation load is expected to be offset by the Central city rebuild. The variability of extreme cold weather leads to a band for possible future load factor. This suggests that load factor may decline from the recent peaks of around 60% to 65%, and level out if battery storage takes the growth out of winter peak demand. FY18 is expected to be slightly below the average of the last few years.

Figure 5-4g System load factor



Load duration

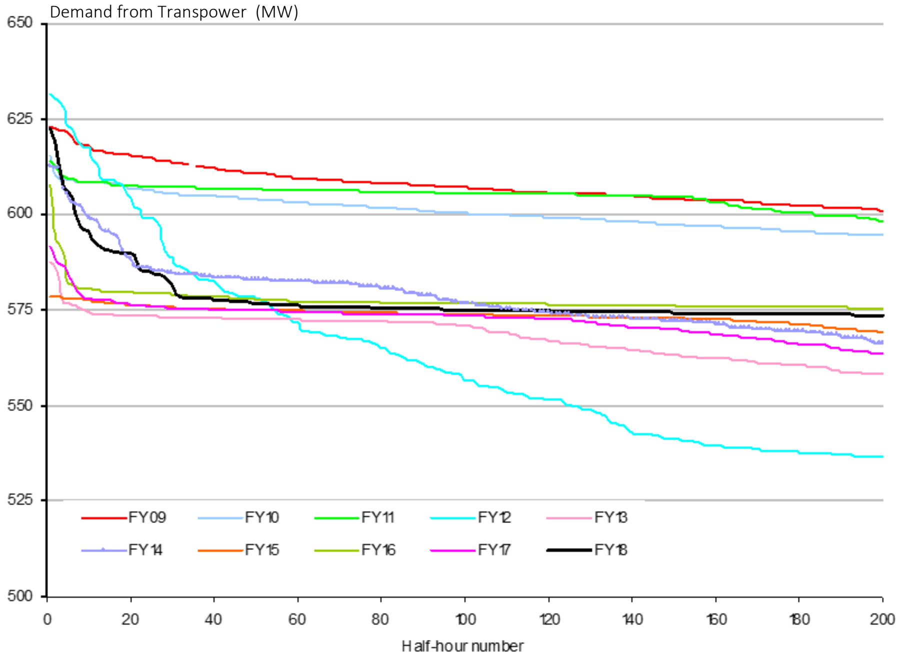
With constantly changing load on our network, the peak demands that determine network capacity generally only occur for very short periods in the year. The following graph shows the load duration curves of our 200 peak half hour demands on Transpower's network over 10 years. The graph shows that Customer Demand Management has been successful in flattening the curve in recent years. FY12 is unusual in that customer demand was reduced due to the earthquakes, but then new peaks were created with the July 2011 snowstorm, followed by extraordinary load due to another snowstorm in August. On average over the last 10 years, an increase in Customer Demand Management for just five hours each year would have reduced our network peak demand by around 10MW. To reduce the peak by a further 10MW would require approximately 40 hours of Customer Demand Management in these years. It is difficult to pick the time to utilise Customer Demand Management to target these few hours when the curve is so flat. However, extreme weather conditions (as mentioned below) give an on-going incentive for Customer Demand Management . In FY18 winter just two hours Customer Demand Management would have reduced the peak by 10MW. The top 10 hours all occurred on 12 July 2017.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions that may last for only a few hours. Peaking generation can help delay the need for increases in Transpower's network capacity. In the FY12 winter, 30MW of peaking generation, operating for about 20 hours would have reduced our urban network maximum demand by about 30MW. FY14 winter was similar where about 10 hours of peaking generation could have reduced the peak by 25MW. The 20/21 June storm accounted for eight hours, during which one of the our new 2MW generators located temporarily at QE2 was run to reduce the peak and support hot water service levels. In unusually prolonged cold conditions longer hours of operation might be needed. FY15 winter stands out as being flat because the absence of very cold weather made managing to our load management limits easier to achieve.

Generation may also be used to reduce Transpower's charges. If used for this purpose, longer hours of operation might be needed, especially to avoid reductions in water heating service levels.

Control of the dominant winter maximum demands depends heavily on suitable price signals, and customers' response to them. If this is to continue to be effective then it is important that electricity retailers continue to support Customer Demand Management initiatives. Of particular importance is the promotion of night-rate tariffs and load control via the on-going installation and maintenance of ripple receivers.

Figure 5-4h **Christchurch area network – load duration curves**



Region B load growth

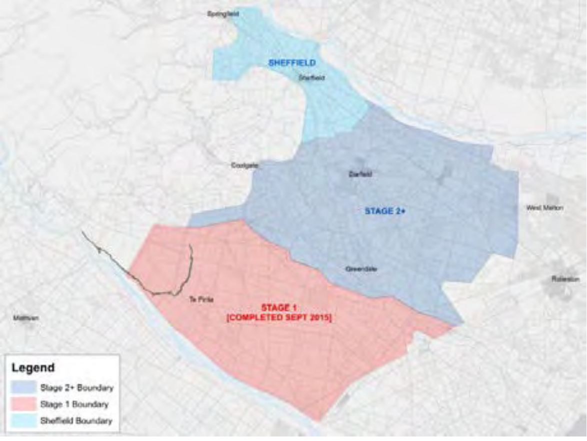
In contrast to region A, growth rates for region B, our summer peaking areas have been high over the last 10 years.

Since FY02, customer applications to connect new load to region B have been reasonably consistent (with an increase in Rolleston and Lincoln in the post earthquake period). Despite growth in the townships which contributes to winter demand, region B is still dominated by the summer peaking rural customers.

The yearly variations in weather and in particular low summer rainfall resulted in an increase of 8 to 12MW during the summers of FY04, FY08 and FY13. This demonstrates how variable peak loads can be, and how weather dependent they are – a dry summer on the Canterbury plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

Stage 1 of the Central Plains Water Scheme (CPW) came online for summer of FY16 supplying up to 20,000Ha between Rakaia and Hororata rivers, inland from SH1. The Sheffield scheme is planned for summer of FY18 to supply up to 4,250Ha, and Stage 2+ for summer of FY19 for up to 20,000Ha between stage 1 and the Waimakariri river. Restrictions due to ground water availability and nutrient leaching will restrict irrigation load growth. Within the CPW area, conversion of existing ground water pumps to the pressurised CPW scheme is forecast to continue to substantially reduce summer power load on two zone substations.

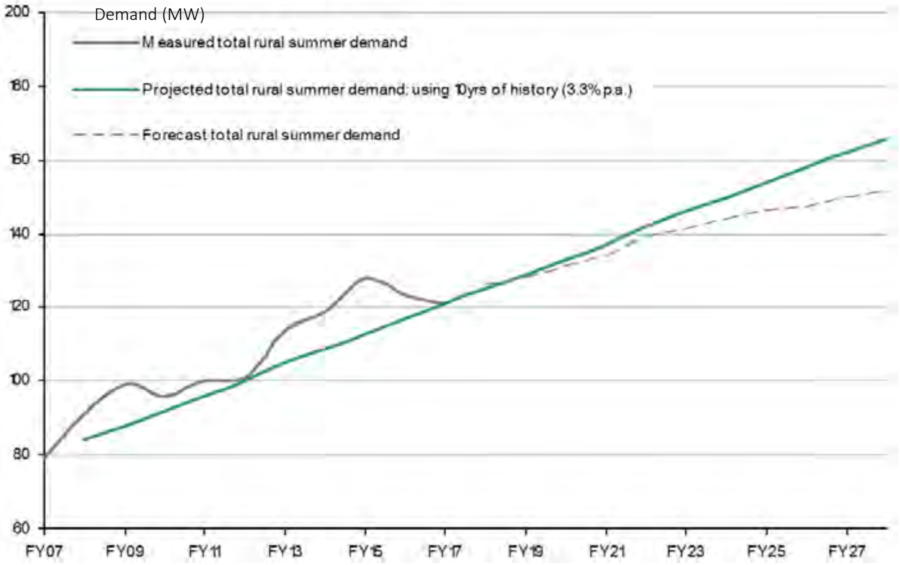
Figure 5-4i **Central plains water scheme area**



The following graph shows recent summer load growth in our region B area. FY13 and FY15 were good examples of a dry summer. FY14 irrigation demand was subdued due to rain events during the summer months. This was offset by Fonterra adding a second drier to their plant near Darfield.

Increased milk processing continues to grow the region B peak, however the rate of irrigation growth is forecast to be significantly reduced from the historical trend due to the ongoing CPW scheme development coming online.

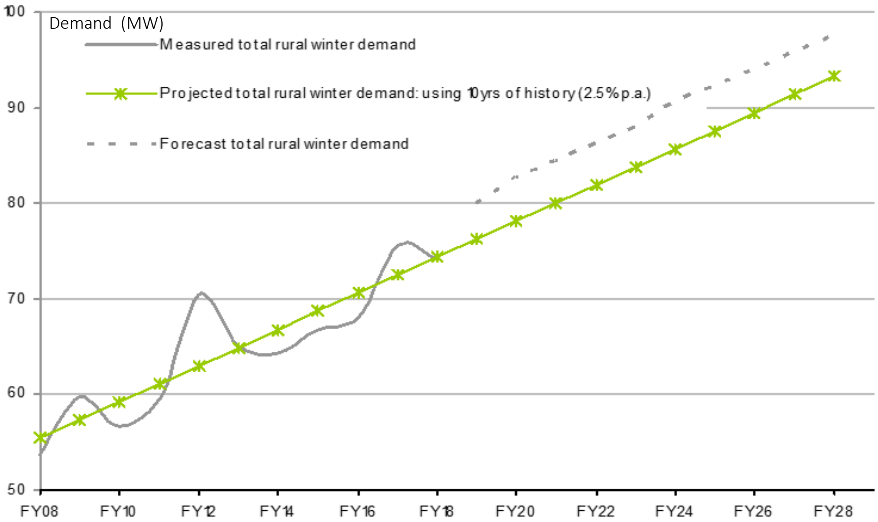
Figure 5-4j Region B **summer maximum demand (MW)**



Financial year	Measured demand	Forecast demand
FY08	91	
FY09	99	
FY10	96	
FY11	100	
FY12	101	
FY13	114	
FY14	119	
FY15	128	
FY16	124	
FY17	121	
FY18		126
FY19		128
FY20		131

Region B winter load growth has averaged 3.2% per annum over the last 10 years. The FY12 peak is due to a significant August snowstorm. The Urban Development Strategy (UDS) and Selwyn District Council residential forecast indicate that significant growth is expected to continue around Rolleston and Lincoln townships for a few years. High growth then is also expected due to planned development of Rolleston-schools and at Lincoln university.

Figure 5-4k **Region B winter maximum demand (MW) graph**



Financial year	Measured demand	Forecast demand
FY07	55	
FY08	54	
FY09	60	
FY10	57	
FY11	60	
FY12	71	
FY13	65	
FY14	64	
FY15	67	
FY16	68	
FY17	76	
FY18		80
FY19		83
FY20		84

5.4.3 Methodology for determining GXP and zone substation load forecasts

Over the next ten years we estimate that future demand growth will average 1.4% (8MW) per annum. Significant volatility can be expected in actual maximum demands, with 10% variation depending on winter weather. Capital investment plans will be modified each year in accordance with load growth that has actually been observed.

The following sections describe some of the factors and methodologies used to estimate the quantity and location of load growth. We forecast growth at the zone substation level and translate this up to Transpower GXPs and finally to a total network demand forecast. In the next three years this total network forecast is higher than the linear history shown in section 5.4.2 due to the forecast population increase, industrial development in Rolleston, other new customer connections and the central city rebuild. Towards the end of the ten year period, growth (approximately 3MW p.a.) from electric vehicles becomes a significant part of our forecast growth. -Our GXP and zone substation forecasts take account of our mid scenario electric vehicle forecast, continued improvements in energy efficiency and growth in households and business associated underlying population growth. Our forecasts in this section do not take account of the potential for battery storage to reduce peaks. We have also included a 'high scenario' forecast for 2027 as described in section 5.4.2.

This process is described in NW70.60.12 - Long term load forecasting methodology for subtransmission and zone substations.

Territorial local authority planning

Our network spans two territorial authority areas; Christchurch City and Selwyn District. Both territorial authorities publish useful area planning information and we use this extensively to plan for growth on our distribution network.

In addition to individual territorial plans, an urban development strategy (UDS) group was formed in 2004 for the greater Christchurch region. The intention was to develop a sustainable long term strategy for growth in the greater Christchurch region. The UDS was approved for implementation and the impact of this was reflected in ECAN's Regional Policy Statement (RPS).

The UDS proposed a greater level of infill development in central Christchurch and encouraged growth at Rolleston and Lincoln townships. Because consolidated areas of growth are less costly to service than sparse development, it was expected that the UDS outcome would lead to lower than otherwise costs for our customers. The UDS was an important input into CERA's land use recovery plan (LURP) that was developed in response to the earthquakes of 2010/11. The LURP provided for more Greenfields development than the UDS. The CCC used the LURP to develop household growth numbers by census area unit. The May 2017 CCC update has a significantly higher forecast than the previous year, due to high immigration projections from Statistics NZ. It has ~2,200 more households in 2019, and by 2028 nearly 6,000 (4%) more. Further refinement of this data and industrial forecasting is described in the following sections.

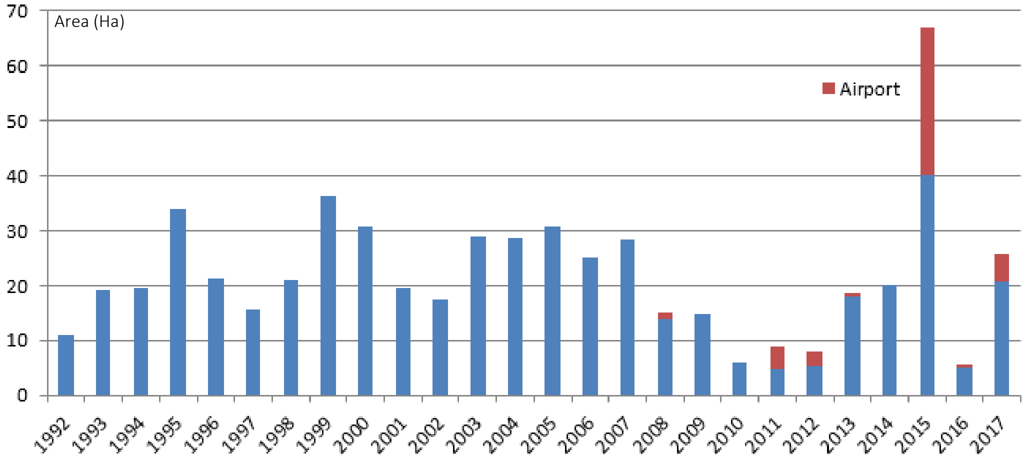
In August 2016 the Greater Christchurch Urban Strategy Update was produced which indicates a review of the UDS is expected from 2018.

Christchurch City

The Christchurch City Council (CCC) reports on vacant land on an annual basis. With the advent of the UDS, the CCC also forecasts yearly household growth by census area unit to 2053. To forecast the growth in residential demand in the CCC area, we map each of the area units to one or more zone substations in our model-as described in section 5.4.1.

To forecast industrial growth we utilise the CCC industrial vacant land reports to identify areas developed and zoned for potential growth. We utilise historic uptake rates and market judgement to allocate 20Ha of growth per annum to the different areas of available land. After discussion with CCC, these allocations have shifted back to the pre-earthquake average value, and are mapped in our model to a zone substation with a forecast load density of 130kW per hectare. The following figure 5-4j shows how the uptake has been affected by the economic slow down and earthquakes. A large portion of the 2015 uptake was associated with development adjacent to the Christchurch Airport. The record low in 2016 is thought to partly relate to uptake in the Rolleston Izone area of Selwyn District.

Figure 5-4l **Take-up of vacant industrial land**



Finally, we utilise the CCC land zone maps to determine the areas suitable for commercial/industrial infill growth. This part of our forecast is a relatively discretionary process and is heavily dependent on the swings of the commercial development market.

In summary, in the medium term CCC's District Plan review plans to deliver an increase in residential infill within the Central City and areas around the shopping malls-by introducing Medium Density Residential zones and Suburban Density Transition. -In the short term, major subdivision growth is planned for Halswell, and Belfast. Industrial development is expected to mainly continue in Hornby, Islington, Wigram and the Airport areas in the short term and in Belfast in the medium term.

Selwyn District

Most of our zone substations within Selwyn District are required to meet irrigation load and predominately have their peak load in summer. However significant residential growth has occurred around Rolleston and Lincoln zone substations and these substations have their peak load in winter. As with the CCC, we utilise the LURP/UDS/Selwyn household growth projections informed by the 2013 Census to forecast residential growth in the greater Selwyn region.

The Izone industrial park at Rolleston has also experienced significant growth in recent times and we are working closely with the developer to ensure that our forecasts in this area are consistent with their expectations.

Growth drivers and forecasting uncertainty

Our network feeds both high density Christchurch City loads and diverse rural loads on the Canterbury plains and Banks Peninsula. Growth in electricity consumption can occur from an increase in population and also the introduction of new end use applications. Growth in electricity consumption in the city and on Banks Peninsula has historically matched growth in population (holiday population for Banks Peninsula). Conversely, electricity growth on the Canterbury plains has not matched population growth but has been driven by changes in land use and hence changes in electricity use.

Winter peak demand on our network is mainly driven by growth in the city and townships and is anticipated to increase by approximately 80MW (13%) over the next 10 years. Our region B network peaks in the summer and it is anticipated to increase by approximately 15MW (12%) in the next 10 years, with most of this in the next couple of years.

The following main issues need to be considered when managing growth:

- sufficient time to procure zone substation land and/or negotiate circuit routes (typically one or two years)
- sufficient time for detailed design (typically one year)

- contractor resources managed via a consistent work flow.

The network development projects listed in this ten year plan seek to ensure that capacity and security of supply can be maintained for the growth rates described above. Actual growth rates are monitored on an annual basis and any change would be reflected in next year's development plan.

Other factors that have been considered as potentially leading to demand varying from forecast demand:

1. Clean Air Plan

ECAN introduced new rules from February 2016 under the Proposed Canterbury Air Regional Plan. These rules phase out low emission enclosed burners in Christchurch. As the analysis of the clean heat programme showed minimal increase in electricity demand, these new rules are not expected to have a material impact on power loads. As at 8 September 2017 there had been four high pollution nights for 2017. This is a noticeable improvement over recent years but still short of the 2016 National Environmental PM10 target of having only three high pollution nights.

Table 5-4a Number of Christchurch high-pollution nights

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
39	30	20	24	16	15	32	19	23	19	7	5	4

2. Development of irrigation and milk processing plant load

Orion has experienced rapid growth in summer irrigation load on the Canterbury plains. In order to meet this growing load, substantial investment has been needed in our subtransmission and distribution networks.

We closely monitor trends in rural irrigation. Some factors now influencing planning for irrigation load are:

- ECAN constraints on groundwater extraction
- land in some areas is approaching its full irrigation potential
- interruptible load arrangements to cover short term fault situations
- design and implementation of the CPW irrigation scheme. Construction of Stage 1 occurred during 2014-2015. The Sheffield scheme is expected for 2017/8 summer and Stage 2 is to be substantially completed in 2018. This changes rural peak demand, and we are working closely with CPW regarding the detail of future stages planned through to 2019
- Trustpower's potential to install up to 70MW of hydro generation from Coleridge along the north bank of the Rakaia River to its gorge.

The proposed CPW irrigation scheme is likely to change irrigation in the affected area from ground water extraction to pumping from a canal into a piped network delivering on-farm pressure. This gives downward pressure on total energy delivered. There was also the medium term potential for stranded assets at Highfield where a transformer upgrade has been avoided by temporarily installing diesel generators to support load growth if needed until CPW Stage 2 reduces ground water pumping in the area. A balance of capacity, security and reliability is required while ensuring that our expectations, and those of our rural customers, are met.

Over the next 10 years, milk processing plants are anticipated to be responsible for approximately 15MW of summer peak growth. However, this growth is expected to be offset by a net reduction of approximately 4MW due to the CPW irrigation scheme reducing ground water pumping. This analysis includes the results of a 2014 Aqualinc study of the impact of likely irrigation changes, and development by Westland Milk, Synlait and Fonterra. The timing/demand changes due to the milk processing plant upgrades causes significant uncertainty in this forecast. For this reason we are cautious about our development plans to ensure that we do not install assets that may later become under utilised.

5.4.4 Transpower GXP load forecasts

The forecasts in the following sections have incorporated the impact of the earthquakes, including returning loads to their normal supply points. However there is more uncertainty than usual due to the eventual reduction in the workforce associated with the rebuild and the range of scenarios from uptake of electric vehicles and battery storage.

The following table indicates the capacity of each Transpower GXP that supplies our network. Present and expected maximum demands over the next 10 years are also shown. **Please note** the impact of projects incorporated in this plan is **NOT** reflected in the GXP load forecasts. The tabled loads are those expected if no development work is undertaken. Firm capacity is the capacity of each site should one item of plant fail. See section 5.2.1 for a map of Transpower's system.

Table 5-4b **GXP substations – load forecasts (MVA)**

GXP substation	Security Standard Class	Firm capacity	Actual FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Bromley 66kV	A1	210	135	138	144	147	149	151	152	154	156	158	160	162
Islington 33kV	B1	107	68	72	75	80	82	84	87	89	91	93	95	98
Orion Islington 66kV	A1	494 [1]	399	414	435	445	459	466	473	480	487	493	500	507
Hororata 33kV	C1	23	18	21	21	21	21	21	21	21	22	22	22	22
Kimberley 66kV, Hororata 66 & 33kV [2]	C1	70*	55	55	56	58	60	60	60	61	61	61	62	62
Arthur's Pass	D1	3	0.4	0.4	0.4	0.4	0.4	0.4	1.4	1.4	1.4	1.4	1.4	1.4
Castle Hill[3]	D1	3.75	0.7	0.7	0.8	0.8	0.8	5.2	5.6	6	6	7	7	8
Coleridge	D1	2.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5

Notes:

1. 532 total firm capacity. Assumes only 32% of Mainpower's load is fed from Islington post Islington T6 contingency. McFaddens can be transferred from Islington to Bromley if needed.
2. Assumes full generating capacity available from Coleridge. Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support.
3. Possible upgrade required for the proposed alpine village and winter sports resort near Porters Pass.

5.4.5 Orion zone substation load forecasts

The following two tables compare the firm capacity of each of our zone substations with present and forecast load. The electric vehicle uptake scenario described in section 5.4.2 has been incorporated into the forecasts. The uptake of solar PV connections is being recorded but not incorporated into the forecasts because the impact on peak demand (especially winter peaking areas) is negligible/zero. At this stage we have not incorporated the impact of battery storage into our zone substation forecasts but a range of impacts has been presented in section 5.4.2.

A 2014 Aqualinc study on irrigation projections and the CPW scheme indicates that over Orion's region B network, CPW pumps could add nearly 10MVA but associated conversion from ground water to surface water irrigation could reduce load by nearly 30MVA. This net 20MVA decrease shows some site loads increasing partly due to an increase in the irrigated area. Bankside, Greendale, Highfield and Te Pirita could drop around 5MVA in the medium term. Hororata capacity was increased to 10MVA during 2015, by relocating a spare transformer, to provide for increased irrigation facilitated by the CPW canal. As of 23 September, 5.5MVA of ground-water pump disconnection requests have been received. CPW supply increased from 1.8 cumecs on 16 Nov 2015 to 8.3 cumecs by 2 Dec 2015 and 12.9 cumecs by 28 Feb 2016. Stage 1 supply is expected to increase a further 5%. Farmers may be keeping existing ground water pump connections until they gain confidence with CPW water, but they won't all be used.

Table 5-4c **Region A 66 and 33kV zone substations – load forecasts (MVA)**

Zone substation	Security Standard class	Firm capacity MVA	Actual winter FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Year 10 High EV Impact
Addington 11kV #1	B2	40	24	24	19	19	19	19	19	19	19	19	19	19	19
Addington 11kV #2	B2	34	13	13	18	18	18	18	19	19	19	19	20	20	21
Armagh	A3	40	12	12	15	15	19	20	20	20	20	20	21	21	22
Barnett Park	B3	15*	8	9	9	9	9	9	9	9	9	9	9	9	10
Bromley	B2	60	31	32	32	32	33	33	33	33	34	34	34	35	39
Dallington	B2	40	27	27	28	28	28	28	28	29	29	29	29	29	33
Fendalton	B2	40	37	38	38	38	38	38	38	38	38	38	38	38	41
Halswell	B2	23	16	17	19	20	21	22	23	23	24	25	25	26	29
Harewood	B3	7.5	2	2	2	2	2	2	2	2	2	2	2	2	2
Hawthornden	B2	40	31	31	31	31	31	31	32	32	32	32	32	33	35
Heathcote	B2	40	23	23	24	24	24	24	24	24	24	25	25	25	25
Hoon Hay	B2	40	35	36	36	36	36	36	36	36	36	36	37	37	37
Hornby	B3	20	14	14	14	15	15	15	16	16	16	16	17	17	17
Ilam	B3	11	8	8	8	8	8	8	8	8	8	8	8	9	9
Lancaster	A2	40	19	19	19	19	20	20	20	20	20	21	21	21	23
McFaddens	B2	40	35	36	37	37	37	37	37	38	38	38	38	38	42
Middleton	B2	40	23	25	25	25	24	24	24	24	24	25	25	25	25
Milton	B2	40	34	34	35	35	35	36	36	36	36	37	37	37	41
Moffett St	B3	23	12	14	15	18	19	19	20	20	21	22	22	23	23
Oxford-Tuam	A2	40	14	15	20	24	27	28	28	29	29	30	30	30	30
Papanui	B2	48	41	42	49	50	50	51	51	52	52	52	53	53	59
Prebbleton	B3	15	5	5	5	5	5	6	6	6	6	6	6	6	6
Rawhiti	B2	40	29	29	33	34	34	34	34	34	34	34	34	34	38
Shands Rd	B3	20	10	10	11	11	12	13	13	14	14	15	15	16	16
Sockburn	B2	35	26	27	27	27	28	28	28	28	29	29	29	30	30
Waimakariri	B2	15*	16	16	17	17	18	18	18	18	18	18	18	19	19

See section 5.3.1 for Security Standard Class definitions

* Single transformer - security standard limits load to 15MW, 11kV ties from neighbouring sites provide backup capacity for all load

Notes

- Orange shading indicates load greater than firm capacity.
- The "Year 10 High EV Impact" final column shows the potentially higher load if there is:
  a) clustering of EV uptake that is three times higher than the network average. This scenario allows for accelerated localised uptake due to neighbourhood influence ie neighbours are more likely to buy an EV, if EVs are more common in the area, and
- b) diminished response to measures to encourage charging away from peak. This allows for twice as many charging at 6pm ie 40% of EVs
- Fendalton Resolve by load shift to Milton
- Halswell Resolve by load shifts and transformer upgrades
- Ilam Included with the 66 and 33kV substations although it is regarded as an 11kV zone substation elsewhere in this plan. This is because it has no transformers on site but has two dedicated 66/11kV transformers located at Hawthornden
- McFaddens Resolve by new Marshland zone substation
- Moffett Resolve by new Templeton zone substation
- Papanui Resolve by transfers to Waimakariri & new Marshland zone substation
- Waimakariri Resolve by 2nd transformer

Table 5-4d Region B 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Year 10 High EV Impact
Annat*	C4	7.5	1.4	4	4	4	4	4	4	4	4	4	4	4	4
Bankside*	C3	10	5.7	6	6	6	6	6	6	6	6	6	6	6	6
Brookside*	C3	10	8.1	8	8	8	8	8	8	8	9	9	9	9	9
Darfield*	B3	8.8	5.8	6	6	6	6	6	6	6	6	6	6	6	6
Diamond Harbour*	B3	7.5	1.6	2	2	2	2	2	2	2	2	2	2	2	3
Dunsandel	A3	10	12.1	12	12	15	15	15	15	15	15	15	15	15	15
Duvauchelle	B3	7.5	4.7	5	5	5	5	5	5	5	5	5	5	5	5
Greendale*	C3	10	6.2	6	5	5	5	5	5	5	5	5	5	5	5
Highfield*	C3	7.5	7.1	7	6	5	5	5	5	5	5	5	5	5	5
Hills Rd*	B3	7.5	6.4	7	7	7	7	7	7	7	7	7	7	7	7
Hororata*	C3	10	6.6	7	6	6	6	6	6	6	6	6	6	6	6
Killinchy*	C3	10	8.8	9	9	9	9	9	9	9	9	9	9	9	9
Kimberley	A3	23	13.8	13	15	15	16	16	16	16	16	16	16	16	16
Larcomb	B3	23	10.0	12	13	13	13	16	16	19	19	20	20	20	20
Lincoln	B3	10	9.1	10	10	10	11	11	11	11	12	12	12	12	13
Little River*	C4	2.5	0.6	1	1	1	1	1	1	1	1	1	1	1	1
Motukarara	C4	7.5	2.7	3	3	3	3	3	3	3	3	3	3	3	3
Rolleston	B3	10	9.6	10	10	10	10	10	10	10	11	11	11	11	11
Springston 66/33kV	B2	60	37	39	39	39	39	40	40	40	41	41	41	41	48
Springston 33/11kV*	B3	7.5	5.7	5	6	6	6	6	6	7	7	7	7	7	7
Te Pirita*	C3	10	7.9	8	8	8	8	8	8	8	8	8	8	8	8
Weedons	B3	23	9.6	11	11	12	12	12	12	12	12	12	14	14	14

See section 5.3.1 for Security Standard Class definitions.

* Denotes single transformer or line substation

Table 5-4e 11kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual winter FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Year 10 High EV Impact
Grimseys-Winters	B2	26.5	14	15	21	22	22	23	23	24	24	24	24	25	28
Knox	A3	12.3	10	10	10	11	11	12	12	12	12	12	12	13	14
Pages-Kearneys	B4	17.2	9	9	9	9	9	9	9	9	9	9	9	9	9
Portman	B3	24	11	11	11	11	11	11	11	11	11	11	11	11	11

Notes:

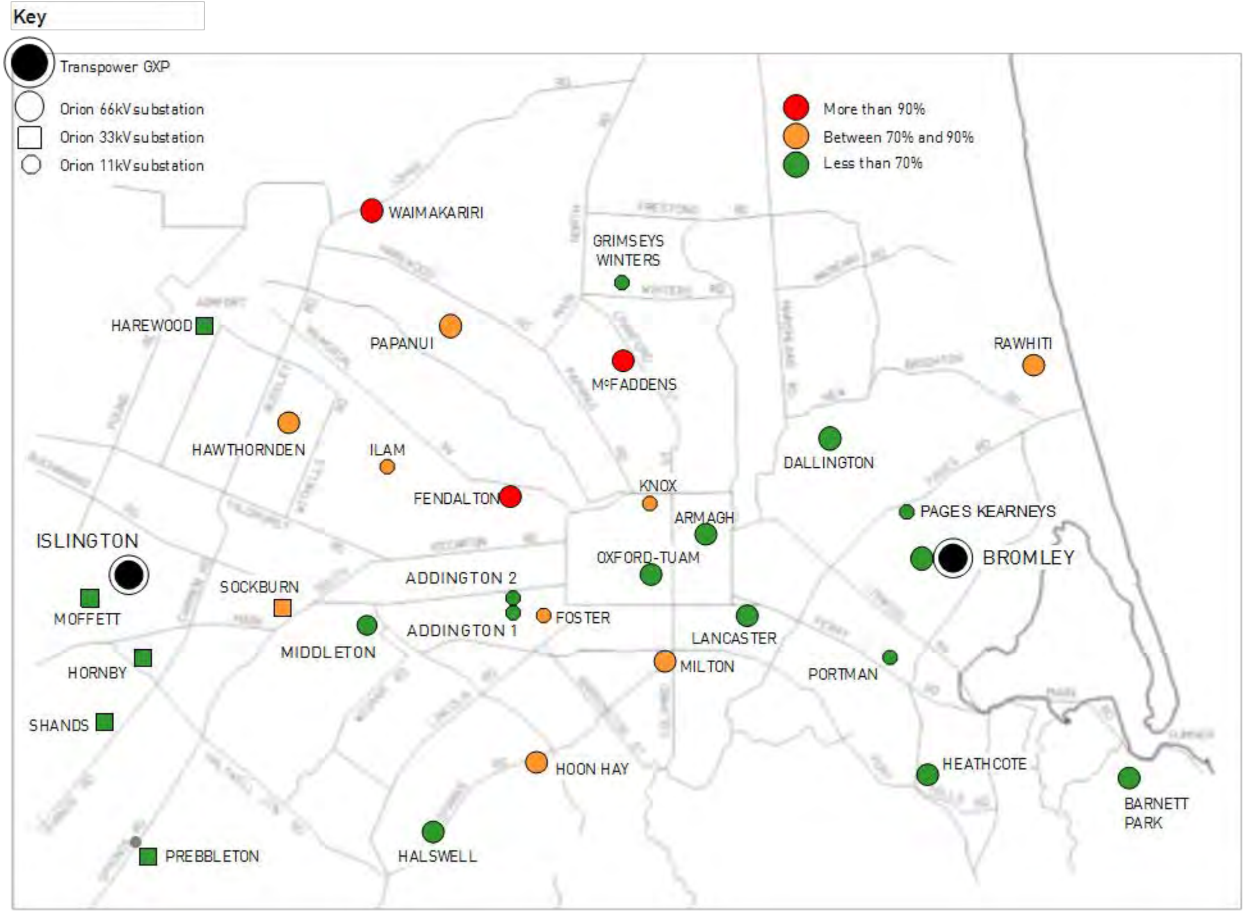
- Orange shading indicates load greater than firm capacity.
- The “Year 10 High EV Impact” final column shows the potentially higher load if there is:
  - a) clustering of EV uptake that is three times higher than the network average. This scenario allows for accelerated localised uptake due to neighbourhood influence ie neighbours are more likely to buy an EV, if EVs are more common in the area, and
- b) diminished response to measures to encourage charging away from peak. This allows for twice as many charging at 6pm ie 40% of EVs

Dunsandel	Resolve by upgraded transformers when required by Synlait
Hills	Resolve by swapping transformer from Motukarara, add fans to give 10MVA (and capacitors if needed)
Lincoln	Resolved by load shift to Springston
Rolleston	Resolved by load shift to Weedons and Highfield, then transformers swapped to 23MVA
Springston	Staged upgrade to 2 x 10MVA transformers at 66kV
Knox	Resolve by load shift to Addington No.2

The following region A geographical map has been produced to demonstrate areas of high and moderate loading on our network. Substations with load exceeding 90% of firm capacity have been coloured red.

The changes from the previous year were: Addington 1, Dallington, Hornby, Middleton and Grimseys-Winters dropped below 70% and Rawhiti passed the 70% threshold. Note Waimakariri changed to red as it exceeded 15MW (security standard for a single transformer site).

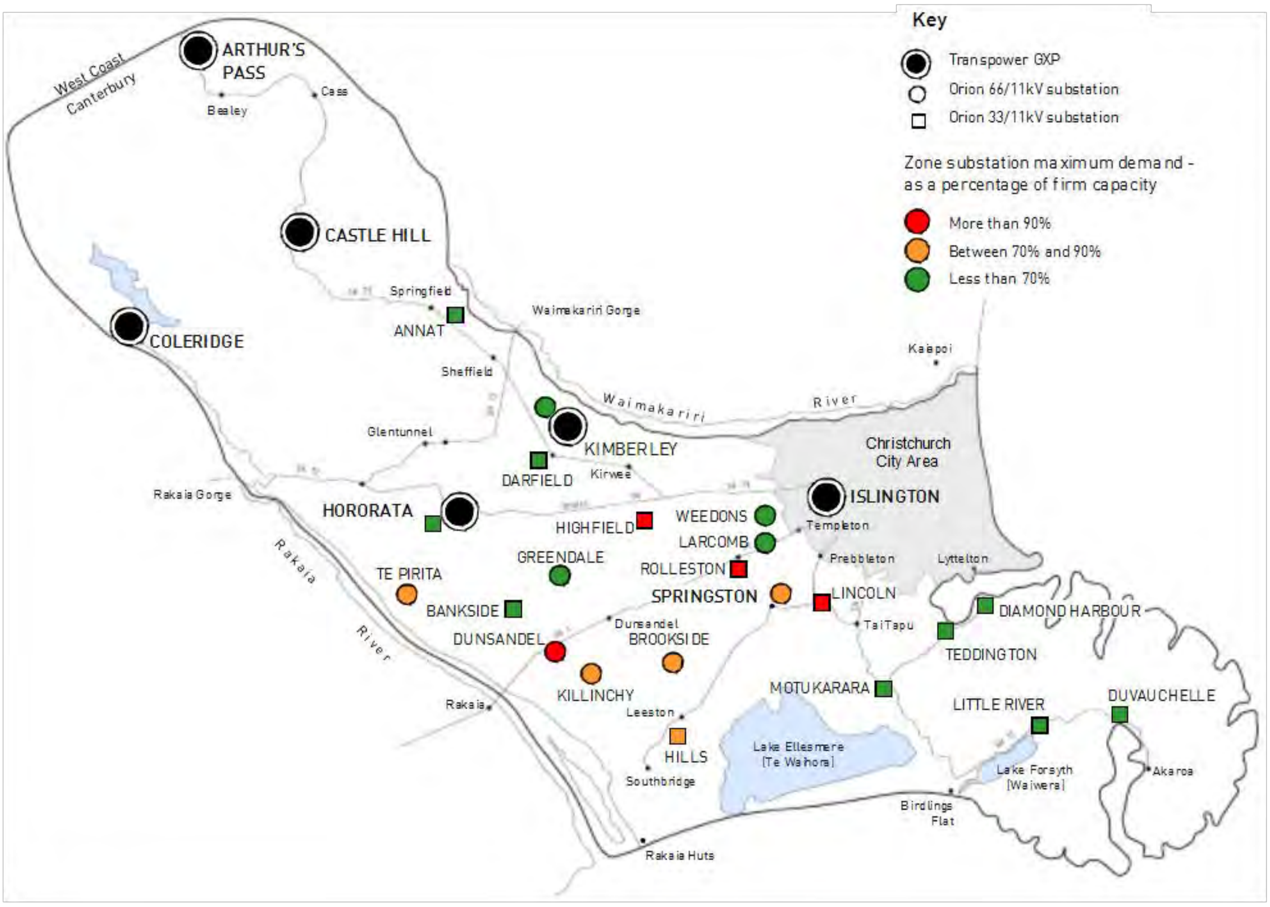
Figure 5-4m **Zone substations – region A (FY17 maximum demand as a percentage of firm capacity)**



We have produced the following region B geographical map to demonstrate areas of high and moderate loading on our network. Substations with load exceeding 90% of firm capacity have been coloured red.

The changes from the previous year are; Te Pirita, Brookside and Hills moved underthe 90% threshold, Greendale-dropped under the 70% threshold Springston moved over-the 70% threshold, and Lincoln moved over the 90% threshold.

Figure 5-4n **Zone subs – region B (FY17-max demand as a percentage of firm capacity)**



Notes:

Highfield is expected to drop as a result of the CPW scheme. Two 400kVA standby diesel generators have been installed at the zone substation in case the load exceeds the site transformer capacity in the meantime.

