Investing for your energy future

POWERCO

ELECTRICITY ASSET MANAGEMENT PLAN 2017

Supporting our Customised Price-Quality Path application

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Introduction

This section introduces our 2017 electricity AMP and provides an overview of our network.

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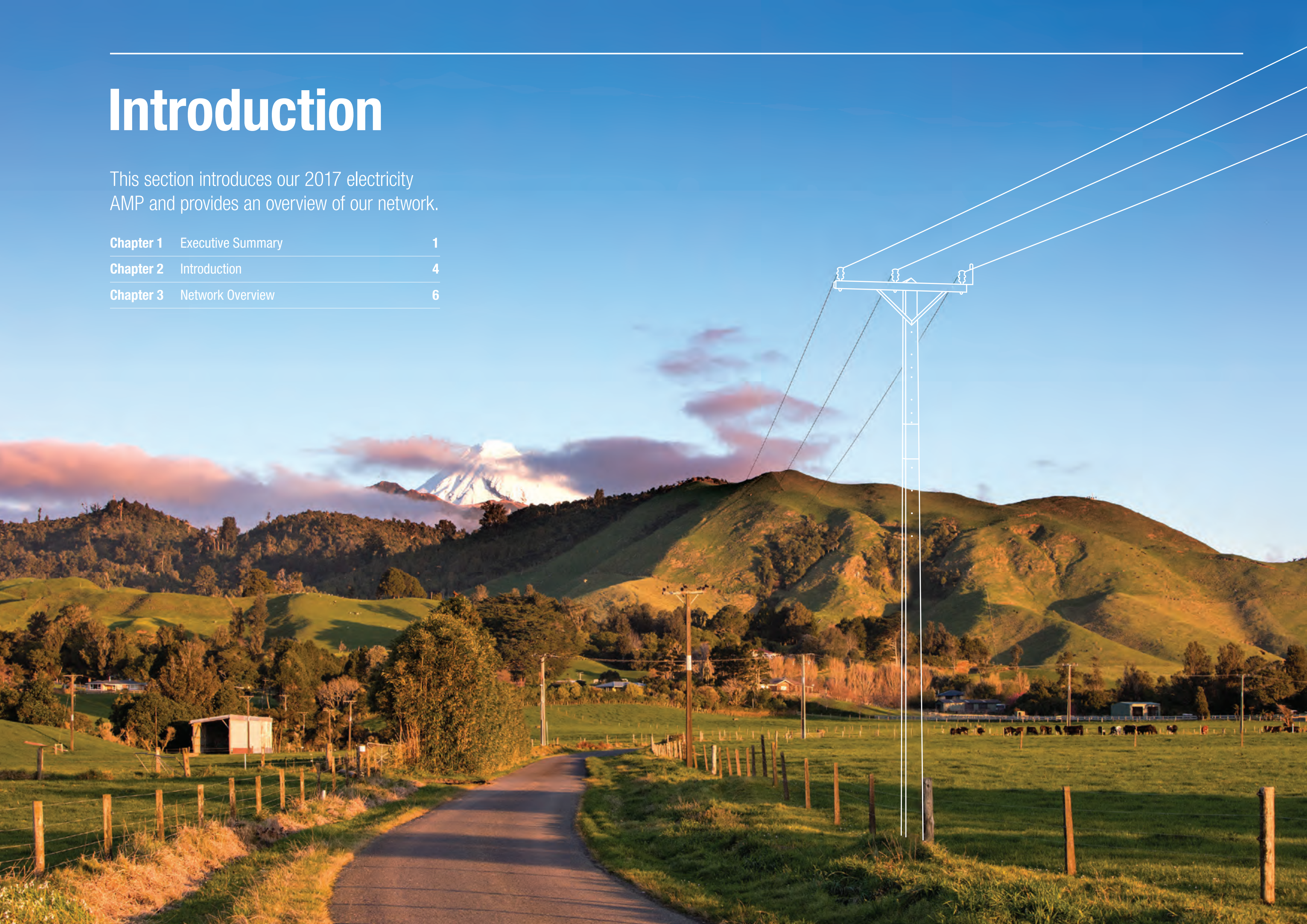


1 EXECUTIVE SUMMARY

1.1 INTRODUCING OUR 2017 ASSET MANAGEMENT PLAN

This Asset Management Plan (AMP) outlines our approach to managing our electricity distribution assets over the period 1 April 2017 to 31 March 2027. It is an essential part of our long-term asset planning and investment framework.

Consistent with our prior AMPs, the 2017 edition sets out the investments we plan to make in order to uphold our vision of being a reliable partner, delivering New Zealand's energy future. We are committed to ensuring our existing network assets are fit for purpose, tailored to meet the future needs of our customers and deliver a reliable and secure service.

The 2017 Edition of our AMP differs in one critical aspect from prior editions: this edition forms part of a Customised Price-quality Path (CPP) application for submission to our sector regulator, the Commerce Commission. The CPP presents our investment plans for the period 1 April 2018 to 31 March 2023 for approval by the Commission.

1.2 A KEY ELEMENT OF OUR CUSTOMISED PRICE-QUALITY PATH APPLICATION

The investments set out in this AMP and CPP application will enable us to undertake prudent investment in our electricity networks so that we can continue to meet our customers' service expectations and support the growth of the communities we serve.

This AMP forms part of our CPP application, which covers investments over the period 1 April 2018 to 31 March 2023, a subset of the investment period covered by this AMP. The content of this AMP and the technical rational that underpins it are entirley consistent with our CPP application.

Our application, and the underlying rationale for our investment plan, has been challenged by independent technical experts, working on behalf of the Commerce Commission. These independent experts have considered the proposed investments to ensure it is prudent. The Commerce Commission set the scope of these reviews and will apply further scrutiny doing the course of 2017.

It should be noted that this Asset Management Plan, while supporting the CPP application process, is a living document that forms an integral part of our day-to-day business and asset management planning processes.

1.3 THE NEED FOR INCREASED INVESTMENT

1.3.1 OVERVIEW

We have reached a point where increased investment is an imperative.

Electricity is a key enabler for economic prosperity and a modern lifestyle. Our core business is to ensure that it is delivered to our customers safely, reliably and efficiently. As such it is essential that we invest in our assets to ensure they are in appropriate condition and of sufficient capacity to meet the needs of our customers in the longer term.

Over the past five years, working within our regulatory price constraints, we have lifted investment by almost 60% in response to the aging of our asset fleets and economic growth in our communities. However, even at this increased level - which exceeds our current regulatory allowance - there is mounting pressure for a further step increase for the following reasons:

- The performance of our assets is degrading as measured across a range of leading indicators, most notably condition and health
- The regions we support have been growing, stretching our network security and putting higher than desirable levels of load at risk
- New technologies are emerging which will place new demands on our networks and will require us to operate in new ways.

Looking forward, we are forecasting increases in the number of assets that are approaching end-of-life, further growth in the communities we serve, and increased complexity assocated with new energy solutions. It is important we take active steps via increased investment to stay ahead of these trends.

If we were to fail to respond, our network performance would continue to deteriorate until we could no longer ensure the safety and reliability expected from a prudent network operator, and we would be unable to meet the needs of our customers.

We explore these trends further in the following sections.

1.3.2 ENSURING SAFE AND RESILIENT NETWORKS

Our networks play a critical role for the customers and communities we serve. It is therefore important that we invest prudently to ensure our assets are safe, secure and resilient in the longer term. This involves carefully managing the condition of our asset fleets with the aim of stabilising condition and managing performance.

As discussed above, in recent years we have seen clear and material degradation of key network measures with the following trends of particular concern:

- In-service asset failures increasing over time for key asset fleets
- Increasing numbers of end-of-life assets remaining in service
- A poor, and deteriorating, reliability position versus our peers
- Pockets of network performance well outside our internal targets
- High levels of defective assets and vegetation encroachment.

Arresting these trends requires strong and focused investment to stabilise the underlying condition of our network, arrest the rate at which assets are failing in service and to establish a proactive vegetation and maintenance approach.

We set out our plans to deliver safe, secure and resilient networks in Chapters 14 to 21 of this AMP.

1.3.3 SUPPORTING GROWTH IN OUR COMMUNITIES

As an energy distribution company, we have a critical role to play in supporting sustained economic growth in the regions we serve. We do this by providing secure, economic and resilient links to central generation, and increasingly in supporting local generation options such as photovoltaic cells.

Our regions have been experiencing sustained population and economic growth in recent years and as a result we have experienced strong demand growth across on parts of our networks. Some of the drivers for this growth include the following:

- Bay of Plenty – population growth and horticulture processing volumes
- Waikato – continued dairy intensification and a shift to snap chilling
- Taranaki – population growth and dairy intensification
- Other regions – population growth

As a result of this growth, there are now a large number of locations where we have no practical way of rerouting supply in the event of a key asset failing, and where the cost of such a failure is now unacceptably high for our customers. The number of high-load, at-risk scenarios on our networks is higher than we consider appropriate and strong, focused action is necessary.

We set our plans to support growth in our communities in Chapter 11 of this AMP.

1.3.4 ENABLING OUR CUSTOMERS ENERGY CHOICES

New technology offerings, combined with increasing consumer willingness to take control of their energy options, are leading to a change in the way energy markets operate.