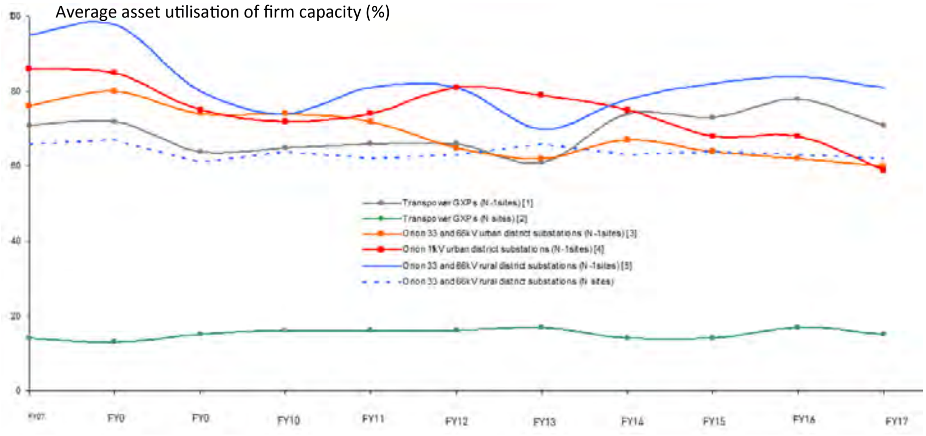
5.4.6 Utilisation of assets

GXP, 66kV, 33kV and 11kV zone substation utilisation

For N-1 sites with dual transformers or parallel 11kV incomers, we calculate utilisation by dividing peak load by the N-1 capacity (capacity available following a single fault) of the site. Utilisation of 100% implies that further increases in load will require further network investment or the security of supply will reduce.

For N security sites with single transformers and/or line or cable supplies, utilisation is calculated by dividing peak load by the installed site capacity. To provide support to neighbouring N security sites during contingencies it is not necessarily desirable to aim for 100% utilisation at these sites. Our interruptible irrigation load initiative has allowed an increase in utilisation of our rural N security sites and utilisation of 70-80% is appropriate in this context.

Figure 5-4o GXP, 66kV, 33kV and 11kV zone substation utilisation



Notes:

[1] Transfer Springston GXP to Islington FY14

[2] Very small GXPs at Arthur's Pass, Castle Hill and Coleridge

[3] Significant new capacity installed in FY12

[4] Three zone substations decommissioned in FY15 & load transferred from Grimseys to Waimakariri in FY17

[5] Significant new capacity installed in FY09

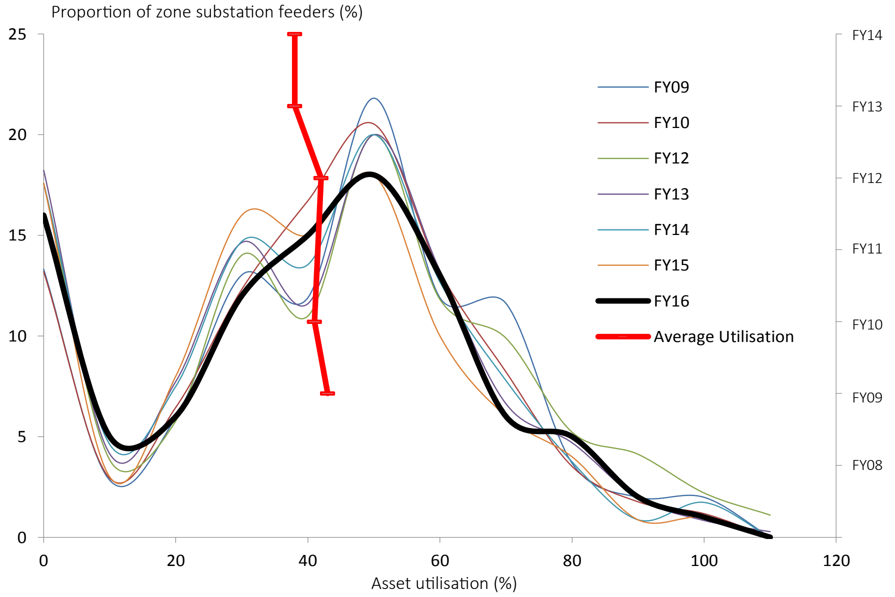
11kV feeder cable utilisation

We have calculated cable utilisation for all region A zone substation 11kV network feeders from recorded SCADA values. It is based on peak load under normal system conditions with respect to the nominal design capacity of the smallest cable section between the zone substation circuit breaker and the first downstream load. A de-rating to 80% of the normal book value has been applied to the cable capacity to allow for the common thermal environment where cables are laid in parallel.

The following figure shows average 11kV feeder cable utilisation is around 40%. Ideally, considering our N-2 urban architecture, the nominal average cable utilisation should be 50%. However, several cables carry zero load under nominal operating conditions which therefore lowers the overall utilisation. This can be attributed to our existing 11kV architecture which historically featured a closed-ring subtransmission network in the urban area. Recent changes to our network design philosophy should see an increase in cable utilisation over time. Over the city rebuild period however, some feeders may have zero utilisation (especially in the CBD) and 'normal' conditions will take time to develop.

Note: in FY11 the data was not meaningful due to serious earthquake disruption (utilisations are meant to be for 'normal' network conditions). In FY12 and to a lesser extent FY13-15, parts of the network were still in transition, cable faults and switching rates were higher. While this reduces the usefulness of these curves for year-on-year comparison, the increase in feeders with zero utilisation can be seen.

Figure 5-4p Region A **zone substation 11kV feeder cable utilisation graph**

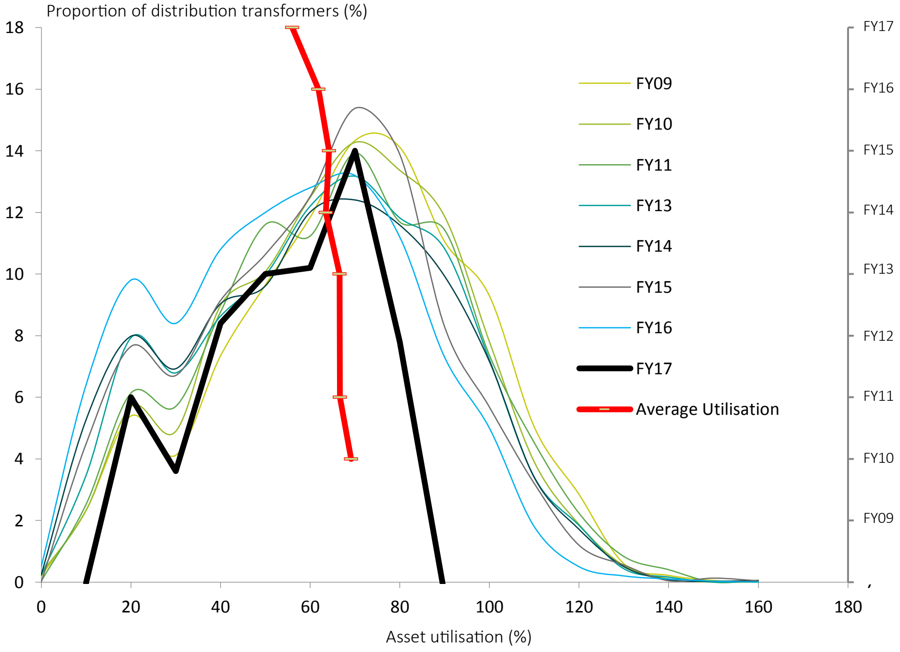


Distribution transformer utilisation

The following figure shows the distribution of utilisation factors for our 11/0.4kV distribution transformers. The graph has been determined by dividing the maximum transformer demands, as recorded on the 20 minute maximum-demand-indicators (MDIs), by the nominal transformer rating. The graph shows that the majority of distribution transformers have peak loads in the range of 60% to 100% of their continuous rated load, with an average around 70%.

While the graph also shows that around ~~1~~8% of distribution transformers are above 100% loaded at peak, the load factor for most distribution transformers is usually quite low. This is certainly true for the transformers that supply mainly residential customers. Customers with higher load factors, such as large industrials, tend to have a dedicated supply transformer that is closely matched to their load requirements. They therefore know the supply capacity limitation and will usually request formally any supply capacity changes. Also, transformers have a large thermal capacity and can tolerate cyclic loads higher than their continuous rating. Therefore we deem it appropriate to allow peak loads on the majority of distribution transformers to rise to 130% of the continuous rating before investigating possible replacement/upgrades.

Figure 5-4q **Distribution transformer utilisation graph**



5.4.7 Management and utilisation of our low voltage (400V) network

The level of low voltage network utilisation is more difficult to determine than our other higher voltage assets. In the absence of peak or real-time load recording devices the level of utilisation is determined through modelling analysis. Our low voltage network contains more than 10,000 feeders connected to our 11kV/400V distribution transformers.

The addition of new load to our low voltage network is managed through our customer connection process - either a new connection or a connection upgrade/downgrade. An assessment of available capacity is made on a case by case basis and if required, reinforcement work is scheduled accordingly. History has proved that this process largely captures the material changes in load. Occasionally, power quality issues (e.g. voltage too low) will emerge through unknown changes in load. We address these immediately following identification.

The above process works well in an environment where the underlying electricity usage behaviour is stable. It also has potential to work well for the connection of distributed generation to our network which requires a connection application outlining the type and quantity of generation - see below for more information about how we intend to manage this. However, in an environment where customers change their electricity usage behaviour (e.g. emerging technologies including heat pumps displacing log burners, electric vehicles, energy efficiency initiatives or battery storage) without the requirement to notify us, we cannot rely entirely on our connection application process to capture the changes in load.

In the short term with relatively low levels of customer behaviour change, we intend to manage the low voltage network capacity by improved high level analysis and modelling tools that enable an annual review of the utilisation of more than 10,000 low voltage feeders. This analysis will enable us to identify those feeders with high levels of utilisation (through either load or distributed generation) for more detailed analysis and perhaps the installation of real time monitoring equipment.

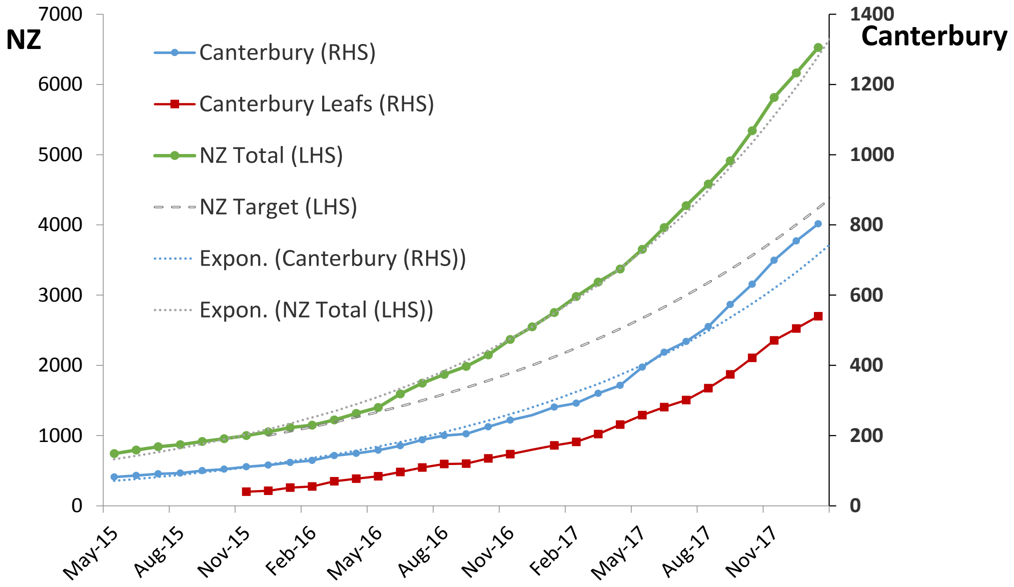
In the medium to long term, the customer uptake of emerging technologies may require the installation of widespread monitoring equipment. There is also an opportunity to better utilise customer metering data for planning analytics and/or real time monitoring. Real time information will enable better signalling of battery charge and discharge times to not only meet the needs of the battery owner but also utilise the technology to the wider benefit of the network resulting ultimately as a gain to customers.

We are mindful of the increased costs associated with monitoring and signalling of customer response to manage the impact of emerging technologies on our low voltage network, especially given the uncertainty associated with the extent and rate of uptake. Hence our staged approach from enhanced modelling to a targeted (as opposed to a network wide) rollout of monitoring and signalling/control devices. We have included a modest budget for some initial monitoring of our low voltage network in our reinforcement budget with an increasing budget toward the end of the 10 year asset management planning period.

Electric Vehicles

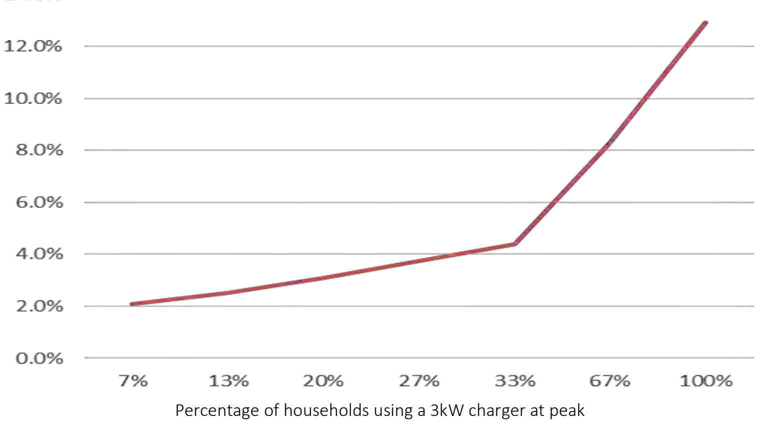
Electric vehicle uptake is increasing above forecasts, driven by used Nissan Leaf imports. The uptake rate now supercedes the PV uptake rate. Clustering of EV uptake due to neighbourhood demographics and awareness may impact areas of the low voltage network before overall numbers are substantial. Data from vehicle registrations indicates the suburbs with a higher concentration are Cashmere, Fendalton, Halswell, Riccarton and Tai Tapu/Motukarara. There is potential for this to develop rapidly as uptake has more than doubled each year as shown in the following figure.

Figure 5-4r Electric vehicle uptake



We have undertaken some preliminary analysis determining the impact of electric vehicles on the low voltage network. The following graph summarises our findings.

Figure 5-4s Residential area LV constraints as a percentage of all LV



Most of our low voltage network is able to provide for quite high electric vehicle penetration levels under normal network conditions (all assets available for service). High penetration levels will erode security of supply margins which will need to be addressed through either network reinforcement, enhanced Customer Demand Management (e.g. battery storage or electric vehicle charging flexibility) or perhaps a greater reliance on existing mobile diesel generation for what are relatively rare and small consequence (in a wider network context) faults. It is worth noting the slope of the curve toward higher penetration levels and therefore the importance of the accuracy of the modelling inputs at these penetration levels.

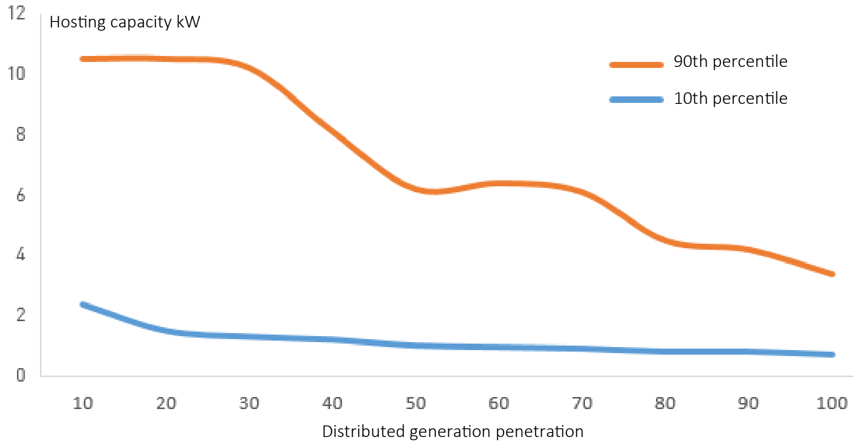
Distributed Generation

In conjunction with University of Canterbury (and thanks to MBIE research funding) we have contributed to the development of a Distributed Generation Connection Guideline. The guideline requires distributors to establish a DG hosting capacity for each low voltage network feeder. This hosting capacity will be based on an expected medium term uptake/penetration level. We believe this strikes the right balance between a 'first in first served' approach and an approach where capacity is reserved indefinitely for every connection.

Prospective DG customer applications will be able to make an informed decision about the size their DG installation. Applications up to the DG hosting capability will be simple to process and manage whereas larger applications will require a more rigorous assessment process and may incur operating constraints and/or costs to reinforce the network. This will enable customers to make smarter choices about the size of their DG and strike the right balance between DG driven network reinforcement and meeting the needs of the DG customer.

The following graph (courtesy of University of Canterbury) provides a preliminary summary of our network's ability to host DG without the need for reinforcement. The large range of hosting capability (the graph shows range from 10th percentile to 90th percentile) reflects the large range of low voltage feeder characteristics and customer types connected to them. For example, we have long rural, short urban, overhead, underground, residential, commercial and industrial etc. This exemplifies the need to have DG hosting capacity specified on a per low voltage feeder basis rather than a 'one size fits all' basis that would require us to act conservatively.

Figure 5-4t Distributed generation hosting capacity of 400V feeders

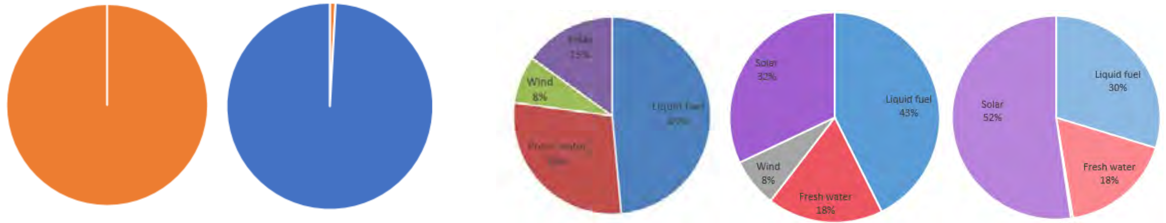


The first of the following two graphs shows the type and location of DG on our network. The second graph shows the current level of uptake of PV on our network.

Although PV is the dominant form of DG by connection count it is significantly smaller than the peaking capacity provided by peaking diesel generation. The annual energy delivered from solar is now greater than liquid fuel generation.

PV penetration is currently under 1% by network connection count-and energy delivered. The installed capacity has reached 1.2%. The uptake rate peaked late 2016 and is now dropping.

Figure 5-4u **PV uptake on our network compared to other DG**



PV annual energy contribution compared to total network offtake

PV installed capacity compared to total network peak demand

FY15

FY16
Injection by fuel type

FY17

Figure 5-4v **Current level of PV uptake on our network**

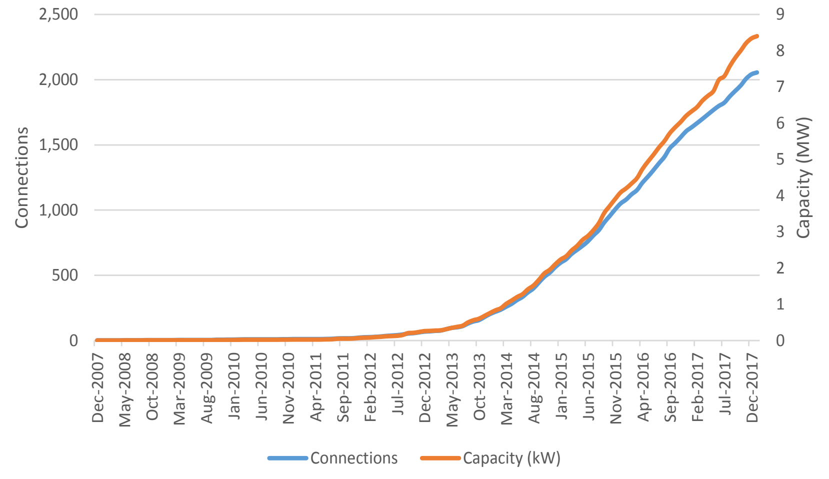


Figure 5-4w **Rolling 12 month increase in PV connections**

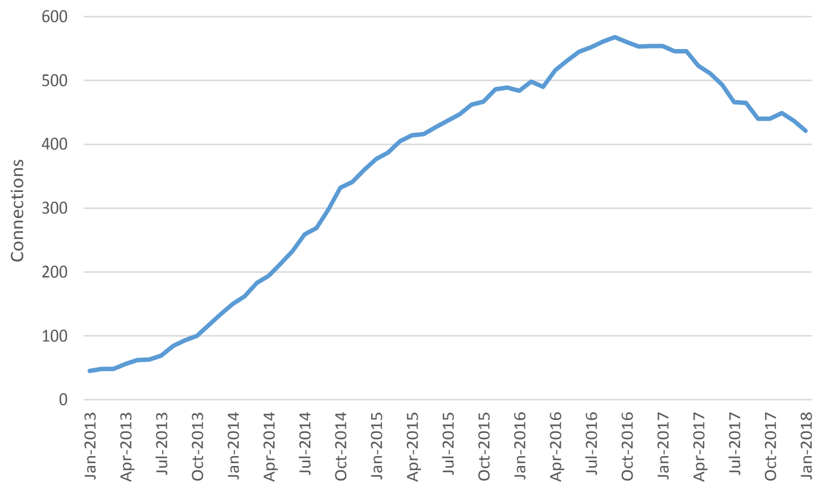
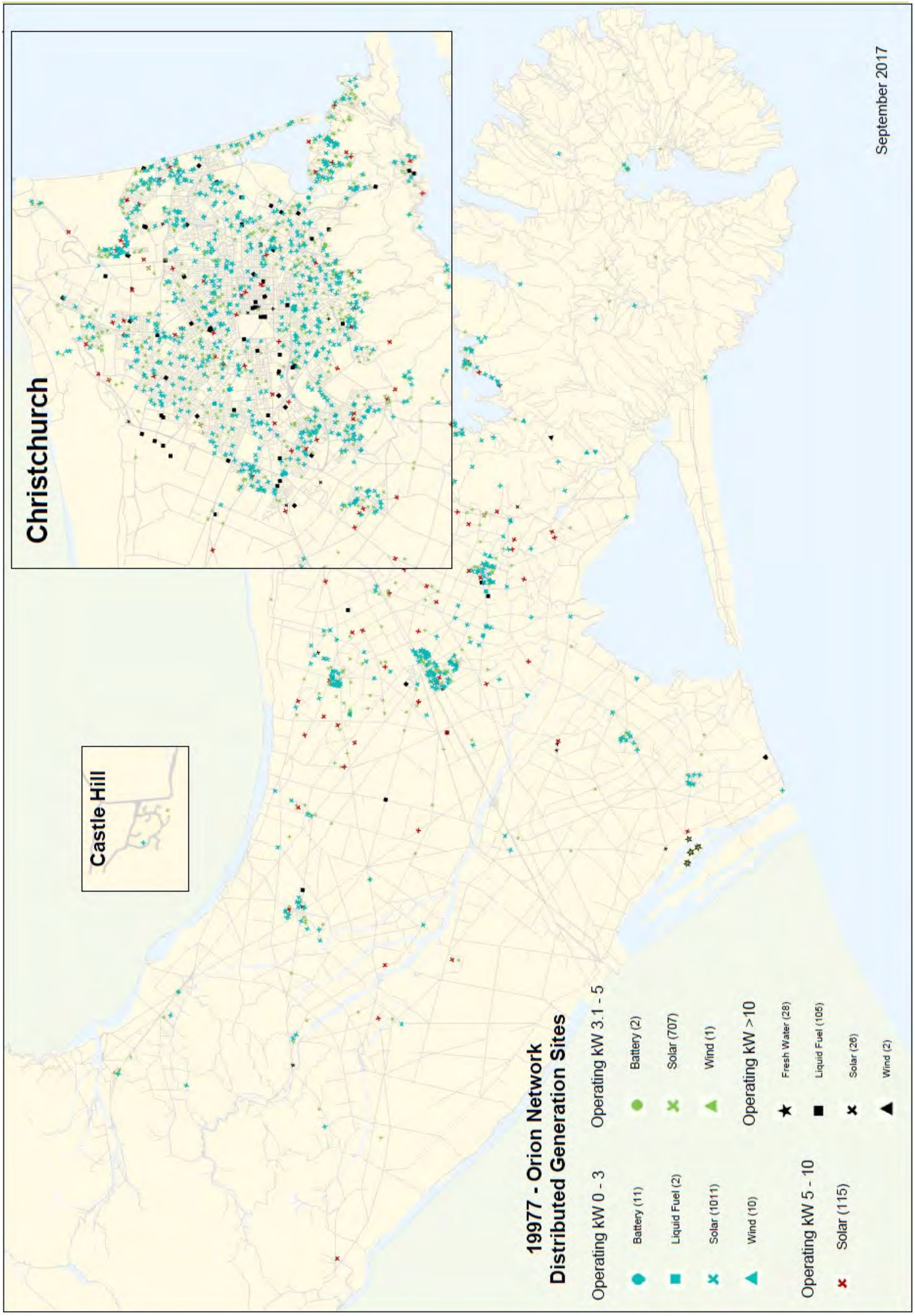


Figure 5-4x Location of distributed generation on our network



5.4.8 Network connections and extensions

Overview

Network connections can range from a 60 amp single-phase connection to a large industrial connection or a big subdivision of several thousand kVA.

Customer connections

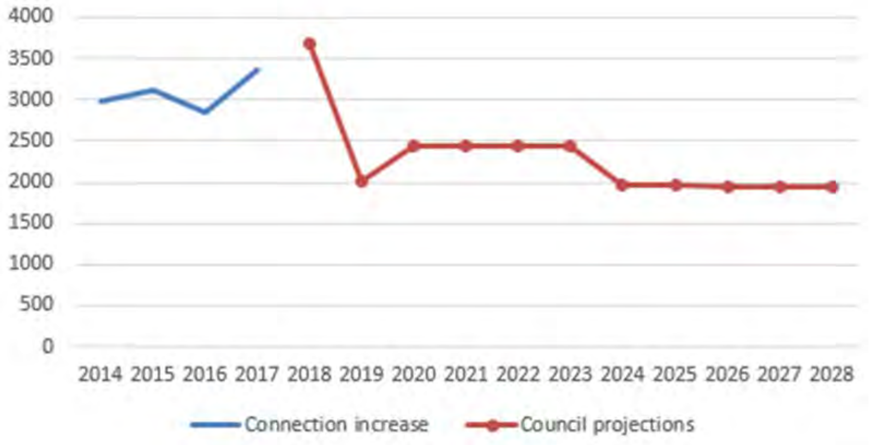
We anticipate that we will continue to connect customers to our network at the present rate of approximately 3,000 each year. Supplying these connections creates a need for:

- kiosk substations
- pole substations
- network or large customer building substations
- low voltage services
- network extensions.

Subdivisions

The level of subdivision activity depends on economic conditions and population growth. The Land Use Recovery Plan March 2015 Monitoring Report indicated residential intensification has been less than expected. The updated forecast has the annual increase in households dropping from current level of ~2,500 to around 2,000 from 2024 as shown in the figure below.

Figure 5-6y Councils projection of household numbers



In our rural area most subdivisions are for lifestyle reasons. In our urban area it can be industrial, commercial or residential, though most developments are residential. Our subdivision investment is made after negotiating with the developer on the basis of a commercial rate of return. 5.6.11 Underground conversions.

The budget for network connections and extensions is provided in figure 5.6f.

5.5 Network gap analysis

Our 'deterministic' Security Standard provides a useful benchmark to identify areas on our network that may not currently receive the same high level of security as the majority of our network.

Economically robust solutions to actual and anticipated network gaps caused by imminent load growth are quickly provided for by our annual capital spend. Network security is maintained on our 11kV distribution network by ensuring that the design of new connections is consistent with our Security Standard.

On an annual basis, our network planning group updates contingency plans for all valid subtransmission (220kV, 66kV, 33kV) and 11kV contingencies. In some cases the Security Standard criteria for 'no interruption' or 'restoration time' of load cannot be economically met.

The network gaps identified in the following tables arise because the cost of reinforcing the network to the performance level identified in our Security Standard would be economically prohibitive. That is, the cost to provide the Security Standard level of performance would exceed what customers are prepared to pay for it.

In general, network security gaps fall into one or more of the following categories:

- solution is currently uneconomic and an economic solution is not anticipated in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but network expansion in adjacent areas is expected to provide a security improvement in the future
- solution requires co-ordination with Transpower's asset replacement programme and/or is subject to Transpower/ Commerce Commission approval.

The economic analysis for each network gap determines the value of lost load (VOLL) when a defined contingency occurs and then utilises probability theory to determine the annual VOLL. This VOLL is calculated using $6.97 per kW for the initial interruption and $16.26 per kWhr thereafter. The Electricity Authority (formerly Electricity Commission) undertook surveys and a review of VOLL in 2010, 2011 and 2012 to better understand the range of VOLL values for different customer groups and also provide a check on inflationary impacts since the last survey (1992) and review (2006). The Electricity Authority (EA) has undertaken further surveys (including in Christchurch) to refine the results, which were released in August 2013. The EA conclusion for an eight hour outage in Christchurch is $18.69 per kWh. The EA report also supports using higher VOLL values for small to medium commercial customers (CDB type loads). Our review of the report did not suggest that a change to our VOLL values (as stated above) were necessary but it highlighted the large variance in VOLL for different customer groups. In 2015 we consulted business customers regarding the security of supply they were willing to fund as part of the central city rebuild. Their response implied a value of $26 per kW for the initial interruption and $66 per kWh for the first hour, rising to $178 per kWh for the second hour.

Although the VOLL of contingencies can be very high, the low probability of occurrence can often lead to a very low annualised VOLL and therefore render the proposed solution uneconomic. This often results in the timing of the solution being largely dependent on the timing of other related network development proposals which are required for load growth or asset replacement in the area.

Because annualised VOLL figures can hide the high VOLL of a particular event it is important to consider the implications of rare but costly (High Impact Low Probability) events if they were to occur. The Canterbury earthquakes have reiterated the importance of building a resilient network and any economic analysis should be considered alongside the asymmetric nature of the risks involved.

Notes to the following tables:

The Electricity Participation Code includes a national transmission grid reliability standard. This standard states that Transpower is required to maintain an N-1 level of security for the core grid. The GXP gaps identified below are based on the application of our Security Standard to Transpower's core-grid, spur or GXP assets. Proposed projects for Transpower's core grid assets will be subject to Transpower and/or Commerce Commission approval. Transpower meets the initial capital cost and then charges us an annualised amount for the use of the additional assets. Transpower costs are essentially passed through to us to be recovered from our customers. Transpower project costs are estimates only.

The table includes current Security Standard gaps only. Additional projects listed in the ten year AMP provide solutions for future forecast gaps that are not stated here.

Some projects address more than one security gap and are therefore quoted in more than one location.

Table 5-5a **Transpower GXP security gaps**

Network gap	VOLL per event $000	VOLL p.a. $000	Solution	Cost $000	Cost p.a. $000	Benefit cost ratio	Proposed date
Islington							
Partial loss of restoration for an Islington 220/33kV dual transformer failure.	2,200	4	Install Templeton 66kV zone substation (Project 502). (Note 1)	5,368	751	1:187	Timing is influenced by load growth at Templeton and not driven by closing this gap
Hororata							
Interruption to all Hororata GXP load for a 66kV bus fault (restorable).	830	19	Install a 66kV bus coupler (75% of load will remain on).	TP 500	55	1:2.9	Uneconomic. No date proposed. Possible-66kV links from Highfield to Greendale and Darfield would significantly reduce the restoration time for some load
Partial loss of restoration for a Hororata 66/33kV dual transformer failure.	1,180	11	Falling irrigation load will help. To be reviewed.				

Note 1. Shared mobile generation could provide an alternative solution.

Table 5-5b **Orion security gaps**

Substation	Network gap	Solution	Cost $000	Proposed date
Hororata	Interruption to all Hororata 33kV GXP load for a 33kV bus fault (restorable).	Investigate installation of a 33kV bus coupler as part of 33kV switchgear replacement	TBA	FY23
Dallington	Loss of 30MW of load for a single 66kV line or transformer failure. Restoration achievable in 5 minutes.	Complete a 66kV loop from Bromley via Rawhiti and Marshland by installing a cable from Marshland to McFaddens zone substation (Project 491).	7,798	FY25
Hoon Hay	Single Hoon Hay 11kV busbar fault causing complete loss of supply to 32MW of load. Restoration achievable in 2 hours.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	80	FY19
Lancaster	Loss of 22MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.	Complete a 66kV loop from Hoon Hay to Milton.	TBA	TBA
Rawhiti	Loss of 26MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.	Complete a 66kV loop from Bromley via Rawhiti and Marshland by installing a cable from Marshland to McFaddens zone substation (Project 491).	7,798	FY25
Waimakiriri	Loss of 16MW of load for a single 66kV circuit or transformer fault	The impact will be reduced by a second transformer at Waimakiriri enabling remote restoration for a transformer or circuit fault	1,278	FY19

5.6 Network development proposals

The previous sections tabled network capacity, growth projections and the security constraints on our network. This section lists our proposals to remove capacity and security constraints.

5.6.1 Impact on service level targets

The network development projects listed in this section are driven mainly by the need to meet the capacity and security requirements of load growth. Where economic, project solutions have been designed to meet our security of supply standard requirements.

This ensures that our network configuration and capacity is constructed in a consistent way and the impact on our reliability of supply service levels will be predictable. It should be noted that reliability of supply service levels are a function of many inputs and, while network configuration and capacity is a major input, it is not the only factor.

Project solutions also need to consider our safety, power quality, environmental and efficiency targets.

Safety performance during construction is influenced by factors such as site security, operating standards and contract management practices. Upon completion, high levels of safety performance are achieved by appropriate choice of network equipment, site security and operating standards.

Power quality is influenced mainly by ensuring that network capacity is adequate. Undersized reticulation or high impedance transformers will increase the risk of power quality issues. Some projects provide for the connection of equipment (for example variable speed drives) which can create high levels of harmonic distortion and it may be necessary to install harmonic filtering equipment to reduce the distortion to acceptable levels.

Environmental targets are met with new projects by ensuring that substation design includes appropriate oil bunding and, where possible, precludes the installation of SF_6 switchgear. On-going environmental targets are met by adhering to appropriate resource management standards.

Our efficiency target is met by ensuring that upgrades or extensions to the existing network are not oversized. During development projects it may be necessary to reconfigure adjacent parts of the network and consideration is given to economic downsizing of existing underutilised distribution transformer capacity.

5.6.2 Overview of projects and budgets

The network development/growth related projects and budgets identified in this section are sorted into the following categories:

- major projects – GXP
- major projects
- 11kV reinforcement
- 400V reinforcement
- network connections and extensions.

With the exception of network connections and extensions, these categories are banded within the following timeframes:

- the current financial year (FY19)
- the next four years (FY20-FY23)
- the remainder of the period (FY24-FY28).

All FY years refer to financial year ending 31 March.

Projects for the current year can be considered firm. Those planned for the following four years will be reviewed annually, and may not proceed as currently envisaged. Projects for the remainder of the period are indicative only because of the uncertainties as to the nature and magnitude of future loads.

A summary of the options for the major projects has been provided. Because most of the projects beyond the current year are still subject to a final review and refinement, it is possible that actual implementation may differ from that proposed if new information becomes available before the need to start detailed design. For projects beyond the current year, the value per kW of deferral has been tabled later in this section (5.6.9) to provide a guide to potential Customer Demand Management providers.

Although GXP alterations are not carried out directly by us, they are included here to provide a greater understanding of the capacity and security issues we face. Transpower is to undertake the GXP projects to improve the capacity, security and quality of supply to our customers. They will meet the initial capital cost and then charge us an annualised amount for the use of the additional assets. Transpower costs are essentially passed through to us to be recovered from our customers.

5.6.3 Urban (region A) 66kV subtransmission review

From FY08 - FY12 we met growth within our region A network without the need to invest significantly in the subtransmission network. Following the earthquakes we anticipated that new zone substation capacity will be required towards the north of Christchurch City at Waimakariri and Marshland. The capacity of our pre-earthquake 66kV subtransmission network in the area was not sufficient to supply any proposed new zone substation. Permanent damage sustained to our 66kV network from the earthquakes meant our network capacity was further reduced.

In FY14 we started to invest significantly to replace capacity in the east and meet the electrical needs of northern Christchurch customers. These investments significantly shape the long term security and reliability of supply outcomes for the northern part of Christchurch City.

In an environment where our standard of living and health is so heavily dependent on a reliable electricity supply it has become increasingly important that our network is resilient to a wide range of factors. The earthquakes prompted the need to review the architecture of our network and our network security of supply standard and a reconsideration of the Christchurch subtransmission network was carried out in FY12. This review is described in our Network Architecture Review - Subtransmission (NW70.60.16).

Our 66kV subtransmission options analysis not only considered the impact of normal network contingencies but also the widespread impact of natural events on our assets and the flexibility of our network architecture to restore power following these events. We work hard to apply preventative maintenance measures to ensure that the chance of electrical, mechanical or external forces causing failure of our assets is economically minimised. However, it is important to consider the impact of major events such as that seen at Otahuhu in 2007 which caused several hours of lost electricity supply to the majority of Auckland City and the series of Christchurch earthquakes in 2010 and 2011 which caused widespread outages for a few hours and isolated area outages for many days.

The review confirmed and refined the approach we have been taking since the year 2000. For future work, we will continue to move away from zone substations being radially fed from GXPs to a more resilient layout. Future design will be based on a closed-ring network topology so the failure of any single route will not interrupt supply to a zone substation. Cables will be sized to give sufficient cross-GXP link capacity to provide full support in the loss of either Islington or Bromley 66kV supply. The preferred layout for 66kV zone substations is to have a ring-bus which has better fault performance than a conventional bus arrangement for either circuit breaker failures or bus faults.

5.6.4 Transpower spur assets

Transpower owned or owns a number of 66kV, 33kV and 11kV assets in our network area (see map, section 5.2.1). Many of these assets do not form part of Transpower's core grid and deliver electricity solely to our network. We call these assets 'spur assets' to Transpower's grid and they fundamentally serve the same purpose as our own 66kV, 33kV and 11kV distribution network assets.

The possibility of Transpower selling spur assets New Zealand wide has been discussed in the industry several times over the last 25 years. This can mainly be attributed to the recognition that these assets serve the purpose of local distribution rather than national transmission. A change of ownership enables configuration and construction efficiency benefits to be achieved through integration into local distribution network asset planning, management, maintenance and operations which would result in downward pressure on prices to our customers.

The Commerce Commission gazetted a new set of 'Input Methodologies' in December 2010 which sets out the upfront regulatory methodologies, rules, processes, requirements and evaluation criteria on which lines businesses will be regulated. As part of our submissions on the input methodologies we have encouraged the Commerce Commission to develop rules that enable lines companies to make a regulated return on the purchase of spur assets. In our view the input methodologies encourage Orion to purchase spur assets from Transpower and thereby achieve benefits for our customers. These benefits are relevant as we focus on the redevelopment of Christchurch with different patterns and location of growth. The Commerce Commission 2013 Customised Price Path decision supported spur asset transfers.

We have worked with Transpower to determine the appropriate ownership boundary between Transpower and Orion and the following diagram provides a summary of the agreed core grid and spur assets in Orion's network area.