New technologies are emerging which we believe will see increased application over time as prices reduce, as suitable applications emerge in the New Zealand context, and as they become better understood by our customers. The most promising emerging technologies include:

- Electric vehicles (EVs)
- Photovoltaic cells (PVs)
- Home battery storage solutions
- Advanced home energy management solutions

Such new solutions will bring benefits to our customers but they will also increase complexity for distribution network operators. Issues such as local voltage fluctuations, two-way energy flows and increased load volatility will need to be anticipated and addressed. It is important that we take action now to understand these new technologies and ensure that we can accommodate them on our networks.

The investment plans set out in this AMP include a range of technology proof-of-concept trials to understand the impact of new customer solutions, and to find ways to cost-effectively accommodate them. Overseas studies have shown that taking action early to understand and plan for technology change creates material savings later by avoiding a reactive approach to technology integration.

We set our plans to enable our customers' energy choices in Chapter 13 of this AMP.

1.4 AN APPROACH UNDERPINNED BY STRONG ASSET MANAGEMENT

We are recognised as a leading asset manager. That recognition has been earned via a track record of strong results.

Our costs and performance compare well against the best utilities in New Zealand and Australia. We are proud of this strong position and the way we manage our assets to provide a cost-effective service to our customers. But there is more to be done. The challenges of aging network, security exposures and increasing energy market complexity necessitate an even more mature asset management approach.

Over the past few years, we have invested heavily to improve our asset management maturity and approach. We have made good progress, and the analysis set out in this AMP and which underpins our CPP submission, are examples of the advances we have made. Our asset management analysis and supporting models are amongst the very best examples in New Zealand.

Looking forward, we are committed to further developing our overall asset management capability to meet internationally-accepted best practice standards. The investments in capability and systems outlined in this AMP are important enablers of that goal. We have set ourselves an ambitious goal to be fully compliant with the internationally recognised asset management standard, ISO 55000, by 2020.

We set out our asset management process including recent enhancements in Chapters 5 to 10 of this AMP.

1.5 10 YEAR EXPENDITURE FORECASTS

We currently forecast that we will need to lift investment levels over the planning period from a base of about $200m per annum in 2017 to a peak of $275 per annum by 2021, before returning to $230m per annum by 2027. This is a significant increase, but one that is necessary to deliver stable network condition and appropriate performance for the long term.

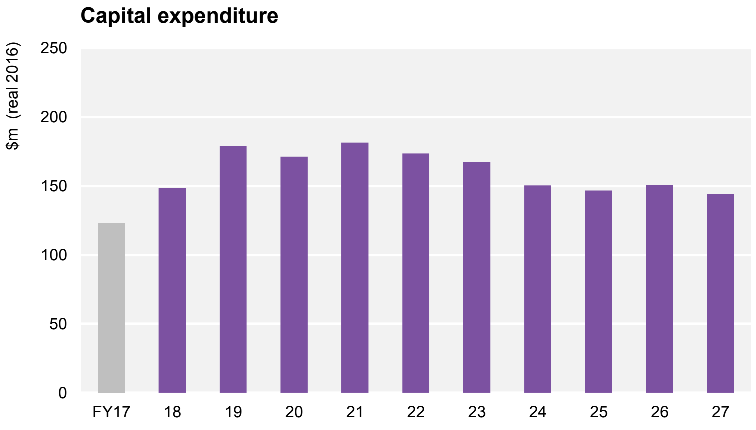
The investments we propose will enable us to undertake prudent investment in our electricity networks to address asset condition and security related issues. It will also help ensure we continue to meet our customers' service expectations and support the growth of the communities we serve.

1.5.1 CAPITAL EXPENDITURE

Our planned capital investments for the 2017-2027 period are set out in detail in Chapters 11 to 22 of this AMP. They reflect a targeted blend of investment across growth and security, asset renewal and non-network categories. Key increases over and above historical levels include the following:

- Increased investment in asset renewals: Asset renewal is forecast to significantly increase over historical levels. This reflects the large proportion of assets constructed from the late 1950s through to the 1970s which are now reaching end-of-life. The main asset classes affected are overhead conductors, overhead structures and zone substations.
- Increased investment in growth and security: Network growth investment is increasing predominantly to reduce the excessive load currently at risk, and also to provide the capacity required to service growing communities in parts of our network area. Customer connection numbers are increasing, along with associated costs to reinforce supplies.
- Increased investment in core systems and network technology: We intend to implement a new ERP system and increase our expenditure on SCADA, communications and remote monitoring early in the CPP period. We will also execute our network evolution plan to allow research and development and testing of new and innovative network and non-network solutions.

Our expected capital investment over the planning period is set out below.

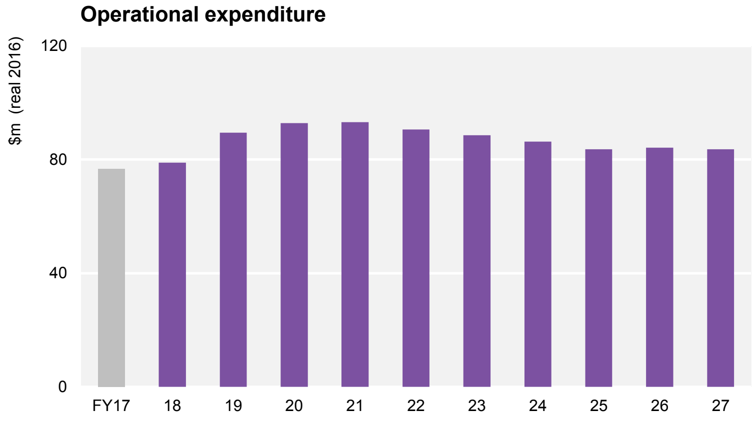


1.5.2 OPERATIONAL EXPENDITURE

The focus for operational expenditure over the planning period is set out in detail in Chapter 23 of this AMP. Key increases over and above historical levels include the following:

- Addressing maintenance defects: The backlog of outstanding maintenance defects has been growing at an alarming rate. We intend to bring this under control and reduce the size of the pool to appropriate levels during the CPP period.
- Improved inspection techniques: New techniques will be implemented to better understand actual asset condition and network risks. Data and information management practices will be enhanced.
- Enhanced vegetation management: We plan to bring our vegetation management up to good industry practice by adopting a cyclical inspection regime, and risk-based assessment of out-of-zone trees.
- Asset Management Maturity: We are proposing substantial improvements in the way we practise asset management to reflect industry good practice and to realise improved efficiencies in the future. To achieve this, we intend to bolster our internal capabilities and skills. As part of our asset management improvements we intend to achieve ISO 55000 certification by 2020.
- Enhanced Capacity: Our project delivery capacity will be increased in proportion to the uplift in construction and maintenance work proposed under the CPP. While mostly capitalised, some additional Opex will be required. Allowance is made for additional business support staff to support the increased business complexity and demands anticipated with enhanced IS systems and increased work volumes.

Our expected operational expenditure over the planning period is set out below.



2 INTRODUCTION

2.1 CHAPTER OVERVIEW

This chapter provides the context for our 2017 AMP. It outlines its purpose and objectives, for whom it is written and how it is structured.

2.2 PURPOSE OF THE 2017 AMP

We recognise that the investment decisions we make impact homes and businesses around New Zealand, now and in the future. It is therefore important that these decisions are transparent and understandable to our customers and other stakeholders.

Our 2017 AMP describes our long-term strategy for managing our electricity assets. It describes the asset management processes we use and explains how these will help, over the coming years, to achieve our asset management objectives and meet stakeholder expectations.

The AMP sets out the planned investments in our electricity network in the coming 10 years. It explains how we will develop our network, renew our asset fleets and undertake maintenance to provide a safe, reliable and valued service to customers.

2.2.1 AMP OBJECTIVES

The objectives of our 2017 AMP are to:

- Be transparent with our stakeholders, particularly on our planned investments
- Help stakeholders understand our asset management approach by providing clear descriptions of our assets, key strategies and objectives
- Discuss how we will respond to changes in electricity distribution
- Explain our asset management objectives and targets, and how we plan to achieve them
- Set out our recent asset management improvements
- Explain how our asset management plans relate to our corporate mission and vision, and business planning processes
- Explain the asset management challenges we face and why we have applied for a CPP.

2.2.2 AMP PLANNING PERIOD

Our AMP covers a 10-year planning period, from 1 April 2017 to 31 March 2027. Consistent with Information Disclosure requirements, a greater level of detail is provided for the first five years of this period.

This AMP was certified and approved by our Board of Directors on 12 June 2017.

2.3 OVERVIEW OF POWERCO

We operate and maintain the largest network of electricity lines in New Zealand over the largest area of the country, serving about 330,000 connected customers. We are the second largest distributor in New Zealand in terms of number of customer connections.

Our over 27,000km of cables and overhead lines supply customers in Tauranga, Thames Valley, Coromandel, Eastern and Southern Waikato, Taranaki, Whanganui, Rangitikei, Manawatu and Wairarapa.

We are a privately owned utility with two institutional shareholders.[1]

2.4 OUR STAKEHOLDERS

As set out above, the main objective of our AMP is to provide information to our stakeholders about how we are managing the assets they have entrusted to us. We aim to provide enough detail to explain how our plans and decisions arise and are implemented. We aim to make it a document our stakeholders can readily follow and digest. Our key stakeholders and their principal interests are summarised below.

Table 2.1: Key stakeholders and their main interests

STAKEHOLDER	MAIN INTERESTS
Our customers	Service quality and reliability; price; safety; connection agreements
Communities, iwi, landowners	Public safety; environment; land access and respect for traditional lands
Retailers	Business processes; price; customer service
Commerce Commission	Pricing levels; effective governance; quality standards
State bodies and regulators	Safety (Worksafe); market operation and access (EA); environmental performance (ME)
Employees and contractors	Safe, productive work environment; remuneration; training and development; asset management documentation
Transpower	Technical performance; technical compliance; GXP planning
Our investors	Efficient management; financial performance; governance; risk management

Further detail on how we meet stakeholders' interests including how they are identified and accommodated in our processes can be found in Appendix 3.