Figure 5-6a Transpower core grid and spur assets in Orion's network area

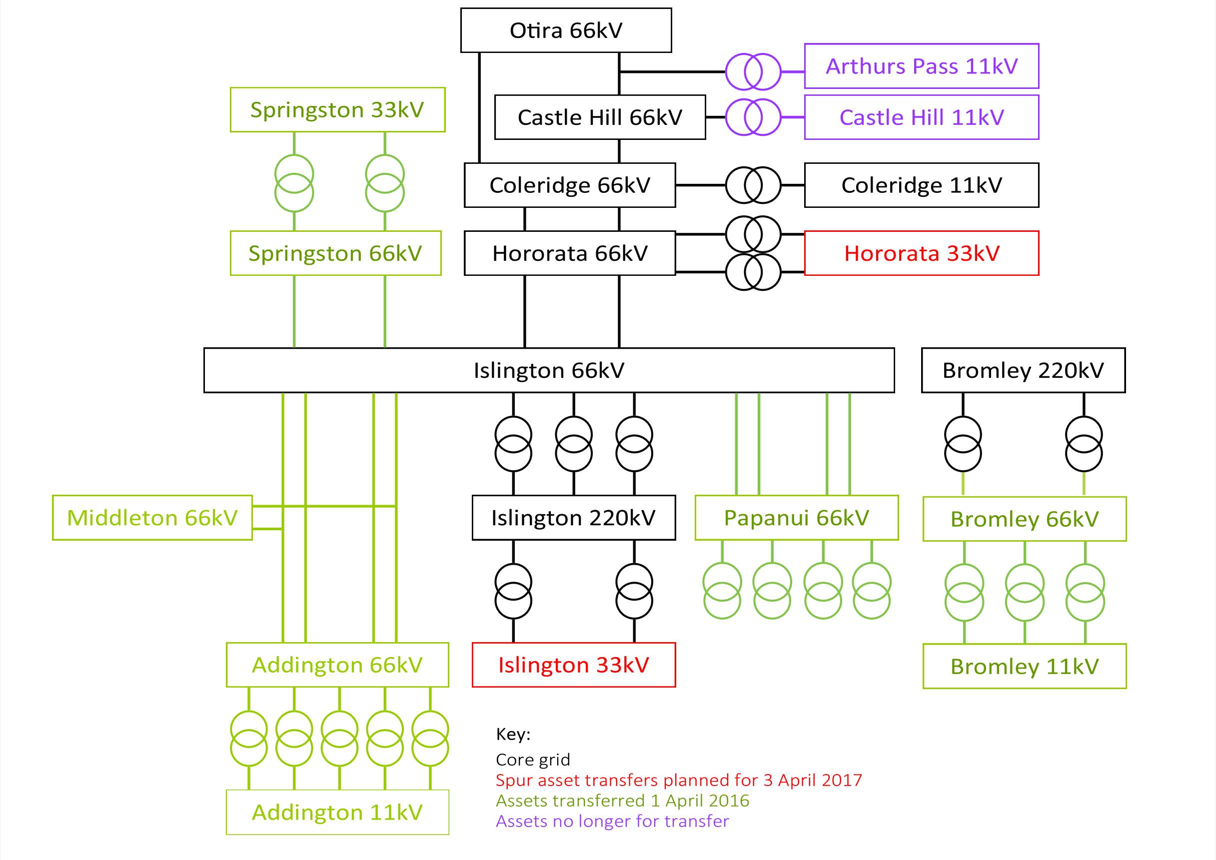


Table 5-6a provides a date for each of the GXP spur assets. The estimated spur asset purchase costs are based on the forecast Transpower 'Regulatory Book Value' of the remaining assets at the time of forecast transfer. These forecasts include the forecast value of Transpower planned replacement or enhancement work prior to the purchase date and also some transaction costs.

Table 5-6a Spur assets, indicative cost to purchase – $000

Spur asset to be purchased	FY19
Hororata 33kV (excluding 66/33kV transformers)	330
Islington 33kV	800
Spur assets total	1,130

In addition to the purchase costs tabled, the ownership of Transpower spur assets will also require an increase in our budgets for reinforcement, replacement, maintenance and operations. Additional capital expenditure as a result of the spur asset purchases associated with growth, reinforcement and replacement has been incorporated into this AMP.

5.6.5 Major GXP projects

Table 5-6b Major GXP projects

Project	FY19	FY20	FY21	FY22	FY23
Hororata separation	20				
Islington separation	20				
GXP total	40	0	0	0	0

5.6.6 Major projects

Figure 5-6b Region A subtransmission 66kV – existing and proposed

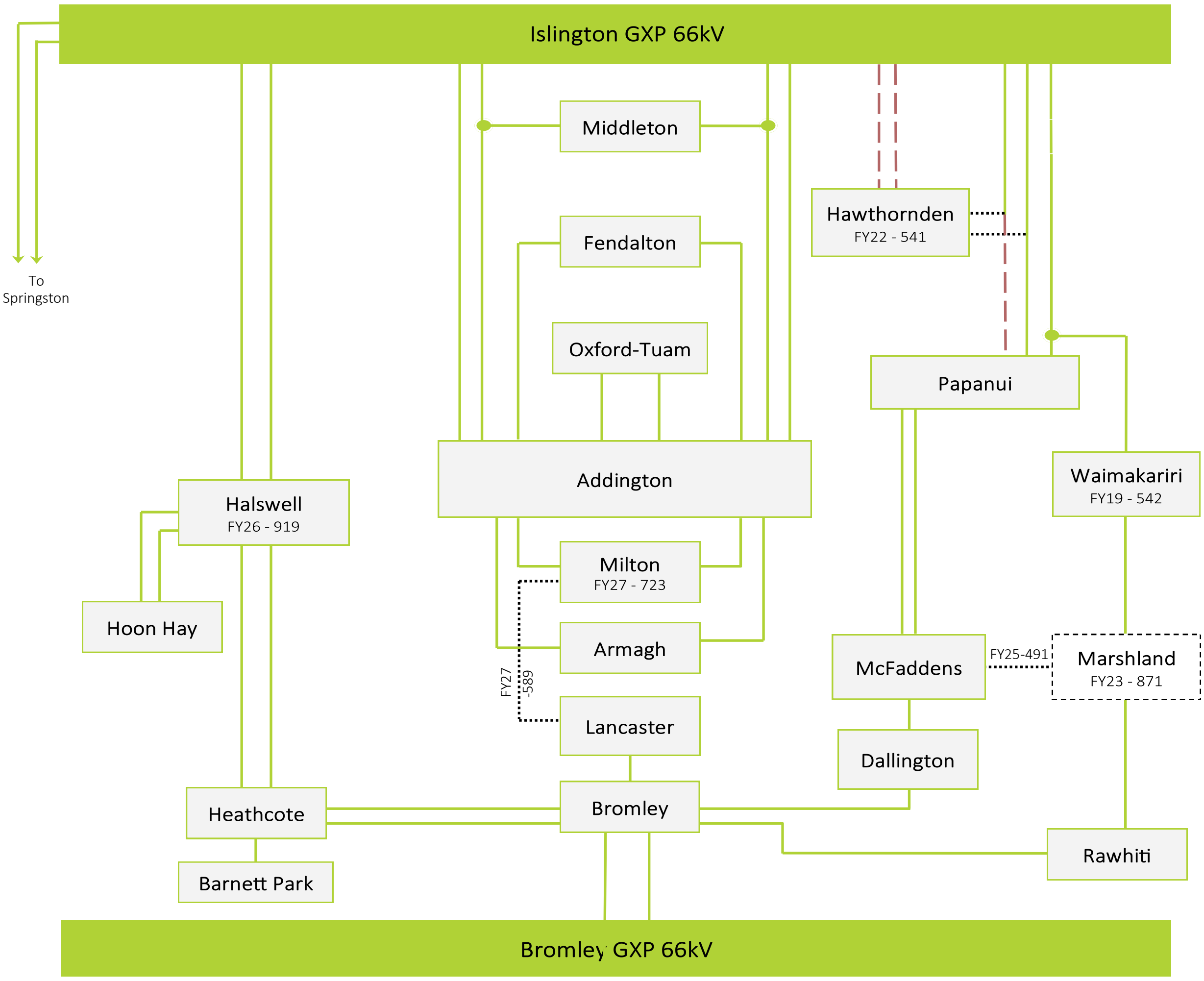


Figure 5-6c Region A subtransmission 33kV – existing and proposed

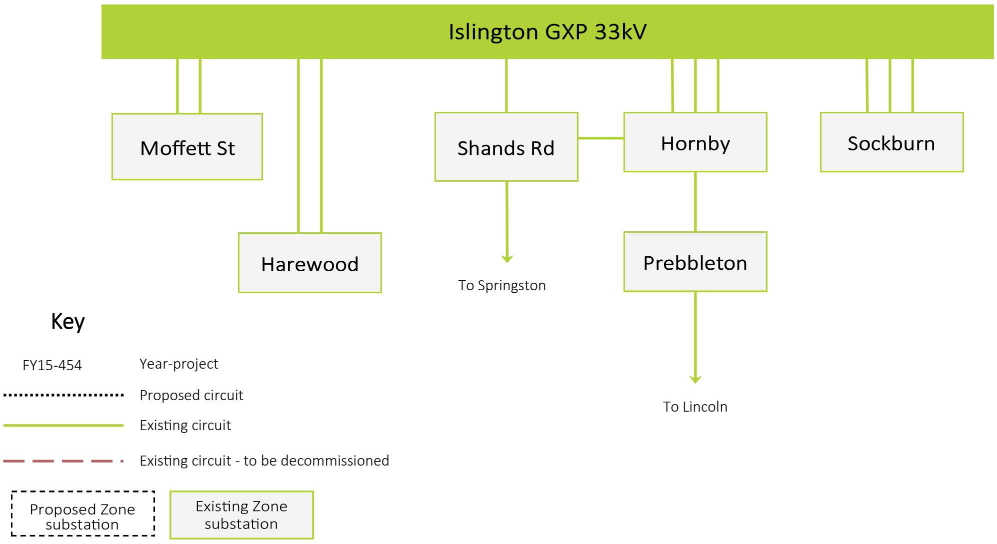
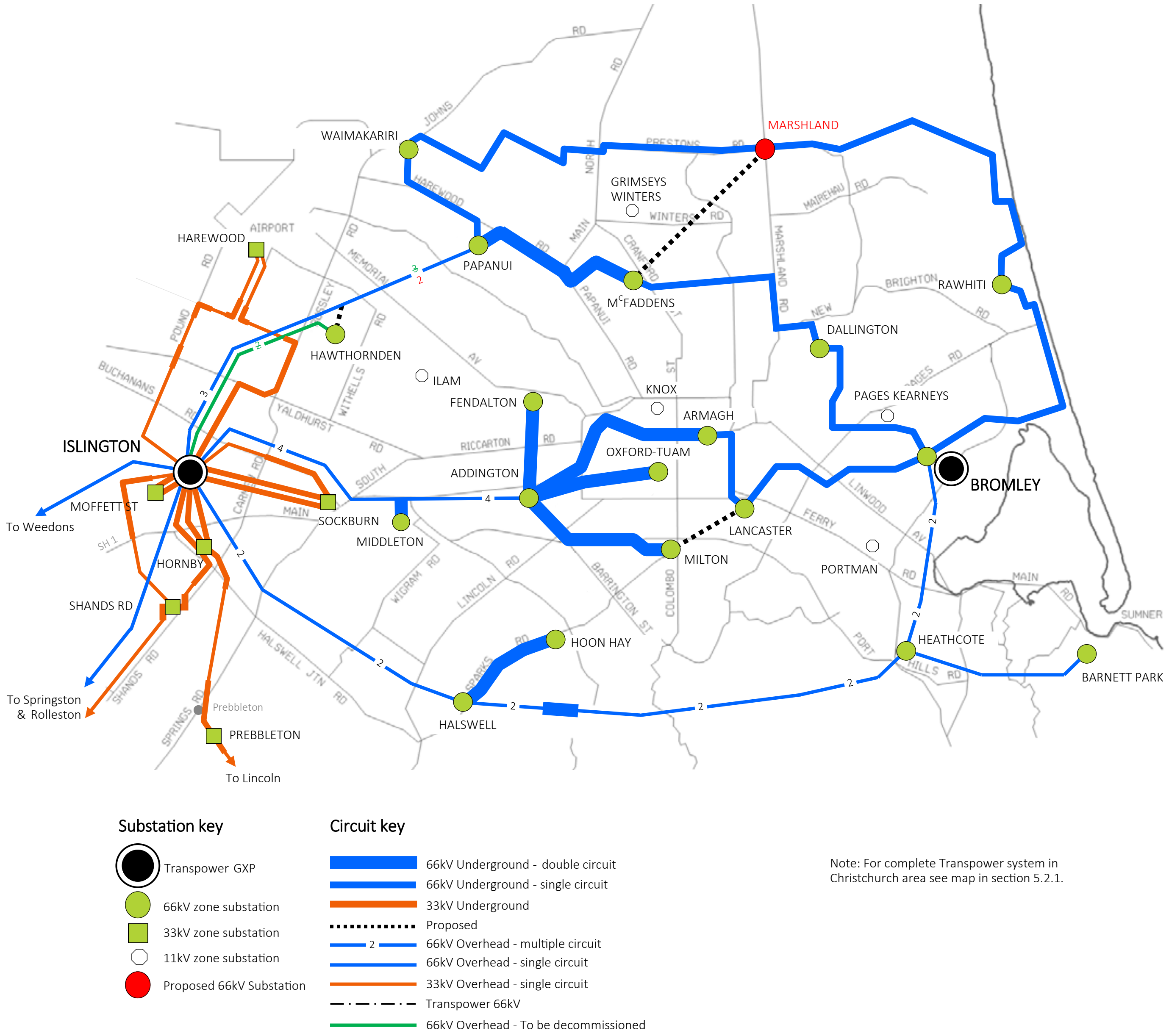


Figure 5-6d **Region A subtransmission 66kV and 33kV – existing and proposed**



Note: For complete Transpower system in Christchurch area see map in section 5.2.1.

Figure 5-6e **Region B subtransmission network 66kV – existing and proposed**

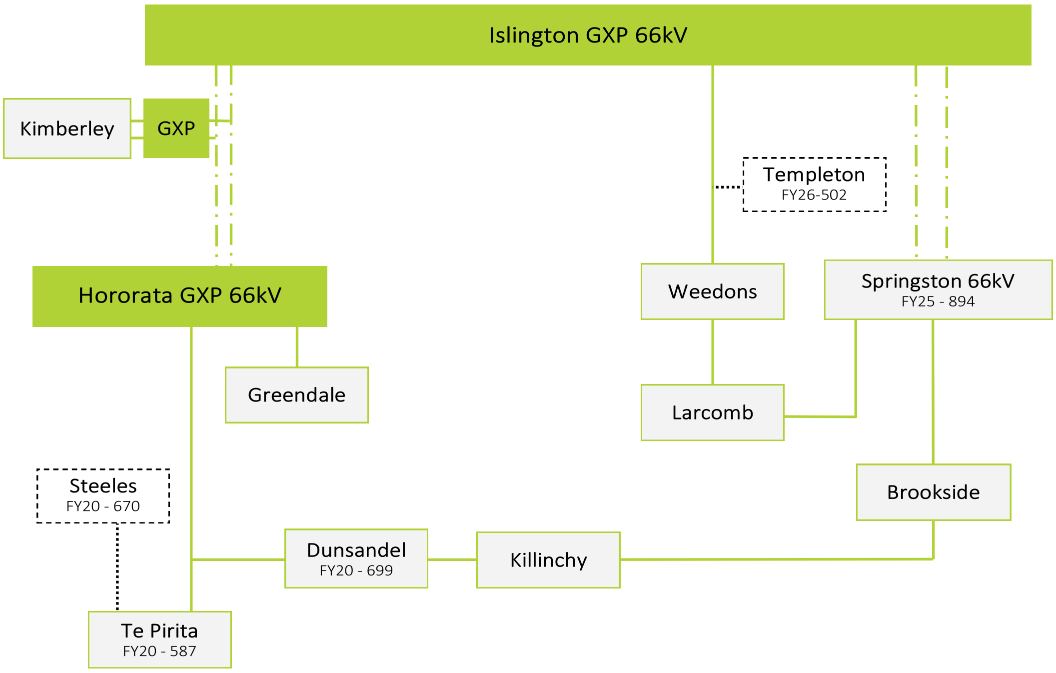


Figure 5-6f **Region B subtransmission network 33kV – existing and proposed**

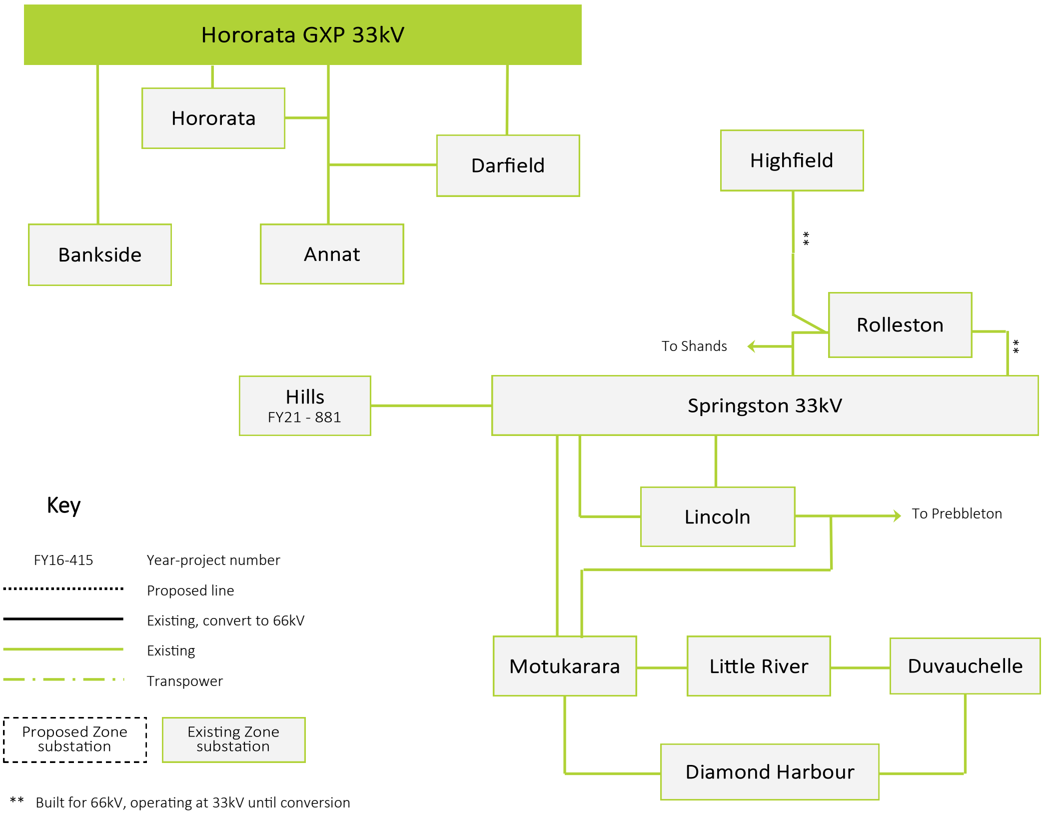


Figure 5-6g Rural Region B subtransmission network 66 and 33kV – existing and future

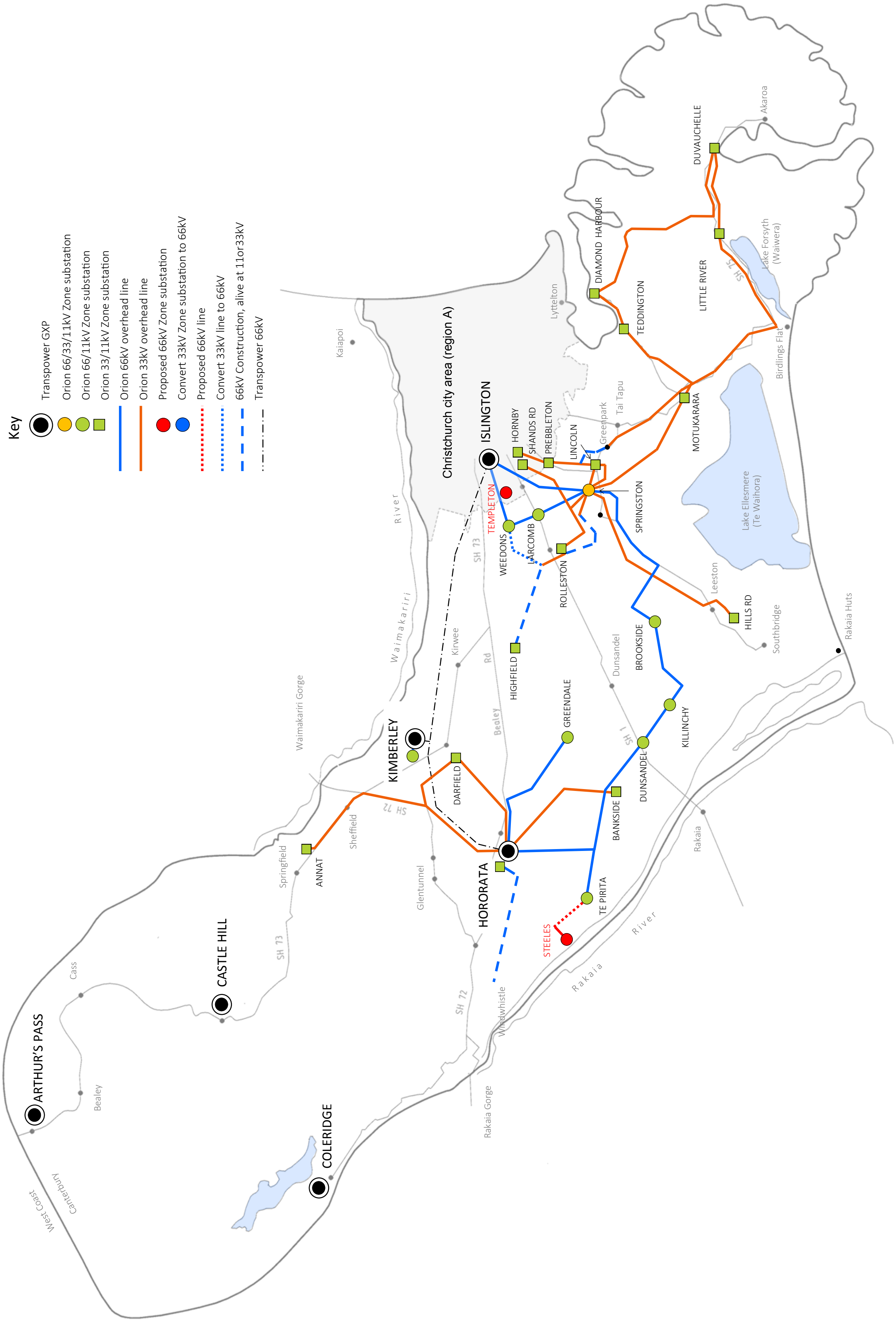


Table 5-6c **Major projects - $000**

Project		FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
50	Lyttelton Tunnel cable	2,500									
542	Waimakariri Stage 2	1,278									
721	Land acquisition Shands Rd 66kV switchyard		500								
587	Te Pirita zone substation 66kV bays		917								
670	Steeles Rd		2,925								
699	Dunsandel transformer upgrade		1,778								
527	Land acquisition Templeton 66kV substation		110								
637	Railway Rd 11kV substation (Westland Milk)			3,297							
900	Castle Hill and Arthurs Pass switchgear upgrade			433							
881	Hills Rd Zone substation transformer upgrade			430							
541	Hawthornden T-off				1,210						
666	Porters Village				4,485						
871	Marshland zone substation					7,115					
491	McFaddens to Marshland 66kV link							7,798			
722	Land acquisition for Hoon Hay 66kV switchyard							200			
728	Springston 11kV switchroom							521			
894	Springston 66/11kV transformer							1,039			
919	Halswell transformer upgrade								4,248		
502	Templeton 66kV zone substation								5,368		
723	Milton 66kV switchgear for Lancaster cable									4,864	
589	Lancaster to Milton 66kV link									4,497	
Major projects total		3,778	6,230	4,160	5,695	7,115		9,558	9,616	9,361	

Table 5-6c.1 **Major project details – Current year FY19**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
50	Lyttelton Tunnel cable	Supply to Lyttelton is vulnerable to failure of the single pole lines over the Port Hills. Projected growth at the Lyttelton Port Company and in Lyttelton township will require an increase in capacity and security to the region.	A new 300mm2 Cu 3x1C 11kV cable will be laid through the Lyttelton Tunnel and connected into the existing 11kV network. When load growth occurs, a seprate reinforcement project will provide additional switchgear to further increase the N-1 capacity to Lyttelton (See Project 913).	An alternative would be to construct a 66/11kV substation in Lyttelton and reinsulate the existing 11kV line to 66kV. This however is a much more costly solution and would remain vulnerable to failure of the single pole lines over the Port Hills.	2,500	FY19
542	Waimakariri Stage 2	Load growth in the north of Christchurch combined with replacement/rationalisation of the Papanui zone substation transformers means Waimakariri zone substation load will exceed 15MVA on N security and the peak load at Papanui will approach its firm capacity of 48MVA. Load growth will also erode security of supply on the 11kV north primary ring from Papanui zone substation.	Waimakariri Stage 2 (Project 542), Marshland zone substation (Project 871) and ultimately Belfast zone substation will progressively address this constraint as growth continues.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	1,278	FY19

Table 5-6c.2 **Major project details – years FY20 to FY28**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
721	Land acquisition for Shands Rd 66kV switchyard	A site is needed for the extension to Shands zone substation - see Project 669.	We propose to purchase additional land around our existing Shands zone substation.	We will undertake more options analysis before we commit to this project and land purchase.	500	FY20
587	Te Pirita 66kV bays	The Central Plains Water scheme will create an opportunity for a hydro generation scheme near Steeles Rd. Assets may be required to connect this into the Orion 66kV network (see Project 670).	Two 66kV circuit breaker bays will be installed at Te Pirita zone substation for the existing Hororata circuit and the Steeles Rd overhead line. If the generator does not proceed, these bays will still be required when the Windwhistle (Project 348) and/or The Point (Project 608) substations are commissioned.	It may be possible to connect the generation at 11kV. We will investigate this in more detail when more information is available.	917	FY20
670	Steeles Rd substation and 66kV line	The Central Plains Water scheme will create an opportunity for a hydro generation scheme near Steeles Rd. Assets will be required to connect this into our 66kV network.	A dedicated substation may be installed at the generation site. The substation would be a simple voltage step up site without the need for a building to house 11kV switchgear, ripple and the usual protection and control equipment. We will build a 66kV line from this substation to Te Pirita zone substation. Switchgear will be required at Te Pirita (Project 587).	This project is dependent on the requirements of Central Plains Water or another party developing hydro generation at the site. Smaller amounts of generation could be directly connected to our 11kV network and therefore prevent the need for a new substation.	2,925	FY20
699	Dunsandel transformer upgrade	Load at Dunsandel will exceed the 10MVA N-1 capability of the site during the summer of 2015/16. An 11kV intertrip scheme has been installed to provide load management capability at the site if one transformer should fail. A fourth Synlait milk drier in FY20 (estimated date) will mean that the capacity constraint can no longer be managed by the intertrip scheme.	We envisage that Synlait will request an upgrade of the 2x7.5/10MVA transformers to 2x11.5/23MVA.	The decision to upgrade will be largely made by Synlait to meet their security and reliability of supply requirements.	1,778	FY20
527	Land acquisition Templeton 66kV substation	Townships to the southwest of Christchurch are expected to show strong growth over the next decade and the associated zone substations and 11kV overhead feeders in the area will likely become constrained.	It is proposed to purchase a site for a future Templeton substation (see Project 502) adjacent to the 66kV line between Islington and Weedons.	We will continue to monitor the location and timing of load growth in the area and progress site investigation accordingly.	110	FY20

Table 5-6c.3 **Major project details – years FY20 to FY28—continued.**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
637	Railway Rd 11kV substation (Westland Milk)	The proposed Westland Milk Products (WMP) processing plant in the Izone industrial park may require up to 8MVA. Steady load growth around this district also means further 11kV reinforcement is needed to maintain security of supply.	We will build an 11kV switching station at the site with two dedicated cables from Larcomb zone substation and a backup circuit from Rolleston zone substation all along Jones Rd. While the trenches are open we will also take the opportunity to complete the undergrounding of our remaining overhead 11kV lines in Jones and Hoskyns Rds and install an extra cable from Larcomb into Izone.	The magnitude of the point load, plus the ongoing growth around Rolleston becomes a driver for a possible new zone substation near WMP. However, there are three nearby substations with sufficient capacity and the 11kV feeders from adjacent substations in this project would still be needed for contingent support.	3,297	FY21
900	Castle Hill and Arthurs Pass 11kV switchgear upgrade	The existing Castle Hill and Arthurs Pass 11kV switchgear are aging assets and due for an upgrade.	We propose to purchase the 11kV switchgear assets from Transpower and replace them with new circuit breakers.	This will improve reliability and give full operational control to this remote location.	433	FY21
881	Hills Rd transformer upgrade	The load at Hills Rd zone substation is expected to exceed capacity in FY21.	The Hills Rd zone substation transformer will be upgraded by relocating an existing 7.5/10MVA long reach transformer. This will assist with the voltage level at Hills and provide the needed capacity.	A new Southbridge zone substation is proposed in the long term however more load is needed to make this option cost effective and an upgrade to the 66kV network would be needed. In the meantime, this plan increases utilisation on existing assets.	430	FY21
541	Hawthornden T-off	The radial configuration of the 66kV lines from Islington to Hawthornden does not enable supply route diversity to be achieved. Furthermore, the purchase of the Papanui 66kV lines provides an opportunity to rationalise and more efficiently supply Hawthornden.	We intend to supply Hawthornden and Papanui zone substations from the three Islington-Papanui high-capacity tower lines currently in service. This project provides for these connections and 66kV re-arrangements at Papanui zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16.	1,210	FY22
666	Porters village	A large resort development near Porters Pass ski field is proposed and if it proceeds it will require connection to the Orion network. Existing electrical load at the site is supplied by 'off grid' generators.	The size of the load and distance from existing assets makes the requirement challenging. Preliminary studies have been undertaken to provide an initial estimate of the costs however detailed design is yet to be undertaken. The solution may involve major business decisions such as GXP changes or the adoption of 22kV assets.	A comprehensive study is yet to be done and there is significant uncertainly around whether the proposal will eventuate and/or the timing.	4,485	FY22

Table 5-6c.4 **Major project details – years FY20 to FY28—continued.**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
871	Marshland zone substation	Load growth in the north of Christchurch combined with rationalisation of the Papanui zone substation transformers leaves little capacity at both Papanui and McFaddens zone subs. The LURP and CCC district plan presents Belfast as a priority area for business development with significant industrial growth in the Belfast area likely when the new northern motorway is constructed.	A new 66/11kV zone substation will be commissioned, with 66kV connections to Waimakariri and Rawhiti zone substations . This significantly enhances the capacity and security of supply for customers in the northern half of Christchurch city.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	7,115	FY23
491	McFaddens to Marshland 66kV Link	A failure of the 66kV supplying Marshland, Rawhiti and Dallington zone substations will result in a short outage while switching takes place. This does not comply with our security of supply criteria.	Orion's urban subtransmission strategy proposes a 66kV closed ring supply from Bromley. This cable completes the northern ring with Rawhiti, Marshland, McFaddens and Dallington zone substations. New 66kV bays will be needed at McFaddens and Marshland. This circuit will connect the two major 66kV routes to the north of the city (Bromley-Dallington-McFaddens-Papanui-Islington and Bromley-Rawhiti-Marshland-Waimakariri-Hawthornden -Islington). It will provide more load transfer options between Islington and Bromley GXPs and improve reliability of supply by allowing the four zone substations to operate in closed subtransmission rings with uninterrupted N-1 security. It will also limit N-2 events to the loss of a single zone substation. The network robustness in HILP events will be markedly improved.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	7,798	FY25
722	Land acquisition for Hoon Hay 66kV switchyard	The proposed Hoon Hay-Milton 66kV link (outside the ten-year AMP scope) requires 66kV switchgear installations at each zone substation. Both substations will require land purchases for new switchyards - also see Project 694.	A site will be secured adjacent to Hoon Hay zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16.	200	FY25
728	Springston 11kV switchgear	This is part of the ongoing development of the Springston zone substation (see project 894).	We propose to expand the existing 11kV supply by installing new circuit breakers and accommodate transformer T3.		521	FY25
894	Springston 66/11kV transformer	The Springston zone substation load will gradually grow and it is also needed to provide contingency support to its growing neighbouring Lincoln, Rolleston and Brookside zone substations.	We will increase the capacity by expanding the 66kV bay and installing a 66/11kV 10MVA transformer.		1,039	FY25
919	Halswell transformer upgrade	Subdivision growth in the Halswell area is increasing the load on Halswell zone substation which is expected to reach capacity around FY26.	This project increases the transformer firm capacity at Halswell zone substation from 23MVA to 40MVA to address this growth.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	4,248	FY26

Table 5-6c.5 **Major project details – years FY20 to FY28—continued.**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
502	Templeton 66kV zone substation	The districts and townships to the southwest of Christchurch are expected to show strong growth over the next decade and our zone substations and 11kV overhead feeders in the area are becoming constrained.	A new zone substation will provide security of supply to the Templeton township and surrounding district. The new substation will be supplied from the Islington to Weedons 66kV line.	We have already reconfigured the 11kV feeders in the area to share load more evenly and have installed an 11kV regulator to increase capacity. The close proximity of the Islington to Weedons 66kV line makes a new zone substation cost effective when compared to 11kV reinforcement from constrained zone substations in the area.	5,368	FY26
723	Milton 66kV switchgear for Lancaster cable	The Milton-Lancaster 66kV cable (Project 589) will require installation of switchgear at both zone substations. See Project 727.	This project will commission a new indoor 66kV switchroom on land (Project 694) adjacent to Milton zone substation.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16.	4,864	FY26
589	Lancaster to Milton 66kV link	The post-earthquake architecture review highlighted that the high value Central City load requires additional subtransmission support. In particular, improved cover for the loss of Addington zone substation is needed.	A 95MVA circuit between Lancaster and Milton zone substations will provide extra security of supply for the Central City. In addition, it contributes to our goal of providing for stronger cross-city connections between Islington and Bromley 220kV GXPs to mitigate a major outage at either site. See also Projects 694, 723 and 727.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16.	4,497	FY27

5.6.7 Reinforcement projects

Table 5-6d **11kV reinforcement projects - $000**

Project		FY19	FY20	FY21
854	Halswell Junction Rd	300		
866	Hussey Rd reinforcement	596		
912	Sawyers Arms Rd feeders	709		
914	Twyford St adjustment	33		
915	Levi Rd reinforcement	305		
916	East Maddisons Rd reinforcement	318		
917	Frankleigh St reinforcement	51		
918	Station Rd reinforcement	258		
930	Townships reliability improvements—Stage 2	325		
855	Waterloo Rd		161	
922	Milton 11kV adjustment		350	
633	Darfield Township reinforcement			595
920	Southfield Drive cable upgrade			361
913	Heathcote Lyttelton reconfiguration			145
Reinforcement subtotal		**2,895**	**511**	**1,101**
Non-scheduled reinforcement		605	900	900
Non-identified reinforcement		0	2,089	1,499
Reinforcement totals		**3,500**	**3,500**	**3,500**

Table 5-6d.1 **11kV reinforcement project details – current year FY19**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
854	Halswell Junction Rd	Load growth resulting from new subdivisions in the Awatea area requires capacity and contingency support.	This project makes use of the Shands Rd north cables (Project 839) by reconfiguring the network in Edmonton Rd and by laying a new 300mm^2 Al cable from Columbia Av No. 52 through to Wilmers Rd No. 5 to deliver capacity to the new subdivisions and industrial developments down Halswell Junction Rd.	This project mitigates the need for the more expensive southern motorway cable (Project 700).	300	FY19
866	Hussey Rd reinforcement	A section of small overhead line down Hussey Rd limits the ability to direct capacity from the new Waimakariri zone substation into the Northwood area.	A new 185mm^2 Al cable will be installed down Hussey Rd to replace the section of small overhead line. This provides capacity into the Northwood area, increases the utilisation on Waimakariri zone substation and provides support under a contingency at Papanui zone substation.	An alternative is to upgrade the existing 11kV overhead line down Hussey Rd, however this line is subject to faults during weather events and thus an underground cable would provide a more reliable solution.	596	FY19
912	Sawyers Arms Rd feeders	Load on Papanui zone substation is forcast to approach 50MVA in FY18 with substantial load tied up in the primary ring network in the north of Christchurch. Subdivision growth in the Claridges/Highstead area combined with a new 6MVA water bottling plant in Belfast is driving this load increase.	Two new feeders from Waimakariri zone substation will be installed down Sawyers Arms Rd. This project aligns with Project 542 – Waimakariri Stage 2 and Project 866 – Hussey Rd Reinforcement to reduce load on the Papanui zone substation and the Northern Christchurch 11kV primary ring network.	This project helps delay the need for the new Marshland zone substation and provides more cost effective capacity by increasing utilisation on existing assets.	709	FY19
914	Twyford St adjustment	Decommissioning of Bishopdale 11kV switching station (completed) and switchgear replacement at Wairakei Rd No. 330 (FY18) has seen the 11kV network in this area reconfigured to align with the 11kV trunk feeder architecture. As part of these changes, an additional feed is needed to provide N-1 capacity.	An existing cable from Papanui zone substation will be cut in and out of the Twyford St N kiosk to provide additional capacity into the Tywford Rd network.	This solution requires minimal work to increase the N-1 capacity in this area and is the most cost effective solution.	33	FY19
930	Townships reliability improvements - Stage 2	Reliability to townships throughout the district is compromised by the travel time for an operator to arrive in the area and switch the 11kV network around the fault.	It is now economic to replace manual ABI switches with remotely controllable 11kV line switches where there is a high concentration of customers.	The Strategic Reliability Review and Forecast NW 70.60.17 identified this as the best current initiative for improving reliability.	325	FY19

Table 5-6d.2 **11kV reinforcement project details – current year FY19** (continued from previous page)

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
913	Heathcote Lyttelton reconfiguration	Load in Lyttelton township and the Lyttelton Port is expected to increase due to plans outlined in the Christchurch City Council development plan and Lyttelton Port Recovery Plan 2015 . A new 11kV cable through the Lyttelton tunnel is planned to improve both capacity and reliability to Lyttelton township.	This project provides switchgear to connect the new cable into the existing network in Heathcote Valley and provide an increase in capacity and resiliency.	This project installs equipment on an existing Orion site and is the most cost effective solution to make use of the full capacity of the new 11kV cable through the tunnel.	145	FY21
915	Levi Rd reinforcement	Rolleston residential subdivisions are continuing to develop, with vacant residentially zoned land yet to fill. Additional network is required into these new subdivisions to provide capacity and N-1 support.	This project combines with Project 916 – East Maddisons Rd reinforcement to provide end-to-end trunk capacity between Larcomb and Rolleston zone substations into the new developments	This solution is customer driven with new subdivisions and 11kV network evolving between Larcomb and Rolleston zone substations.	305	FY19
916	East Maddisons Rd reinforcement	Rolleston residential subdivisions are continuing to develop, with vacant residentially zoned land yet to fill. Additional network is required into these new subdivisions to provide capacity and N-1 support.	This project combines with Project 915 – Levi Rd Reinforcement to provide end-to-end trunk capacity between Larcomb and Rolleston zone substations into the new developments	This solution is customer driven with new subdivisions and 11kV network evolving between Larcomb and Rolleston zone substations.	318	FY19
917	Frankleigh St reinforcement	Changes to the 11kV network around Therese St No. 8 and future changes at Hoon Hay zone substation mean the 11kV network in the Barrington area needs a minor adjustment to reinforce and provide N-1 security of supply.	This project cuts a large 0.5AL cable in and out of Frankleigh St No. 70 to increase the N-1 capacity and provide resilency.	This solution requires minimal work toincrease the N-1 capacity in this area and is the most cost effective solution.	51	FY19
918	Station Rd reinforcement	A new water bottling plant being installed in Belfast requires 6MW of capacity in FY19. This will contribute load to the already constrained Papanui zone substation and 11kV primary network in the north of Christchurch.	A new cable is needed to direct capacity from the lower and stronger 11kV primary ring network from Papanui zone substation, up to the new water bottling site. This also assists with balancing the 11kV primary network at the very top of the city and provides N-1 security to the site. Additional work is needed in Northwod to cut in extra capacity and redirect load away from the top part of the 11kV primary ring network.	This work is customer driven and is the simplest solution to address the capacity needs.	258	FY19

Table 5-6d.3 **11kV reinforcement project details – years FY20 to FY23**

No.	Project title	Issue	Chosen solution	Remarks/alternatives	Budget $000	Year
855	Waterloo Rd	The major commercial/industrial development being constructed off Waterloo Rd in Hornby requires capacity into the North Eastern end of the development.	A cable will be laid from Moffett St zone substation CB115 down Waterloo Rd and into the new development. A second cable will connect from Fulham St down Waterloo Rd and through-joint on to an existing cable to provide extra capacity into the existing Brixton St network.	A supply is planned from Shands Rd zone substation (Project 681) for the south western end of the development and this project provides capacity to the north eastern end of the development from Moffett St zone substation.	161	FY20
922	Milton 11kV adjustment	Milton zone substation 11kV incomers do not currently share the 11kV load well which reduces the firm capacity of the site. Balancing or reconfigurtion of the 11kV switchboard is needed to optimise the site capacity.	This project will investigate the reason for the sharing imbalance and will either adjust the existing loads to better balance the 11kV board, install a bus coupler or replace the existing 11kV incomer cables and incomer circuit breakers with two 2500A incomers.	This solution will provide the most cost effective option to increase the capacity of existing assets.	350	FY20
663	Darfield township reinforcement from Kimberley	Growth at Darfield township is expected to reach the 4MVA threshold for security of supply, which requires four hours of restoration time after a transformer outage. The switching plan requires 17 operations and while most of them are around the township, meeting the time requirement would be challenging.	The project involves installing a new 185mm^2 Al XLPE cable from Homebush Rd, down West Coast Rd and terminated on to an overhead line feeding into Darfield township.		595	FY21
920	Southfield Drive cable upgrade	Subdivision developments in Lincoln are progressing between Lincoln and Springston zone substations. End-to-end 11kV feeders are needed to allow security of supply and load shifting between the existing zone substations and the future Greenpark zone substation.	This project upgrades existing small cables to provide a strong 11kV trunk between Lincoln and Springston zone substations.	This project requires the least work to provide the 11kV trunk where the capacity is needed.	361	FY21

Table 5-6e 400V reinforcement projects - $000

Project		FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
884	Low voltage network monitoring	25	25	25	50	150	250	250	250	250	250
885	Low voltage network reinforcement	250	250	250	300	300	300	350	350	350	350
Urban 400V reinforcement totals		**275**	**275**	**275**	**350**	**450**	**550**	**600**	**600**	**600**	**600**

Low voltage network monitoring and reinforcement forms part of our staged approach to emerging technologies. More information about the impact of emerging technologies is provided in section 5.4.7.