[1] Queensland Investment Corporation (58%) and AMP Capital (42%).

2.5 STRUCTURE OF THE AMP

Reflecting our ongoing asset management improvement programme, this 2017 AMP builds upon our 2016 AMP, which was significantly revised and expanded from previous versions. In particular we offer a significant amount of detail about our investment plans which are consistent with our application to the Commerce Commission for a Customised Price Path during 2017.

The diagram below sets out the structure of the 2017 AMP, including the sections (grey boxes) and the chapters within these. Appendix 14 maps the chapters and appendices to relevant Information Disclosure requirements.

AMP section *AMP chapter*

INTRODUCTION
This section introduces our 2017 electricity AMP and provides an overview of our network.

1 Executive Summary
Provides context to stakeholders on key factors that influence our investments over the planning period.

2 Introduction
Explains the purpose of the AMP and provides an overview of our business, our main stakeholders, and the structure of the AMP.

3 Network Overview
Describes our electricity network and its assets.

SERVING OUR CUSTOMERS
This section explains how we plan to meet our customers' needs, now and in the future.

4 Customer Strategy
Provides an overview of our customers, what they value, and our strategy to ensure we continue to meet their evolving needs.

MANAGING OUR ASSETS
This section sets out our asset management strategy and network targets, explains our approach to investment decision-making, and describes how we are preparing for an increase in investment during the planning period.

5 Asset Management Strategy
Explains our asset management philosophy, and the line of sight from our overall company objectives through to our day-to-day activities.

6 Asset Management Framework – Governance
Explains our approach to asset management decision-making (including expenditure governance), investment planning, project delivery and risk management.

7 Asset Management Framework – Capital Project Planning and Delivery
Explains our approach to capital project development, planning and delivery.

8 Asset Management Framework – Operations & Maintenance Planning and Delivery
Explains our approach to operations and maintenance planning and delivery.

9 Network Targets
Outlines our targets for safety, reliability, asset performance and customer service.

10 Enhancing Delivery Capability
Describes how we are going to deliver the plan.

NETWORK DEVELOPMENT
This section explains how we plan to develop our network, how we use automation to enhance reliability, and how we will ensure the network's readiness for the future.

11 Growth and Security
Outlines our approach to forecasting demand growth and how we invest to ensure supply security. It provides a summary of our area plans.

12 Reliability
Explains what we are planning to invest in automation systems to enhance network reliability performance.

13 Network Evolution
Sets out our plans to develop our network in a way that will enable our customers to access new energy options as energy markets evolve and mature.

FLEET MANAGEMENT
This section explains our approach to managing our network and non-network assets.

14 Fleet Management – Introduction
Introduces the contents of the fleet management chapters.

15 Overhead Structures
16 Overhead Conductors
17 Cables
18 Zone Substations
19 Distribution Transformers
20 Distribution Switchgear
21 Secondary Systems

For each portfolio, we describe:
- High level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition and risks
- Routine maintenance tasks
- Renewal strategies
- Renewal forecasting approaches

22 Non-network Assets
Sets out the road map for our non-network assets, and how this will meet the future requirements of our customers and the wider business.

23 Network Opex
Describes our maintenance activities for the period.

CUSTOMER WORKS
This section summarises our approach to consumer connection and asset relocation projects.

24 Consumer Connections
Explains how we connect new customers to our network.

25 Asset Relocations
Discusses how we facilitate asset relocations for third parties.

EXPENDITURE FORECASTS
Provides an overview of our Capex and Opex forecasts for the planning period.

26 Expenditure Forecasts Provides an overview of Opex and Capex forecasts for the planning period. It explains our inputs and assumptions, and our cost estimation approach.

3 NETWORK OVERVIEW

3.1 CHAPTER OVERVIEW

Our network covers two large, separate regions of the North Island. This chapter provides an overview of the zones, network configurations and assets in these regions.

Chapter 11 provides detailed information on the 13 associated planning areas.

A summary list of our assets is included at the end of this chapter, with more detailed descriptions provided in Chapters 15-21.

3.2 OUR NETWORK

Our network supplies electricity to around 330,000 customer connections across two coastal regions of the North Island. In terms of both supply area and network length, our network is the largest of any single distributor in New Zealand.

3.2.1 NETWORK CONFIGURATION

The operation of the electricity network is analogous to roading. Road capacity ranges from high-volume national highways to small access roads. In a similar way, an electricity network uses high voltages to move large amounts of power over longer distances to service a zone or area. As electricity is distributed to less populated areas, the size and voltage of network assets reduce.

We have lines and cables operating in three distinct voltage ranges:

- **Subtransmission** – mostly 33kV but also 66kV and 110kV
- **Distribution** – mostly 11kV but also 6.6kV and 22kV
- **Low Voltage (LV)** – 230V single phase or 400V three phase

Changing electricity from one voltage to another requires the electricity to flow through a transformer.

For electricity flowing from a subtransmission circuit to a distribution circuit, it passes through a transformer housed in a zone substation. When electrical flow is from a distribution circuit into the LV network, a smaller ground or pole-mounted distribution transformer is used.

3.2.2 TRANSMISSION POINTS OF SUPPLY

Our place in New Zealand's electricity sector is illustrated in **Figure 3.1**.

Figure 3.1: Our place in the electricity sector

Generation	Transmission	Distribution	Retail
Electricity is generated across New Zealand using water (hydro), wind, geothermal, gas and coal stations.[2]	This electricity is transported from generators to distribution networks using the national grid, owned and operated by Transpower.	Finally, electricity is distributed to homes and businesses via distribution networks. Powerco is one of 29 distribution companies.	Retailers buy electricity from generators and sell it to homes and businesses.

Our network connects to the national grid at voltages of 110kV, 66kV, 33kV and 11kV via 30 points of supply or grid exit points (GXPs). These GXPs are the points of interface between our network and Transpower. The national grid conveys electricity from generators throughout New Zealand to distribution networks and large directly-connected customers.

GXP assets are mostly owned by Transpower, although we do own transformers, circuit breakers, and protection and control equipment at some sites.

GXPs are the key upstream connection points supplying local communities. Large numbers of consumers can lose supply due to a GXP failure or outage so we and Transpower build appropriate amounts of redundancy into the GXPs by duplicating incoming lines, transformers, and switchgear.

Detail on the GXPs in each zone and associated network maps can be found in Chapter 11.

3.2.3 REGIONAL NETWORKS

Our network includes two non-contiguous networks, referred to as our Eastern and Western regions. Both networks contain a range of urban and rural areas, though both are predominantly rural. Geographic, population and load characteristics vary significantly across our supply area.

[2] Distributed generation is a growing trend but still only a very small proportion of total generation.

Our development as a utility included a number of mergers and acquisitions that have led to a wide range of legacy asset types and architectures. This requires an asset management approach that accounts for these differences, while seeking to standardise network equipment over time.

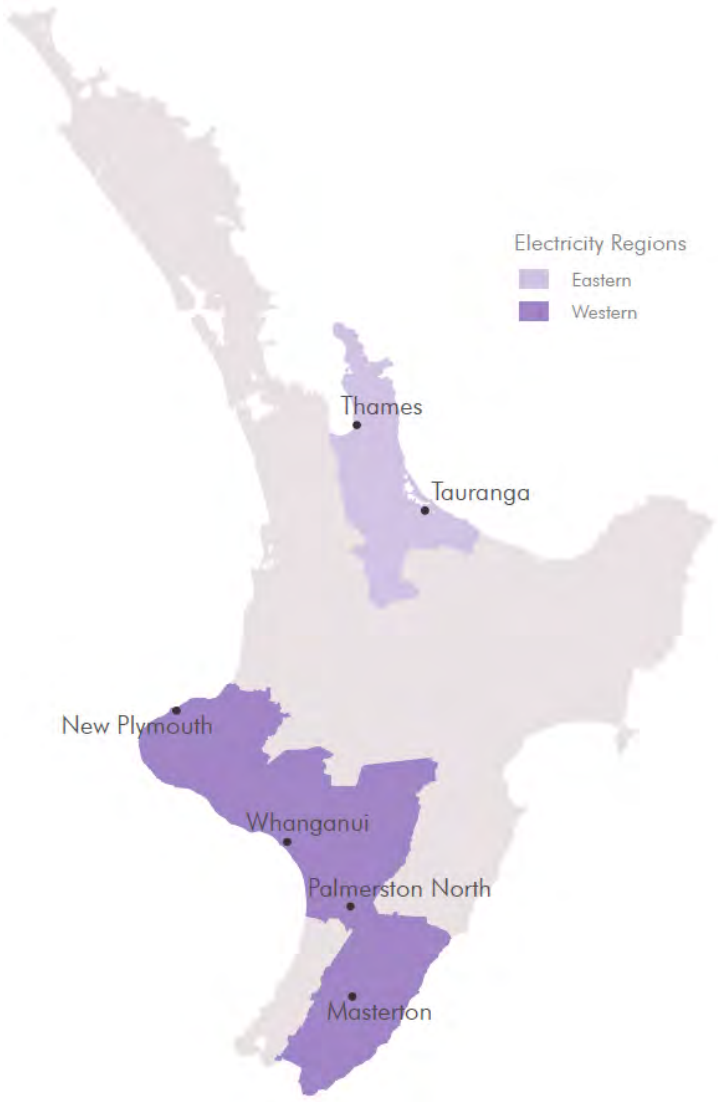
Table 3.1 provides summary statistics pertaining to our assets in the Eastern and Western Regions.

Figure 3.2 provides a geographical overlay of these regions.

Table 3.1: Key regional statistics (2016)

MEASURE	EASTERN	WESTERN	COMBINED
Customer connections	152,679	177,899	330,578
Overhead circuit network length (km)	7,196	14,557	21,753
Underground circuit network length (km)	3,227	2,923	6,150
Zone substations	48	68	116
Peak demand (MW)	463	447	906
Energy throughput (GWh)	2,382	2,427	4,809

Figure 3.2: The regions we cover



3.3 EASTERN REGION

3.3.1 OVERVIEW

The eastern network consists of two zones - Valley and Tauranga. These have differing geographical and economic characteristics presenting diverse asset management challenges.

Figure 3.3 shows the eastern network region and its planning areas.

For planning and pricing purposes we divide this region into two zones:

- **Valley** – includes a diverse range of terrains from the rugged and steep forested coastal peninsula of Coromandel to the plains and rolling country of east and South Waikato. Economic activity in these areas is dominated by tourism and farming respectively.

  From a planning perspective, this region presents significant challenges in terms of maintaining reliability on feeders supplying sparsely-populated areas in what is often remote, difficult-to-access terrain.

  Investment priorities have focussed on improving network security and resilience, and developing better remote control and monitoring facilities.

- **Tauranga** – rapidly developing coastal region, with horticultural industries, port and large regional centre at Tauranga.

  The principal investment activities in this region have been associated with accommodating the rapid urban growth in Tauranga, maintaining reliable supplies to the port, and supplying new businesses that have sprung up in the area.

The Valley and Tauranga zones are discussed in more detail in the following sections.

Figure 3.3: Eastern network and planning areas

3.3.2 VALLEY ZONE

The Valley zone covers the eastern area of the Waikato as far south as Kinleith, plus Waihi and the Coromandel Peninsula.

There are several small towns in the Valley zone and some industrial load. The Waikato region is a predominantly rural, dairy farming region. The Coromandel area consists of rugged, densely-forested areas.

The Valley zone has four planning areas.

- Coromandel
- Waikino
- Waikato
- Kinleith

Below we provide further background on the area including the characteristics that will drive improvement projects over the planning period.

Coromandel

The Coromandel planning area covers the Coromandel Peninsula and upper Hauraki Plains. All six zone substations in the area are supplied from Kopu GXP. Whitianga and Thames are the largest substations in the area and directly serve the towns of the same name. Other substations are located at smaller towns and settlements serving rural customers.

Subtransmission is dominated by a long 66kV ring serving the Coromandel Peninsula. A smaller interconnected ring serves Thames, with radial lines branching out to other substations.

In the last five years, we have undertaken a number of large projects to improve capacity and security of supply, especially on the long circuits up to Whitianga. Despite this, a number of security of supply issues remain to be addressed.

Developing a more secure supply to the Coromandel

The Coromandel planning area includes rugged hilly terrain covered in native bush. The dense vegetation makes it difficult to access some lines and complete repairs, with helicopters frequently being required. In addition, there are some environmental concerns associated with building new electricity lines across areas of significant natural beauty on the peninsula.

The key driver of the region's economy is tourism, particularly seasonal holidaymakers. There is also some primary agriculture and forestry. Although the permanent population is small, it increases significantly during holiday periods. Some popular resort towns such as Tairua and Whitianga can see the population increase up to six times during these periods. The transient nature of electricity demand poses some challenging technical and economic questions.

We have lifted investment in this area significantly in the last decade and several further upgrades are scheduled during this planning period. Our long-term plan to improve security in the area may include upgrading the main Whitianga line to 110kV.

Waikino

Our network in the Waikino area utilises a 33kV subtransmission system connected to Waikino GXP. Twin circuits serve both Paeroa and Waihi substations, with single radial lines to Whangamata and to Waihi Beach.

The 33kV line to Whangamata is long and the only alternate supply is a limited 11kV circuit sharing some of the same poles. Whangamata has been growing and experiences a large influx of customers during holiday periods. The security of supply to Whangamata is therefore a key focus of our planning.

Waikato

The Waikato area is quite extensive, reaching from Tahuna in the north to Putaruru in the south. The largely flat to rolling country is used for intensive dairy production. The area is supported by primary industries and urban centres including Morrinsville, Te Aroha, Waharoa, Matamata, Tirau and Putaruru.

Three GXPs serve this area. In the northern part, Waihou and Piako GXPs connect to nine substations around the Morrinsville-Piako district.

The larger substations at Mikkelsen Rd, Morrinsville, Piako, Waitoa and Waharoa serve the respective urban centres and industrial facilities in these locations. The remaining substations serve surrounding rural districts and two large industrial customers.

Hinuera GXP connects six substations in the southern part of the Waikato area to the grid via a largely radial network of 33kV overhead lines. Hinuera is a single circuit GXP. The security issues associated with this are driving major investments in the 33kV network and GXP works at Putaruru.

Kinleith

The Kinleith area takes its name from the GXP and the pulp and paper mill that dominates the area's economic activity. The mill's electricity network uses the bulk of the capacity at the Kinleith GXP. Its principal supply is via 11kV switchgear located at the GXP itself

Tokoroa is the only substantial urban centre in the area. Our 33kV network from Tokoroa consists of a single 33kV circuit to each of the two substations at Maraetai and Baird Rd.

Oji Fibre Solutions – a key customer in the Kinleith area

A significant part of our network supplies electricity to the Oji Fibre Solutions pulp and paper mill at Kinleith, near Tokoroa. The network is highly interconnected, beginning at the cable terminations of Transpower's switchgear at the Kinleith GXP and ending at the LV terminals of the supply transformers. The system is mainly underground, comprising 29 11kV feeders and includes one 33kV circuit that supplies Midway and Lakeside substations.

Supply at 11kV is taken from Kinleith GXP for the Kinleith mill site. A cogeneration plant is connected to the Kinleith GXP.

3.3.3 TAURANGA ZONE

The Tauranga zone covers the Western Bay of Plenty area from near Athenree, to along the coast east of Te Puke. This coastal region continues to see growing demand and development - both residential and commercial/industrial.

Tauranga is a major New Zealand city and has significant industrial load including a major port. The remainder of the Bay of Plenty has predominantly dairy and horticultural industries, particularly kiwifruit and avocados.

The Tauranga zone has two planning areas.

- Tauranga
- Mt Maunganui

Below we provide further background on the area including the characteristics that will drive improvement projects over the planning period.

Tauranga

The Tauranga planning area includes the parts of Tauranga city and northern rural areas supplied from the Tauranga and Kaitimako GXPs. Tauranga is a very large capacity GXP connecting all substations via a number of dual 33kV circuits with some interconnection, most significantly at Greerton switching station.

The main urban substations are Hamilton St, Waihi Rd, Otumoetai, Bethlehem, Matua and Welcome Bay.

The substations distributed along the northern Tauranga coast are generally of smaller capacity serving agricultural loads , rural and lifestyle properties.

An additional substation is planned for Pyes Pa in the coming years to accommodate the new urban development. Other substations may be required if growth within existing urban areas proves higher than expected or more new developments eventuate.

The subtransmission network in the Tauranga region also connects to generation from the Kaimai hydro scheme and embedded generation at a fertiliser factory.

Mount Maunganui

The Mount Maunganui planning area covers Mount Maunganui itself and urban development spreading down the coast. From a planning perspective this is interconnected with the network at Te Puke so we treat it as a single planning area.

Mount Maunganui GXP is a fully secure 75MVA capacity grid connection. However, high load growth in the area and the rapid urban spread down the Papamoa coast will require additional grid offtake capacity in the future.

Mount Maunganui GXP supplies five substations, all designed for twin transformer, urban configuration. Matapihi, Triton and Omanu supply the Mount Maunganui area, while Te Maunga and Papamoa currently supply the Papamoa coastal strip.

Omanu and Te Maunga substations are relatively new, reflecting our past investment to meet increasing demand. Beyond Papamoa substation, a new Wairakei substation is under construction.

The existing 33kV network from Te Matai GXP serves Te Puke and Pongakawa. The other substations, including the new Paengaroa substation, supply predominantly rural load. They have with small capacities and single circuit constraints.