5.6.8 Network connections and extensions

Overview

Network connections can range from a 60 amp single-phase connection to a large industrial connection or a big subdivision of several thousand kVA.

Customer connections

We anticipate that we will continue to connect customers to our network at the present rate of approximately 3,000 each year. Supplying these connections creates a need for:

- kiosk substations
- pole substations
- network or large customer building substations
- low voltage services
- network extensions.

Subdivisions

The level of subdivision activity depends on economic conditions and population growth. The Land Use Recovery Plan originally forecasts the combined Selwyn district and Christchurch City council areas to develop more than 2,000 new residential lots per annum over 10 years. The LURP Monitoring Report March 2015 indicated residential intensification has been less than expected. The updated forecast has the annual increase in households dropping from current level of 2,500+ to around 2,000 from 2024. In our rural area most subdivisions are for lifestyle reasons. In our urban area it can be industrial, commercial or residential, though most developments are residential. Our subdivision investment is made after negotiating with the developer on the basis of a commercial rate of return.

The network connections and extensions budget includes households and business connections. Forecast connection numbers are outlined in section 5.4. Business connections are becoming more expensive as different layouts are introduced to further enhance worker safety. Costs are also being driven up by implementing the National Code of Practice for Utility Operators' Access to Transport Corridors to its full extent.

Table 5-6f Connections/extensions capex - expenditure forecast ($000)

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Totals
General connections	4,589	4,266	4,216	4,166	4,166	4,166	4,166	4,166	4,166	4,166	**42,233**
Large connections	1,490	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412	**14,198**
Subdivisions	4,060	3,849	3,849	3,849	3,849	3,849	3,849	3,849	3,849	3,849	**38,701**
Switchgear purchases	1,400	1,400	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	**13,520**
Transformer purchases	2,670	2,670	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,480	**25,180**
Network capex totals	**14,209**	**13,597**	**13,297**	**13,247**	**13,247**	**13,247**	**13,247**	**13,247**	**13,247**	**13,247**	**133,832**

5.6.9 Customer demand management value for network development alternatives

Customer Demand Management initiatives can provide alternatives to investment in traditional network development solutions. This section is included in our AMP to assist potential Customer Demand Management providers to determine the approximate funding available from Orion when specific projects are deferred through Customer Demand Management.

The following table is a high level assessment of the annual per kW cost of proposed network solutions where Customer Demand Management could be used to defer the project. If a Customer Demand Management solution is presented, then further detailed analysis is undertaken to compare options.

For example:

Upgrading the Hills Rd zone substation transformer scheduled for FY21 has a capital cost of $430k and an annual capital funding cost of $52k. It provides capacity for 140kW of load growth per annum. For a Customer Demand Management solution to be economic and provide a one year deferral of a network solution, the cost per kW must be lower than $370 ($52k /140kW). If the Customer Demand Management solution can provide three years of deferral (0.42MW at peak) then the Customer Demand Management proposal cost must be lower than:

- $370 for 140kW in the first year
- $190 for 280kW in the second year
- $120 for 420kW in the third year.

The values in the following table assume that the Customer Demand Management solution is provided in the year required and therefore discounted values apply for Customer Demand Management solutions implemented earlier than required.

Table 5-6g Customer Demand Management value for network development alternatives

Year	Project description	Budget capital ($000)	Growth per year (kW)	$ per kW available for CDM alternative		
				Year 1	Year 2	Year 3
FY21	Hills Rd transformer upgrade	430	140	370	190	120
FY22	Porters Village	4,485	4,400	120	60	40
FY23	Marshland zone substation	7,115	1,100	780	390	260
FY25	Springston 66/11 kV transformer	1,039	480	260	130	90
FY26	Templeton zone substation	5,368	690	2,430	1,220	810
FY26	Halswell zone sub transformer upgrade	4,428	800	660	330	220
		22,865	**7,610**	**4,620**	**2,320**	**1,540**

Business support

6

Continued overleaf

List of figures and tables in this section

6.1 Introduction

This section describes our forecast opex to plan, operate and administer our network operations. It does not include opex on our network assets, consistent with the Commission's expenditure breakdowns and definitions. It also does not include the following, consistent with the opex forecasts that are shown in non-network opex schedule 11b in Appendix A:

- pass-through costs, such as local authority rates and industry levies
- transmission purchases.

The Commission requires EDBs to disclose opex forecasts into two categories:

- system operations and network support
- business support.

The Commission defines these items in section 1.4.3 of the Electricity Distribution Information Disclosure Determination 2012 (IDD).

Our most significant opex in these categories is remuneration for our employees who undertake these tasks. Our summary forecast for employee full time equivalents (FTEs) at the start of each financial year is as follows:

Table 6-1a **Employee FTE forecast summary**

	FY19	FY20	FY24
System operation and network support	156	159	160
Business support	49	55	55
Total	**205**	**214**	**215**

6.2 System operations and network support

This category covers operational expenditure where the primary driver is the management of the network and includes expenditure relating to control centre and office-based system operations. Around three quarters of our employees are in this category. Our forecast for employee FTEs at the start of each financial year is as follows:

Table 6-2a **Employee FTE forecast (numbers) system operations and network support**

	FY19	FY20	FY24
Network asset management	51	51	51
Lifecycle management	21	21	21
Network operations	48	49	49
Contact centre	10	10	10
Engineering support	13	13	14
Network growth and planning	4	5	5
Quality, health, safety and environment	4	5	5
Infrastructure management	5	5	5
Total	**156**	**159**	**160**

6.2.1 Network asset management

Our network asset management team:

- sets the network asset standards to safely manage, maintain and renew our network to achieve our expected service levels
- use robust contractor management processes to safely construct, maintain and renew our network
- ensures robust environmental management systems are operational within our management systems
- provides a responsive service to our customer and public interactions in terms of:
  - managing situations where the network may be compromised by other parties
  - ability for customers to connect in a timely manner.

6.2.2 Lifecycle management

Our lifecycle management team is responsible for:

Contract Delivery

This team contracts out a large portion of physical works on our network assets and corporate properties and provides robust contract management processes. The team:

- ensures appropriate contracts are in place for timely delivery of network services
- recommends appropriate contract models and frameworks
- ensures clear and unambiguous contract documentation for contract implementation
- ensures fair and reasonable contract management processes are implemented
- provides independent support for contract implementation such as:
  - contract tendering
  - support, monitoring and auditing of contract systems – including safety, quality assurance, contractor performance etc.
  - approving correct contractor payments and appropriate delegated authorities
  - third party recovery where appropriate.

Asset Data Systems

Our Asset Data Systems team:

- manages and develops our network asset register and geospatial systems that are necessary to ensure our network asset data is accurate and available for the effective management of our network

- manages the content, review and dissemination of certain controlled business documents, internally and external to Orion
- manages and develops systems and procedures to ensure accurate network reliability statistics.

Lifecycle

Our Lifecycle team:

- develops appropriate whole of life strategies for our network assets
- monitors, analyses and reports network performance, including detailed network failure analysis
- monitors, analyses and reports on the condition of our network assets
- develops appropriate maintenance and replacement programmes, based on the above analysis
- develops an annual work plan and ensures progress against the plan is updated regularly.

6.2.3 Network operations

This team is responsible for:

Control centre

Our Control Centre team:

- monitors and controls our electricity network in real time, 24/7
- provides safe network switching and fault restoration
- utilises load management to minimise peak load and maintain security
- provides load management assistance for all upper South Island EDBs.

Release planning

Our Release Planning team:

- coordinates the release of network equipment to contractors, while maintaining network security
- liaises with all parties to minimise planned outage frequency, size and duration
- allocates operators and generators to planned works
- notifies customers of planned outages.

Field response (operators)

Our Release Planning team:

- operate high and low voltage switchgear
- provides a first response to network and customer faults
- makes safe network equipment and customer premises for emergency services
- repairs minor faults
- liaises with customers.

Operations services

Our Operations services team provide support for:

- power quality – investigates complex Orion and customer network issues. Analyses voltage disturbance and deviation problems, predominantly in industrial and commercial customer groups whilst offering support and education
- distributed generation – apply and maintain regulatory policy. Approve customer connected generation. Ensure safe connections. Update registry to ensure compliance
- street lighting and new technology connection management - apply and maintain regulatory policy. Develop and maintain Distributed Unmetered Load Data Base for major customers. Ensure accuracy and integrity of SL data on GIS
- low voltage management – enable safe switching operations to be carried out on Orion's network through accurate schematics and site identification. Create and support business process to enable accurate updating of GIS. Identify opportunities to allow our contractors to supply effective and efficient documentation
- HV labelling - enable safe switching operations to be carried out on Orion's network through site and network circuit identification
- generators – maintain Orion owned generation to ensure safe operation. During disaster recovery, provide a specialised team to work independently from the network to enable generator power restoration to communities

- electric and magnetic fields and your health – work with customers and our community to identify safe exposure levels
- technical surveys – Innovative and safe collection of field information. Provide capability to survey complex technical information allowing concise and simple reporting.

Network access

Our Network Access team:

- coordinates and approve access to our network, including setting standards and writing training and assessment material for both employees and authorised service providers
- trains and assesses the competency of staff and contractors to enter and work in restricted areas, and to operate our network
- maintains an accurate database of competencies held by every person accessing and working on our network
- develops operating manuals for equipment used on our network, and support material for our network operators
- reviews applications for and issue as appropriate close approach permits to Orion authorised service providers, third party contractors and members of the public who need to work closer than four meters to our overhead lines and support structures
- provides contractor and public safety advice and education for others who are working close to or around Orion assets
- provides stand-overs for safety on excavations or other work conducted by third parties on Orion's sub-transmission asset.

6.2.4 Contact centre

This team is responsible for providing a point of contact for our customers seeking the help and reassurance of a real person who can provide information about power outages, resolve complaints and assist with the supply of our services. The Contact Centre operates 24/7 and responds to approximately 3,000 calls from customers each month.

Our contact centre team's skills are also used to support other parts of the business when they can. This may vary from processing customer connections to providing administrative and support services in other departments.

6.2.5 Engineering support

This team is responsible for:

- support with engineering or technical issues
- focus on a safe, reliable and effective network
- set and maintain standards for materials and applications and maintain documentation associated with establishing, maintaining and developing our network assets
- research and review new products and alternative options with a view to maximising network safety and reliability and minimising lifetime cost
- research latest trends in maintenance and replacement of assets and evaluate these
- investigate plant failure, manage protection setting data and keep the integrity of control and protection systems at high levels
- work with our contractors when developing commissioning plans and the introduction of new standards and equipment
- analyse technical data and act on the information to minimise the risk of loss of supply to network
- manage and mentor engineers in our development programme as they progress through their training.

6.2.6 Network growth and planning

This team is responsible for:

- forecasting changes in customer behaviour and demand
- identifying network constraints and developing network and non-network solutions
- providing the planning interface with Transpower
- documenting our network development plans and forecasts
- emerging technology.

6.2.7 Quality, Health, Safety and Environment (QHSE)

Our QSHE team:

- provides governance over and continuously improve the Orion QHSE systems
- provides general QHSE advice to business and other stakeholders (PCBUs) as required
- administers Vault (Safety Information Management System)
- leads audit program and deliver process assurance
- leads significant investigations
- coaches business based ICAM investigation team and build competency
- coordinates QHSE training initiatives
- provides QHSE assurance to Orion, board and management and the EEA.

6.2.8 Infrastructure management

This team is responsible for the overall direction and management of our infrastructure group.

6.2.9 Opex forecast

We forecast that our opex for each of the above activities will be (in FY19 dollar terms):

Table 6-2b System operations and network support - $000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Network asset management	6,341	6,341	6,341	5,972	5,972	5,972	5,972	5,972	5,972	5,972	**60,458**
Lifecycle management	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	**19,740**
Network operations	6,704	6,633	6,633	6,633	6,633	6,633	6,633	6,633	6,633	6,633	**66,401**
Contact centre	677	677	677	677	677	677	677	677	677	677	**6,770**
Engineering support	1,950	1,888	1,996	1,996	1,996	1,996	1,996	1,996	1,919	1,919	**19,652**
Network growth and planning	613	615	613	613	615	613	613	615	613	613	**6,136**
Quality, health, safety, environment	631	621	621	621	621	621	621	621	621	621	**6,230**
Asset storage	465	465	465	465	465	465	465	465	465	465	**4,650**
Infrastructure management	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	**10,830**
Less capitalised internal labour	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	**(20,084)**
Totals	**18,354**	**18,213**	**17,950**	**17,950**	**17,957**	**17,950**	**17,950**	**17,957**	**17,873**	**17,873**	**180,027**

6.3 Business support

This category covers opex, other than that included in 6.2 system operations and network support. Around one quarter of our employees are in this category. Our forecast for employee FTEs at the start of each financial year is as follows:

Table 6-3a **Employee FTE forecast (numbers) business support**

	FY19	FY20	FY24
People and strategy	4	4	4
Finance and fleet	7	7	7
Information solutions	15	18	18
Commercial, regulatory and communications	11	14	14
Corporate and governance	12	12	12
Totals	**49**	**55**	**55**

6.3.1 People and strategy

The People and strategy team supports the development, review and renewal of organisational strategy. In addition, the People function provides strategic, tactical and operational support and advice to the business in the people/HR space, including payroll, in order to build and enhance peoples capability and support the achievement of the organisations goals.

6.3.2 Finance

This team is responsible for financial reporting, treasury, tax and tax compliance, regulatory reporting, budgets, accounts payable and receivable, financial forecasting, job management, financial and tax fixed asset register and support for financial systems.

6.3.3 Information solutions

Information solutions non-network related operating costs fall into two main categories; software/infrastructure maintenance and team administration.

Software and infrastructure maintenance includes a small allowance for maintenance of server, network and desktop infrastructure, although we typically manage hardware through a lifecycle and the bulk of maintenance costs are covered by warranties. Most costs in this category are associated with annual software maintenance agreements for both larger corporate systems (financials, document management, payroll) and productivity software. Agreements cover both on-premise systems, supported directly by Information Solutions, and off-premise (cloud based) systems.

A key element of maintenance agreements is that they pre-purchase upgrades, deliver standard product enhancements and ensure that performance and security related “patches” are made available.

We review all software agreements annually.

The Information solutions team is insourced and salaries are the largest single component of opex. Team numbers are divided evenly among IT operations, system development/business change and the administration of the real time systems which are used to operate the electricity network. We capitalise $0.3m of internal labour to IT projects each year.

The expenditure shown here is before any depreciation expense is recognised as depreciation does not form part of business support opex.

6.3.4 Commercial, regulatory, communications and engagement

This team’s responsibilities include pricing, regulation, billing, future development and our overall customer strategy and engagement.

We plan to increase the size of our communications and engagement team to address the need for additional engagement and to improve our customers’ experience. An increase in opex is necessary for further development of team functions. This includes costs associated with a customer advisory panel, workshops with customers, focus groups on pricing, targeted surveys and emerging technology.

This team also co-ordinates:

- our engagement with and submissions to the Commerce Commission, Electricity Authority and other industry regulators
- our network delivery pricing and billing to retailers and major customers.

6.3.5 Corporate

The corporate management team provides overall company governance and leadership, and oversees key stakeholder interaction.

6.3.6 Governance and risk

This team provides support for the board and corporate management and it is also responsible for:

- our overall risk framework
- our insurance programme
- internal audit
- special projects.

6.3.7 Board

We have a board of six non-executive directors, with extensive governance and commercial experience.

6.3.8 Insurance

We purchase insurance to transfer specified financial risks to insurers.

6.3.9 Property

The expenditure shown here excludes depreciation expense is recognised as depreciation does not form part of business support opex

6.3.10 Fleet

We have a fleet of around 100 vehicles as an internal profit centre, we 'lease' vehicles to the business units that use them. The surplus shown in Table 6-3b excludes depreciation expense and insurance.

6.3.11 Plant and vehicles

Forecast plant and vehicle capex is based on our replacement cycles for different types of vehicles (refer to section 8.2.2 - Capex - non network assets). We are not currently forecasting significant growth in vehicle numbers.

6.3.12 Information technology

Our forecast IT capex is cyclical, as hardware and software are upgraded. Our forecast FY19 capex is relatively high, due to our planned end-of-life replacement of our landline phone systems.

6.3.13 EV charging stations

Most EV charging will likely occur at home. Our EV charging stations aim to reduce range anxiety and we have installed a number of chargers at strategic locations throughout our network area. The chargers are available for public use and have been warmly welcomed by drivers and community leaders. We plan to install around twenty more EV chargers, of varying size/expense over the next few years. Many of our chargers will likely need replacing after FY21 due to market obsolescence (chargers will likely need to be faster). However, we expect that:

- other entities will increasingly pay to replace them as part of their marketing objectives
- the cost of EV chargers will reduce over time.

We forecast that our annual expenditure for each of these activities will be as follows:

Table 6-3b **Business support opex - $000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
People and strategy	944	970	627	947	930	962	942	962	948	968	**9,500**
Finance	1,196	1,134	1,103	1,114	1,123	1,114	1,103	1,134	1,103	1,114	**11,235**
Information solutions	3,250	3,197	3,133	3,102	3,078	3,113	3,078	3,078	3,078	3,078	**31,185**
Commercial, regulatory,	4,093	4,032	3,902	3,802	3,802	3,812	3,802	3,802	3,802	3,812	**38,661**
Corporate, governance, TC	4,423	4,405	4,395	4,385	4,395	4,385	4,395	4,405	4,385	4,385	**43,958**
Property	1,024	1,029	1,033	1,038	1,043	1,047	1,052	1,056	1,061	1,065	**10,448**
Insurance	1,654	1,686	1,719	1,753	1,787	1,822	1,857	1,893	1,930	1,968	**18,069**
Board	396	396	396	396	396	396	396	396	396	396	**3,960**
Fleet	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	**(10,000)**
Less capitalised internal labour	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	**(5,220)**
Totals	15,455	15,327	15,086	15,015	15,032	15,129	15,103	15,204	15,181	15,264	151,796

6.4 Buildings

6.4.1 Asset description

Orion's corporate property covers our administration building at 565 Wairakei Rd and property and land throughout the Canterbury region.

Administration building

We relocated our administration function to 565 Wairakei Rd, following the FY11 earthquakes. The Crown purchased our old administration building in 2013. Future development on the site by Ōtākaro will include installing a block wall around our existing Armagh zone substation.

Our administration building at 565 Wairakei Rd

Waterloo depot

The Waterloo depot has been purpose built by Orion to provide a fit for purpose and resilient depot for Connetics. Orion will retain ownership of the site with Connetics entering a long-term 'arms-length' lease arrangement. The building was completed in late 2017 and Connetics relocated in early 2018.

Rental Properties

We own nine rental properties of which four are residential properties adjacent to zone substations. Some of these were acquired as part of a package when substation land was purchased. Others have been strategically purchased to allow the substation to expand if necessary. We receive income from these properties, provided they are tenanted, and this rental income is in line with the rental market in the Christchurch area.

6.4.2 Asset capacity/performance

As a lifelines utility (Under the Civil Defence Emergency Management Act 2002) providing essential services to the community, we are required to be operational after a significant event. Our new administration building has been built to Importance Level 4 (IL4). This means that the building is designed to remain operational following a 1 in 500 year seismic event. The building is also equipped with a standby generator (with 500 litre diesel tank) which is able to provide back-up power.

Our property assets must meet the following criteria:

- they must be fit for purpose and maintained in a reasonable condition so the tenant can fully utilise the premises
- they shall comply with all building, health and safety standards that may apply
- they must be visually acceptable.

6.4.3 Asset condition

Our corporate properties vary in both construction and age.

Our Wairakei Rd No.565 administration building was built in FY14.

Our residential properties are clad with either brick or timber weather-board with the roofs being a mix of concrete tile or iron. Other than superficial earthquake damage these properties are in good general condition.

The commercial properties that we have at Darfield (Selwyn Gallery) and Duvauchelle (ex line depot) sustained mainly superficial damage during the Canterbury earthquakes. The roof and fence at the Selwyn Gallery were replaced in FY14.

Work has been completed to strengthen and repair the Akaroa Gallery which suffered more substantial damage.

6.4.4 Standards and asset data

Asset management report:

- NW70.00.42 - Corporate property.

Standards and specifications

Technical specifications covering the construction and ongoing maintenance of this asset group are:

- NW72.20.07 - Grounds maintenance.

6.4.5 Maintenance plan

We have no assigned 'end of life' for our corporate properties. The purpose of our asset management programme is to ensure that our corporate property is managed in a manner that is consistent with Orion's corporate obligations to deliver an effective and efficient service.

We carry out regular inspections of our buildings to ensure that they do not deteriorate further as a result of the seismic activity that the area has experienced. Several databases are used to assist us with the management process such as our asset register and our works management system. We also use a 'fault incident report' database to collect any faults or safety issues with our corporate properties. For any instances where further expertise is sought we employ an external consultant to offer an independent judgement to assist in the decision making process for any maintenance or repair programmes. The risks that our corporate buildings are exposed to are listed below in no particular order of importance:

- seismic damage
- liquefaction and subsidence
- defective drainage and guttering
- roof leaks
- vegetation/tree roots
- vandalism - repairs carried out as soon as reported
- rust and rot
- extreme weather conditions
- fire
- graffiti.

Minor repairs are undertaken as they are identified in the inspection process. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis. Vandalism and graffiti is fixed as soon as we are notified. We have maintenance contracts in place with several contractors to ensure that all aspects of our property and land maintenance are covered. These include:

- site security
- grounds maintenance
- building services maintenance
- graffiti removal.

Our budgeted maintenance costs are in section 8.2.1 – Opex - Non network.

6.4.6 Replacement plan

We have no replacement plan for our corporate properties. These assets are maintained to ensure they provide the required levels of performance.

Our budgeted replacement costs are in section 8.2.2— Capex—Non network.

6.4.7 Creation/aquisition plan

We have no creation plan for our corporate properties at this time.

6.4.8 Disposal plan

We currently have no plans to dispose of any corporate property. We will relinquish ownership of sites we no longer have a use for, or as required under the Christchurch Central Recovery Plan.

6.5 IT Corporate

6.5.1 Asset description

Our corporate business information systems and productivity software support cross-organisational processes within Orion. They include financial systems, employee management systems (e.g. Human resources, Payroll, Health and Safety) and personal productivity software (desktop applications, email, web and document management).

Our supporting computer infrastructure hosts, connects and provides the physical tools for access to our information systems. In most cases we manage our computer infrastructure rather than outsource to third parties because of the critical nature of some of our information systems and the need for them to be continuously connected in real time to equipment on the electricity network.

In some cases however it is more appropriate to deliver services on a system hosted by a third party, such as our PayGlobal payroll system and parts of our Website.

This category includes:

Information systems software

- corporate financial management system
- HR/payroll
- document management system
- Orion internet website
- email system.

Supporting infrastructure

- desktop/laptop clients and operating systems
- replicated computer room
- VM and SAN
- physical servers.

6.5.2 Asset capacity/performance

Corporate financial management system

This system was implemented in 2009. Its capacity and performance are adequate for the period of this plan and could easily accommodate a significant increase in scale if required.

HR / payroll

As a cloud based application the performance and availability of this system is subject to a service level agreement. Its capacity and performance are adequate for the period of this plan.

Document management system

This is a new system and has been built to cater for projected increases in storage and breadth of function. Its capacity and performance are adequate for the period of this plan.

Orion internet website

The Orion internet website has recently been upgraded. The upgrade includes a new architecture that places the main landing page and supporting static content pages on third party infrastructure while dynamic content and pages to which logins are required, are hosted on our site. The capacity and performance of the web site are adequate for the period of this plan.

Email system

The capacity and performance of our Email system is adequate for the period of this plan if there are no major changes required.

Desktop software

Our choice of operating system and desktop software capacity/performance are adequate for the period of this plan.

Replicated computer rooms

We operate two Transportable Data Centres linked by diverse fibre networks which are both performing to expectations. The capacity and performance of both are adequate for the period of this plan and could easily accommodate a significant increase in scale if required.

VM and SAN

Our VMware Virtual Server infrastructure has recently been upgraded to replace aging and out of warranty equipment. Capacity and performance are adequate for the period of this plan.

Having dealt with server infrastructure our attention now turns to the Storage Area Network (SAN) which is approaching end-of-life and requires regular attention to ensure business continuity is maintained. This is not only due to the age of the equipment but also to lack of disk space. The capacity and performance are considered mostly adequate but a review of alternative solutions and an upgrade are currently under evaluation.

Physical servers

PowerOn servers and Telephony Servers have been replaced as part of a complete lifecycle upgrade of systems. The health of these servers is monitored and we typically replace servers of this type in three to five years. The capacity and performance is adequate for the period of this plan.

Desktops and laptops

We typically upgrade our desktops and laptops on a three yearly cycle. We expect that the capacity and performance of this equipment will not be adequate for the period of this plan.

Tablets

A number of tough-books (tablets) have just been rolled out to field operations staff. We expect that the capacity and performance of this equipment will not be adequate for the period of this plan.

Network

Several data networks are supported in our information system infrastructure which uses switches and firewalls to provide Gigabit network speeds between servers and to desktops. Our policy is to separate our corporate and engineering networks by providing access to each on a least privilege basis.

6.5.3 Asset condition

Corporate financial management system – Microsoft Dynamics Nav

The system was upgraded to the most current revision in FY16.

Document management system

In-house developed document management solutions are fit for purpose and operating effectively. Our focus is on further embedding SharePoint by introducing project workspaces and workflow.

Orion internet website

The Orion website was recently upgraded.

Email system – Microsoft Exchange Server

Our Email system is a mature and well established application. It will be integrated with document management as part of the current implementation.

Desktop software

The desktop operating system is current and subject to regular security and performance updates from Microsoft. Changes may be forced on us in the future as new equipment becomes unsupported on the current version.

6.5.4 Standards and asset data

Asset management report:

- NW70.00.49 - Information Systems – Corporate.

6.5.5 Maintenance plan

All systems are supported directly by the Orion Information Solutions group with vendor agreements for third tier support where appropriate.

License costs are considered to provide a degree of application support but are substantially a prepayment for future upgrades. Although licenses guarantee access to future versions of software, they do not pay for the labour associated with implementation. Our experience has been that significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

Software releases and patches are applied to systems as necessary and only after testing.

Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices.

Our budgeted maintenance costs are shown in section 8.2.1 – Opex — non network.

6.5.6 Replacement plan

We employ a standard change management approach to all software and hardware systems. Major changes to all corporate business information systems will follow the predefined steps of project proposal/concept socialisation, business case and approval, business requirements and implementation via a Project. All project costs are capitalised.

Our budgeted replacement costs are shown in section 8.2.2 – Capex - Non network.

6.5.7 Creation / aquisition plan

Some recoveries are made from salaries to capital budgets to recognise the contribution of our software development staff in system enhancements.

6.5.8 Disposal plan

There are no specific disposal plans for this asset group.

6.6 Vehicles

6.6.1 Asset description

We own 97 vehicles to enable us to operate and maintain the electricity network and to respond to any events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver.

Table 6-6a **Vehicle quantities**

Description	Quantity	Lifecycle
Generator truck	3	20 years
Network operator utility	19	5 years or 200,000km
Electric Vehicle (EV)	2	6 years
Petrol Hybrid EV (PHEV)	16	6 years
Other	58	4 years on average, earlier for high km
Total	98	

6.6.2 Asset capacity/performance

The performance criteria vary for each vehicle class. All are operated within their manufacturer specified parameters.

6.6.3 Asset condition

Our vehicles are relatively new and regularly maintained. As a result they are in good condition. Road conditions in parts of Christchurch are still poor due to the recent earthquakes. As a result of this we have seen a small increase in premature wear on components such as suspension bushings, etc. Our maintenance plan addresses such issues.

6.6.4 Standards and asset data

Asset management report:

- NW70.00.47 - Vehicles.

Our vehicles are operated to the requirements of current legislation.

Our financial system is used to hold usage data and schedule all regular maintenance and compliance requirements.

6.6.5 Maintenance plan

All vehicles within their warranty period are serviced according to the manufacturers' recommended service schedule by the manufacturers' agent. For vehicles outside of their warranty the servicing requirements are also maintained in accordance with the manufacturers' specifications by a contracted service agent.

Our budgeted maintenance costs are in section 8.2.1 – Opex - Non network.

6.6.6 Replacement plan

Our fleet replacement plan aims to replace vehicles on a like-for-like basis, where applicable, when the vehicle reaches its designated age or distance covered. If the fundamental needs of the driver change, the change will be reflected in the type of vehicle purchased for replacement. Where possible we purchase vehicles that better fit our purpose and where there is a demonstrable gain in safety, efficiency, reliability and value for money.

Our budgeted replacement costs are in section 8.2.2 – Capex - Non network/Vehicles and mobile plant.

6.6.7 Creation/aquisition plan

The aim is to have the right vehicle and driver to the right place at the right time. This is a critical aspect of operating our network in a safe, reliable and efficient manner.

The key drivers in our vehicle acquisition plan are:

- fitness for purpose
- safety
- reliability
- environment and fuel economy
- value for money / lowest economic cost over the life of the vehicle (including disposal value)
- diversity within the fleet (spreading the risk).

Mobile generator truck

6.6.8 Disposal plan

Our vehicles are typically disposed of via auction. In this way we achieve a market value for the vehicle and also incur the minimum disposal cost in terms of time and money.

Risk management

7

List of figures and tables in this section

7.1 Introduction

We aim for proportionate risk management and continuous improvement. Proportionate means that we aim to identify and treat our key risks in cost-effective and practicable ways that prevent harm to person or property.

Our risk management objectives are based on the international risk management standard ISO 31000-2009. Our risk management policy document (OR00.00.28) outlines our objectives, which are to:

- apply a proportionate approach to risk management, acknowledging that not all risk can or should be eliminated
- identify our critical risks
- determine the acceptable target level of risk, based on risk tolerance and appetite
- control inherent risk where it cannot be easily eliminated
- monitor and manage residual risk after controls are applied
- proactively meet our commitments under law
- apply appropriate resources to risk management.

Our risk management processes aim to control the potential for uncertainty and negative events that prevent the achievement of our objectives, and to identify opportunities to enhance the achievement of our objectives.

Our risk management processes:

- aim to reduce the potential for negative events
- apply to all aspects of our business.

Our risk management framework is based on international risk management standard ISO 31000-2009 and is shown in Figure 7-1a. The framework provides a foundation on which to design, implement, monitor, and continually improve our management of risk.

Figure 7-1a - **Our risk management framework**

We comment on the above elements as follows:

Establish context	We take account of our external environment (local, regional, national and international) such as cultural, social, political, legal, regulatory, financial, technological and economic factors. We monitor trends, perceptions and values of our external stakeholders.
Identify risks	We identify potential risks as specific projects and/or as part of normal day-to-day activities.
Analyse risks	We analyse risks to understand causes, dependencies, likelihood, and consequences. We also consider the effectiveness of current and potential mitigations.
Evaluate risks	We evaluate risks in conjunction with other business risks in order to determine priorities and resource allocations.
Treat risks	We implement our risk controls and mitigations.

We monitor and review our processes to ensure that new information and context are understood and incorporated. Our communicate-and-result loop helps to ensure that we follow our processes and learn and continually improve our risk management.

7.2 Our risk management context

Our customers and our community depend on our service, so it is essential that we identify and treat our key risks. As we say in our statement of intent, we have an important role in meeting our community's aspiration for:

- a 'liveable' city and region – with strong, connected communities
- a healthy environment
- a prosperous economy.

As a lifelines utility, section 60 of the Civil Defence Emergency Management (CDEM) Act requires us to ensure that we are:

> '*… able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency*'.

Our service area of Christchurch and central Canterbury has particular relevant context as it is:

- in an earthquake zone and near the Alpine fault
- particularly dependent on a resilient and reliable supply of electricity - due to cold winters, no reticulated natural gas and restrictions on the use of solid fuel heating systems
- subject to weather extremes – including snow storms and/or wind storms.

Given this wider context, we believe that our key roles are to:

- connect our customers with New Zealand's largely renewable electricity generation
- ensure that our electricity delivery service matches our customer's and our community's expectations for network capacity, safety, resilience and reliability – prudently, efficiently and sustainably
- act in the long term interests of our customers, our community and our shareholders.

The electricity that we provide, if not controlled, can cause harm to people, these being the public, our customers and personnel that work on or near our assets. Our industry is rapidly evolving, with new technologies changing the way in which our customers consume and now produce and store energy, potentially impacting the use of our network assets and the business model. Our business is regulated and we have statutory obligations that we must uphold.

In making risk management decisions we seek to properly understand how risks if realised would affect our objectives and the interests of our stakeholders, and we develop mitigating responses that are proportionate and in the long-term interests of our customers.

7.3 Our overall risk appetite

Given our risk management context that we outline in section 7.2 above, we have a cautious (relatively risk-averse) risk appetite for our network asset management approach.

Our caution risk appetite is consistent with our statement of intent (SOI) objective to act in the long-term interests of our customers, our community and our shareholders.

7.4 Our risk management responsibilities

7.4.1 Everyday risk responsibilities

Our risk management begins with risk identification in all areas of our business, within the context of our objectives and operating environment. These risks are recorded in our risk registers. Our Board of Directors oversees risks that have the greatest potential to adversely affect the achievement of our objectives. Management regularly reports to the board on those key risks. Senior management and the board seek independent expert advice when appropriate.

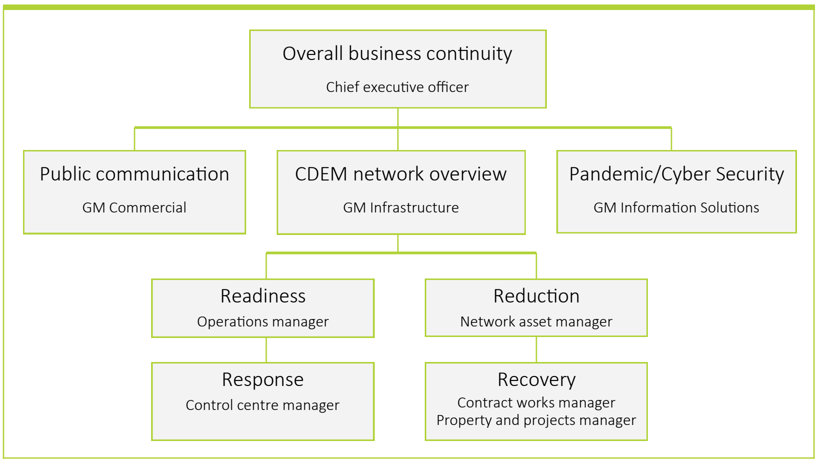
Our everyday risk management is mostly handled by line management as part of their normal duties. We have two teams that support our line managers to undertake risk management:

- Governance and Risk – two FTEs help to coordinate our board and management governance processes, our overall risk management approach and our insurance programme
- Quality, Health, Safety and Environment – four FTEs help our line management to continuously improve our processes in these areas.

7.4.2 Disaster/crisis risk responsibilities

High impact low probability (HILP) events such as natural disasters, pandemics or cyber-attacks necessitate situation specific reporting and responsibility structures – and a plan-to-plan approach. Each HILP event will be different and so it is not possible or desirable to fully prescribe detailed procedures before such events.

Figure 7-4a - Our HILP risk management responsibilities



The CDEM Act requires us to plan for HILP events. It requires us to:

- function during and after an emergency, and have plans to support this
- participate in CDEM planning at national and regional level if requested
- provide technical advice on CDEM issues where required.