3.4 WESTERN REGION

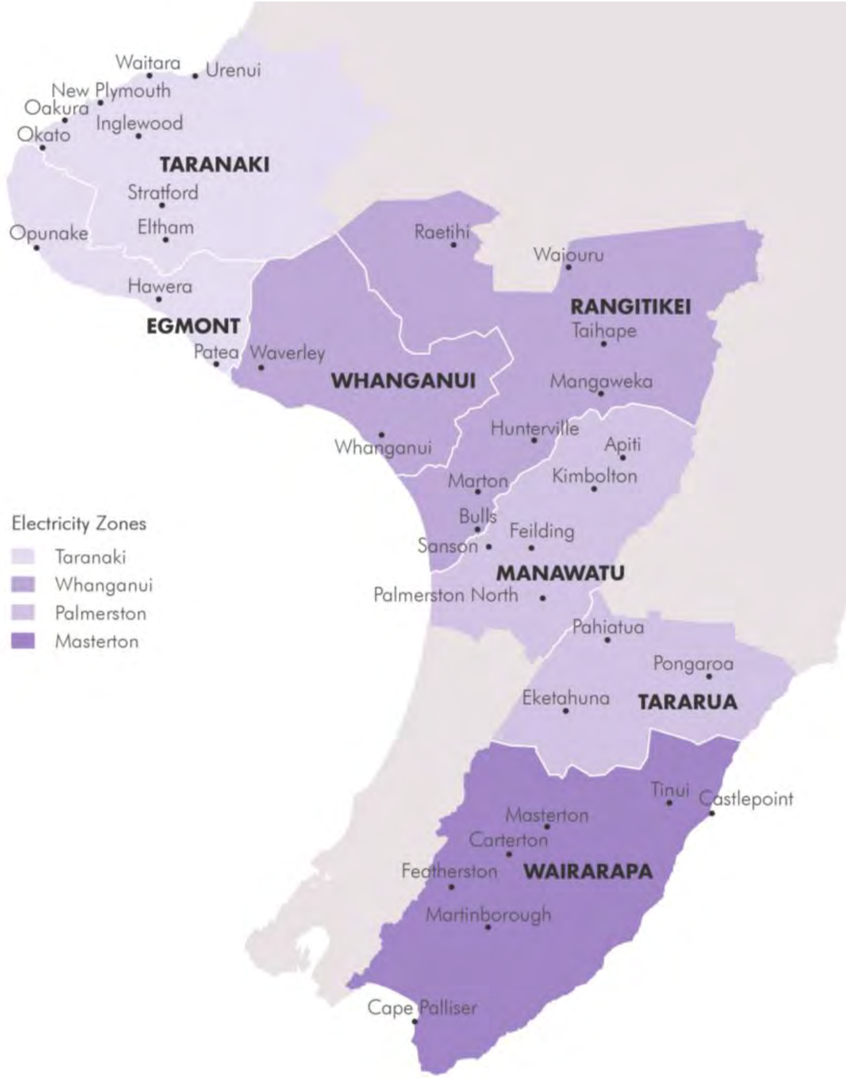
3.4.1 OVERVIEW

The Western Region includes the four network zones described below. Similar to the Eastern Region, these zones have differing geographical and economic characteristics, presenting various asset management challenges. Because of the age of the network and declining asset health of overhead lines in particular, extensive asset renewal is required in this region – about double cost-wise compared to what is required in the Eastern Region on an annual basis .

- **Taranaki** – situated on the west coast plains is exposed to high winds and rain. The area has significant agricultural activity, oil and gas exploration and production, and some heavy industry.
- **Whanganui** – includes the surrounding Rangitikei and is a rural area exposed to westerly sea winds at the coast and snow storms in inland high country areas. It is predominantly agriculture based with some industry.
- **Palmerston** – includes rural plains and high country areas exposed to prevailing westerly winds. It is mainly agricultural with logistical industries and has a university, with associated research facilities, in the large regional centre of Palmerston North.
- **Wairarapa** – is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.

The map in **Figure 3.4** shows the western network footprint and planning areas.

Figure 3.4: Western network and planning areas



3.4.2 TARANAKI ZONE

This zone includes two planning areas—Taranaki and Egmont—where we supply the major urban areas of New Plymouth and Hawera. There are also large sites for oil and gas exploration, and intensive dairy farming.

Below is background on the two planning areas.

Taranaki

The Taranaki area covers the northern and central parts of the region with Eltham and Okato defining the southern limits.

New Plymouth is the largest urban centre. Five urban substations serve the wider city and are supplied from three GXPs. The largest grid offtake at Carrington St supplies Katere Substation, Brooklands substation and the City substation, which serves New Plymouth's CBD. All three of these substations have dual 33kV circuits and transformers. Moturoa substation is the only substation off New Plymouth GXP, located at the site of the original power station near the port. Moturoa also has dual 33kV cables and dual transformers.

Bell Block substation is now fed from a dual overhead line from Huirangi GXP.

Huirangi GXP also supplies substations that serve Inglewood, Waitara, some major oil and gas sites and the surrounding rural community. The 33kV subtransmission is overhead in a meshed configuration with one back-feed line linking right through Inglewood to Stratford GXP.

Stratford GXP is the last GXP in the Taranaki area. Cloton Rd and Eltham are the only substations of significant size. Five other substations serve rural districts.

Stratford's 33kV subtransmission is entirely overhead and is a highly meshed configuration which leads to limitations in security due to protection issues.

Egmont

Egmont encompasses Hawera and up to Warea on the coast. Hawera is the only significant sized commercial centre.

Hawera GXP is located just outside the urban limits and supplies our Cambria substation in Hawera via two dedicated 33kV oil-filled cables. Cambria has recently been upgraded.

In addition, Hawera GXP supplies Manaia and Kapuni substations off an overhead 33kV ring. Livingstone (Patea) and Whareroa substations are supplied from another ring. Whareroa substation is located within, but does not supply, the large Fonterra plant of the same name. The Patea hydro generation also injects into Hawera GXP.

Three coastal substations (Pungarehu, Tasman and Ngariki) are supplied from Opunake GXP via a meshed network of 33kV overhead lines. Loads and capacities are relatively small, although importantly this network supplies the Maui production station.

3.4.3 WHANGANUI ZONE

The Whanganui zone covers the area from Waiouru in the north to Bulls in the south. Whanganui and Marton have significant industrial load. The rural area has a predominantly mixed farming load.

The Whanganui zone has two planning areas.

- Whanganui
- Rangitikei

Below is background on those planning areas including the characteristics that will drive improvement projects.

Whanganui

The Whanganui planning area encompasses Whanganui city, surrounding districts, and north to Waverley along the coast. Whanganui city is the only major commercial centre.

There are three GXPs in this area. Whanganui and Brunswick GXPs are high capacity and are located on either side of the city. Waverley GXP is a small grid offtake directly supplying the local 11kV distribution

Nine substations are located in and around the city. Peat St is the largest and supplies part of the CBD. Peat St was recently upgraded with two large capacity transformers but is only supplied by a single high capacity 33kV overhead line from Brunswick GXP.

Hatricks Wharf and Taupo Quay substations are also important to our central city customers. These two substations are fed by single 33kV lines from Whanganui GXP and have space for just a single transformer each. There is a high capacity 11kV tie between these two large single transformer substations allowing mutual support.

The remaining substations serving the urban area are Roberts Ave and Castlecliff, off Brunswick GXP, and Beach Rd and Whanganui East, off Whanganui GXP. These are medium sized substations fed by either single radial or interconnected radial 33kV overhead lines. Back-feeds often rely on transfer between GXPs which limits operational flexibility.

Rangitikei

The Rangitikei planning area encompasses both the Rangitikei district which stretches from the coast, through Bulls and Marton and inland to parts of upper Whanganui, and the Central Plateau. Though widespread with differing topography and climate, the area's network characteristics are common. It is sparsely populated with a predominantly rural load served by long and low capacity overhead lines.

Marton GXP is a relatively small but twin transformer GXP which supplies the four substations serving Bulls, Marton and surrounding districts. Mataroa and Ohakune GXPs supply the inland networks which have no connection between GXPs. Ohakune is a shared GXP and feeds the 11kV distribution directly.

The entire 33kV network from either Mataroa or Marton GXP is overhead. Subtransmission is almost entirely radial with dual circuits only to Taihape substation. Substations are all single transformer sites. There is generally a low level of demand growth in the area. Investment in the area is focussed mostly on renewal and distribution back-feed upgrades.

3.4.4 PALMERSTON ZONE

The Palmerston zone includes Palmerston North city, Manawatu and Tararua. Palmerston North is a large urban area that is a hub for many distribution centres, and the surrounding district has significant farming loads.

The Palmerston zone has two planning areas:

- Manawatu
- Tararua

Below is background on the planning areas including the characteristics that will drive improvement projects over the planning period.

Manawatu

The Manawatu area is dominated by Palmerston North city and includes the rural network located on the surrounding plains between the Tararua Ranges and the coast that stretch between Foxton and the Rangitikei River. Feilding and Sanson are included, as is the inland country heading north towards Apiti.

Two high capacity GXPs serve the area with Bunnythorpe GXP located to the north of the city and Linton GXP to the south-east.

Subtransmission is entirely 33kV via high capacity circuits which are predominantly overhead. Use of underground cables is increasing. Multiple circuits, in a variety of configurations, supply the six substations in the city. There is a degree of interconnection between the GXPs at various points across the city but due to inherent operational limitations this is largely reserved for emergency backup purposes. Tararua Wind Farm also injects electricity into two locations on our 33kV network which adds complexity to both protection and operations.

Keith St substation is supplied by two 33kV circuits from Bunnythorpe. These circuits have been interconnected with a further circuit directly to Kelvin Grove substation. Two paralleled 33kV oil-filled cables from Keith St form one supply circuit the Main St substation which is close to the CBD. The second circuit is a recently installed XLPE cable. Pascal St substation, on the other side of the CBD, takes supply via two 33kV circuits from Linton GXP.

Outlying suburbs and rural areas close to Palmerston North are supplied from the Kelvin Grove, Milson, Kairanga and Turitea substations. All are supplied by at least two 33kV circuits from either Linton GXP or Bunnythorpe GXP.

Wind farm connections

An underground 33kV cable system links 97 wind turbines in the Te Rere Hau wind farm and connects them to the Tararua Wind Central Grid Injection Point (GIP). This comprises 28km of 33kV underground cable, 33kV/400V distribution transformers, an optical fibre network and a 33kV switching station.