Certain events such as natural disaster, pandemic or crisis situations necessitate situation - specific temporary reporting and responsibility structures (figure 7-3a). We have aligned our disaster and crisis risk responsibilities using the Civil Defence 'four R's' approach to resilience planning—reduction, readiness, response and recovery.

Readiness	Means having the people and resources in place or available to respond to an event.
Reduction	Means implementing measures in advance so that the impacts of future HILP events will be less. A good example of this was that we strengthened our key substations prior to the Canterbury earthquakes and this significantly reduced the impacts on our network and customers.
Response	Means dealing with the immediate and short term impacts of a HILP event. We first seek to understand what has occurred and the main impacts, and we then plan and implement a targeted set of measures to ensure an effective response that has the greatest benefit for the greatest numbers of customers. When HILP events occur, we divert many of our resources (including our contractors) from normal planned activities to our response.
Recovery	Means dealing with the long term impacts of a HILP event. This involves prioritising and planning major works to restore our network condition – and it can also involve upgrading certain aspects of our network, given our new risk learnings from the HILP event.

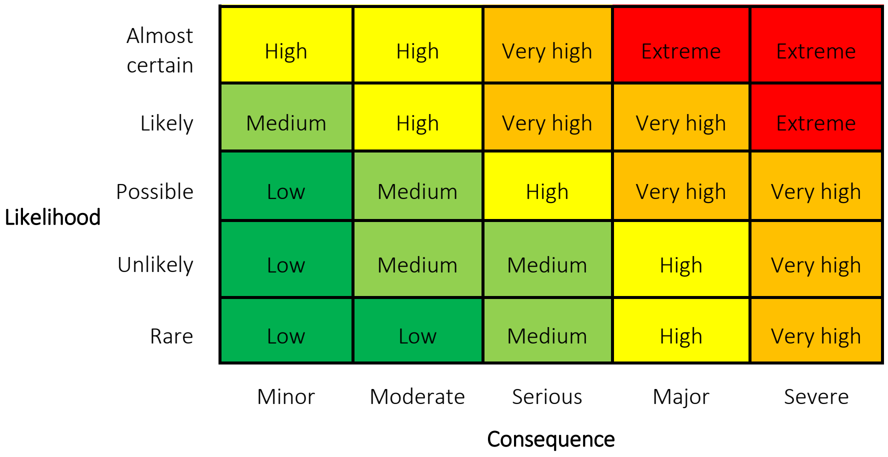
7.5 Our risk management process

7.5.1 Risk evaluation

Our ongoing risk assessments mostly follow the international standard. We use the matrix below to assess different types of risk: We have a number of risk consequence definitions for different types of risk – for example:

- network outages
- health and safety
- environmental
- cyber security and IT systems continuity
- financial
- reputation.

Figure 7-5a **Our risk evaluation matrix**



Likelihood

Almost certain	High	High	Very high	Extreme	Extreme
Likely	Medium	High	Very high	Very high	Extreme
Possible	Low	Medium	High	Very high	Very high
Unlikely	Low	Medium	Medium	High	Very high
Rare	Low	Low	Medium	High	Very high
	Minor	Moderate	Serious	Major	Severe

Consequence

We plan to review our risk consequence definitions and weightings for our key risks, as part of our review of our overall risk framework over the next year. From time to time we engage independent external experts to carry out reviews , assess risks, control gaps and provide advice on mitigation remedies.

7.5.2 Resilience plans

Resilience refers to our ability to respond to significant events. We approach our network resilience planning from two perspectives:

- first, we aim to reduce the impacts of future significant events by how we design, construct and operate our network
- second, we aim to ensure that we have a fit for purpose respond and recover capability.

The following is a summary of our key network resilience documents:

Asset risk management plan document (NW70.60.02)

This plan documents our approach to a major incidents or emergencies. Topics covered include:

- natural disaster risks
- a rating system to identify network most at risk
- risk treatments and practical solutions to reduce risk
- the location, likely reasons for failure and our contingency measures
- a schedule of network spares held.

Disaster resilience summary document (NW70.00.14)

This document provides an overview of how we design and construct our network and supporting infrastructure to cope with a major disaster event. The document aims to inform Civil Defence and other parties of our network resilience so that this can be incorporated into community-wide disaster response plans.

Participant rolling outage plan document (NW20.40.09)

Pursuant to the Electricity Industry Participant Code 2010, our participant rolling outage plan outlines how we will respond to grid emergencies that have been declared by the grid System Operator. Typical scenarios include very low hydro lake levels, loss of multiple generating stations or multiple transmission grid component failures. Our plan outlines how we will shed load when requested by the System Operator – the plan is on our website.

We help to prevent cascade failure in the transmission grid by:

- assisting Transpower with its automatic under frequency load shedding (AUFLS) by providing a schedule of our preferred urgent load shedding locations and AUFLS provision where embedded in our network
- assisting Transpower with its automatic under voltage load shedding (AUVLS) for upper South Island transmission constraints by providing a schedule of our preferred urgent load shedding locations and AUVLS provision where embedded in our network
- otherwise providing 'blocks' of load to Transpower for emergency load shedding.

We always endeavor to keep supply on to our customers. Disconnecting supply is always a last resort – after all other forms of electricity demand savings (including voluntary savings) have been exhausted.

Security standard

Our security standard is key to how we plan to meet the demand for electricity in certain circumstances when electrical equipment fails on our network. It is discussed in detail in section 3.3.3 and section 5.3.1.

Network physical access security plan – (NW70.60.03)

Our network physical access security plan details our security policies, principles and procedures that restrict physical access to our electrical network and associated infrastructure. The principles defined in this document underpin our stated commitment to provide a safe reliable network and a safe and healthy environment for the public, employees and contractors.

The predominant focus of the plan is to restrict access by unauthorised personnel. However, some of the risks associated with access to equipment, together with mitigation measures, also directly affect authorised personnel.

In terms of security, the general principle is to prevent unauthorised entry by the public and opportunist intruders without specialised tools, and slow determined intruders. This is achieved by:

i. reasonable measures to prevent access by members of the public to potentially fatal voltages

ii. additional measures to deter, detect and slow determined intruders at higher risk sites.

For further discussion on safety see section 6.3.

Environmental risk register – (NW70.10.06)

The aim of this register is to summarise the environmental risks that relate to our business and operations, including likelihood of occurrence, consequences and mitigation.

Environmental risks associated with loss of supply or fluctuations in supply are not included, either generally, or in relation to particular large industrial users. At this stage we consider these risks are more appropriately addressed through the asset management process, Lifelines Project and individual users' own environmental risk assessments.

We have assessed the risk (likelihood, consequence) of an event and our mitigation-effectiveness based on a subjective estimate. This assessment is therefore not supported by historical data or records.

The register is a tool that helps us to manage risk – it is not an exhaustive list of all risks. Its value is that it identifies general risk to the company and highlights any areas of high risk that may require particular management attention.

Business continuity plans

The aim of these plans is to provide an assessment of the risks that relate to the continuity of our business and operations due to the loss of systems or personnel. Each corporate manager is responsible for their functional part of these plans.

Contingency plans

Failures of primary network assets such as 66/11kV transformers or 66kV cables while rare, can have significant consequences. To mitigate this risk, we have identified the credible failure scenarios for our primary assets and for each failure scenario we have developed a contingency plan to restore supply in a timeframe consistent with our security of supply standards. In some cases, our contingency plans have identified the need to alter our network or hold additional spare assets to meet our objectives. Our contingency plans are held by our network operations team and they are updated regularly.

Communication plans

As part of our emergency preparedness, we have stakeholder communication plans. In emergencies, we aim to keep our customers and our community informed, and especially our key stakeholders.

7.6 Our key risks

We believe that the key risks to our electricity delivery service are:

Table 7-6a Key risks

Our key risks	Examples
Natural disaster (HILP event)	Major earthquake, major tsunami, major storm
Major network asset failure	Transpower grid problem, Orion network asset failure
Cyber attack	International malware affects our network control systems
Serious public or worker injury	Serious injury or a fatality to a worker, contractor or member of the public
Emerging technology	More complex two-way power flows with consumers

We discuss these risks in the following sections.

7.6.1 Natural disaster risks

We believe that our greatest natural disaster risk is a major earthquake – most likely the Alpine Fault, which is currently rated at a 30% chance of an 8.0 magnitude event in the next 50 years. We rate this as a medium to high risk, one with potentially major consequences for our network and for our wider community.

An Alpine Fault earthquake would be different to the 22 February 2011 earthquake:

- the 2011 earthquake was centred very close to our urban network – it was sharp but relatively short (less than one minute)
- an Alpine Fault earthquake would be centred further away from our urban network – it would not be as sharp but it will be long (perhaps some minutes).

Now that we have substantively completed our post-earthquake network recovery projects, we believe that our network and our operational preparedness are in good shape. For example, since 2011 we have:

- rebuilt our existing 66kV network in the eastern suburbs – using better diverse routes (following independent geotechnical advice) and improved trench design
- partially created an interconnected 66kV urban sub-transmission system
- repaired our damaged 11kV cables
- repaired and rebuilt our damaged substations
- improved the resilience of our key network assets – including local spur assets we have purchased from Transpower since 2012 (we will continue to improve these assets over the next three years)
- moved to a resilient (IL4) and fit-for-purpose head office, which includes our 24-hour network control centre
- built a standby hot site, that can be used if our head office and control room become unusable after a major event
- built a resilient and fit-for-purpose depot for our key network contractor, Connetics
- moved our key network component spares to sites that are less susceptible to critical natural event risks such as tsunami
- improved the capability and resilience of our operational systems so that that we are better able to respond to major events.

The above work since 2011 has built on our substantial pre-earthquake seismic strengthening work and our highly interconnected urban high voltage network (which facilitates our ability to switch load around our network when necessary).

Another major natural disaster risk is tsunami, most likely from a major earthquake off the coast of South America. We rate this as a low to medium risk. Since 2011, we have significantly reduced the potential impacts of a major tsunami by moving our head office and both our emergency contractors significantly further inland. Our network assets near the east coast will inevitably remain exposed to tsunami.

Our other major natural disaster risk is a significant weather event – such as a major snow and/or wind storm. We rate this as a low to medium risk. We have adapted our network practices in light of past major storms in our region – including a major wind storm in 1975 and a major snow storm in 1992. We have implemented these improvements over time as part of our ongoing network asset lifecycle process and our improved asset loading standards for new or upgraded network components. Examples include revised conductor spans and pole and cross arm types for our rural network, based on possible severe wind and/or snow loading scenarios. Our urban network is largely underground – and so our most significant weather risks relate to our widely dispersed rural overhead lines. Most downed overhead lines in storms are caused by trees and many of the trees concerned are well outside regulatory cut zones. So we have an active vegetation management programme that aims to:

- ensure tree owners comply with the tree regulations
- enlist the long-term support of tree owners to reduce threats to our rural overhead network in particular.

We do not believe that flooding is a major risk to our network. Some events will involve localised flooding near the Avon and Heathcote rivers – and we have documented procedures to isolate substations before electrical equipment is significantly damaged. Our head office, including our control room, is not considered at significant risk from flood.

We continue to progressively assess and improve the resilience of our key network assets – our summary assessments of our current HILP risks by asset category is as in the following table:

7.6.2 Major network asset failure risks

Table 7-6b **HILP event risks**

Network asset class	**Our assessment and mitigations**
Our two main Transpower grid exit points at Islington and Bromley	Low to medium risk. Liquefaction potential at Bromley is considered low to medium with a possibility of settlement in the range of 20-40mm. At Islington the risk of liquefaction is considered to be low and any settlement unlikely. At Bromley we have implemented improvements to the assets we have purchased from Transpower and we will continue this process over the next few years. Transpower has also implemented improvements at our grid exit points, pursuant to new investment agreements with us. Our recently completed 66kV sub-transmission 'northern loop' has created a more interconnected sub-transmission system – and this significantly reduces our risks to single grid exit points.
Our zone substations	Low to medium risk for the majority of our 53 zone substations. We had two severely damaged zone subs in the 2011 earthquake, we subsequently: • replaced Brighton zone sub on better ground 1.5km away at Rawhiti • rebuilt Lancaster zone sub on the same site to be more resilient. Since 1995, we have assessed and seismically strengthened our zone substations as appropriate, following detailed engineering studies. We also have: • targeted interconnectivity and diversity of supply • 'n minus 2' contingency switching plans • oil containment bunds at key sites • hold-downs for transformers.

	Liquefaction susceptibility:			Potential for foundation failure	Potential for settlement induced damage
	150 year	450 year	1,000 year		
Addington	Medium/high	Medium/high	Medium/high	Possible	Likely
Armagh	Medium	Medium	Medium	Unlikely	Unlikely
Bromley	Low	Medium	Medium	Possible	Possible
Dallington	Low	Medium	Medium	Unlikely	Unlikely
Heathcote	Medium	Medium	Medium/high	Unlikely	Possible
Lancaster	Medium/high	Medium/high	Medium/high	Possible	Likely
Milton	Medium	Medium	Medium/high	Possible	Unlikely
Papanui	High	High	High	Possible	Likely
Portman	Medium/high	Medium/high	Medium/high	Unlikely	Unlikely

Table 7-6b **HILP event risks—continued**

Network asset class	Our assessment and mitigations
Kiosk substations	Low risk. They are widely dispersed and their transformers are connected with flexible cables and bolted down. Most transformers have metal cable boxes over their HV bushings that will protect them from impact damage. We hold transformer emergency spares for each of our standard ratings and voltages.
Overhead lines	Low to medium risk. There was relatively little damage to our overhead lines in 2011, although there was damage to certain components, such as insulators. Our overhead lines are widely dispersed and they are relatively easily repaired in a quake event. We have rigorous engineering standards and systematic inspection processes for our overhead lines and towers. Our overhead lines in rural areas are exposed to extreme weather events, but they are relatively easy and quick to repair, subject to the ability of our repair teams being able to access the affected areas. Our vegetation management programme minimises the impact of trees on overhead lines particularly during storm events.
66kV oil-filled cables	Medium to high risk. It is likely we will get multiple joint failures on our remaining 40km of oil-filled 66kV cables during an Alpine Fault (M8) event. We are undertaking a project to determine when and how we should replace these cables. Our improved, subtransmission network architecture will provide route diversity which will further reduce this risk.
Underground cables	Low to medium risk, depending on location. Our non-oil filled 66kV and 11kV underground cables in areas that are more susceptible to lateral movement and liquefaction (for example, near the Avon River in the eastern suburbs) are susceptible to damage from a major earthquake. This risk has reduced post 2011: • we abandoned our badly damaged oil-filled 66kV cables in the eastern suburbs and rebuilt them to higher engineering standards along better routes including strengthening of bridges • the residential red zone is now empty and it contains a good portion of our badly damaged 11kV cables. The practical strategy for existing assets in this class is to repair/rebuild cables after a major quake. We retain access to appropriate emergency spares.
Network communications systems	Low to medium risk. We have several communications systems that aim to provide resilience to our operations if a HILP event occurs – this includes cellular networks, fibre networks, our own pilot cables and our radio network. Diversity helps to ensure resilience. Our radio communications repeater site at Sugarloaf is supplied from our underground network and it now has a generator as back-up. Our radio communications repeater site nearby at Marleys Hill has an overhead feed from our rural network and we have replaced the portion of the overhead most at risk with underground cable. Key lifeline operators at the site have a back-up power supply.
Motor vehicles	Low to medium risk. We have an above-ground diesel tank that will provide emergency reserve supply for our operators and head office building if local fuel supply lines become disrupted in a HILP event A backup generator will supply our main building and provide charging capacity for our electric vehicles fleet in an HILP event.

As we describe in section 4 of this AMP, we proactively and continually monitor, assess, maintain and replace our network asset components over time – in line with good industry practice. Features of our approach include:

- higher voltage components (especially at 33kV and 66kV) affect greater numbers of our customers – and so those components have a greater focus for us. For example, we physically inspect and assess components at our zone substations at regular intervals
- we seek to know the condition of our key network asset components as far as is practicable
- we schedule necessary maintenance and replacement work on network components consistent with what we know about their condition and after considering any relevant contextual issues.

The following table summarises our views about key network asset failure risks.

Table 7-6c **Key network asset failure risk**

Network asset class	Our assessment and mitigations
Major 66kV oil-filled cable failure	Medium risk. The most likely causes of major 66kV cable failure are: • mechanical or electrical failure of joints or terminations of 66kV oil-filled cables, due to long-term expansion and contraction from high power loadings – some possibly exacerbated by the impact of past earthquakes • third party cable strikes by contractors working on road or building projects. If there is an outage to more than two major 66kV feeders, the potential for serious overload and damage to the remaining 66kV cables increases. A 66kV cable repair can take some time – up to a week for an oil-filled cable. Multiple failures of cable terminations at GXPs could also cause outages to two or more substations. Repair times here could be two or three weeks, due to the complexity and resource requirements involved. Our key mitigations are: • we are investing to create a more interconnected 66kV network • we have replaced our most susceptible (and earthquake damaged) 66kV cables in the east of Christchurch with modern XLPE cables along better routes and employing better installation methods • we have replaced all at risk 66kV oil-filled cable joints with joints that will withstand thermo-mechanical buckling forces • we continue to inspect and assess other 66kV joints and we will replace them on a case-by case basis if necessary • we can switch our network via our pre-prepared emergency switching plans. In times of high system loading, we can shed all water-heating load and additional load if necessary to manage these events within available capacity – and we assess and know all reasonable and prudent emergency load ratings of our key 66kV cables • we retain appropriate network spares and we retain appropriate skilled contracting resource • we proactively communicate with developers and contractors with the aim to prevent cable strikes and we robustly follow-up any strikes that do occur.

Table 7-6c **Key network asset failure risk - continued**

Network asset class	Our assessment and mitigations
Zone substation transformer failures	Low risk. Our urban zone substations each have two transformers (typically 20–40MVA) with dual rating to cope with one transformer failure (N minus 1). If both transformers are unavailable for extended periods (N minus 2) then the risks of overloading adjacent substations and losing customer load increases, especially during winter peak load periods. Repair times for large transformer can be weeks or months – so the key is to prevent asset failure via ongoing condition monitoring and timely and effective maintenance. The most likely causes of a transformer fault are high loading, lightning strike or high fault currents resulting in mechanical or electrical breakdown, causing tap-changer or winding failure. Mal-operation of cooling equipment or overloading can also contribute to excessive temperature rise and subsequent over-temperature protection trip operation. Our key mitigations include: • we carefully plan our transformer maintenance to reduce the risk of cascade failure due to exceeding plant capacity • we have 'N minus 2' contingency plans for switching load away from zone substations • we can reduce loads in affected network areas by switching off customer water heaters via our ripple system • we have arrangements to maximise the emergency use of customer-owned standby generators.
Zone substation switchgear failure	Low risk. Catastrophic failure of high voltage switchgear can cause a zone substation busbar to fail, either by associated collateral damage from an explosion or combustion by-products causing a short-circuit. Cascade failures are rare in our network, due to partitioning of switchgear in separate fire-rated compartments, therefore the consequences of switchgear failure are generally low. Repair times for high voltage switchgear (generally less than 24 hours) are much less than for major cables and transformers. We retain a stock of emergency spares of 11kV switchgear.

Table 7-6c **Key network asset failure risk - continued**

Network asset class	Our assessment and mitigations
Failure of our PowerOn network management system	Low risk. PowerOn is our key distribution management IT system, and it includes our SCADA network monitoring and remote switching control system. PowerOn enables us to efficiently monitor the electrical state of key network components and it is invaluable in diagnosing network faults and delivering solutions to network related issues. From a risk perspective and given its critical importance to our network operations we have installed PowerOn with significant resilience and redundancy – including: • state-of-the-art computer servers and related components (including communication equipment), with full remote back-up located at a duplicate site • state-of-the-art back up technologies and processes • state-of-the-art cyber security technologies and processes • effective vendor relationships for the software and hardware involved. We seek continuous improvements and enhancements in this system. Future focus - communication lines to remote field devices will be able to be routed to both server sites.
Failure of our network ripple injection system	Low risk. Our ripple injection system is a key element of our demand management – especially during winter peak demand periods. We also use our ripple system at other times – for example, to quickly reduce demand during grid emergencies. The ripple receivers that control hot water cylinders at customer premises are mostly owned by electricity retailers. If our ripple injection system failed this could: • cause system overloading on network components • necessitate significant capex to increase the capacity of our network to meet a winter peak demand increase of up to 15%. Our key risk mitigation measures include: • multiple independent 33kV and 11kV injection plants that provide back-up to each other • Spare components for both 33kV and 11kV • we require electricity retailers to maintain ripple receivers at connections • a network delivery pricing structure that incentivises electricity retailers to maintain ripple receivers.
Administration building	Low risk. We moved to a level 4 "Lifelines" (IL4) compliant building located at 565 Wairakei Rd in May 2013. This site meets our head office and operational requirements. The building has a current building warrant of fitness and is inspected six monthly by our Health and Safety Committee. We reviewed the environmental risks associated with the Wairakei Rd site. The risks assessed included seismic events, flooding from the Waimakariri River, localised weather events (rain, wind and snow), tsunami and land movement (slips and subsidence). In addition we looked at the likelihood and consequences of fire within the building. Our conclusion was that the Wairakei Rd site was appropriate for our requirements and that the IL4 building standard dealt with many of the risks we identified. We have located our portable data centre to a suitable secondary site to provide diversity. We have established portable emergency office accommodation at our Papanui zone substation site.

7.6.3 Legacy asset risks

With long-life network assets, it is inevitable that we have some legacy network assets that do not meet our current standards and potentially pose an unacceptable risk. As we become aware of them, we assess the risks and decide on our priorities and timeframes to eliminate or mitigate those risks. Our actions may include replacement over time or interim mitigations until full replacement can be practicably be achieved. Our legacy asset treatments are described and forecast as lifecycle opex and capex.

An example of our approach is that we have recently completed our multi-year project to remove or replace our bare high voltage equipment in our kiosks and substations with screened or 'all insulated equipment'. We have also improved our substation and kiosk locking systems.

We assess our key network legacy risk is as follows:

Table 7-6d **Assessing key network legacy risk**

Low voltage system where service fuses are in customer meter boxes	Low to medium risk. This is a legacy issue from many years ago that originally affected over 24,000 customer connections. The modern standard is for service fuses to be installed at each property boundary to reduce fire risks and protect underground cables - although the fire risk is low for any individual connection. In 2016, we started our 12 year project to move all such fuses to property boundaries – with a forecast capex cost of $57m (in FY19 dollar terms).

7.6.4 Serious injury or fatality risks

Our electricity distribution network spans 8,000 square kilometres of territory, with diverse terrain and ever-changing environmental conditions. Electricity is potentially harmful and our network has hundreds of thousands of individual components of many different types that have been installed over many years.

These factors are typical of electricity distribution networks and they are important context – electricity distribution networks are inherently potentially hazardous to our employees, our contractors and the public. So we take all reasonably practicable steps to minimise harm to person and property. Our health and safety management system is summarised at a high level with the following chart:

Figure 7-6a **Achieving health and safety**

As for our other risk management systems, our primary health and safety risk management is achieved through our operational systems – through our line management. We support those operational systems with support services – for example: via our Quality, Health, Safety and Environment team. Because of the above context, our operational systems must constantly identify, assess and treat safety risks in dynamic and complex settings. It is no exaggeration to say that safety requires eternal vigilance by every person involved.

We actively consider potential health and safety risks when we design and construct new network components through our 'Safety in Design' process.

We recruit, train and equip our staff as appropriate for their tasks and we carefully document and ensure our processes and procedures as appropriate. We also require equivalent safety procedures of our network contractors through our formal contract management system – and we ensure that our network contractors comply with our requirements.

Since almost all work associated with our network is carried out by contractors, we have developed registers of known hazards along with recommended actions to control hazards. Contractors must have their own documented health and safety management systems and they are further reminded of their health and safety obligations when they sign a new contract. We carry out regular site audits to ensure compliance.

We have documented policies and procedures that restrict access to our electrical network and associated infrastructure. Our aim is to prevent access by unauthorised personnel and inadvertent access to hazardous areas by authorised personnel. The general principle is to prevent unauthorised entry by the public and opportunist intruders without specialised tools, and to slow or impede determined intruders.

Section 61A of the Electricity Act requires us to have an audited safety management system, with the aim to prevent serious harm to the public or significant damage to third party property. Compliance with NZS7901:2014 Electricity and Gas Industries – Safety Management Systems for Public Safety meets this obligation. We comply with this standard, and our compliance is independently audited at regular intervals.

We investigate and follow-up all reported incidents and implement any learnings as part of our continuous improvement philosophy.

7.6.5 Cyber attack risks

Virtually all businesses and individuals around the world are now potentially susceptible to cyber-attacks from any part of the globe. We take our responsibilities to prevent these attacks very seriously, within our context, that we are a vital local lifelines utility.

Our information systems are vital to our ability to deliver a resilient and reliable electricity delivery service. We have two key categories of information systems risk:

- catastrophic failure of our systems, for any reason
- malicious third party attack on our systems.

We reduce the likelihood and potential impact of catastrophic failure of our information systems through the combination of procedures and technologies – including:

- robust systems procurement and maintenance – hardware and software
- rigorous change management
- good practice for regular and ongoing data and system backups and archiving
- highly resilient facilities
- robust security – computer network and physical
- mirroring of key hardware and systems between physically separate sites.

To prevent and reduce the potential impacts of attacks by malicious third parties, we employ layers of security at server, network and device levels. We aim to employ fit-for-purpose and up-to-date security systems that track and respond to suspicious patterns of behavior, known digital signatures and explicit security breaches.

We regularly update staff on cyber security and we seek their vigilant and active support for a secure information systems environment.

We use the knowledge and experience of others by consulting with our peers in the industry, government agencies and independent experts. The latter group helps us to build our capacity and also audit our systems and practices so that we continuously improve our resilience to cyber threats.

7.6.6 Emerging technology risks

Emerging technologies will continue to create issues and opportunities for our electricity distribution network. Examples include:

- the growth in electric vehicles – this will cause greater demand for our network
- the impact of battery technology and energy management systems – these will have demand impacts for our network
- the impact of more distributed electricity generation, such as solar – this will potentially create more complex two-way flows between our network and end-use customers.

Our risk management approach is to:

- keep up do date with technologies as they emerge
- assess the potential impacts on our network
- understand more about our low voltage network – as this is where most two-way electrical flows will occur
- adhere to our business purpose and strategy – which is to be an 'enabler'

We assess these risks as low to medium in the long-term – there is still a compelling customer need for our delivery service and our network should be capable of accommodating changing customer needs as they arise.

7.6.7 Environmental risks

We take all practicable steps to prevent undue harm to the environment. We have a documented environmental policy and we maintain an environmental risk register (NW70.10.06).

Our environmental management system covers the sustainable use of natural resources, reduction and safe disposal of waste, the wise use of energy, restoring the environment following works, commitment of management resources, stakeholder consultation, assessment, and annual audit. Our job specifications for our network contractors include requirements to identify and manage environmental risks related to the work they do for us.

We aim to reduce electrical losses on our network. We do this via our efficient network delivery pricing that signals system winter peaks (high loadings increase electrical losses) and via our network load management systems (especially our hot water cylinder control systems). It makes good environmental sense to reduce winter system peaks – in order to reduce electrical losses and to reduce the amount of network necessary to deliver electricity.

We have over the years invested to reduce the risks of ground contamination from oil-filled transformers. Our main substation transformers have now been fully bunded to contain any spill and we have fully documented management procedures and the necessary equipment to effectively deal with any minor spills from smaller transformers – for example: those that are pole mounted in rural areas.

Table 7-6e **Possible causes of contaminant discharge and their relative risks**

	Risk of discharge of contaminant – (low, moderate, high)									
	Transformer oil spill									
Cause of discharge	Zone substn	Building substn	Pole substn	Pad or kiosk	Inside/ outside OCB oil spill	Holding tank spill	Transport accident	Portable tank spill	Oil filled cable leak	Battery fluid spill
External/natural *1	L	L	M	L	L	L	L	L	L	L
Accident	L	L	M	L	L	L		L/M	M	L
Vandalism	L	L	L	L/M	L	L	L	L	L	L
Fire	L	L	L	L	L	L	L	L	L	L
Vehicle collision	L	L	M	L/M	L	L	L/M	L/M	L	L
Human error	L	L	L	L	M/H	M	M	M	M	L/M
Design fault	L	L	L/M	L	L	L	L	L	L	L
Plant failure	L	L	L	L	L/M	L	L	L/M	L/M	L
Probable severity of outcome *2	H	M/H	L/M	L/M	L	M/H	L/H	M/H	H	L
Note.*1 Includes discharge of contaminants occurring as a result of damage caused by earthquake, wind, snow, flood, lightning or other causes.										
Note.*2 Severity of outcome with respect to contravention of the Resource Management Act.										

Most of our 66kV circuit breakers use Sulphur hexafluoride gas (SF_6) as the interruption medium. We have not found a viable alternative for this voltage. In our memorandum of understanding with the Ministry for the Environment, we commit to keeping annual SF_6 gas losses below 1% of the total contained in our circuit breakers. We have a documented procedure (NW70.10.01) to ensure we achieve that commitment.

We have documented management procedures that our service providers are required to adhere to for the discovery and handling protocols for:

- asbestos (NW70.10.25)
- hazardous substances (NW70.10.02)
- items of archaeological significance.

7.6.8 Lifelines utility interdependence risks

Many key service organisations' rely on the services of others to perform. For example, all lifelines utilities rely on electricity and communication systems when responding to any HILP event. It is important to understand these interdependencies and plan accordingly.

We understand the fundamental role that electricity plays for virtually all other services – and we plan for our network resilience accordingly. We also plan and have contingencies in place for when other services might not be available to us – for example, the cellular network.

Lyttelton port - In FY18, we made several resilience improvements to our 11kV overhead feed into the Lyttelton area. We are now working to install a new 11kV cable through NZTA's road tunnel to provide an alternative supply to Lyttelton – including the port. Our new cable through the tunnel will cost around $2m and should be in place by the end of FY19.

Airport - In FY16, we installed a new 11kV cable feed so that the airport can now be supplied from both our 66KV Waimakariri and Hawthornden zone substations. This has improved the airport's supply resilience.

Our summary of key lifeline interdependencies in our network region is as follows:

Table 7-6f **Interdependence of lifelines (one week after earthquake)**

These → are dependent on these ↓	Water supply	Sanitary drainage	Storm drainage	Mains electricity	Standby electricity	VHF radio	Telephone systems	Roading	Railways	Sea transport	Air transport	Broadcasting	Fuel supply	Fire fighting
Water supply		2	#	#	#	#	#	#	#	#	#	#	#	3
Sanitary drainage	#		#	#	#	#	#	#	#	#	#	#	#	#
Storm drainage	#	2		#	#	#	#	#	#	#	#	#	#	#
Mains electricity	2	3	2		#	3	3	#	2	#	3	1	#	#
Standby electricity	3	3	2	#		3	3	#	#	#	3	3	2	#
VHF radio	1	1	2	3	#		3	2	2	2	2	2	2	3
Telephone systems	2	1	#	1	1	#		#	#	#	1	3	1	2
Roading	2	2	2	3	2	2	2		2	3	3	2	3	3
Railways	#	#	#	#	#	#	#	#		1	#	#	#	#
Sea transport	#	#	#	#	#	#	#	#	#		#	#	1	#
Air transport	#	#	#	1	#	#	#	#	#	#		#	#	#
Broadcasting	1	2	#	#	#	#	1	1	#	#	#		#	1
Fuel supply	3	2	1	#	3	2	1	3	2	#	1	1		3
Fire fighting	#	#	#	#	#	#	1	#	#	#	2	#	1	
Equipment	3	3	2	3	3	2	3	3	3	3	3	3	2	2

3. High dependence 2. Moderate dependence 1. Low dependence # No dependence

7.7 Other comments about our risks and risk management

7.7.1 Our approach to network asset management

We aim to be proactive and prudent network asset managers. This includes continuously improving our:

- forecasting of customer demand and potential impacts of emerging technologies
- network capacity and security of supply planning
- asset condition monitoring and lifecycle management
- automation and control of key network components – including remote switching
- emergency spares management
- contractor management
- key contractor resilience
- vegetation management.

7.7.2 Our approach to people management

We achieve effective risk management via our people. We therefore aim to be an 'employer of choice'. This includes our aim to have:

- a healthy and collaborative culture
- a healthy and safe workplace
- effective employee recruitment and retention processes
- effective competence development and training
- effective engagement and communication
- effective long-term succession planning for key competencies.

We also support wider industry competency initiatives – for example:

- the Ara Trades Innovation Centre, which has an electricity distribution trades training centre
- the University of Canterbury's Power Engineering Excellence Trust.

There is increasing competition from other infrastructure providers around New Zealand for competent people. Our strategy to meet that employee recruitment and retention risk is to be an employer of choice. Supporting diversity and inclusion is part of our strategy.

7.7.3 Our approach to regulatory management

The electricity industry is highly regulated, via multiple regulatory agencies. Key regulatory areas include:

- safety
- electrical quality standards – for example, electrical voltage and frequency
- network service standards – for example, the maximum acceptable level of duration and frequency of network outages in any given year
- network pricing – for example, the maximum delivery price we may charge
- regulatory information disclosure requirements
- vegetation management.

We aim to comply with our regulatory obligations and to constructively engage with regulatory agencies on key regulatory proposals and developments.

7.7.4 Our approach to commercial management

Our aim is to have prudent and effective governance and internal control systems – this includes ensuring sufficient sustainable revenues to support the ongoing investment required to meet customer requirements.

We manage revenue risk:

- via our delivery service agreements with electricity retailers – this includes: payment terms and credit requirements, although our credit requirements are limited by the Electricity Industry Participation Code (the code). Our delivery services agreements also include caps that limit our potential liabilities, although the Consumer Guarantees Act reduces our ability to cap our liability in certain circumstances
- via good service and constructive engagement with electricity retailers
- via active engagement with regulatory agencies – sometimes via submission on proposed regulatory changes
- via transparent and prudent delivery price structures and price levels – within regulatory requirements and constraints.

7.7.5 Our approach to insurance

Insurance is the transfer of specified financial risks to other parties (insurers). We have the following insurance measures in place – consistent with good industry practice:

- our material damage insurance policy insures us against physical loss or damage to specified buildings, plant, equipment, zone and network substation buildings and contents and is based on assessed replacement values
- our business interruption insurance policy indemnifies us for increased costs as a consequence of damage to insured assets, with an indemnity period of 18 months
- we have several liability policies, including directors and officers, professional indemnity, public liability and statutory liability.

Key uninsured risks are:

- lost revenues – for example, due to depopulation following a catastrophic event
- damage to overhead lines and underground cables.

These uninsured risks are effectively uninsurable for all EDBs in Australasia.

Our network contractors and suppliers are required to have appropriate insurance for:

- third party liabilities
- contract works
- plant and equipment
- motor vehicle third party
- product liability.

Financial

8

List of figures and tables in this section

8.1 Network expenditure forecasts

Our forecasts are based on our network opex and capex programmes and projects as detailed in sections 4 and 5. These forecasts are based on the best information available regarding the timing and extent of the post earthquake key recovery projects. Whether or not these projects will proceed, and the timing of them, is determined by Government and local Authorities and/or Developers.

Changes described are referenced to our last published AMP for the period from 1 April 2017 to 31 March 2027.

All figures in section 8.1 are in 'real' (FY19) dollar terms capex and opex forecasts allow for the capitalization of $2.6m of internal labour into capital works.

This is apportioned as follows:

- Network capex $2.26m
- Non-network fixed assets $0.34m.

Schedule 11a in Appendix A allocates this capex across the Commerce Commission's disclosure categories. In this financial section (Section 8) where relevant, the forecasts include this capex as a single line item. However, in all other sections within this AMP we provide forecasts which exclude the internal capitalised labour, that is we focus on direct external project expenditure. Appendix A also has these section 8 tables, reworked to include general CPI inflation and other cost escalators.

The following financial forecasts exclude costs for major projects substantially started in FY18 (carry-over costs in FY19). Carry-over costs in FY19 are likely to be largely offset by delays/deferrals of spending on forecast FY19 projects into FY20.