Trustpower's adjacent Tararua Wind Farm also injects part of its generation into the above GIP. However, stages 1 and 2 of this wind farm have capacity to inject up to 34MW into each of our 33kV networks supplied by Bunnythorpe GXP and Linton GXP. This embedding of generation seeks to maximise the economic benefits of locating generation close to load. It does, however, introduce operational and planning complexities that impact our 33kV networks and nearby substations.

The old Manawatu rural subtransmission network (ex-Manawatu Oroua Electricity Power Board) comprised of open 33kV rings feeding substations around the periphery of Palmerston North. Single 33kV radial feeders from Feilding supply Sanson and Kimbolton substations. Feilding substation is supplied by two high capacity circuits from Bunnythorpe GXP. The 33kV circuits are predominantly overhead on concrete poles and are close to their firm capacity limit..

Tararua

The Tararua planning area covers the upper Wairarapa, including Eketahuna and Pahiatua and out to the coast beyond Pongaroa. Terrain is rugged, especially towards the coast and load is relatively light and widely distributed.

Mangamaire GXP supplies all four substations in the area. Of these, Mangamutu is the largest and most significant and has been upgraded because of increased demand at Fonterra's plant. Two overhead 33kV lines supply Mangamutu substation.

The remaining three substations are low capacity, rural class, with single transformer and minimal switchgear. All three are supplied from a 33kV overhead ring.

3.4.5 WAIRARAPA

This zone includes a single planning area called Wairarapa, which covers the south Wairarapa from Eketahuna to Cape Palliser. Masterton city has significant industrial load. Overall the area has a predominantly dairy and sheep farming load, with significant orchard and vineyard activity.

Wairarapa zone is connected to the grid through Masterton and Greytown GXPs. While both subtransmission networks are 33kV there is no interconnection between them.

Four substations, Chapel, Akura, Norfolk, and Te Ore Ore, are located in or around Masterton city. These are supplied via an open meshed network of overhead lines.

Chapel and Akura are the largest with highest security and, along with Norfolk, have two transformers.

Clareville substation, which serves Carterton and surrounds, is supplied via two 33kV overhead lines and has two transformers also. The remaining three substations serve light loads in the remote rural areas with a single transformer and a single radial subtransmission line.

Further south, Greytown GXP supplies Greytown from Kempton substation, with a single 33kV overhead line and single transformer. A 33kV overhead subtransmission ring feeds Featherston and Martinborough, with radial tee offs to two other small rural substations. One of these, Hau Nui, provides interconnection for the Hau Nui wind farm via a long radial 33kV line.

3.5 ASSET SUMMARY

This section provides an overview of the asset fleets that we own and operate, including the overall populations of our key fleets.

3.5.1 OUR ASSET FLEETS

We use the term "asset fleet" to describe a group of assets that share technical characteristics and investment drivers. We have categorised our electricity assets into 25 fleets. These in turn are organised into seven portfolios, as set out below.

- Overhead structures
- Overhead conductor
- Cable
- Zone substations
- Distribution transformers
- Distribution switchgear
- Secondary systems

Our approach to managing our asset fleets is explained in Chapter 14.

3.5.2 ASSET POPULATIONS

In **Table 3.2** we set out an overview of our asset populations across our full electricity network[3]. The large number of assets in certain fleets (e.g. poles) gives an indication of the scale of our network and the work we undertake on it. Further detail on these assets, including their condition and ages, is included in Chapters 15-21.

[3] Some population quantities in the table vary slightly to information disclosure, due to the use of different classifications used for fleet management planning.

Table 3.2: Asset population summary (2016)

ASSET TYPE	POPULATION
Overhead network	
Subtransmission (km)	1,499
Distribution (km)	14,834
LV (km)	5,135
Underground cables	
Subtransmission (km)	149
Distribution (km)	1,984
LV (km)	4,155
Overhead structures	
Poles	265,219
Crossarms	418,753
Zone substations	
Power transformers	191
Indoor switchboards	119
Buildings	158
Distribution assets	
Transformers	33,379
Switchgear	41,021
Secondary systems	
Zone substation protection relays	1,835
Remote terminal units	297

Serving our customers

This section explains how we plan to meet our customers' needs, now and in the future.

4.1 CHAPTER OVERVIEW

This chapter explains who our customers are[4] and what they care about when it comes to electricity delivery. It explains how we actively engage with them to understand what they value and summarises the feedback we received in the course of recent customer engagement.

The expectations of our customers guide our investment approach. They are the starting point for setting our asset management objectives and investment plans for the planning period. In the final part of the chapter we explain the links between the service standards our customers tell us they require and processes we use to determine investment requirements on our networks.

4.2 CUSTOMER DEMOGRAPHICS

4.2.1 CUSTOMERS

We are proud to serve over 320,000 homes and businesses across the north island of New Zealand. This includes diverse groups of households, businesses and communities. Our customer base includes:

- 15 electricity retailers who have contracts with us to operate on our network
- 330,078 homes and businesses comprising:
  - Residential consumers and small businesses ('mass market')
  - Medium-sized commercial businesses
  - Large commercial or industrial businesses
- 24 directly-contracted industrials, including large distributed generators
- 19 local territorial authorities and the NZTA.

The table below sets out ICP numbers by category. It shows the proportion of our customer base in contrast to the volume of electricity used, showing the significant electricity consumption of our larger customers.

[4] Under the current industry structure, we do not have a direct relationship with most of our end-users. Regardless of this, we consider all homes and businesses connected to our network to be our customers.

Table 4.1: Number of customers (ICPs) and electricity delivered (2016)

CUSTOMER TYPE	ICPS	% OF TOTAL ICPS	ELECTRICITY DELIVERED (GWH)	% OF TOTAL ELECTRICITY DELIVERED
Mass market	328,134	99.4	2,601	57.5
Commercial	1,342	0.4	245	5.4
Large commercial / industrial	602	0.2	1,681	37.1
Total	330,078	100%	4,527	100%

Our customers are distributed relatively evenly across our network regions. The largest regional concentrations are in the Bay of Plenty, Taranaki and Manawatu, each having a large urban centre – Tauranga, New Plymouth and Palmerston North respectively.

The mass market segment includes our residential customers and small to medium enterprises. As shown above, the majority of our ICPs are mass market (99%), who account for around 66% of electricity delivered through our network.

We have over 1,300 medium-sized commercial customers. These customers range from medium-sized retail and dairy producers through to food processing, ports, and large manufacturing. A further 602 customers have demand greater than 300 kVA. These latter customers are classed as large commercial and industrial due to their demand.

Over the past three years, growth across all of our customer segments has exceeded our regional forecasts. We have had to refine our forecast load estimates and increase network capacity. Our customer connection teams and processes have been bolstered to ensure we meet this growing need and continue to provide good customer service. How we connect customers to our network is discussed in Chapter 24.

More information on our large customers is provided in Appendix 4.

4.2.2 EMBEDDED GENERATORS

We provide direct network connections for a number of embedded generators. Sixteen of these have export capacity over 1MW, while a further four are classed as industrial cogeneration where generated power is wholly or partly consumed on-site.

In addition, there are approximately 2,500 distributed generation installations of less than 1MW capacity connected to our network. The combined capacity of these smaller generators is just over 14MW. Of these, nearly all are domestic photovoltaic (PV) panel installations of less than 10kW capacity.

The uptake rate of small scale distributed generation (SSDG) on our network has risen from about 10 to 70 installations per month in the last three years as prices of PV and inverter technologies has dropped.

Our policy as set out in section 7.2.11 of this AMP is intended to support and facilitate the appropriate development of distributed generation, while ensuring appropriate control given the potential local impacts on network operation.

4.2.3 ELECTRICITY RETAILERS

Like most New Zealand EDBs we operate an interposed model. That means retailers purchase our services, bundle them with energy supply and the cost of accessing the transmission grid and provide a bundled price for delivered energy to their customers. We currently have contracts with 15 retailers that are used by our customers. Of these, Genesis Energy, Trustpower, and Mercury serve 70% of our customers.

Given the importance we place on our relationship with electricity retailers, we have a dedicated relationship management service in place that focuses on providing them with a high level of commercial and operational support. This helps them to provide a quality bundled service to customers and seamlessly resolve any supply issues on their behalf. Working with retailers to deliver a simple and effective energy supply for customers is a key part of what we do.

The retail market is also undergoing considerable change. Over the past few years, we have signed agreements with seven new retailers that have very targeted products. This reflects expectations that retail competition will intensify, become more sophisticated and become more segmented. These changes will most certainly occur during the coming planning period.

4.2.4 OTHER STAKEHOLDERS

We provide network services to a range of other stakeholders. These include the NZTA and territorial local authorities that require us to move our lines or cables for roading projects. House relocation organisations may also require us to switch off our lines during their operations. Developers require us to provide connection services to housing developments. Our approaches to new connections and relocations are discussed Chapters 24 and 25.

4.3 CUSTOMER SERVICE PRIORITIES

4.3.1 OVERVIEW

We use a variety of means to engage with our customers and capture their feedback.