8.1.1 Opex - network

Table 8-1.1 **Opex - network - $000**

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Subtransmission overhead lines	1,650	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	1,665	**16,635**
11kV overhead lines	6,560	6,515	6,515	6,055	6,055	6,515	6,515	6,515	6,055	6,055	**63,355**
400V overhead lines	3,430	3,385	3,385	3,845	3,845	3,385	3,385	3,385	3,845	3,845	**35,735**
Earths	280	280	280	280	280	280	280	280	280	280	**2,800**
Subtransmission underground cables	850	850	850	850	850	850	850	850	850	850	**8,500**
11kV underground cables	3,445	3,405	3,305	3,305	3,210	3,210	3,210	3,210	3,210	3,210	**32,720**
400V underground cables	3,395	3,305	3,315	3,210	3,210	3,210	3,210	3,210	3,210	3,210	**32,485**
Asset information management	515	515	485	485	485	485	485	485	485	485	**4,910**
Storms	245	245	245	245	245	245	245	245	245	245	**2,450**
Meters	75	75	75	155	155	155	155	155	155	155	**1,310**
Protection	770	770	770	770	770	770	770	770	770	770	**7,700**
Communication cables	310	310	310	310	310	310	310	310	310	310	**3,100**
Communication systems	645	715	645	645	645	645	645	645	645	645	**6,520**
Control systems	570	570	570	570	570	570	570	570	570	570	**5,700**
Load management	295	295	295	295	295	295	295	295	295	295	**2,950**
Switchgear	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	**12,500**
Transformers	1,385	1,385	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	**11,850**
Substations	555	555	555	555	555	555	555	555	555	555	**5,550**
Buildings and enclosures	2,060	1,675	1,215	1,195	1,105	1,105	1,205	1,155	1,155	1,155	**13,025**
Grounds	690	715	715	715	715	715	715	715	715	715	**7,125**
Generators (fixed)	60	60	60	60	60	60	60	60	60	60	**600**
Totals	29,035	28,540	27,640	27,595	27,410	27,410	27,510	27,460	27,460	27,460	277,520
Grand totals from 1 April 2017 AMP	27,910	26,105	25,775	25,855	25,760	25,760	25,735	25,735	25,805	n/a	

8.1.2 Network operational expenditure forecast

Table 8-1.2 Network operational expenditure forecast - $000

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
System interruptions and emergencies	8,975	8,675	8,675	8,675	8,675	8,675	8,675	8,675	8,675	8,675	**87,050**
Vegetation	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	**35,600**
Routine & corrective maintenance and inspections	13,150	13,125	12,775	12,730	12,545	12,545	12,545	12,495	12,495	12,495	**126,900**
Asset replacement and renewals	3,350	3,180	2,630	2,630	2,630	2,630	2,730	2,730	2,730	2,730	**27,970**
Totals	29,035	28,540	27,640	27,595	27,410	27,410	27,510	27,460	27,460	27,460	277,520

8.1.3 Opex contributions revenue

Table 8-1.3 Opex contributions revenue - $000

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
USI load management	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	**(1,000)**
Network Recoveries	(1,800)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	**(15,300)**
Totals	(1,900)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(16,300)

8.1.4 Capex summary

Table 8-1.4 Capex summary - $000

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Customer connections/network extensions	14,209	13,597	13,297	13,247	13,247	13,247	13,247	13,247	13,247	13,247	**133,832**
Asset relocations	8,020	3,700	1,200	1,600	1,600	1,200	1,200	1,200	1,200	1,200	**22,120**
Reinforcement 11kV	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	**35,000**
Reinforcement 400V	275	275	275	350	450	550	600	600	600	600	**4,575**
Major projects	3,778	6,230	4,160	5,695	7,115		9,558	9,616	9,361		**55,513**
Replacement	27,835	31,055	32,330	33,515	32,560	36,960	37,940	38,040	40,790	33,325	**344,350**
Transpower spur asset purchases	1,130										**1,130**
Capitalised internal labour	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	**22,600**
Network capex totals	61,007	60,617	57,022	60,167	60,732	57,717	68,305	68,463	70,958	54,132	619,120

8.1.5 Capital contributions revenue

Table 8-1.5 Capital contributions revenue - $000

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Asset relocations	(5,390)	(2,690)	(690)	(1,010)	(1,010)	(690)	(690)	(690)	(690)	(690)	**(14,240)**
Customer connections/network extensions	(1,086)	(1,058)	(1,018)	(983)	(973)	(973)	(973)	(973)	(973)	(973)	**(9,983)**
Major projects		(2,361)	(1,720)	(2,243)							**(6,324)**
Totals	(6,476)	(6,109)	(3,428)	(4,236)	(1,983)	(1,663)	(1,663)	(1,663)	(1,663)	(1,663)	(30,547)

8.1.6 Customer connections / network extensions

Table 8-1.6 Connections/extensions capex - expenditure forecast ($000)

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
General connections	4,589	4,266	4,216	4,166	4,166	4,166	4,166	4,166	4,166	4,166	**42,233**
Large connections	1,490	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412	**14,198**
Subdivisions	4,060	3,849	3,849	3,849	3,849	3,849	3,849	3,849	3,849	3,849	**38,701**
Switchgear purchases	1,400	1,400	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	**13,520**
Transformer purchases	2,670	2,670	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,480	**25,180**
Net totals	14,209	13,597	13,297	13,247	13,247	13,247	13,247	13,247	13,247	13,247	133,832

8.1.7 Asset relocations / conversions

On occasion we are required to relocate some of our assets or convert sections of our overhead lines to underground cables at the request of road corridor authorities, councils or developers. We negotiate with the third parties to share costs and agree on timeframes. Our forecast for asset relocations / conversions are shown in table 8-1.7

Table 8-1.7 Asset relocation/conversion capex - expenditure forecast ($000)

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
FY19 AMP	8,020	3,700	1,200	1,600	1,600	1,200	1,200	1,200	1,200	1,200	**22,120**
Contributions	(5,390)	(2,690)	(690)	(1,010)	(1,010)	(690)	(690)	(690)	(690)	(690)	(14,240)
Net totals	2,630	1,010	510	590	590	510	510	510	510	510	7,880

8.1.8 Capex - reinforcement projects

Table 8-1.8 **Capex - 11kV reinforcement - $000**

Project		FY19	FY20	FY21	FY22-28
854	Halswell Junction Rd	300			
866	Hussey Rd reinforcement	596			
912	Sawyers Arms Rd feeders	709			
914	Twyford St adjustment	33			
915	Levi Rd reinforcement	305			
916	East Maddisons Rd reinforcement	318			
917	Frankleigh St reinforcement	51			
918	Station Rd reinforcement	258			
930	Townships reliability improvements - Stage 2	325			
922	Milton 11kV adjustment		350		
855	Waterloo Rd		161		
633	Darfield township reinforcement			595	
920	Southfield Dr cable upgrade			361	
913	Heathcote Lyttelton reconfiguration			145	
Reinforcement subtotal		2,895	511	1,101	
Non-scheduled reinforcement		605	900	900	900
Non-identified reinforcement		0	2,089	1,499	2,600
Reinforcement totals		3,500	3,500	3,500	3,500
Grand totals from 1 April 2017 AMP		3,500	3,500	3,500	3,500

For details of individual projects see section 5.6.7 – 11kV reinforcement projects.

8.1.9 Capex - 400V reinforcement

Table 8-1.9 **Capex - 400V reinforcement - $000**

Project		FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
884	Low Voltage network monitoring	25	25	25	50	150	250	250	250	250	250	**1,525**
885	Low Voltage network reinforcement	250	250	250	300	300	300	350	350	350	350	**3,050**
Urban 400V reinforcement totals		**275**	**275**	**275**	**350**	**450**	**550**	**600**	**600**	**600**	**600**	**4,575**

For details of individual projects see section 5.6.8 – 11kV urban reinforcement projects.

8.1.10 Capex - major GXP projects

Table 8-1.10 **Capex - major GXP projects - $000**

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Hororata separation	20										20
Islington separation	20										20
Totals	40										40

8.1.11 Capex - major projects

Table 8-1.11 **Capex - major projects - $000**

Project		FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
50	Lyttelton Tunnel cable	2,500									
542	Waimakariri Stage 2	1,278									
721	Land acquisition for Shands Rd 66kV switchyard		500								
587	Te Pirita zone substation 66kV bays		917								
670	Steeles Road		2,925								
699	Dunsandel transformer upgrade		1,778								
527	Land acquisition Templeton 66kV substation		110								
637	Railway Rd 11kV substation (Westland Milk)			3,297							
900	Castle Hill and Arthurs Pass switchgear upgrade			433							
881	Hills Road zone substation transformer upgrade			430							
541	Hawthornden T-off				1,210						
666	Porters Village				4,485						
871	Marshland zone substation					7,115					
491	McFaddens to Marshland 66kV link							7,798			
722	Land acquisition for Hoon Hay 66kV switchyard							200			
728	Springston 11kV switchroom							521			
894	Springston 66/11kV transformer							1,039			
919	Halswell transformer upgrade								4,248		
502	Templeton 66kV zone substation								5,368		
723	Milton 66kV switchgear for Lancaster cable									4,864	
589	Lancaster to Milton 66kV link									4,497	
Major projects total		**3,778**	**6,230**	**4,160**	**5,695**	**7,115**		**9,558**	**9,616**	**9,361**	
Totals from 1 April 2017 AMP		12,802	3,363	430		8,200		9,403	10,032	4,425	

- For details of individual projects see section 5.6.6 – Major projects.

8.1.12 Capex - replacement

Table 8-1.12 Capex - replacement - $000

Project	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Subtransmission overhead lines	990	3,140	640	3,140	640	640	640	640	640	640	**11,750**
11kV overhead lines	3,005	3,150	2,630	3,225	4,705	4,705	5,905	5,905	7,905	7,995	**49,130**
400V overhead lines	1,115	1,465	1,815	2,165	2,515	2,865	3,215	3,565	3,915	4,265	**26,900**
Subtransmission underground cables						4,000	4,000	4,000	4,000	4,000	**20,000**
11kV underground cables	100	100	100	100	100	100	100	100	100	100	**1,000**
400V underground cables	5,320	6,570	6,570	6,570	6,570	6,570	6,570	6,570	6,480	320	**58,110**
Communication cables	140	140	140	140	140	140	140	140	140	140	**1,400**
Meters	185	245	185	245	185	185	185	185	185	185	**1,970**
Protection	2,405	2,165	2,870	3,055	3,005	2,690	3,045	2,720	3,135	2,650	**27,740**
Asset management systems	40	420	170	40	170	170	40	170	170	40	**1,430**
Communication systems	970	1,100	405	315	315	315	265	265	265	265	**4,480**
Control systems	785	240	785	640	295	240	390	640	295	385	**4,695**
Load management	240	140	1,370	1,140	190	190	670	190	190	190	**4,510**
Switchgear	7,670	8,320	7,790	8,950	9,940	8,860	8,985	9,160	9,580	8,360	**87,615**
Transformers	3,070	3,070	6,070	3,070	3,070	4,570	3,070	3,070	3,070	3,070	**35,200**
Substations	380	380	380	380	380	380	380	380	380	380	**3,800**
Buildings and enclosures	520	410	410	340	340	340	340	340	340	340	**3,720**
Grounds	900										**900**
Generators (fixed)											
Replacement totals	27,835	31,055	32,330	33,515	32,560	36,960	37,940	38,040	40,790	33,325	344,350
Totals from 1 April 2017 AMP	28,425	25,715	26,655	28,750	26,350	25,995	27,005	27,645	26,655	n/a	

8.1.13 Asset Replacement and Renewals Capital Expenditure

Table 8-1.13 Asset replacement and renewals capital expenditure forecast - ($000)

Category	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Subtransmission	990	3,140	640	3,140	640	4,640	4,640	4,640	4,640	4,640	**31,750**
Zone substations	4,925	4,090	5,480	2,315	3,050	4,145	840	3,075	1,815	2,160	**31,895**
Distribution & LV lines	3,480	3,975	3,805	4,750	6,900	7,250	8,800	9,150	11,500	11,940	**71,550**
Distribution & LV cables	420	420	420	420	420	420	420	420	420	420	**4,200**
Distribution substations and transformers	3,605	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	**35,060**
Distribution switchgear	4,445	5,030	6,110	7,435	7,370	6,695	8,575	6,515	8,195	6,630	**67,000**
Other network assets	9,970	10,905	12,380	11,960	10,685	10,315	11,170	10,745	10,725	4,040	**102,895**
Totals	27,835	31,055	32,330	33,515	32,560	36,960	37,940	38,040	40,790	33,325	344,350

8.1.14 Capex - Transpower spur assets, purchase values

Table 8-1.14 Capex - Transpower spur assets, purchase values - $000

Spur asset to be purchased	FY19	FY20
Hororata 33kV (excluding 66/33kV transformers)	330	
Islington 33kV	800	
Totals	1,130	

8.1.15 Transpower new investment agreement charges

Table 8-1.15 Transpower new investment agreement charges - $000

Project		FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
	Hororata GXP additional 66kV feeder	24	24	24	24	24	24	24	12			180
	GXP Metering relocation from Papanui and Springston to Islington	159	159	159	159	159	159	159				1,113
305	Bromley GXP 220/66kV transformer upgrade	768	768	768	768	768	768	768	768	768	768	7,680
632	Hororata GXP 33kV bus alterations (Fonterra)	23	23	23	23							92
704	Kimberley GXP	1,014	1,014	1,014	253							3,295
784	Addington metering relocation	90	90									180
Totals		2,078	2,078	1,988	1,227	951	951	951	792	768	768	12,540

Note: Assumes 5 year contracts for new agreements.

8.1.16 Transpower connection and interconnection charges

Table 8-1.16 Transpower connection and interconnection charges - $000

Project	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Interconnection charges	65,836	59,252	57,706	58,221	59,251	60,281	61,311	61,826	62,341	62,856	**608,881**
Connection charges	4,330	4,286	4,243	4,201	4,159	4,117	4,076	4,035	3,995	3,955	**41,397**
Totals	70,166	63,538	61,949	62,422	63,410	64,398	65,387	65,861	66,336	66,811	650,278

8.2 Non-network expenditure forecasts

8.2.1 Opex - non network

This section describes our forecast opex to plan, operate and administer our network operations. It does not include opex on our network assets, consistent with the Commission's required expenditure breakdowns and definitions.

Table 8-2.1 System operations and network support - $000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	**Totals**
Network asset management	6,341	6,341	6,341	5,972	5,972	5,972	5,972	5,972	5,972	5,972	**60,458**
Lifecycle management	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	**19,740**
Network operations	6,704	6,633	6,633	6,633	6,633	6,633	6,633	6,633	6,633	6,633	**66,401**
Contact centre	677	677	677	677	677	677	677	677	677	677	**6,770**
Engineering support	1,950	1,888	1,996	1,996	1,996	1,996	1,996	1,996	1,919	1,919	**19,652**
Network growth and planning	613	615	613	613	615	613	613	615	613	613	**6,136**
Quality, health, safety and environment	631	621	621	621	621	621	621	621	621	621	**6,230**
Asset storage	465	465	465	465	465	465	465	465	465	465	**4,650**
Infrastructure management	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	**10,830**
Less capitalised internal labour	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	**(20,084)**
Totals	18,354	18,213	17,950	17,950	17,957	17,950	17,950	17,957	17,873	17,873	180,027

Table 8-2.2 Business support - $000

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Totals
People and strategy	944	970	627	947	930	962	942	962	948	968	**9,500**
Finance	1,196	1,134	1,103	1,114	1,123	1,114	1,103	1,134	1,103	1,114	**11,235**
Information solutions	3,250	3,197	3,133	3,102	3,078	3,113	3,078	3,078	3,078	3,078	**31,185**
Commercial, regulatory, communications	4,093	4,032	3,902	3,802	3,802	3,812	3,802	3,802	3,802	3,812	**38,661**
Corporate, governance, TC	4,423	4,405	4,395	4,385	4,395	4,385	4,395	4,405	4,385	4,385	**43,958**
Property	1,024	1,029	1,033	1,038	1,043	1,047	1,052	1,056	1,061	1,065	**10,448**
Insurance	1,654	1,686	1,719	1,753	1,787	1,822	1,857	1,893	1,930	1,968	**18,069**
Board	396	396	396	396	396	396	396	396	396	396	**3,960**
Fleet	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	**(10,000)**
Less capitalised internal labour	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	**(5,220)**
Totals	15,455	15,327	15,086	15,015	15,032	15,129	15,103	15,204	15,181	15,264	151,796

8.2.2 Capex - non network assets

Table 8-2.3 **Routine expenditure - $000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Totals
Plant and vehicles	1,231	548	769	989	1,346	1,233	1,007	613	646	1,608	9,990
Information technology	1,820	1,402	917	1,007	862	812	802	872	572	782	9,848
Corporate land and buildings	435	285	285	285	285	285	285	285	285	285	3,000
Tools and equipment	525	419	291	289	364	189	191	189	191	244	2,892
Electric vehicle charging stations	250	150	100	100	100	50	50	0	0	0	800
Capitalised internal labour	346	346	346	346	346	346	346	346	346	346	3,460
Totals	4,607	3,150	2,708	3,016	3,303	2,915	2,681	2,305	2,040	3,265	29,990

8.3 Total capital and operations expenditure

Table 8-3.1 **Total capital and operational expenditure - $000**

	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Totals
Capital expenditure	134,052	124,284	120,749	123,186	127,003	124,828	136,171	136,256	138,949	123,823	1,289,301
Operational expenditure	60,947	60,480	59,145	58,960	58,794	58,889	58,963	59,016	58,914	58,997	593,105
Total	194,999	184,764	179,894	182,146	185,797	183,717	195,134	195,272	197,863	182,820	1,882,406

8.4 Changes from our previous forecasts

Changes described in these budgets are referenced to our last published AMP (for the period from 1 April 2017 to 31 March 2027). All forecasts are now in FY19 dollar terms (previously in FY18 dollar terms).

Opex - network

Details of our maintenance plans are described by asset type in section 4 – Lifecycle and asset management.

Our opex forecasts are generally consistent with last year's forecasts.

Capex - network

ASSET REPLACEMENT

Our asset replacement plans are described by asset type in section 4 – Lifecycle and asset management.

Our replacement programme is broadly consistent with last years forecast with the significant exceptions of:

- increasing our pole replacement programme (see section 4.8.6 and 4.9.6)
- a new programme introduced from FY24 onward for the replacement of our 66kV oil-filled cables (see section 4.10.6).

CUSTOMER CONNECTIONS AND NETWORK EXTENSIONS

Our load demand forecasts are detailed in section 5 – Network development. Our network extensions and customer connection cost forecasts are based on our current and forecast business and residential growth forecasts. We are expecting one further year of strong household connection numbers. Thereafter falling to 2,500 pa in the medium term and 2,000 pa in the last five years of the AMP period. The Christchurch CBD will continue to have growth with replacement buildings and developments occurring over the next 10 years.

ASSET RELOCATIONS

Underground conversions are carried out predominantly with road works, at the direction of Selwyn District Council, Christchurch City Council and/or the New Zealand Transport Agency (NZTA). Costs associated with these works can vary depending on council or roading authority demands. Currently the Christchurch City Council has indicated they will not be carrying out undergrounding within the next few years. Selwyn District Council is continuing with its on-going programme. Undergrounding associated with NZTA projects has currently provided works that have compensated for the reduction by CCC. We estimate that activity will decrease after the major 'Roads of National Significance (RONS)' Programme is completed by NZTA over the next few years.

REINFORCEMENT

Our 11kV reinforcement forecasts remain constant at $3.5M per annum. Our reinforcement forecasts are in section 5 – Network development.

SPUR ASSETS

The transfer of Hororata and Islington 33kV assets has been deferred from FY18 to FY19. The Hororata 66/33kV transformers will no longer be transferred to Orion and hence the lower transfer cost.

MAJOR PROJECTS

Our major projects have a long term focus to meet forecast growth while delivering our resilience, reliability and security of supply objectives. They typically include new 66kV subtransmission lines or cables and/or new 66/11kV zone substations.

Our overall major project 10 year budget forecast is relatively stable but there have been a number of timing changes. The following changes mainly reflect changes to customer plans:

- Steels Rd - deferral of substation and line from FY19 to FY20
- Dunsandel - deferral of transformer upgrade from FY19 to FY20
- Railway Rd - deferral of 11kV substation from FY20 to FY21
- Shands Rd - deferral of land acquisition for switchyard from FY19 to FY20
- Hawthornden - bring forward of tee-off from FY23 to FY22
- Porters Village—deferral from FY19 to FY22
- Hills Rd - deferral of substation upgrade from FY19 to FY21.

9

Evaluation of performance

List of figures and tables in this section

9.1 Introduction

In this section we review our performance against targets stated in our previous AMP. These targets may be actual values as stated in section 3, or a declaration to carry out particular maintenance or reduce risk. We also include whether or not budgets were met and explain any variances.

Also included is a discussion on some current and future initiatives along with a reliability gap analysis.

9.2 Review of customer service

9.2.1 Review of reliability

Interruption data recorded in our control centre OMS (see section 2.9.1 10) provides all relevant statistical data needed to calculate our reliability statistics using the international measures of SAIDI and SAIFI (see the Glossary for a definition of these measures).

It is important to note that one-off factors such as bad weather and earthquakes can heavily influence the results in any one year.

As shown in the table below, our FY17 SAIDI and SAIFI results were consistent with our targets and under the Commerce Commission's CPP reliability limit. The year was free of any major weather events. See section 3.3.1 network reliability for our reasoning behind not setting a specific target for faults per 100km.

Table 9-2a **Orion network reliability results for FY17 and last five year average**

Category	FY17 target	FY17 result**	FY13-FY17 average	FY17 CPP reliability limit
SAIDI	< 91	78	177	91
SAIFI	< 1.15	0.77	1.1	1.16
Faults restored within 3 hours (%)	> 60	63	61	
Subtransmission lines faults per 100km*	-	1.7	-	
Subtransmission cables faults per 100km*	-	0.8	-	
Distribution lines faults per 100km*	-	17.6	-	
Distribution cables faults per 100km*	-	2.4	-	
Subtransmission other faults*	-	1	-	
Distribution other faults*	-	99	-	

* As per Disclosure schedule 10(v).

** Major event daily limits applied in accordance with CPP.

As shown in the following figures the Canterbury earthquakes caused the loss of 718 million customer minutes. There were also heavy snow storms in FY93, FY03 and FY07 and a major windstorm in FY14 that caused significant damage to our network.

Figure 9-2a **SAIDI - Orion network FY93-FY17**

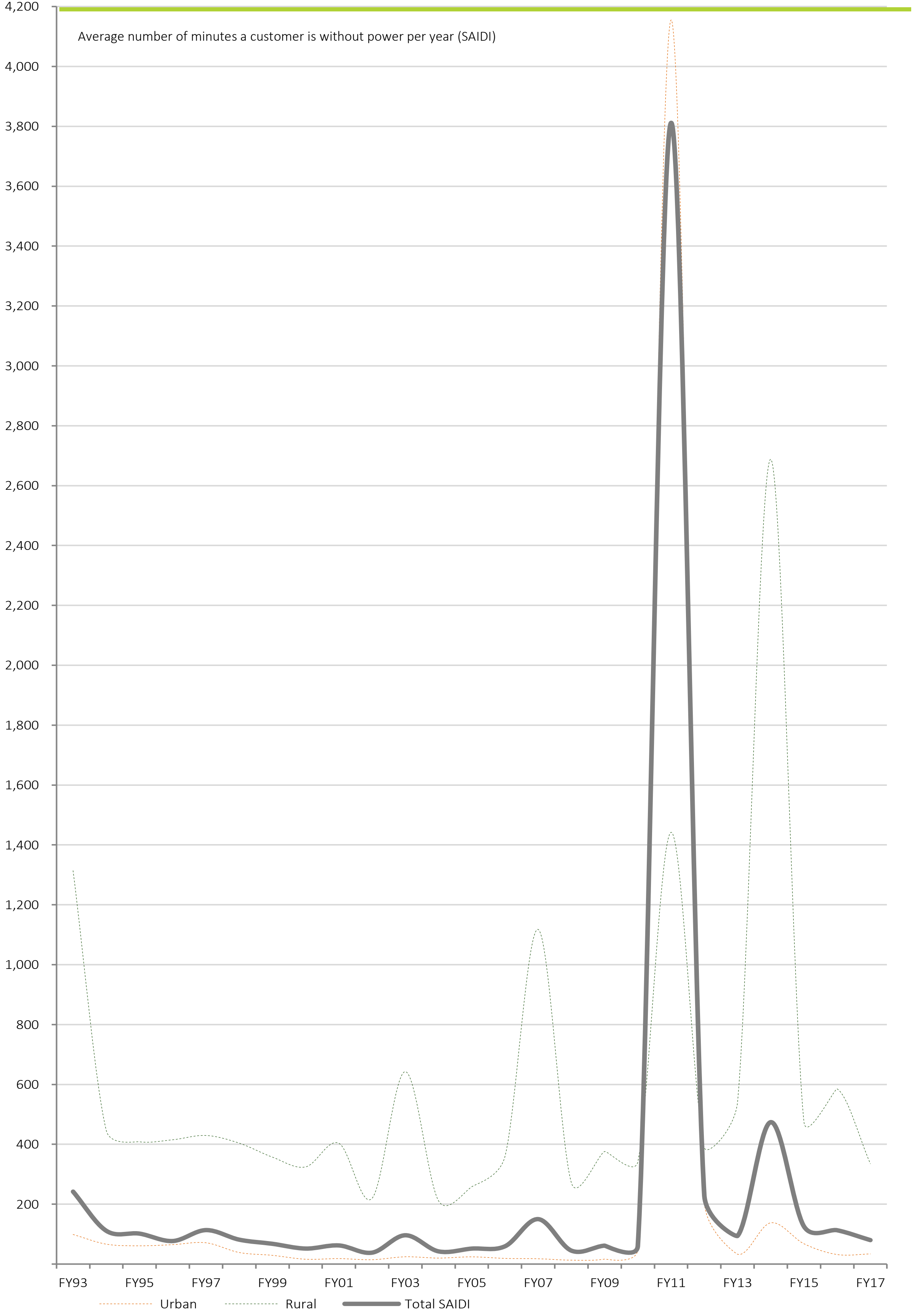
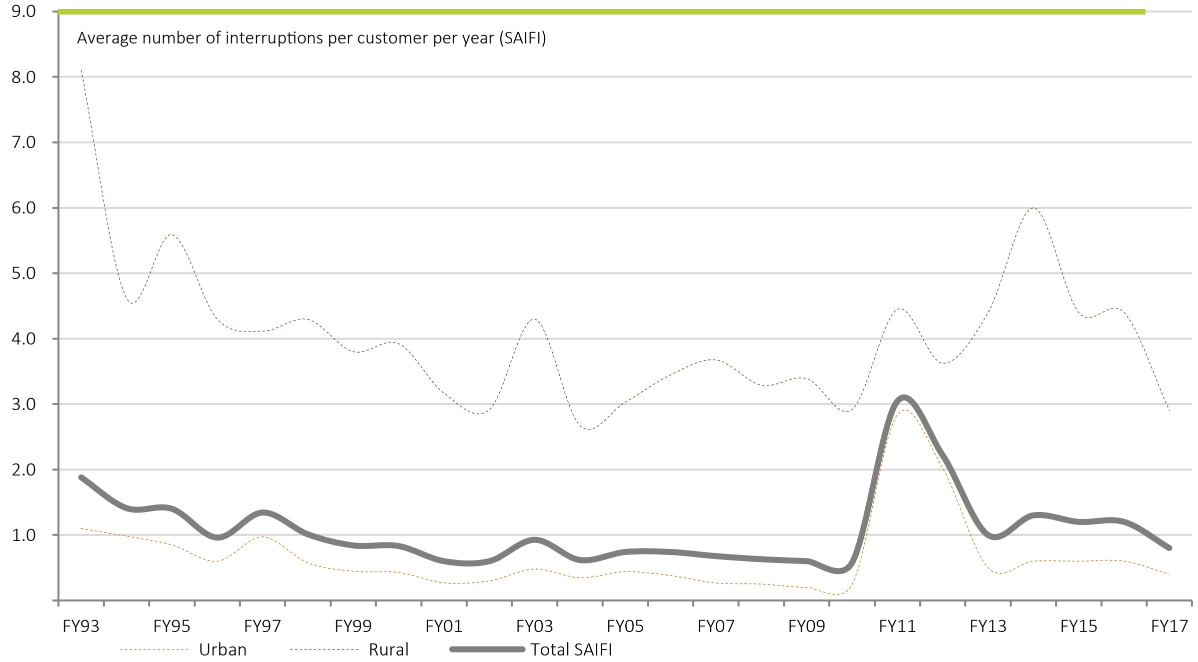


Figure 9-2b **SAIFI - Orion network FY93-FY17**

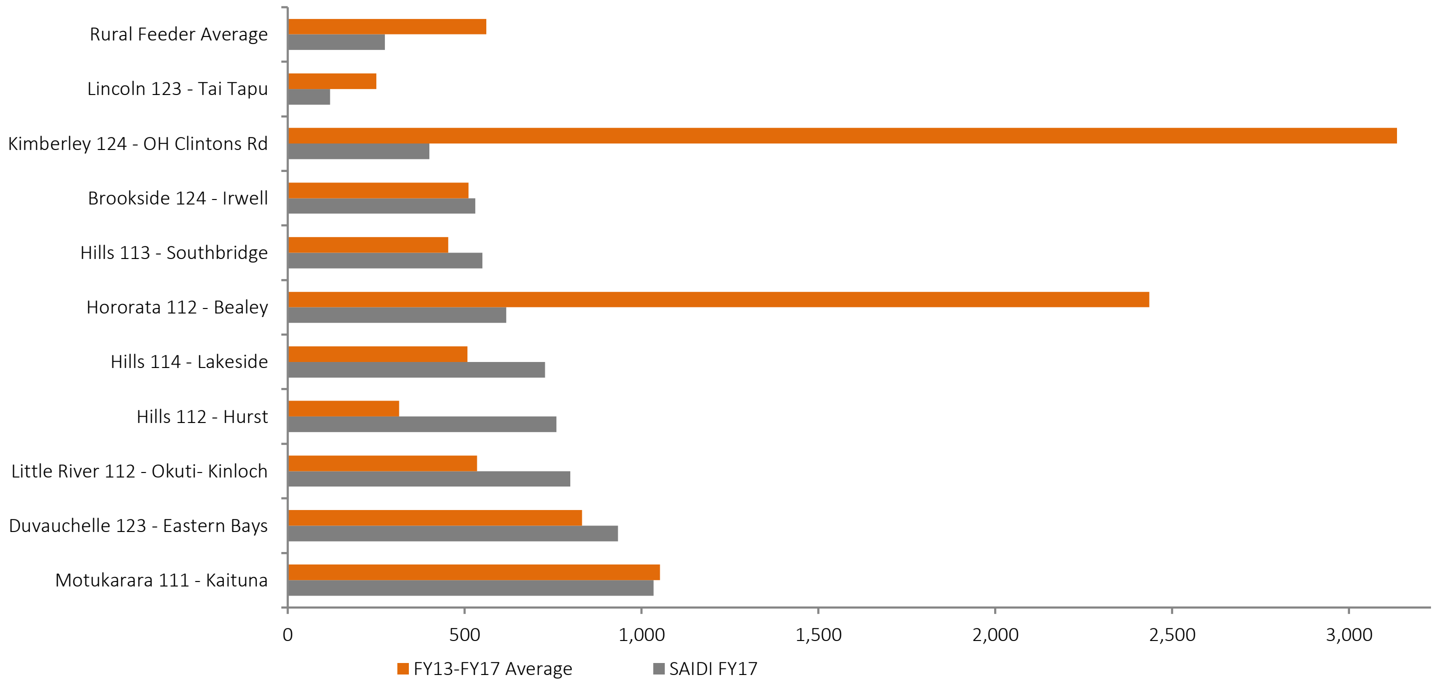


9.2.2 Least reliable feeders

Our network has 94 rural and 336 urban 11kV feeders that originate from our zone substations.

The 10 least reliable feeders on our rural network are shown below. All of these feeders were adversely affected by recent storms and some were also affected by the earthquakes in FY11.

Figure 9-2c **Orion's 10 least reliable rural feeders FY13-FY17 (SAIDI)** (unplanned interruptions only)

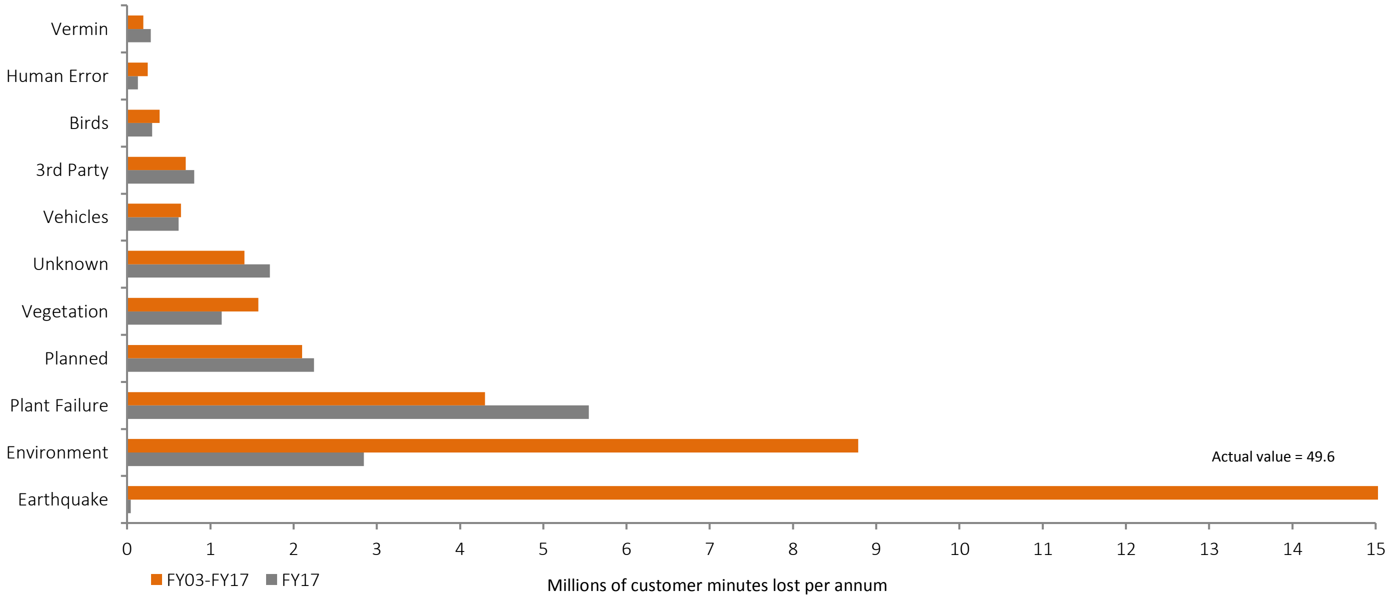


9.2.3 Cause of interruptions

The chart below compares the cause of customer minutes lost per annum on our network over the 15 year period FY03 to FY17 against the most recent year (FY17).

Where plant-failure and vegetation interruptions have been caused by severe abnormal weather conditions, such as a snow or wind storm, they are placed in the 'environment' category.

Figure 9-2d **Cause of interruptions - for FY17 and fifteen year average FY03-FY17**



9.2.4 Reliability performance comparisons

When compared with other New Zealand line companies, the reliability of our urban network (when not subjected to earthquakes) appears to be above average, while our rural network (when there are no storms) is slightly below average. There is still scope to improve our performance and we discuss improvement initiatives later in this section.

9.2.5 Power quality

Our main objective in relation to power quality is to identify and resolve customer quality of supply enquiries. To achieve this we fit test instruments close to the point where ownership changes between Orion's network and the customer's electrical installation.

Data gathered from the test instruments is analysed against the current New Zealand Electricity Regulations. By applying key regulations in relation to voltage, frequency, quality of supply and harmonics we are able to determine which quality problems have originated within our network.

Our network performs well in terms of voltage and quality. We receive a number of voltage complaints every year but only approximately 30% of complaints are due to a problem in our network. In the following table, 'proven' means that the non-complying voltage or harmonic originated in our network.

Table 9-2b **Service level targets and results for FY17 – network power quality**

Category	Measure	Target	Achieved FY17	Performance indicator	Measurement procedure
Power quality	Voltage complaints (proven)	<70	21	Non compliances per annum	Tracking of all enquiries
	Harmonics (wave form) complaints (proven)	<4	1	Non compliances per annum	Checks performed using a harmonic analyser

9.3 Efficiency

9.3.1 Economic efficiency

Economic efficiency reflects the level of asset investment required to provide network services to customers, and the operational costs associated with operating, maintaining and managing the assets.

Figure 9-3a Capex per annum per MWh supplied to customers FY06-FY17

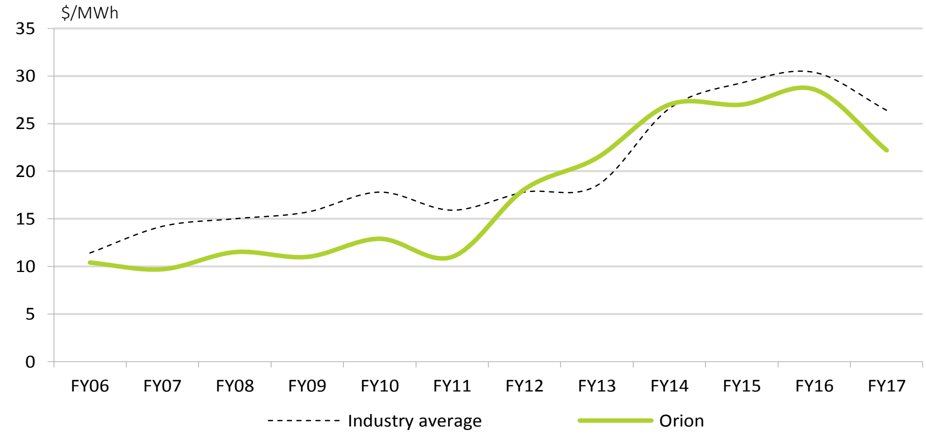


Figure 9-3b Opex per annum per MWh supplied to customers FY06-FY17

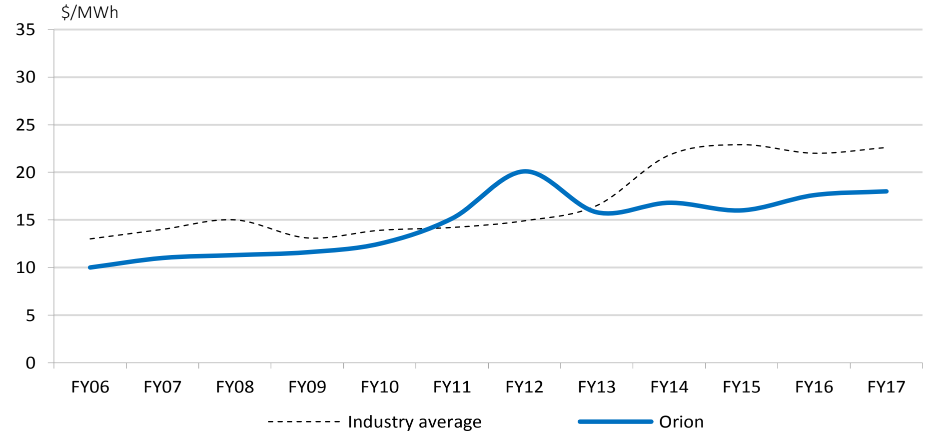
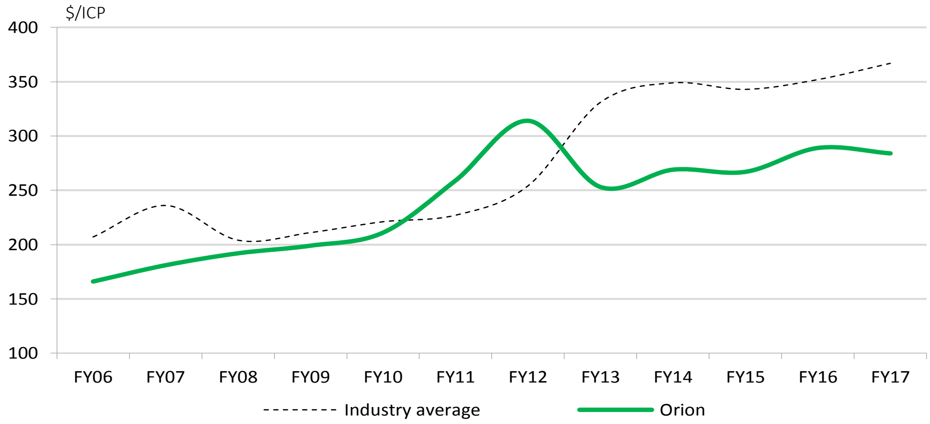


Figure 9-3c Opex per annum per ICP FY06-FY17



9.3.2 Capacity utilisation

This ratio measures the utilisation of transformers in our network. It is calculated as the maximum demand experienced on our network divided by the network distribution transformer capacity.

Table 9-3a **Capacity utilisation results for FY17 and five year average FY13-FY17**

Category	Target	Achieved FY17	Achieved five year average
Capacity utilisation (%)	No Target set*	26.2	28

* See section 3.3.8 for reasoning why no specific forecast is set for capacity utilisation.

9.3.3 Load factor

Annual load factor is calculated as the average load that passes through our network divided by the maximum load experienced in a given year. We always seek to optimise load factor as this indicates better utilisation of capacity in the network.

Load factor has trended upwards from 1990-2009 by ~0.6% per annum, and has since levelled off. The impact on load factor from the anticipated reduction of irrigation load due to CPW scheme is expected to be partially offset by the Central City rebuild. This is expected to reduce load factor in the short term. Longer term load factor will level out if battery storage takes the growth out of winter peak demand.

Table 9-3b **Load factor results for FY17 and five year average FY13-FY17**

Category	Target	Achieved FY17	Achieved five year average
Load factor (%)	No Target set*	61.5	61

* See section 5.4.1 for our load factor forecasts.

9.3.4 Losses

Measurement of losses

Electrical losses are the difference between energy volumes entering our network (mainly at Transpower GXPs) and the energy volumes leaving our network at customer connections. We estimate that these losses are around 5% with a margin of error of +/ - 1 percent. Significant deviations from this value exist in some parts of our network, for example, when we compare urban areas against rural areas.

Table 9-3c **Loss results for FY17 and five year average FY13-FY17**

Category	Target	Achieved FY17	Achieved five year average
Losses (%)	No Target set*	<5 estimated	<5 estimated

* See the following for reasoning why no specific forecast is set for losses.

Source of losses

Our assessment of the main contributors to our loss ratio is as follows:

NETWORK

Table 9-3d **Network loss contributors**

Asset	Urban	Rural	Average
Subtransmission lines and cables	0.4%	1.0%	
Zone substation (power) transformers	0.4%	0.4%	
11kV lines and cables	1.4%	3.5%	
Subtotal subtransmission + 11kV	2.2%	5.0%	
Distribution transformers	1.1%	1.0%	
230/400V lines and cables	1.2%	0.3%	
Subtotal low voltage	2.3%	1.3%	
Totals	4.5%	6.2%	5%

OTHER SOURCES

Internal usage by Orion – All our major facilities, such as our administration office, are metered and we purchase electricity from a retailer like any normal customer. However, many unmetered supplies are needed at our substations to operate equipment that is integral to a safe and reliable network. The annual volume of energy involved is estimated at 0.1% of total energy volume across our network.

Unmetered supplies – Substantial volumes, such as supply to street and traffic lights, are estimated and included with retail sales. Other miscellaneous outlets, such as those at parks, contribute towards losses at insignificant levels.

Theft – Theft may significantly contribute towards losses, although actual volume is unknown. Electricity retailers are responsible for integrity of metering at connections and for reading meters. It is in their interest to minimise theft.

Transformer purchases

New distribution transformers that we purchase must comply with the Minimum Energy Performance Standards (MEPS) as prescribed in AS 2374.1. In addition to MEPS, our equipment specification NW74.23.05 – Distribution Transformers 200 to 1,500kVA, includes a 'no-load load loss' multiplier and a 'load loss multiplier' that are used for the capitalisation of loss costs when comparing distribution transformers for purchase. As a result we purchase even lower loss transformers than MEPS requires.

Our equipment specifications for power transformers also use these loss multipliers when we evaluate tenders.

For more detailed assessments in specific circumstances, we also refer to 'Purchase and Operating Costs of Transformers', published by the Electricity Engineers' Association of New Zealand.

Our approach ensures we consider the trade-offs between purchase cost and the future cost of energy losses. It costs more to manufacture a transformer with lower losses because higher quality materials are needed. Our loss capitalisation calculation for transformers assumes a value of 11.055c/kWh for the future cost of energy. This leads to the capitalisation values per kW of losses shown in the table. We review these values when we purchase new power transformers and when we tender distribution transformer supply contracts for transformers up to 1500kVA.

Table 9-3e **Transformer 'loss' values**

Transformer size	Present value of 'no load loss' ($/kW)	Present value of 'load loss' ($/kW)
Up to 200kVA Pole mounted	9,319	833
200 to 500kVA Ground mounted	9,319	1,184
750 to 1500kVA Ground mounted	9,319	1,625
7.5 to 40MVA Zone substation	9,523	1,424

Selecting conductor size

Most electrical losses in our network occur in the conductors. We calculate losses from the expression I^2R, where I is the current, and R is the resistance of the conductor. The connected load determines the current and conductor size, while materials determine the conductor resistance. The larger the conductor size, the lower the resistance and losses. However, larger conductors cost more so a trade-off exists between costs of capital and losses.

Overhead lines

There is a complex trade-off between conductor size, losses, capital cost and alternatives such as regulators and capacitors. We are currently modelling and reviewing our rural 66kV and 11kV architecture to seek the most optimum network. It should be noted that a conductor is typically a low cost component of overhead line construction and therefore larger conductors are often economically effective.

Underground cables

For a given rating, cables cost more and have lower resistance per unit length. A comparative example is shown in table 9-3f:

Consequently, with much higher capital costs and much lower resistance, we never achieve an economic cross-over because losses are low – an increase in size cannot be justified by the small reduction in losses alone. However, the collective benefits (increased security of supply and reduced transmission charges) justify the increased cost of the larger cable. We proved this justification when we reviewed our Security Standard in FY06. Analysis showed it was economic to install an 11kV network capable of restoring power for N-2 faults at zone substations. Two thirds of the additional expenditure required for larger N-2 feeder cables was justified by reduced energy losses and lower peak demand charges due to fewer losses at peak. Our security standard drives economic investment in our 11kV network – the policy to install N-2 capacity creates fewer losses on our network.

Selecting voltage

For the same power or energy volume delivered, losses are lower when conductors are operated at a higher voltage. Capital costs also increase for higher voltage equipment. A continuous range of voltage is not practical. We use discrete voltages of 66kV, 33kV, 11kV and 230/400V.

When extending our network, we model the development and consider all future costs, including the cost of losses. In a rural area, for example, our network may be extended at 11kV, 33kV or 66kV to supply future loading such as large irrigation plants.

Table 9-3f Underground cable versus overhead line comparison

Conductor	Rating (amps)	Installed cost ($/km)	Resistance (ohms/km)
Dog overhead line	350	40,000	0.273
185mm^{2}Al cable	280	160,000	0.164

For developments at the connection level, we also consider alternatives for supply voltage and whether or not to extend the low or high voltage reticulation. We may consider losses when we make decisions although other factors tend to dominate such as future access to plant, shared land use and customer preferences.

Summary

Overall, losses do not impact significantly on how we design and operate our network – other factors tend to dominate. Losses are significant in some aspects of network design though, and require policies for optimisation. Significant points are:

- lines and cables (around two-thirds) and transformers (around one-third) account for nearly all the losses on our network
- a trade-off exists between capital and loss costs, which results in optimisation of losses, not minimisation
- we give specific consideration to losses when purchasing transformers
- we optimise losses on the 11kV underground network by applying our economically derived security of supply standard to reinforcement
- we consider loss optimisation when we design overhead lines but other factors tend to dominate
- for any major network development, we consider the cost of losses.

9.4 Works

9.4.1 Expenditure in FY17

The previous AMP figures shown here are from our AMP for the period 1 April 2016 to 31 March 2026.

Maintenance

Our maintenance costs for FY17 were $26.2m, compared with our budget forecast of $29.5m. The under-expenditure was largely due to deferred works due to the uncertain requirements around earthquake recovery, third-party works and constrained resources. Contractor resources have prioritised the large amount of road works, infrastructure rebuild projects, and customer connection works. The key areas of under expenditure are in emergency and scheduled maintenance works. Details are as follows:

EMERGENCY WORKS -$0.3m

We observed a lower than expected number of wind/weather events that impacted on the network.

SCHEDULED MAINTENANCE -$2.3m

Areas of significant under-expenditure were:

- Overhead and underground feeder maintenance (-$1.0m)

We had issues coordinating contractor resources to undertake works. Connection and relocation works were given a higher priority.

- Substation removal (Red Zone) (-$0.4m)

Decisions regarding the removal of substations in the red zone area have been deferred until land/area use has been decided.

- Generators (-$0.2m)

Expected use of connected generators less than expected hence reduced fuel and maintenance costs.

- Load Management, Communications and SCADA (-$0.6m)

The costs associated with communications and SCADA have reduced due to the introduction of new technology and work practices.

NON SCHEDULED MAINTENANCE -$0.6m

- Road works (-$0.7m)

Significant roadworks required replacement of infrastructure rather than relocation.

Capex

CUSTOMER CONNECTIONS AND EXTENSIONS

Our customer connection and extension costs for FY17 were $20.8m, compared with our previous budget forecast of $13.7m. Customer connection demand remained higher than expected in subdivision, in-fill development and large commercial connections.

REINFORCEMENT

Our reinforcement costs for FY17 were $3.3m, compared with our budget forecast of $3.5m.

RELOCATION

Our relocation costs for FY17 were $11.6m, compared with our previous budget forecast of $9.5m.

This expenditure is dependent on project timing associated with the needs of the Road Controlling Authorities, Christchurch City Council, Selwyn District Council, NZTA and developer requirements.

The over-expenditure was largely driven by significant works being undertaken by the NZTA.

MAJOR PROJECTS

Major project costs for FY17 were $7.4m, compared with our previous budget forecast of $10m. The under-expenditure was largely due to delays in projects that will be completed in the next financial year.

REPLACEMENT

Our replacement costs for FY17 were $19.2m, compared with our previous budget forecast of $17.4m. The over-expenditure is largely due to the following factors:

- our revised suspect pole inspection procedures and education program resulted in an increased number of replacements (+$0.7M)
- we accelerated our customer LV supply fuse replacement program (+$1.5M).

9.4.2 Project completion status

Table 9-4a Project completion status

Project number	Description	Completion date	Comments (if applicable)
Grid exit points			
Major projects – urban			
727	Lancaster zone substation rebuild	Nov 2017	
694	Land acquisition for Milton 66kV switchroom		Negotiations underway
Major projects – rural			
886	Springston to Rolleston 33kV line upgrade	Jun 2017	
880	Highfield generator	Dec 2016	
635	Remote indication (rural)	Mar 2017	
Reinforcement – urban			
681	Marshs Rd cable	Jun 2016	
788	Travis Rd reinforcement	Oct 2016	
851	Moffett St rearrangement	Jan 2017	
874	Post contingency load transfer—PAP to HAW		Cancelled due to capacity review deferring need
869	Ron Guthrey Rd reinforcement	Oct 2016	
882	McFaddens 11kV incomer upgrade	Mar 2017	
Reinforcement – rural			
58	Brookside Rd north cables (Rolleston)	Dec 2016	
887	Two Chain Rd cable	Dec 2016	
878	Jones Rd reinforcement	Dec 2016	

9.5 Safety

We report all employee injury incidents via Vault and collect similar statistical incident data from our contractors. These contractor statistics, our own statistical data and our incident investigations, enable us to provide staff and contractors with indicators of potential harm.

See section 7.3 – Risk management – Safety, for details of our risk mitigation initiatives.

Table 9-5a **Personal safety – performance results**

Key asset management driver	Measure	Target	Achieved FY17	Performance measure	Measurement procedure
Personal safety	Safety of employees	0	0	Notifiable injury, incident or illness.	Accident/incident reports
	Safety of our contractors	0	1		
	Safety of public	0	1	Number of accidents involving members of the public (excluding car v pole accidents)	

9.6 Environment

All service providers are required to adhere to our environmental management manual and procedures.

All polychlorinated biphenyls (PCBs) have previously been removed from our network.

Table 9-6a **Environmental responsibility – performance results**

Key asset management driver	Measure	Target	Achieved FY17	Performance indicator	Measurement procedure
Environmental responsibility	SF_6 gas lost	<1% loss	<1% loss	Identification of environmental problems	Environmental spill/loss report
	Oil spills (uncontained)	0	0		

9.7 Legislation

We have analysed our compliance with relevant statutes and identified the risk, compliance process and managerial responsibility for each.

Statutes analysed include:

- Electricity Act 1992 and associated regulations
- Electricity Industry Act 2010
- Health and Safety at Work Act 2015 and associated regulations
- Resource Management Act 1991
- Hazardous Substances and New Organisms Act 1996
- Building Act 2004
- Fire Services Act 1975 and associated regulations
- We report our compliance, including any exceptions and corrective actions, to our board twice each year.

9.8 Improvement initiatives

Our initiatives to reduce network risk in areas such as safety, seismic damage and major asset failure are discussed in section 7 – Risk management.

We discuss initiatives to improve network performance and reliability in the following sections.

9.8.1 Subtransmission network

We have identified a need to improve security and performance in the upper network (higher voltage), since this asset affects the largest number of customers. Initiatives taken in relation to this asset include:

Underground

- completed the northern 66kV loop which allows for better resilience to the eastern suburbs, as was shown from the two isolated incidents since its completion
- carried out thermal engineering checks to determine/confirm the current rating of cables
- specified trench backfill to provide the required thermal and mechanical support
- replaced the 66kV oil-filled cable joints and 33kV oil-filled cables to counter thermo-mechanical effects.

Overhead

- replaced insulators and installed vibration dampers
- re-rated conductor for 75^0C operating temperature
- applied dynamic ratings
- assessed condition of tower foundations and repaired where required.

Substations

- increased reliability at Addington by splitting the 66kV bus
- rearranged existing 11kV supplies at Addington to increase security
- constructed a 66kV bus at Springston
- installed a 66kV bus zone scheme at Bromley.

Transpower GXP

- major alterations at Islington GXP to increase capacity and alter vector grouping along with replacing half of the 33kV outdoor switchgear with indoor equipment.

9.8.2 Distribution overhead lines

Historical performance

Historically our rural 11kV overhead network experienced around 12 faults per 100km per year. Since the Canterbury earthquakes in FY11 this has increased to approximately 19 faults per 100km per year. This increase can be attributed to the failure of insulators exposed to seismic shock, a number of strong weather events and changes to how our network is switched during outages. We are actively targeting any areas of poor performance with the aim of returning to a lower rate of around 12 faults per 100km per year.

Our major initiatives are:

- completed a review of our overhead line design standards
- use live-line techniques where appropriate
- complete regular tree maintenance on a complete feeder basis
- actively working with land owners to trim at risk trees outside the regulatory trim area
- introduce softwood poles and phase-out concrete poles
- increase the use of thermal/corona scanning to identify potential problems
- increase use of smooth-body conductors in areas exposed to snow and high winds
- re-tighten hardware to minimise damage caused by loose components
- modify protection systems and add remote control to all line circuit breakers
- install additional pole mounted line circuit breakers
- underground selected troublesome customer high voltage spur lines
- installation of new line switches with remote indication and control.

Opportunities for further improvement

The reliability performance of our rural network is driven by the fault rate on overhead lines. Methods to improve performance can either attempt to reduce the overhead line fault rate or minimise its impact. We initially improved our reliability performance by reducing the fault rate. More recent improvements have come from minimising the impact of line faults. In the five years from FY00-FY04 we installed 29 additional line circuit breakers in our rural network – the first significant installation of line circuit breakers in approximately 15 years. Significant performance gains were seen.

We believe it is sensible to compare the costs of reliability improvements with the reduced costs of lost supply to our customers. The CAE Reliability of Electricity Supply Project Report, 1993, published the values of un-served energy, providing typical values of between $5.00 and $10.00 per kWh. Adjusting these costs for inflation, we get un-served energy costs of between $14 and $20 per kWh. Further analysis of irrigation customers during 2005 indicated that the value of supply to irrigation pumps is significantly less than $14 to $20 per kWh, but it is thought that the high value placed on milking supply balances the analysis. A value of $15 per kWh is applied in the analysis below.

We estimate that the average load of a rural customer is 2kW, so the cost of an outage to the average rural customer is $30 per hour. Therefore the annual cost of network enhancement must not exceed the $30 per hour of customer reliability improvement. The annual cost of network enhancement is approximately 14% of the capital cost. For example in the case of a $50,000 line circuit breaker, we require $7,000 of annual revenue to be charged to customers.

As circuit breakers have now been installed in the most effective locations, the benefits versus costs have decreased.

Current available options to improve rural network reliability come at considerably differing costs and each needs to be assessed for its suitability to the application. These options include:

1. Increase our tree trimming programme – this could improve our network reliability significantly. Of our unplanned interruptions, trees currently cause between 15 and 20% of total customer-minutes lost. However, our analysis of our existing tree trimming programme indicates it probably cannot be expanded in any major way. We trim trees to the limit allowed under law, i.e. clear of power lines for safety reasons. Tree control legislation that defines clearance corridors has now been passed into law.

   If we increased our expenditure on tree trimming around 11kV lines by approximately $500,000 each year we could reduce customer minutes lost in the range of 500,000 to 1,000,000 minutes (8,350 to 16,700 hours) at an annual cost of $15 to $30 per kWh. The economic benefits of this approach are marginal, but the project is also driven by safety and legislation. Our remaining tree trimming expenditure is in relation to 400V lines and will not be reflected in our interruption statistics.

2. Continue to install additional line circuit breakers – we appear to have reached an incremental level of around 15,000 minutes (250 hours) per $50,000 line circuit breaker installation ($14 per kWh). This suggests additional line circuit breakers would have marginal benefit for rural customers.

3. Shorten feeder lengths by installing additional zone substations. Each additional substation could halve the length of three existing feeders and, if we assume that each feeder supplies 250 customers and consists of 50km of 11kV line, this strategy could reduce customer-minutes lost by about 500,000 (8,300 hours). An additional rural zone substation typically costs about $4m, giving an annualised cost of $33 per kWh. This exceeds the benefit of reliability improvement. Therefore this method of performance improvement is generally only acceptable as a side-effect of network reinforcement.

4. Replace the existing bare conductor with a covered conductor on a major proportion of the rural overhead network. If we assume the average cost of replacing the existing conductor, including strengthening existing poles and structures and installing modified covered ancillary equipment (switches, transformers etc.) is $25 per metre, then for 3,200km of rural overhead line, the cost would be approximately $80m. Covered conductors' impact on reliability has not been comprehensively documented elsewhere in the world. However, a Norwegian network operator has claimed improvement ratios of 10:1. Part of this improvement may be due to the fact that the network was substantially rebuilt when the covered conductor was installed, which in itself would improve reliability, at least transiently, until the aging process reduced the reliability again.

   We prefer to be conservative in claiming reliability improvement from covered conductor and assume a long term reduction in customer-minutes lost to 33% of existing figures. This could result in a reduction of 4.3 million minutes or 71,700 hours (assumes rural SAIDI of 300 and 21,500 customers giving total minutes of 6.45 million minutes) at an annualised cost of $78 per kWh. This once again clearly exceeds the benefit of reliability improvement, therefore this method of performance improvement is not viable.

5. Replace the existing bare conductor overhead system with underground cable. The cost to convert our rural network to underground is estimated to be $600m. This would reduce the loss of customer-minutes by approximately six million (100,000 hours) at an annualised cost of approximately $870 per kWh.

6. Installing smart switches. Installing line switches that are equipped with smart technology that allows our staff to make quick decisions around the restoration of supply. Some of these line switches are also able to be remotely operated once the decision to restore supply has been made.

7. Installing ground fault neutralisers (GFN) at rural zone substations has the potential to significantly improve network reliability. The potential to cost-effectively improve reliability using traditional methods (1-5) is limited and expensive. However, we have successfully trialled a GFN and are completing the installation of this technology at all of our rural zone substations.

A GFN can reduce the residual earth-fault current close to zero during single-phase earth-faults and makes it safer should a fault develop.

Investigation has shown we can conservatively assume that 20% of unplanned long-term outages due to permanent faults, and 30% of all momentary interruptions, can be attributed to single-phase earth-faults, and therefore minimised.

Our analysis for installing a GFN at all rural zone substations using these conservative estimates yields reliability savings greater than the annual cost to customers. A breakdown of reliability savings for each of the existing rural substations (excluding Dunsandel) is shown in the following table.

Table 9-8a **Installation of GFN – reliability savings**

Zone substation/ Transpower GXP	Anticipated savings for long term interruptions p.a. ($)	Anticipated savings for momentary interruptions p.a. ($)	Total anticipated savings p.a. ($)	Benefit/cost ratio
Lincoln	78,432	36,852	115,284	3.07
Rolleston	69,289	32,352	101,641	2.71
Hills Rd	52,623	45,135	97,758	2.61
Weedons	47,319	49,879	97,198	2.59
Hororata	41,738	47,233	88,970	2.37
Springston	55,278	31,414	86,692	2.31
Brookside	35,112	40,554	75,666	2.02
Killinchy	31,213	41,993	73,206	1.95
Darfield	28,321	37,951	66,272	1.77
Duvauchelle	24,558	23,637	48,195	1.29
Bankside	15,546	24,387	39,933	1.06
Motukarara	26,863	9,762	36,624	0.98
Te Pirita	7,230	25,606	32,836	0.88
Greendale	6,772	18,476	25,248	0.67
Annat	10,052	9,272	19,324	0.52
Highfield	4,394	10,417	14,810	0.39
Teddington	11,356	2,878	14,234	0.38
Diamond Harbour	5,923	4,255	10,178	0.27
Little River	6,083	3,699	9,781	0.26
Castle Hill GXP	4,223	1,830	6,053	0.16
Coleridge GXP	3,368	2,569	5,937	0.16
Arthur's Pass GXP	2,133	207	2,340	0.06
		Average	48,554	1.29

Rural spur lines

We have for the past 17 years maintained lines right up to the customer's building at no direct cost to the customer. This allows us to plan work based on performance and safety rather than on a customer's willingness to pay.

9.8.3 Substations

We have instigated several initiatives to reduce problems with switchgear, primary transformers and their terminations. These include:

Metal-clad switchgear

- standardise equipment types
- improve installation drawings
- engage internationally recognised consultants to evaluate switchgear in the network
- establish partial discharge testing as ongoing preventive maintenance

- locate and replace older air terminations using tape insulation with heat shrink
- remove dual cable terminations with insufficient clearances
- ventilate air termination cable boxes
- increase levels of training for jointers working on this equipment
- modify older circuit breakers to enable more reliable operation.

Primary transformers

- carry out half-life maintenance programme
- replace/refurbish on-load tapchangers
- replace pressure relief glass bursting diaphragms with pressure relief valves
- conduct tests to establish on-site overload ratings
- install extra cooling as required
- install dynamic controllers at key locations
- perform dissolved gas analysis of transformers.

Interference with telecommunications networks (review needed VM)

We have installed neutral earthing resistors (NER) at five urban 33/11kV zone substations in the Hornby area where 11kV reticulation is predominantly overhead. In these areas we frequently connect industrial/commercial customers with short lengths of underground cable connected to the overhead, with no continuous earth connection back to the zone substation. Faults on these isolated sections of cable can cause extremely high earth potential rise (EPR) on customer's premises. This may result in severe damage to telecommunications plant and customer equipment and possible injury to telecommunications workers. NERs restrict earth fault current and minimise damage to telecommunications equipment.

Significant industrial and commercial area development in Rolleston and Darfield townships brings an increased risk of damage to telecommunications equipment from EPR in those areas. We have now installed a ground fault neutraliser (GFN) at 23 zone substations to reduce earth fault levels.

9.8.4 Power quality

Although the power quality attributes discussed in section 3.3.4 and other parts of this AMP are well known, until recently considerable disagreement has existed about how to qualitatively measure them. As a result equipment manufacturers have developed their own individual measurement methods. Therefore equipment from different manufacturers gives different results when it measures the same input quantities. This is not ideal as it is impossible to accurately and consistently compare power quality measurement results.

A comprehensive set of international standards (IEC61000) now exists which defines standardised methods to measure power quality. Equipment that conforms to these standards is now available.

Our power quality management has generally been reactive. We respond to customer complaints which usually arise from the customer's own activities, and assume that fundamental network performance is satisfactory.

We have completed a three year project to install 30 power-quality measurement instruments at selected sites throughout our distribution network. This equipment complies with the standards mentioned above. The aim of the project is to undertake a long term survey to determine the power quality performance of our distribution network and how it changes over time. The measurement sites chosen represent the average and worst performing parts of our network over a variety of customer types.

We have a 'PQView power quality analysis package' to archive and analyse the data. These instruments collect power quality trend data plus triggered transient event information

We are now collating the results to develop and calculate power quality indices to define the power quality performance of our distribution network.

Our analysis of data collected showed very high harmonic levels on the network supplied from Hororata GXP which have been traced to the installation of large numbers of unfiltered variable speed drives on irrigation pumps. This data has helped us to analyse the problem and develop economic solutions. The solutions chosen are in two parts:

1. All new variable speed drive (VSD) pump installations must include harmonic filters that reduce the total harmonic current to less than 10%.
2. Because of the difficulty of retrofitting harmonic filters on existing installations (cost and size), all transformers supplying VSD pump installations were identified and sorted by pump motor size. The transformers supplying approximately half of the total load were replaced with Dzn0 units which provide a 30 degree electrical phase shift from the normal Dyn11 units. This phase shift cancels most of the troublesome harmonic currents and reduces the resulting harmonic voltage.

At Darfield, total harmonic voltage distortion was exceeding 8% during the summer of FY09. During the summer of FY10 after the transformers were changed and despite an increase of 50% in the VSD load, the total harmonic voltage decreased to approximately half that of the previous summer. Note that transformers removed from service are simply put back in stock and used elsewhere so the cost is limited to the actual change-out costs plus a slight premium for the Dzn0 transformer.

The data has also assisted Transpower to analyse the effect of transposing the 220kV lines as part of a project to reduce voltage imbalance and has also been used to discover and monitor the increasing harmonic distortion caused by everyday domestic customer electronic equipment.

The European Union and the EL/34 joint committee of Standards Australia and New Zealand are currently attempting to develop more statistically defensible methods of measuring the limits on the characteristics of power delivered to customers. The measurements from our power quality instruments will provide invaluable information about how our network currently performs and will help the committee develop the standards.

The New Zealand Foundation for Research, Science and Technology in conjunction with the Electricity Engineer's Association awarded a contract to the University of Canterbury Electric Power Engineering Centre to carry out research into power quality issues in New Zealand electricity networks. The research work developed a set of guidelines for network development and mitigation techniques for existing problems. To assist with this work Orion provided power quality data collected over a two year period.

9.8.5 Emergency stock

Our emergency stock holdings valued at approximately $4m have been reviewed by looking at the reliability statistics of each asset, and systematically identifying the need for components that make up that asset. It was necessary to set a reasonable level of risk to ensure that we balanced the need for carrying emergency supplies with the cost of holding these items. For the overhead line asset we set this level at about a 1-in-50 year event. As risk assessment of individual items is further refined some items may be released or additional critical items will be held.

9.9 Gap analysis

9.9.1 Asset management processes

The Commerce Commission released new Information Disclosure (ID) requirements in 2012. As part of these requirements EDBs must provide an overview of asset management documentation, controls and review processes using an instrument known as the Asset Management Maturity Assessment Tool (AMMAT). While the AMMAT does not formally specify a standard upon which to assess compliance, the requirements are clearly aligned with 31 questions from the 121 questions prescribed by the PAS 55 Assessment Methodology (PAM). These questions have been selected to provide information not previously required by the Information Disclosure (ID) requirements.

AMMAT reviews are usually self-assessment. However we engaged EA Technology Ltd to undertake an independent assessment. We wanted EA Technology to:

- identify any blind-spots or gaps in our asset management processes and practices
- give us a true and unbiased indication of our asset management maturity.

Assessment is undertaken against detailed criteria for each question (see full results in Appendix A.13). An overview of the general criteria required to be met for each maturity level is:

- Maturity Level 0

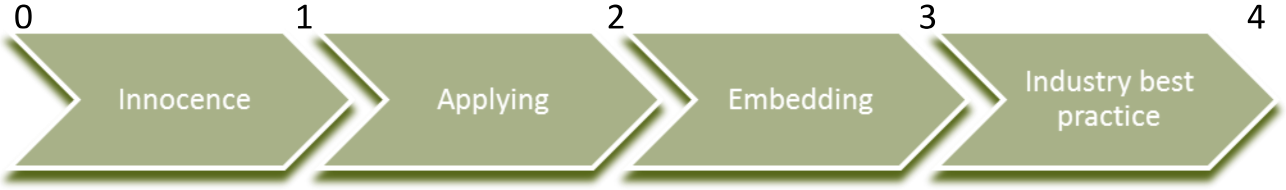
  The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function.
- Maturity Level 1

  The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them.
- Maturity Level 2

  The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation.
- Maturity Level 3

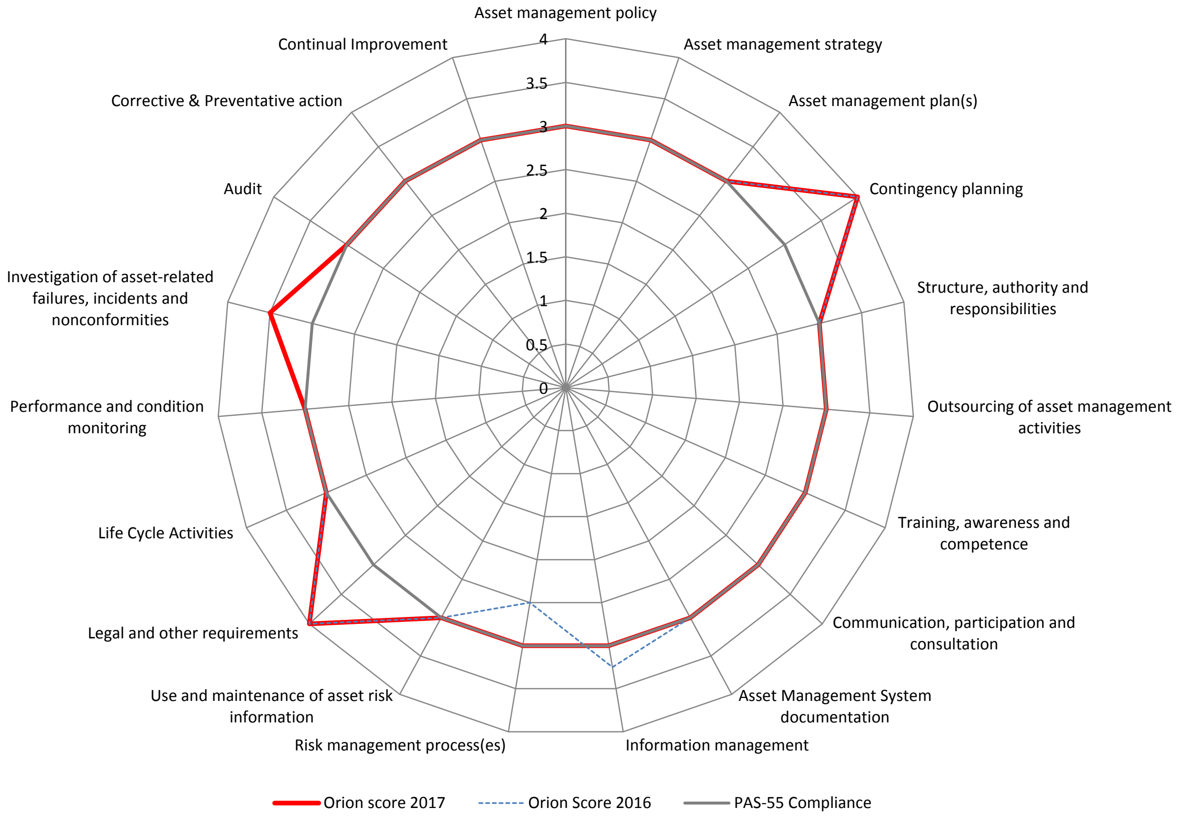
  All elements of the function are in place and being applied and are integrated. Only minor inconsistencies may exist.
- Maturity Level 4

  All processed and approaches go beyond the requirements of PAS 55. The boundaries of Asset Management Development are pushing to develop new concepts and ideas.



In 2017 EA Technology assessed that we complied overall with a maturity level of 3 or better in all areas. This showed that we are making steady improvement.

Figure 9-9a **Orion's maturity level scores**



9.9.2 Reliability

We have compiled detailed reliability statistics for the past 26 years. Statistics from the first few years indicate that most interruptions occurred in the rural area and were due to trees on lines, vehicles hitting poles and equipment failure to a lesser extent. Since then we have made considerable effort to control tree growth and instigate various maintenance programmes on our rural 11kV lines. A project to install reflectors on roadside poles to reduce the incidence of vehicles hitting poles has also been completed.

Our plant failure statistics show that as loads increase in parts of our network, we have to work harder to keep aging equipment performing satisfactorily. We use a UV corona imaging camera that utilises the latest technology in an effort to identify potential problems before they cause an interruption.

We have also completed a project to shorten the interrupted portions of our feeders by installing additional line circuit breakers. Circuit breakers are relocated to more appropriate locations as the network is altered and total 50 in our rural network.

We have installed and put into service 23 Ground Fault Neutralisers (GFN). These units are equipped with 5th harmonic residual current compensation and are starting to contribute to an improvement in rural network reliability and safety.

We are currently targeting feeders with poor performance and there is programme in place for FY18 and FY19 to identify and replace seismically damaged insulators.

9.9.3 Security Standard

Our Security Standard provides a useful benchmark to identify areas on our network that may not currently receive the high level of security that the majority of our network has. Any gaps against our Security Standard are discussed in section 5.5 – Network gap analysis.

Appendices

A

Appendix A - Disclosure schedules

Schedule 11a: Report on forecast capital expenditure

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

7		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	For year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
9	**11a(i) Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10	Consumer connection	14,315	15,000	14,802	14,871	15,194	15,571	15,948	16,325	16,702	17,080	17,458
11	System growth	8,987	8,813	10,767	8,864	10,837	12,798	5,127	16,446	16,899	16,974	5,680
12	Asset replacement and renewal	20,890	28,661	32,807	35,015	37,195	37,063	42,974	45,138	46,307	50,715	42,534
13	Asset relocations	7,080	8,208	4,000	1,463	1,933	1,980	1,573	1,609	1,646	1,683	1,720
14	Reliability, safety and environment:											
15	Quality of supply											
16	Legislative and regulatory											
17	Other reliability, safety and environment	250	325	-	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	250	325	-	-	-	-	-	-	-	-	-
19	**Expenditure on network assets**	51,522	61,007	62,376	60,213	65,160	67,412	65,621	79,519	81,555	86,451	67,392
20	Non-network assets	20,218	4,607	3,246	2,871	3,294	3,706	3,371	3,187	2,806	2,543	4,251
21	**Expenditure on assets**	71,740	65,614	65,622	63,084	68,454	71,118	68,992	82,706	84,361	88,994	71,643
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	4,382	6,476	6,288	3,622	4,591	2,203	1,893	1,938	1,983	2,028	2,074
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	67,358	59,138	59,334	59,463	63,863	68,915	67,099	80,768	82,378	86,966	69,570
28												
29	Value of commissioned assets	78,658	89,138	59,334	59,463	63,863	68,915	57,099	80,768	82,378	86,966	69,570
30												
32												
33	Consumer connection	14,315	15,000	14,389	14,089	14,039	14,039	14,039	14,039	14,039	14,039	14,039
34	System growth	8,987	8,813	10,460	8,390	10,000	11,520	4,505	14,113	14,171	13,916	4,555
35	Asset replacement and renewal	20,890	28,661	31,881	33,156	34,341	33,386	27,786	28,766	38,866	41,616	34,151
36	Asset relocations	7,080	8,208	3,888	1,388	1,788	1,788	1,388	1,388	1,388	1,388	1,388
37	Reliability, safety and environment:											
38	Quality of supply	-	-	-	-	-	-					
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	250	325	-	-	-	-					
41	**Total reliability, safety and environment**	250	325	-	-	-	-	-	-	-	-	-
42	**Expenditure on network assets**	51,522	61,007	60,617	57,022	60,167	60,732	57,717	68,305	68,463	70,958	54,132
43	Non-network assets	20,218	4,607	3,150	2,708	3,016	3,303	2,790	2,441	2,000	1,660	2,970
44	**Expenditure on assets**	71,740	65,614	63,767	59,730	63,183	64,035	60,507	70,746	70,463	72,618	57,102
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and DSM reduction of energy losses											
48	Overhead to underground conversion	7,080	8,208	4,000	1,463	1,933	1,980	1,573	1,609	1,646	1,683	1,720
49	Research and development											

Note: Forecast capex totals are consistent with totals in prior sections of this AMP. However, Schedule 11a has total capex broken into the Commerce Commission disclosure categories and includes the apportionment of capitalised internal labour. The financial section (Section 8) has the amount of internal capitalised labour shown as a single line item.

Schedule 11a: Report on forecast capital expenditure (cont)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	For year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
53	Difference between nominal and constant price forecasts	$000										
54	Consumer connection	-	-	414	782	1,156	1,532	1,909	2,286	2,664	3,042	3,420
55	System growth	-	-	307	474	837	1,278	622	2,333	2,728	3,058	1,125
56	Asset replacement and renewal	-	-	927	1,860	2,855	3,677	5,188	6,373	7,442	9,099	8,384
57	Asset relocations	-	-	112	75	145	192	185	221	258	295	332
58	Reliability, safety and environment:											
59	Quality of supply	-	-	-	-	-	-	-	-	-	-	-
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
62	Total reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
63	Expenditure on network assets	-	-	1,759	3,191	4,993	6,680	7,904	11,214	13,092	15,493	13,260
64	Non-network assets	-	-	96	163	278	403	581	746	806	883	1,281
65	Expenditure on assets	-	-	1,855	3,354	5,271	7,083	8,485	11,960	13,898	16,376	14,541

68 11a(ii) Consumer Connection

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
69	*Consumer types defined by EDB (see note)*	$000 (in constant prices)					
70	General connections	4,019	5,177	4,855	4,805	4,755	4,755
71	Large customers	1,606	1,601	1,523	1,523	1,523	1,523
72	Subdivisions	4,370	4,132	3,921	3,921	3,921	3,921
73	Switchgear	1,460	1,420	1,420	1,360	1,360	1,360
74	Transformers	2,860	2,670	2,670	2,480	2,480	2,480
75							
76	Consumer connection expenditure	14,315	15,000	14,389	14,089	14,039	14,039
77	*less* Capital contributions funding consumer connections	1,102	1,086	1,058	1,018	983	973
78	Consumer connection less capital contribution	13,213	13,914	13,331	13,071	13,056	13,066

79 11a(iii) System Growth

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
80	Subtransmission	-	18	18	18	1,228	18
81	Zone substations	6,657	2,659	7,375	1,523	5,396	8,026
82	Distribution and LV lines	381	179	179	179	204	204
83	Distribution and LV cables	1,386	5,764	2,590	2,955	2,826	2,826
84	Distribution substations and transformers	-	12	12	12	12	12
85	Distribution switchgear	331	51	156	3,572	178	178
86	Other network assets	231	131	131	131	156	256
87	System growth expenditure	8,987	8,813	10,460	8,390	10,000	11,520
88	*less* Capital contributions funding system growth	-	-	2,361	1,720	2,243	-
89	System growth less capital contribution	8,987	8,813	8,099	6,670	7,757	11,520

90
Note: Our Capex budgets for new connections are broken down into asset types rather than consumer types and therefore the consumer type definitions in this schedule differ from schedule 12c(i).