These include:

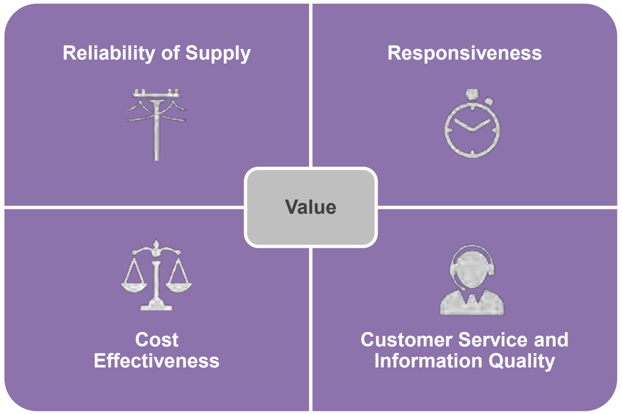
- Having stands at agricultural field days, expos and trade shows
- Direct interaction with larger commercial and industrial customers
- Customer surveys
- Stakeholder meetings and focus groups
- Website and phone feedback (www.powerco.co.nz and 0800 POWERCO)
- Consultation videos, published on YouTube
- Consultation documents, such as this AMP
- Community-wide consultation, as took place recently in the lead up to our CPP application.

The scale and range of consultation we complete provides us with appropriate insight into the areas of our service that our customers value. Feedback from our customers typically falls into four key service dimensions as set out in **Figure 4.1**.

As part of the process to develop our CPP submission we have also completed structured and detailed consultation in relation to our specific near term investment proposals. This feedback is set out in detail in our CPP submission.

We discuss these in turn, alongside associated customer feedback, in the following sections.

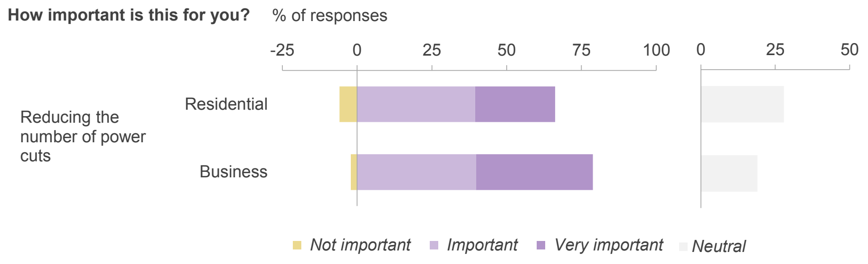
Figure 4.1: The four service dimensions most valued by our customers



4.3.3 RELIABILITY OF SUPPLY

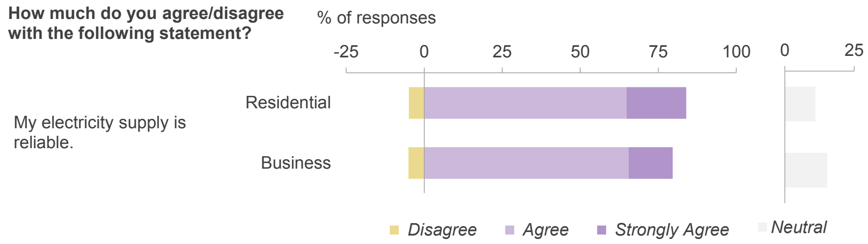
We know from our regular engagement activities that customers place a high value on reducing or avoiding outages. This is especially true for certain groups such as businesses. Resilience is similarly important, as our customers expect our network to be able to withstand storms and for supply to be restored within a reasonable period. The chart below shows that the majority of our customers would value a reduction in outages.

Figure 4.2: Customer Feedback – reducing outages



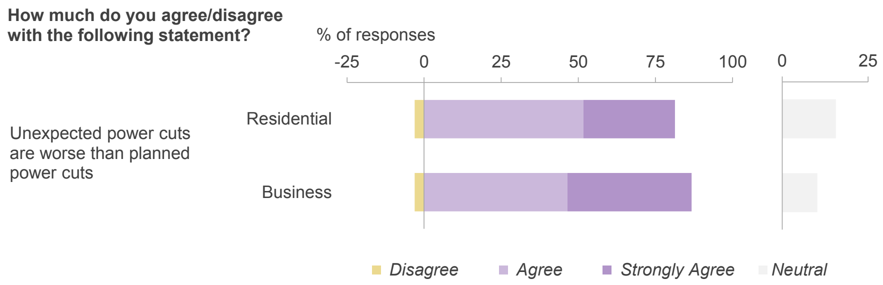
We continually focus on ensuring that the homes, businesses and industries we supply can count on us to keep them connected. While we cannot guarantee that a customer will never experience an interruption, we are committed to being one step ahead and minimising the chances of this occurring. A large majority of our customers think we are succeeding; however we clearly have work to do given a material number of customers who disagree. We have also found there is very little appetite from our customers to accept future reductions in reliability.

Figure 4.3: Customer feedback – reliability of supply



When planned outages are needed to undertake work on the network, we do our best to ensure the disruption is as short as possible and does not occur at peak times. We work closely with electricity retailers to ensure affected customers are informed and given plenty of notice.

Figure 4.4: Customer feedback – planned versus unplanned outages



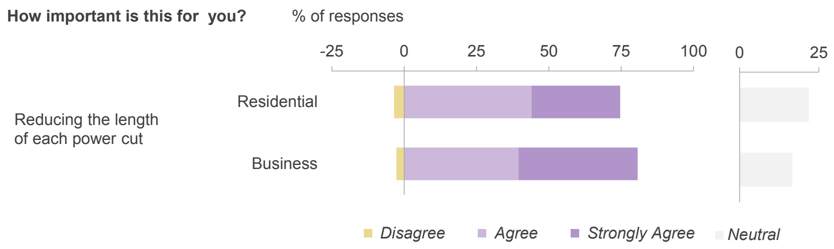
Our surveys indicate that the majority of residential respondents and business respondents regard unexpected outages as worse than planned outages. This customer feedback highlights the importance of addressing asset issues, such as defects, and poor performing older assets, before they result in a failure.

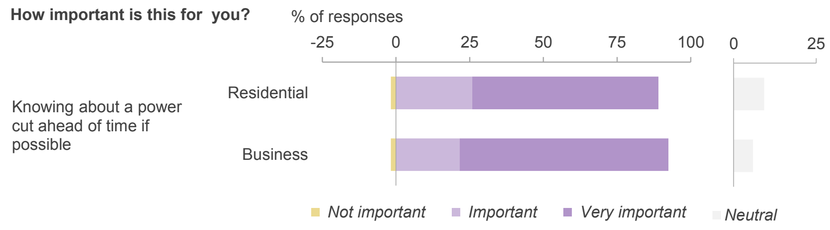
4.3.4 RESPONSIVENESS

Unplanned outages occur for a variety of reasons. Some of these outages are considered to be within our control, such as equipment failures. Others are beyond our control, such as lightning strikes or vehicles hitting poles. Those outages that are within our control are easier to foresee and prevent, and we do everything we reasonably can to eliminate them.

When an unplanned outage does occur, our customers expect us to respond quickly in order to reduce their impact and lessen potential safety risks. The value that customers place on responsiveness is indicated in the survey results below.

Figure 4.5: Customer feedback – responsiveness





It is evident from our customers' feedback that strategies to minimise the number of customers affected and to minimise repair times in the event of an outage are highly valued. Therefore, understanding the nature of these events, their causes and how to prevent them remain a key focus for us. When failures do occur, our main focus is to restore supply as quickly and safely as possible.

4.3.5 COST EFFECTIVENESS

While our customers recognise the importance of investing in the network to ensure that it is safe and reliable, they are also concerned about the price of electricity, as indicated in the following survey results.

Figure 4.6: Customer feedback – asset replacement

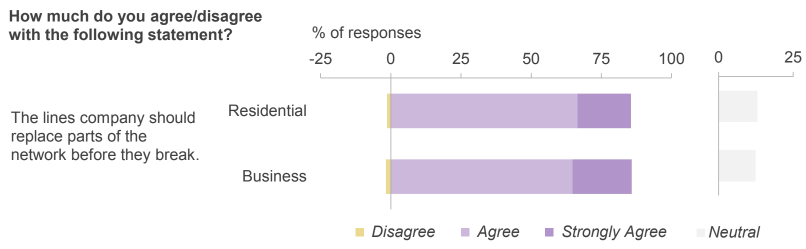
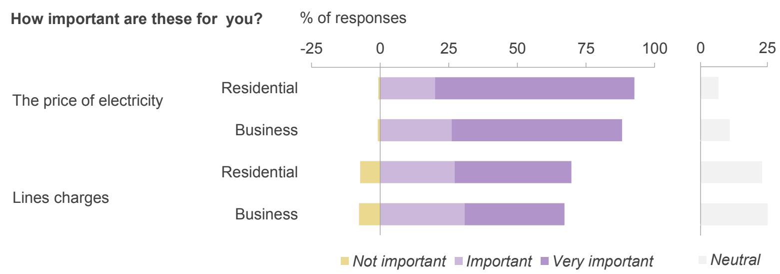


Figure 4.7: Customer feedback – price of electricity and line charges



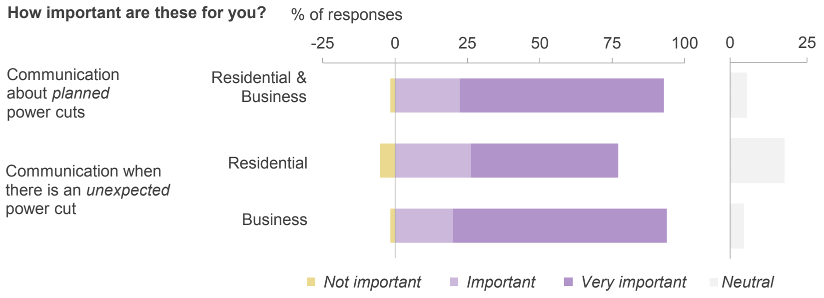
Customers expect our expenditure to be prudent and efficient in order to minimise electricity prices. Therefore, customers expect us to evaluate our decisions carefully so we optimise our expenditure and minimise total life cycle costs.