Schedule 11a: Report on forecast capital expenditure (cont)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

			Current year	CY+1	CY+2	CY+3	CY+4	CY+5
91			*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
92		For year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
93		**11a(iv) Asset Replacement and Renewal**	$000 (in constant prices)					
94		Subtransmission	1,200	1,056	3,206	706	3,206	709
95		Zone substations	2,435	5,022	4,187	5,577	2,412	3,147
96		Distribution and LV lines	3,005	3,615	4,110	3,940	4,885	7,035
97		Distribution and LV cables	410	576	576	576	576	576
98		Distribution substations and transformers	3,605	3,758	3,648	3,648	3,648	3,648
99		Distribution switchgear	3,180	4,515	5,100	6,180	7,505	7,440
100		Other network assets	7,055	10,120	11,055	12,530	12,110	10,835
101		**Asset replacement and renewal expenditure**	20,890	28,661	31,881	33,156	34,341	33,386
102	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103		**Asset replacement and renewal less capital contributions**	20,890	28,661	31,881	33,156	34,341	33,386
107		**11a(v) Asset Relocations**						
108		*Project or programme*						
109		NZTA and Others	2,680	2,552	332	332	332	332
110		Christchurch City Council and Others	950	1,344	344	344	744	744
111		Selwyn District Council and Others	450	376	376	376	376	376
112		Developer Specific Projects	300	3,305	2,805	305	305	305
113		Otakaro	2,700	631	31	31	31	31
114								
115		All other projects or programmes - asset relocations	-	-	-	-	-	-
116		**Asset relocations expenditure**	7,080	8,208	3,888	1,388	1,788	1,788
117	*less*	Capital contributions funding asset relocations	3,280	5,390	2,690	690	1,010	1,010
118		**Asset relocations less capital contributions**	3,800	2,818	1,198	698	778	778
122		**11a(vi) Quality of Supply**						
123		*Project or programme*						
124			-	-	-	-	-	-
125								
130		All other projects or programmes - quality of supply	-	-	-	-	-	-
131		**Quality of supply expenditure**	-	-	-	-	-	-
132	*less*	Capital contributions funding quality of supply						
133		**Quality of supply less capital contributions**	-	-	-	-	-	-
137		**11a(vii) Legislative and Regulatory**						
138		*Project or programme*						
139			-	-	-	-	-	-
144								
145		All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146		**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less*	Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Schedule 11a: Report on forecast capital expenditure (cont)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

149		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
150	For year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
151	**11a(viii) Other Reliability, Safety and Environment**						
152	*Project or programme*	$000 (in constant prices)					
153	Reliability improvement reinforcement projects	250	325	-	-	-	-
154							
155							
156							
158							
159	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
160	Other reliability, safety and environment expenditure	250	325	-	-	-	-
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	Other reliability, safety and environment less capital contributions	250	325	-	-	-	-
166	**11a(ix) Non-Network Assets**						
167	Routine expenditure						
168	*Project or programme*						
169	Sundry land and buildings	230	435	285	285	285	285
170	Vehicles and mobile plant	1,275	1,231	548	769	989	1,346
171	Information solutions	1,776	2,166	1,748	1,263	1,353	1,208
172	Sundry tools and equipment	487	525	419	291	289	364
174							
175	All other projects or programmes - routine expenditure						
176	Routine expenditure	3,768	4,357	3,000	2,608	2,916	3,203
177	Atypical expenditure						
178	*Project or programme*						
179	Construction of a depot (postponed from FY17)	16,200	-	-	-	-	-
180	Electric vehicle charging stations	250	250	150	100	100	100
181							
184							
185	All other projects or programmes - atypical expenditure						
186	Atypical expenditure	16,450	250	150	100	100	100
187							
188	Expenditure non-network assets	20,218	4,607	3,150	2,708	3,016	3,303

Schedule 11b: Report on forecast operational expenditure

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

7		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
9	Operational Expenditure Forecast	$000 (in nominal dollars)										
10	Service interruptions and emergencies	7,110	8,975	8,882	9,085	9,287	9,489	9,692	9,894	10,096	10,299	10,501
11	Vegetation management	3,505	3,560	3,645	3,728	3,811	3,894	3,977	4,060	4,143	4,226	4,309
12	Routine and corrective maintenance and inspection	14,215	13,150	13,439	13,378	13,628	13,723	14,015	14,308	14,542	14,833	14,058
13	Asset replacement and renewal	3,735	3,350	3,256	2,754	2,816	2,877	2,938	3,114	3,177	3,241	3,305
14	Network Opex	28,565	29,035	29,223	28,946	29,542	29,983	30,622	31,376	31,959	32,599	33,173
15	System operations and network support	17,141	18,354	18,988	19,257	19,832	20,413	21,010	21,588	22,256	22,774	23,442
16	Business support	16,025	15,455	15,895	16,094	16,503	17,003	17,625	18,093	18,768	19,281	19,969
17	Non-network opex	33,166	33,809	34,883	35,351	36,335	37,416	38,635	39,681	41,024	42055	43,411
18	Operational expenditure	61,731	62,844	64,106	64,297	65,877	67,399	69,257	71,057	72,983	74,654	76,584
22	Service interruptions and emergencies	7,110	8,975	8,675	8,675	8,675	8,675	8,675	8,675	8,675	8,675	8,675
23	Vegetation management	3,505	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560	3,560
24	Routine and corrective maintenance and inspection	14,215	13,150	13,125	12,775	12,730	12,545	12,545	12,545	12,495	12,495	12,495
25	Asset replacement and renewal	3,735	3,350	3,180	2,630	2,630	2,630	2,630	2,730	2,730	2,730	2,730
26	Network Opex	28,565	29,035	28,540	27,640	27,595	27,410	27,410	27,510	27,460	27,460	27,460
27	System operations and network support	17,141	18,354	18,213	17,950	17,950	17,957	17,950	17,950	17,957	17,873	17,873
28	Business support	16,025	15,455	15,327	15,086	15,015	15,032	15,129	15,103	15,204	15,181	15,264
29	Non-network opex	33,166	33,809	33,540	33,036	32,965	32,989	33,079	33,053	33,161	33,054	33,137
30	Operational expenditure	61,731	62,844	62,080	60,676	60,560	60,399	60,489	60,563	60,621	60,514	60,597
31	Subcomponents of operational expenditure (where known)											
32	Energy efficiency and DSM, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	1,322	1,654	1,686	1,719	1,753	1,787	1,822	1,857	1,893	1,930	1,968
37	**Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
41	Difference between nominal and real forecasts											
42	Service interruptions and emergencies	-	-	207	410	612	814	1,017	1,219	1,421	1,624	1,826
43	Vegetation management	-	-	85	168	251	334	417	500	583	666	749
44	Routine and corrective maintenance and inspection	-	-	314	603	898	1,178	1,470	1,763	2,047	2,338	2,563
45	Asset replacement and renewal	-	-	76	124	186	247	308	384	447	511	575
46	Network Opex	-	-	683	1,306	1,947	2,573	3,212	3,866	4,499	5,139	5,713
47	System operations and network support	-	-	775	1,307	1,882	2,456	3,060	3,638	4,299	4,901	5,569
48	Business support	-	-	568	1,008	1,488	1,971	2,496	2,990	3,564	4,100	4,705
49	Non-network opex	-	-	1,343	2,315	3,370	4,427	5,556	6,628	7,863	9,001	10,274
50	Operational expenditure	-	-	2,026	3,621	5,317	7,000	8,768	10,494	12,362	14,140	15,987

Schedule 12a: Report on asset condition

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

7 Asset condition at start of planning period (percentage of units by grade)

9	Voltage	Asset category	Asset class	Units	Grade 1 %	Grade 2 %	Grade 3 %	Grade 4 %	Grade unknown %	Data accuracy (1-4) %	% of asset to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	-	2%	8%	90%	-	3	0%
11	All	Overhead Line	Wood poles	No.	0%	6%	24%	70%	-	3	8%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	18%	82%	-	3	5%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	100%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	0%	100%	-	3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100%	-	3	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	12%	88%	-	3	1%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	16%	18%	66%	-	3	47%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	40%	60%	-	4	12%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	100%	-	4	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	17%	83%	-	4	5%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	0%	34%	66%	-	4	16%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	N/A	-

See Section 4.3 for explanation of condition grading methodology

Schedule 12a: Report on asset condition

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

36					Asset condition at start of planning period (percentage of units by grade)						
38	Voltage	Asset category	Asset class	Units	Grade 1 %	Grade 2 %	Grade 3 %	Grade 4 %	Grade unknown %	Data accuracy (1 -4)	% of asset to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	4	20	10	65	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	5	79	16	3	9
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	7	93	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	100	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	12	87	1	3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	2	98	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	34	51	15	4	19
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	-	19	81	-	4	18
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	37	63	-	4	18
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	18	82	-	4	3
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	8	92	-	3	5
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	15	85	-	3	10
53	HV	Distribution Transformer	Voltage regulators	No.	-	7	27	67	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	8	92	-	3	1
55	LV	LV Line	LV OH Conductor	km	-	-	1	99	-	3	-
56	LV	LV Cable	LV UG Cable	km	-	-	-	100	-	3	1
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	-	N/A	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	100	-	2	1
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	17	83	-	3	19
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	2	98	-	3	4
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100	-	2	-
62	All	Load Control	Centralised plant	Lot	-	-	-	100	-	2	5
63	All	Load Control	Relays	No.	-	-	-	100	-	2	-
64	All	Civils	Cable Tunnels	km	-	-	-	100	-	2	-

See Section 4.3 for explanation of condition grading methodology

Schedule 12b: Report on forecast capacity

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

7 ### 12b(i) System Growth - Zone Substations

8	Existing zone substations	Current peak load (MVA)	Installed firm capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)	Utilisation of installed firm capacity	Installed firm capacity +5 years (MVA)	Installed firm capacity +5 years %	Installed firm capacity constraint +5 years (cause)	Explanation
9	Addington 11kV #1	24	40	N-1	24	59%	40	48%	No constraint within +5 years	
10	Addington 11kV #2	13	34	N-1	13	37%	34	54%	No constraint within +5 years	
11	Armagh	12	40	N-1	12	29%	40	49%	No constraint within +5 years	Central City Rebuild expected to give large load increase over next few years
12	Barnett Park	8	15	N	8	56%	15	59%	No constraint within +5 years	Single 66kV line and 23MVA transformer backed up by 11kV but limited to 15MVA by
13	Bromley	31	60	N-1	31	52%	60	55%	No constraint within +5 years	
14	Dallington	27	40	N-1	27	66%	40	71%	No constraint within +5 years	
15	Fendalton	37	40	N-1	37	94%	40	95%	No constraint within +5 years	
16	Halswell	16	23	N-1	16	70%	23	94%	No constraint within +5 years	
17	Harewood	2	8	N-1	2	23%	8	23%	No constraint within +5 years	
18	Hawthornden	31	40	N-1	31	77%	40	79%	No constraint within +5 years	
19	Heathcote	23	40	N-1	23	57%	40	60%	No constraint within +5 years	
20	Hoon Hay	35	40	N-1	35	88%	40	90%	No constraint within +5 years	
21	Hornby	14	20	N-1	14	68%	20	76%	No constraint within +5 years	
22	Ilam	8	11	N-1	8	76%	11	77%	No constraint within +5 years	
23	Lancaster	19	40	N-1	19	46%	40	50%	No constraint within +5 years	
24	McFaddens	35	40	N-1	35	88%	40	93%	No constraint within +5 years	
25	Middleton	23	40	N-1	23	57%	40	61%	No constraint within +5 years	
26	Milton	34	40	N-1	34	84%	40	89%	No constraint within +5 years	
27	Moffett	12	23	N-1	12	54%	23	84%	No constraint within +5 years	
28	Oxford Tuam	14	40	N-1	14	34%	40	69%	No constraint within +5 years	Central City Rebuild expected to give large load increase over next few years
29	Papanui	41	48	N-1	41		48	106%	No constraint within +5 years	Resolve by transferring load to new Waimakariri zone substation when second
30	Prebbleton	5	15	N	5		15	37%	No constraint within +5 years	
31	Rawhiti	29	40	N-1	29		40	85%	No constraint within +5 years	
32	Shands	10	20	N-1	10		20	63%	No constraint within +5 years	
33	Sockburn	26	35	N-1	26		35	80%	No constraint within +5 years	
34	Waimakariri	16	15	N	16		40	44%	No constraint within +5 years	Second transformer to be installed FY19

Continued on next page...

Schedule 12b: Report on forecast capacity (cont)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

7 12b(i) System Growth - Zone Substations

8	Existing zone substations	Current peak load (MVA)	Installed firm capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)	Utilisation of installed firm capacity %	Installed firm capacity +5 years (MVA)	Installed firm capacity +5 years %	Installed firm capacity constraint +5 years (cause)	Explanation
35	Annat	1	-	N	1		-	-	No constraint within +5 years	
36	Bankside	6	-	N	4		-	-	No constraint within +5 years	
37	Brookside 66kV	8	-	N	6		-	-	No constraint within +5 years	
38	Darfield	6	-	N	4		-	-	No constraint within +5 years	
39	Diamond Harbour	2	-	N	2		-	-	No constraint within +5 years	
40	Dunsandel	12	10	N-1	8		23	63%	No constraint within +5 years	Transformer replacement increases capacity
41	Duvauchelle	5	8	N-1	5		8	62%	No constraint within +5 years	
42	Greendale	6	-	N	4		-	-	No constraint within +5 years	
43	Highfield	7	-	N	5		-	-	No constraint within +5 years	
44	Hills	6	-	N	4		-	-	No constraint within +5 years	
45	Hororata	7	-	N	5		-	-	No constraint within +5 years	
46	Killinchy	9	-	N	6		-	-	No constraint within +5 years	
47	Kimberley	14	23	N-1	10		23	69%	No constraint within +5 years	
48	Larcomb	10	23	N-1	7		23	58%	No constraint within +5 years	
49	Lincoln	9	10	N-1	6		10	108%	Transformer	Constraint to be resolved by transfers to Springston zone substation
50	Little River	1	-	N	1		-	-	No constraint within +5 years	
51	Motukarara	3	8	N-1	3		8	36%	No constraint within +5 years	
52	Rolleston	10	10	N-1	7		10	103%	Transformer	Constraint to be resolved by transfers to Weedons & Highfield
53	Springston	6	-	N	4		8	83%	No constraint within +5 years	Staged upgrade to 2 x 10MVA transformers (one ex Dunsandel)
54	Te Pirita	8	-	N	6		-	-	No constraint within +5 years	
55	Weedons	10	23	N-1	7		23	50%	No constraint within +5 years	

Schedule 12c: Report on forecast network demand

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

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

7 12c(i): Consumer Connections

			Number of connections					
8	*Number of ICPs connected in year by consumer type*							
9			*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		For year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
11	*Consumer types defined by EDB*							
12	Street lighting		10	25	25	25	25	25
13	General		4,071	3,940	3,540	3,340	3,240	2,240
14	Irrigation		12	20	20	20	20	20
15	Major customer		7	15	15	15	15	15
16	Large capacity		-	-	-	-	-	-
17	Connections total		4,100	4,000	3,600	3,400	3,300	3,300
18								
19	Distributed generation							
20	Number of connections		400	400	400	400	400	400
21	Installed connection capacity of distributed generation (MVA)		4	5	5	5	5	5

22 12c(ii): System Demand

				Current year	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		Maximum coincident system demand (MW)	For year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
25		GXP demand		605	629	641	652	657	662
26	*plus*	Distributed generation output at HV and above		3	3	3	3	3	3
27		Maximum coincident system demand		608	632	644	655	660	665
28	*less*	Net transfers to (from) other EDBs at HV and above							
29		Demand on system for supply to consumer's connection points		608	632	644	655	660	665
30		Electricity volumes carried (GWh)							
31		Electricity supplied from GXPs		3,327	3,360	3,394	3,428	3,462	3,497
32	*less*	Electricity exports to GXPs		-	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation		7	8	8	8	9	9
34	*less*	Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35		Electricity entering system for supply to ICPs		3,334	3,368	3,402	3,436	3,471	3,506
36	*less*	Total energy delivered to ICPs		3,093	3,189	3,222	3,255	3,289	3,324
37		Losses		241	179	180	181	182	182
38									
39		Load factor (%)		63%	61%	60%	60%	60%	60%
40		Loss ratio (%)		7.2%	5.3%	5.3%	5.3%	5.2%	5.2%

Schedule 12d: Report forecast interruptions and duration

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
9	For year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
10	**SAIDI**						
11	Class B (planned interruptions on the network)	15.5	15.5	15.5	15.5	15.5	15.5
12	Class C (unplanned interruptions on the network)	89.5	78.5	78.5	78.5	78.5	78.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.07	0.07	0.07	0.07	0.07	0.07
15	Class C (unplanned interruptions on the network)	1.23	1.13	1.13	1.13	1.13	1.13

Appendix A.13 - Report on asset management maturity

Note:

Schedule 13 is laid out with the questions and Orion's maturity level (Score) results on left hand page with the questions repeated on the facing page along with the detailed maturity level assessment criteria. See section 9.9.1 for information regarding the assessment process.

Schedule 13: Report on asset management maturity

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The Asset Management Policy, NW70.00.46, was updated and approved by the Board on 17 February 2016. The Asset Management Policy aims to consistently deliver a safe and cost-effective supply of electricity to Orion's customers by using good asset management practices.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	The updated Orion Asset Management Strategy has been finalised but not yet approved. The Asset Management Strategy aims to consistently deliver a safe and cost-effective supply of electricity to Orion's customers by using good asset management practices. Through the Asset Management Strategy, Orion are committed to regularly review processes and systems to ensure continual improvement.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Individual asset class technical strategies exist in the form of 22 Asset Management Reports (AMRs), there are also strategies around supersets of assets e.g. the development of the subtransmission network.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management.	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plans	How does the organisation establish and document its asset management plans across the life cycle activities of its assets and asset systems?	3	Orion's asset management work plan is documented in broad terms within the AMP. Detailed work plans are documented in the annual work plan and project/ program work package documents in NW70.01.17 Annual Work Plan. Asset management plan documents are made available to stakeholders as appropriate to their role within the asset management system, via publishing on a protected area of the Intranet. For low cost high volume items, the plan is expressed in terms of expenditure rather than volume.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimise costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
26	Asset management plans	How does the organisation establish and document its asset management plans across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
27	Asset management plans	How has the organisation communicated its plans to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The Asset Management Plan is published annually and made public on Orion's web site. The work plan is communicated initially in the AMP but it is developed further into a Gantt chart for the major capital projects and maintenance programs, in the form of a 4 page A3 Gantt chart in MS Project which is updated monthly. Contractors have read only access to the Gantt chart. The AMP process is sufficiently mature that stakeholders are aware of the availability of the AMP and may access as required. Detailed work plans are also communicated directly with contractors via the outsourcing process.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan (s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plans	How are designated responsibilities for delivery of asset plan actions documented?	3	Overall responsibility of delivery of the AMP is documented to reside with the Network Asset Manager. Asset management tasks are detailed through contract specifications clearly defining requirements for individual work packages. Responsibility for delivery of tasks by service providers is formalised through a commercial contract which is actively managed. This contracting process is documented in NW73.00.04, Contract Delivery Guide. A formal delegation of authority document exists and appears appropriate for execution of the AMP.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plans	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plans? (Note this is about resources and enabling support)	3	Delivery of the asset management work plan is achieved through outsourcing arrangements with service providers. Asset management planning actively considers contractor work levelling in the timing of projects. Publishing long term plans actively signals future workload to the contracting market. See also NW70.01.17 Annual Work Plan. Cost effectiveness is managed by using competitive tendering and ensuring that multiple viable providers are available for all material asset management tasks. Mutual aid agreement with other utilities for emergency response is included in contracts.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plans and procedures does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	4	Orion has a documented contingency planning process in place and this process has been shown to be effective as demonstrated by Orion's response to recent events such as storms, and historical earthquake events. Contingency planning includes participation in regional lifelines planning, policy defining emergency roles and responsibilities, and detailed contingency plans for major network scenarios. Orion has load flow contingency plans including switching sheets prepared for total loss of all zone substations. Orion has contingency plan for their resources including internal and external resources. There are multiple contingency planning documents in place for example NW20.40.02 Supply of Emergency Generators and NW20.40.03 Loss of Supply to the CBD, Zone Substations or Grid Exit Points.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
27	Asset management plans	How has the organisation communicated its plans to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan (s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
29	Asset management plans	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/ authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
31	Asset management plans	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plans? (Note this is about resources and enabling	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
33	Contingency planning	What plans and procedures does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
37	Structure, authority and responsibilities	What has the organisation done to appoint members of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plans?	3	The organisation is structured as an asset management organisation. Group roles are defined and overall accountability for the delivery of asset management outcomes rests with the Chief Operating Officer. Where applicable position descriptions include specific Asset Management responsibilities. There is also a matrix of responsibilities for the preparation of the Asset Management Plan.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/ objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	A management review process exists where achievement of asset management activities are routinely monitored and discussed at General Manager level. There is a process for establishing the need for additional FTE employees for internal resourcing, external resourcing is handled by Contractors. Resource levelling is managed by the availability of several external Contractors who can carry out the same type of work. External Contractors are also made aware of the future work program via consultation, the AMP, and workflow reporting so can manage their own resource requirements.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	An overarching Communications Plan is presently being developed. As a component of the Communications Plan extant subsidiary communications plans will be included e.g. the "Customer Engagement Framework" which outlines how Orion communicates with its Customers. A range of strategies are employed to communicate the importance of meeting asset management requirements. These range from (i) weekly management meetings attended by all asset management groups, (ii) regular group manager level meetings with service providers, and roadshow presentations to all Orion and service provider scheduled as required.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	All field delivered works are managed through an outsourcing arrangement with two principal service providers. Formal processes are in place to assure service provider capability and work quality. These align with NW73.00.04, Contract Delivery Guide. Control processes include formal project specifications and documentation, capability audits, process audits and practical completion inspections of works. A Project Manager is accountable for the control of compliant delivery of outsourced activities.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint members of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plans?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
48	Training, awareness and competence	How does the organisation develop plans for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, processes, objectives and plans?	3	Key competencies are documented in Job profiles and competence is assessed during bi annual performance reviews. Training requirements are identified during the performance review process. Orion has an ongoing programme to develop and place talented staff and external candidates into key positions in the business. Engineering trainees are gain work experience in the business, with a view to placement in areas where there are current or forecast skill shortages and/or succession opportunities. Trainees usually complete the programme in three years, and are then placed in permanent roles.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	As for question 48 above, core competencies are identified in the job design process and included in job profiles. Competency is regularly reviewed against the requirements of the job profile and training needs identified. Some competencies are held in the PowerOn application which ensures that critical tasks e.g. switching cannot be carried out by persons without the relevant training and competency.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organisation 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	Service provider training and competence requirements are controlled through contractual relationships with the service provider and are audited for compliance. Asset management skills and competencies are documented in job profiles and reviewed during the twice yearly performance review process. Compliance could be enhanced through the development of a formal skills and competence framework linked to process roles. There is a requirement that Contractors have product vendor training and certification for critical assets e.g. 400V, 11kV, 33kV and 66kV joint kit training and certification	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
48	Training, awareness and competence	How does the organisation develop plans for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, processes, objectives and plans?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan (s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
50	Training, awareness and competence	How does the organisation 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?	The organisation has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organisation is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Orion's small size has historically allowed a less formal communication strategy to be effective than would be necessary for large organisations. Orion acknowledge this and a over arching Communications Plan is presently being developed. Once it is in place it can be signed-off by top management and implemented to communicate the key asset management information with internal and external stakeholders.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Orion has in place the key elements of an asset management system and these are documented within the Asset Management Policy, Asset Management Strategy, Asset Management Plan, Asset Management Reports and Network standards framework.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process (es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information systems should contain in order to support its asset management system?	3	The 2017-2027AMP details all the information and systems required to support Orion's asset management system e.g. Figure 2-8a detailing the management systems and information flows. The main applications used by Orion to support asset management are also listed. There is an opportunity to develop a formal Asset Information Strategy separately from the AMP	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers.	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information systems and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Processes exist to verify the integrity of mission critical asset information such as network connectivity. Section 4 of the AMP records the types of asset data held for each asset class. Updated data generally comes from routine compliance inspections listed in the asset maintenance plans as well as specific inspections carried out as required for a particular asset class.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process (es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
62	Information management	What has the organisation done to determine what its asset management information systems should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
63	Information management	How does the organisation maintain its asset management information systems and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process (es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	The AMP describes the overall information architecture and demonstrates alignment with the asset management information needs of the business. Asset data users confirm that data is relevant to their needs. A change advisory board periodically evaluates system capability and user needs, and implements changes as required.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management processes	How has the organisation documented processes and/ or procedures for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Section 6 of the AMP details the overall approach to risk, systems utilised, documents and risk management plans. Orion has a number of separate initiatives for the management of risk across the various lifecycle phases. Examples of sub systems include, Vault, CBRM, Public Safety Management System, ICAM and others. While general strategies are documented in the AMP, the formal integration of the various risk management initiatives into an overarching risk management system is not fully complete.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	While there is evidence that risks are being identified, and mitigated, there is not evidence that mitigating actions are being comprehensively linked to resourcing, competencies and training plans. There is an opportunity to use the capabilities available in a) Vault and b) PowerOn to assist with the resource management forecasts and competency & training requirements.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	4	Orion has commissioned a compliance manual outlining the companys legal compliance obligations. This manual is reviewed annually with company lawyers monitoring relevant legislation and regulation for change. Senior managers are required to review and sign a declaration to ensure that obligations pertinent to their area of operations are met. Any potential non-compliances are noted and managed.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
69	Risk management processes	How has the organisation documented processes and/or procedures for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
88	Life Cycle Activities	How does the organisation establish implement and maintain processes for the implementation of its asset management plans and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Orion has a comprehensive suite of standards and specifications covering all aspects of the asset lifecycle. The process of contracting out the works program is well documented. There are design processes and standards for a majority of the work required at the power distribution level. The activities around the creation, acquisition or enhancement of major asset classes are detailed in 22 Asset Management Reports. Some processes and workflows are not formally documented but these are typically around one off designs or projects where it is difficult or not economic to implement standard workflows.	Life cycle activities are about the implementation of asset management plan (s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement.	Orion has a comprehensive suite of standards and specifications covering all aspects of the asset lifecycle. The process of contracting out the works program is well documented. There are design processes and standards for a majority of the work required at the power distribution level. The activities around the creation, acquisition or enhancement of major asset classes are detailed in 22 Asset Management Reports. Some processes and workflows are not formally documented but these are typically around one off designs or projects where it is difficult or not economic to implement standard workflows.
91	Life Cycle Activities	How does the organisation ensure that processes and/or procedures for the implementation of asset management plans and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with AM strategy and control cost, risk and	3	Orion's outsourcing processes ensure that only pre-qualified service providers may construct, operate and maintain Orion assets. Contract specifications and standards clearly define the scope of work and place requirements on contractor competency and training. An audit process checks for compliance in terms of contractor capability, work process and finished product. Orion asset management staff or approved auditors witness key operations to ensure compliance with standards.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business.	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	Orion has identified a suite of service levels and associated performance measures. These service levels, associated measures and targets are documented in the AMP. Orion has implemented a comprehensive methodology Condition Based Risk Management (CBRM) for using asset condition and performance information to evaluate asset health and risk. The methodology has been consistently applied to all key asset classes and is being continually improved. Included in the AMP is this AMMAT review which is externally reviewed on an annual basis.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3.5	Orion has a robust system in place for recording customer outage information and collating network performance statistics. Network outages are routinely reviewed. Minor failures are monitored at a statistical level, with action being taken if frequency increases abnormally, major failures and incidents are investigated on a case by case basis. Procedures for emergency response and repair are clear, with this process being initiated from the control room. A process is in place for investigating equipment failures and nonconformities and recommending actions this includes the formalised ICAM Process. Actions are implemented through normal management channels.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to customers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain processes for the implementation of its asset management plans and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/ incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure (s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
91	Life Cycle Activities	How does the organisation ensure that processes and/or procedures for the implementation of asset management plans 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?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/ or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Score	Evidence-Summary	Why	Who	Documented info
105	Audit	What has the organisation done to establish procedures for the audit of its asset management system (processes)?	3	As Orion does not have a formally certified PAS-55 asset management system there is no requirement for formal periodic audits. However Orion does take actions to periodically review its overall asset management system and capability. The AMMAT process is one of the components of auditing Orion's Asset Management performance and maturity. In this AMMAT review the independence of the process has been further clarified by changing the independent contractor from the one used in previous years.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Non conformances or issues are actively managed through normal business activities, roles and responsibilities and the subcontractor management process. Orion could potentially benefit from the implementation of a non conformance register, possibly linked or associated with the corporate risk register. The outage report process has been formalised and effectively investigating significant network outages and equipment failure events. Where the ICAM process is used to investigate a non conformance it will recommend corrective and preventative actions.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	Continual improvement is documented as integral to the asset management strategy, and in practice this is achieved through numerous initiatives: The 22 Asset Management Reports, the 11kV Network Architecture Review, Improvements to the Condition Based Risk Management (CBRM) system , the Asset Management system development plan, the incident Cause Analysis Method (ICAM) which not only analyses the root cause of asset related incidents but proposes changes that can be adopted to mitigate any failures or incidents.	Widely used AM standards have requirements to establish, implement and maintain process(es)/ procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Orion obtains information for improvements from a range of sources. External sources of information include: - equipment suppliers - consultants - domestic and international conferences - Participation in industry groups and conferences reviewing the introduction and impact of new technologies and practices e.g. The Electricity Engineers' Association (EEA) Asset Management Group and Safety Standards and Procedures Group The New Zealand Electricity Networks Association (ENA) Smart Technologies Working Group (STWG) and Regulatory Working Group. The Electricity Authority (EA)	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 13: Report on asset management maturity (cont.)

Company name: Orion NZ Ltd.
AMP Planning period: 1 April 2018 - 31 March 2028
AM standard applied: PAS-55

No.	Function	Question	Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
105	Audit	What has the organisation done to establish procedures for the audit of its asset management system (processes)?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognised for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Appendix A.14a - Mandatory explanatory notes on forecast information

COMPANY NAME	ORION NEW ZEALAND LIMITED
FOR YEAR ENDED	31 MARCH 2018

Schedule 14a Mandatory explanatory notes on forecast information

Box 1: Comment on the difference between nominal and constant price capital expenditure forecasts

In our AMP we have disclosed our:

- constant price (real) opex and capex forecasts
- nominal opex and capex forecasts for the ten years FY19 to FY28 inclusive.

In escalating our real forecasts to nominal forecasts, we have:

- split our forecast opex and capex into a number of groups
- forecast an escalation index for each group that represents a reasonable proxy for forecast movements in unit costs for each group
- applied the forecast escalation indices for the ten-year forecast period.

We applied forecast opex and capex escalators as follows:

- network labour – NZIER labour index forecasts to FY21, extrapolated by PWC to FY28
- non-network labour – Management's forecast to FY28
- other – NZIER producer price index (PPI) forecasts to FY21, extrapolated by PWC to FY28.

Box 2: Comment on the difference between nominal and constant price operational expenditure forecasts

- Please refer to Box 1 above.

Appendix B - Cross reference table

As our AMP has been structured as a practical planning tool, it does not strictly follow the order laid out in the Electricity Distribution Information Disclosure Determination 2012. We have prepared the cross reference table below to help you find specific sections.

Sections as per the Electricity Distribution Information Disclosure Determination 2012	Orion AMP
1. Summary of the plan	1. Summary
2. Background and objectives	2. Business context 6. Business support
3. Assets covered	4. Lifecycle asset management
4. Service levels	3. Service levels
5. Network development plans	5. Network development
6. Lifecycle asset management planning (maintenance and renewal)	4. Lifecycle asset management
7. Risk management	7. Risk management
8. Evaluation of performance	9. Evaluation of performance

Appendix C - Glossary of terms

ABI: **A**ir **B**reak **I**solator, a pole mounted isolation switch. Usually manually operated.

Alpine Fault: is a geological fault, specifically a right-lateral strike-slip fault, that runs almost the entire length of New Zealand's South Island. It has an average interval for a major earthquake at every 290 years, plus or minus 23 years. The last major Alpine Fault earthquake occurred in 1717. The longest known major Alpine Fault earthquake return rate is believed to be around 350 years and the shortest around 160 years.

Alternating current (AC): a flow of electricity which reaches maximum in one direction, decreases to zero, then reverses itself and reaches maximum in the opposite direction. The cycle is repeated continuously.

Ampere (A): unit of electrical current flow, or rate of flow of electrons.

Bushing: an electrical component that insulates a high voltage conductor passing through a metal enclosure.

Capacity utilisation: a ratio which measures the utilisation of transformers in the network. Calculated as the maximum demand experienced on an electricity network in a year, divided by the transformer capacity on that network.

Capacitance: is the ability of a body to store an electrical charge.

CBRM (condition based risk management): CBRM is a modelling programme which combines asset information, observations of condition and engineering knowledge and experience to produce a measure of asset health, the CBRM Health Index. The model also produces forecasts of asset probability of failure, and a measure of asset related risk in future years which can be used for developing optimised asset renewal plans.

Circuit breaker (CB): a device which detects excessive power demands in a circuit and cuts off power when they occur. Nearly all of these excessive demands are caused by a fault on the network. In the urban network, where most of these CBs are, they do not attempt a reclose after a fault as line circuit breakers may do on the rural overhead network.

Continuous rating: the constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely effecting it characteristics.

Conductor: is the 'wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.

CPP: the Commerce Act (Orion New Zealand Limited **C**ustomised **P**rice-Quality **P**ath Determination 2013) in effect for FY15 to FY19. This determination applies to Orion, and replaces all terms of the Orion DPP Determination as they apply to Orion.

Current: the movement of electricity through a conductor, measured in amperes (A).

Customers: in this context (page 36) we are referring to customers in the broadest sense, this includes community, customers and retailers (see 2.6 Stakeholder interests).

Customer Demand Management: shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the network operator.

DIN: **D**eutsches **I**nstitut für **N**ormung (the German Institute for Standardisation). Equipment manufactured to these standards is often called 'DIN Equipment'.

Distributed/embedded generation (DG): a privately owned generating station connected to our network.

Distribution substation: is either a building, a kiosk, an outdoor substation or pole substation taking its supply at 11kV and distributing at 400V (see sections 4.4.3 and 4.26).

Dog: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 103mm^2.

DPP: The Commerce Act (Electricity Distribution **D**efault **P**rice-quality **P**ath) Determination

EA Technology Ltd: is an international consultancy based in the UK. They were appointed as peer reviewers to the Auckland CBD cable failure ministerial enquiry and subsequently engaged by us to review our 66kV cable network.

Fault current: the current from the connected power system that flows in a short circuit caused by a fault.

Feeder: a physical grouping of conductors that originate from a zone substation circuit breaker.

Flashover: a disruptive discharge around or over the surface of an insulator.

Flounder: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 20mm^2. The cores are shaped to give the conductor a smooth surface that offers less resistance to wind and snow.

Frequency: on alternating current circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)

Fuse: a device that will heat up, melt and electrically open the circuit after a period of prolonged abnormally high current flow.

Gradient, voltage: the voltage drop, or electrical difference, between two given points.

Grid exit point (GXP): a point where Orion's network is connected to Transpower's transmission network.

Harmonics (wave form distortion): changes an ac voltage waveform from sinusoidal to complex and can be caused by network equipment and equipment owned by customers including electric motors or computer equipment.

High voltage (HV): voltage exceeding 1,000 volts (1kV), in Orion's case generally 11kV, 33kV or 66kV.

ICP: installation control point, a uniquely numbered point on our network where a customer(s) is connected.

Inductance: is the property of a conductor by which current flowing through it creates a voltage (electromotive force) in both the conductor itself (self-inductance) and in any nearby conductors.

Insulator: supports live conductors and is made from material which does not allow electricity to flow through it.

Interrupted N-1: a network is said to have 'Interrupted N-1' security or capability if following the failure of 'one' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

Interrupted N-2: a network is said to have 'Interrupted N-2' security or capability if following the failure of 'two' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

ISO 55000: International Standards for Asset Management.

Jaguar: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 207mm^2.

kVA: the kVA, or Kilovolt-ampere, output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.

Legacy assets: assets installed to meet appropriate standards of the time, but are not compliant with current day safety standards.

Lifelines groups: local collaborations between lifeline utilities. They aim to reduce infrastructure outages, especially if HILP events occur. It was this collaboration that lead us to invest to strengthen our key substations before the Canterbury earthquakes. For more information see http://www.civildefence.govt.nz/cdem-sector/lifeline-utilities/lifelines-groups/

Lifelines project: an engineering study into the effects of a natural disaster on Christchurch city undertaken in the mid 1990s. (see section 6.6 - natural disaster)

Line circuit breaker (LCB): a circuit breaker mounted on an overhead line pole which quickly cuts off power after a fault so no permanent damage is caused to any equipment. It switches power back on after a few seconds and, if the cause of the fault has gone, (e.g. a branch has blown off a line) then the power will stay on. If the offending item still exists then power will be cut again. This can happen up to three times before power will stay off until the fault is repaired. Sometimes an LCB is known as a 'recloser'.

Low voltage (LV): a voltage not exceeding 1,000 volts, generally 230 or 400 volts.

Maximum demand: the maximum demand for electricity, at any one time, during the course of a year.

Mink: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of 62mm^2.

MOCHED: major outage causing huge economic damage.

N: a network is said to have 'N' security or capability if the network cannot deliver electricity after the failure of 'one' overhead line, cable or transformer.

N-1: a network is said to have 'N-1' security or capability if the network continues to deliver electricity after the failure of 'one' overhead line, cable or transformer.

N-2: a network is said to have 'N-2' security or capability if the network continues to deliver electricity after the failure of 'two' overhead lines, cables or transformers.

Namu: an aerial aluminium conductor (AAC) with a cross sectional area of 25mm^2.

Network deliveries: total energy supplied to our network through Transpower's grid exit points, usually measured as energy supplied over the course of a year.

Network substations: are part of Orion's primary 11kV network all within the Christchurch urban area.

Ohm: a measure of the opposition to electrical flow, measured in ohms.

ORDC: optimised depreciated replacement cost, prepared in accordance with New Zealand International Financial Reporting Standards (NZ IFRS) under International Accounting Standard NZ IAS 16 - Property, Plant and Equipment as at 31 March 2007

Outage: an interruption to electricity supply.

PCB: Polychlorinated biphenyls (PCBs) were used as dielectric fluids in transformers and capacitors, coolants, lubricants, stabilising additives in flexible PVC coatings of electrical wiring and electronic components. PCB production was banned in the 1970s due to the high toxicity of most PCB congeners and mixtures. PCBs are classified as persistent organic pollutants which bio-accumulate in animals.

Proven voltage complaint: a complaint from a customer concerning a disturbance to the voltage of their supply which has proven to be caused by the network company.

Rango: an aerial aluminium conductor (AAC) with a cross sectional area of $50mm^2$.

Ripple control system: a system used to control the electrical load on the network by, for example, switching domestic water heaters, or by signaling large users of a high price period. Also used to control streetlights.

RTU: **R**emote **T**erminal **U**nit. Part of the SCADA system usually installed at the remote substation.

SAIDI: **S**ystem **A**verage **I**nterruption **D**uration **I**ndex; an international index which measures the average duration of interruptions to supply that a customer experiences in a given period.

SAIFI: **S**ystem **A**verage **I**nterruption **F**requency **I**ndex; an international index which measures the average number of interruptions that a customer experiences in a given period.

SCADA: **S**ystem **C**ontrol **A**nd **D**ata **A**cquisition. See section 4.22.

Sparrow: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of $34mm^2$.

Squirrel: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of $20mm^2$.

Transformer: a device that changes voltage up to a higher voltage or down to a lower voltage.

Transpower: the state owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to grid exit points (GXPs) on distribution networks throughout the country.

Voltage: electric pressure; the force which causes current to flow through an electrical conductor.

Voltage drop: is the reduction in voltage in an electrical circuit between the source and load.

Voltage regulator: an electrical device that keeps the voltage at which electricity is supplied to customers at a constant level, regardless of load fluctuations.

Weke: an aerial aluminium conductor (AAC) with a cross sectional area of $100mm^2$.

Wolf: an aerial aluminium conductor with steel reinforcing (ACSR) and a cross sectional area of $155mm^2$.

XLPE cable: cross linked polyethylene insulated cable.

Zone substation: a major substation where either; voltage is transformed from 66 or 33kV to 11kV, two or more incoming 11kV feeders are redistributed or a ripple injection plant is installed.

Appendix D - Schedule 17

Certificate for Year-beginning Disclosures

We, **Nicholas Miller** and **Bruce Gemmell**, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:-

a) the following attached information of Orion New Zealand Limited prepared for the purposes of clauses 2.6.1 and 2.6.6 of the Electricity Distribution Disclosure Determination 2012 in all material respects complies with that determination.

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

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

Director

Director

Date 26th March 2018

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