4.3.6 CUSTOMER SERVICE AND INFORMATION QUALITY

Our customers value timely and accurate information about their electricity supply. Advances in mobile technology and social media have created an expectation that information should be readily available through a number of alternative communication channels.

As shown in the figure below, the most important information for residential customers is communication in relation to power cuts. Information on upcoming planned power cuts is important to 90% of residential respondents. Information relating to unexpected power cuts is also highly valued by 78% of respondents. The results are similar for business customers who place even greater value on each of these aspects.

Figure 4.8: Customer feedback – communication about power cuts



These results show that communication about power cuts is very important to our customers.

4.4 HOW CUSTOMER FEEDBACK INFLUENCES OUR STRATEGY

4.4.1 OVERVIEW

Feedback from our customers on the service standards they value is at the heart of our asset management process.

At their core the investment proposals set out on this AMP have been developed to ensure we invest prudently in our networks so that we are able to continue to deliver the level of service our customers require in the long term. This includes our commitment to our customers to ensure the safety of our assets, and to deliver stable reliability outcomes over time.

As part of our CPP development process we consulted with our customers regarding our specific investment proposals, to determine their service preferences, and explore how the valued our services in terms of the prices they pay and the level of reliability we provide.

The themes of our discussion and the feedback from our customers are set out in the sections below.

4.4.2 SAFE AND RELIABLE NETWORKS

Customer feedback unequivocally indicates that they want their electricity delivered safely, reliably and efficiently. It is thus essential that we invest appropriately in our assets to ensure they are in appropriate condition, are safe and reliable, and meet the needs of our customers.

Over the past five years:

- Key indicators such as asset health, fault rates, and supply quality have deteriorated
- The level of deferred maintenance and vegetation works has increased markedly

We have concluded that we have reached the point where an increased level of investment is imperative. If we fail to lift investment, our network performance will continue to deteriorate until we can no longer ensure the safety and reliability supporting growth in our communities.

The timing of our maintenance, vegetation and asset renewal programmes are designed to minimise life-cycle cost. If we do it now we avoid even higher expenditure later.

4.4.3 FACILITATING CUSTOMER GROWTH

The regions we serve have been experiencing sustained population and economic growth in recent years, and as a result we have experienced sustained demand growth across many of our networks.

Consequently, there are now a large number of locations where we have no practical way of rerouting supply in the event of a key asset failing, and where the cost of such a failure is becoming unacceptably high for our customers.

The situation we find ourselves in is neither acceptable nor sustainable. The number of high load-at-risk scenarios on our networks is inappropriate and demonstrates strong and focused action is necessary.

Because this situation may affect our ability to provide a secure, stable power supply, our customers recognise the need to continue to expand and augment the capacity of our network to cope with demand growth.

4.4.4 ENABLING OUR CUSTOMERS ENERGY CHOICES

Customers are increasingly expecting more flexibility and choice in the services they procure. This applies to electricity also, along with an expectation of improving supply reliability and resilience. Emerging energy technologies and service offerings are putting this within realistic reach.

While not a strong theme in customer feedback, we are cognisant that new technology offerings, combined with an increasing consumer willingness to take more control of their energy options, is leading to a change in the way energy markets operate.

This change creates a necessity for us to learn about these new technologies and new energy solutions to enable our networks to support and accommodate the future choices of our customers. This has influenced our strategy to create a new Network Transformation team, which will be studying customer trends and emerging requirements, and preparing our network to accommodate them.

4.4.5 LINKING CUSTOMER FEEDBACK TO OUR ASSET MANAGEMENT PROCESS

Our asset management process provides a mechanism that links the service levels our customers tell us they require to the specific investments we make on our networks. Our asset management strategy, objectives and targets combine to provide structure to guide our engineering decisions. Chapters 5-10 describe our asset management frameworks.

Our network growth and development strategies aim to provide just-in-time capacity by using best industry practice to predict probable load growth and customer demographics. This enables us to meet demand growth without providing more capacity than is needed. Our plans to support growth in our communities are described in Chapter 11 of this AMP.

Similarly, our asset renewal strategies aim to ensure appropriate asset condition and maintain current levels of reliability in the longer term. We aim to achieve this via effective management of the health of our asset fleets via targeted maintenance and renewal. Our maintenance and renewal plans are discussed in Chapters 15-23 of this AMP.

Our plans to adapt to changing customer needs in the face of technological change and to ensure that we are able to anticipate and accommodate customer needs beyond traditional distribution services are set out in Chapter 13.

Managing our assets

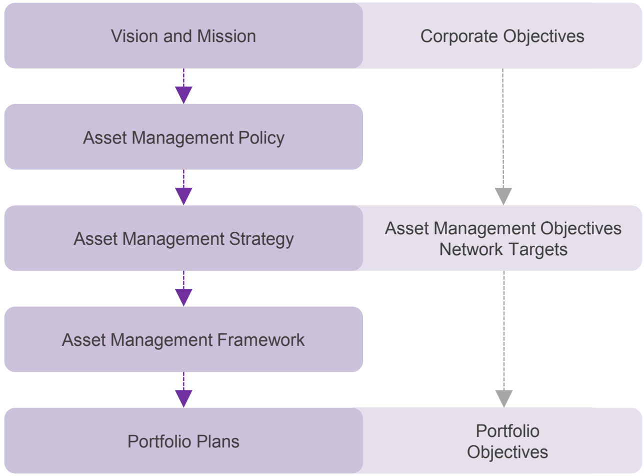
This section sets out our asset management strategy and network targets, explains our approach to investment decision-making, and describes how we are preparing for an increase in investment during the planning period.

Chapter 5	Asset Management Strategy	**21**
Chapter 6	Asset Management Framework – Governance	**28**
Chapter 7	Asset Management Framework – Capital Project Planning and Delivery	**43**
Chapter 8	Asset Management Framework – Operations & Maintenance Planning and Delivery	**56**
Chapter 9	Network Targets	**60**
Chapter 10	Enhancing Delivery Capability	**77**

5.1 CHAPTER OVERVIEW

This chapter explains our Asset Management Strategy. It sets out how we translate our corporate vision into our day-to-day investment and operational decisions. This ensures an effective line-of-sight from our Corporate Objectives through our strategies to our daily activities.

Figure 5.1: Our asset management 'line-of-sight'



As depicted above, our asset management approach provides a clear 'line-of-sight' between our corporate vision and our investment plans. This is reflected in our asset management documentation. Key elements in this line-of-sight are set out below.

Outlined in this chapter:

- **Corporate Objectives** – expressed through our corporate vision and mission.
- **Asset Management Policy** – aligns our electricity asset management approach with our Corporate Objectives. This provides overall direction and guidance for our asset management approach.
- **Asset Management Strategy** – builds on our Asset Management Policy to develop high level asset management objective and goals and set our network performance targets.

Outlined in Chapters 6-8:

- **Asset Management Framework** – provides an overview of how we implement our asset management activities. It sets out the structure we use to govern our asset management decisions.

5.2 CORPORATE OBJECTIVES

The core function of our electricity business is to deliver electricity safely, reliably and affordably to our customers, now and into the future. This forms the basis of our Corporate Objectives which are reflected in our vision, mission and values. They describe the expectations of our Board and provide the basis for our asset management governance. They also provide a reference point for our asset management decisions.

5.2.1 CORPORATE VISION

Our corporate vision below reflects the balance we, as a modern electricity distributor, seek to strike between providing a safe, secure and resilient network, supporting growth in the communities we serve, and ensuring our readiness for a changing future.

Powerco, your reliable partner,
delivering New Zealand's energy future

5.2.2 CORPORATE MISSION

Our corporate mission below encapsulates our core purpose, which is to deliver electricity safely, reliably and affordably to our customers, now and into the future. We will do so while ensuring an appropriate, sustainable commercial return to our shareholders. It reflects the importance of our other stakeholders to our business.

In profitable **partnership** with our **stakeholders**,
we are **powering the future** of New Zealand through the
delivery of **safe**, **reliable**, and **efficient** energy

5.2.3 CORPORATE VALUES

Our corporate values define our identity: who we are and what we stand for. They describe the behaviours we expect from our employees and service providers. These are summarised in **Table 5.1.**

These values define the way we go about our work and what we can expect in our relationships with others. They help define our culture, inform our decisions and give authority to our leaders.

Table 5.1: Our values

Safe	We are committed to keeping people safe.
Trustworthy	We act with integrity. We are honest, consistent and ethical. We trust each other and our external partners and work to be trusted in return.
Collaborative	We work together with our partners, contribute our capabilities and provide timely support and consideration to achieve our collective goals.
Conscientious	We are proactive, hardworking, diligent and thoughtful. We are mindful of the needs of others and of the environment. We take ownership for our actions.
Intelligent	We make informed decisions for the best outcome. We continually seek improvement and innovative solutions from our suppliers and ourselves.
Accountable	We lead. We take ownership of our decisions and responsibility for our actions. We are proactive in identifying and resolving problems.

5.3 ASSET MANAGEMENT POLICY

Our Asset Management Policy sets out high level asset management principles that reflect our vision, mission and values. It highlights our Board's expectations for the way we will manage our assets and make our decisions.

The policy has been developed to ensure we continually focus on delivering the service our customers want in a sustainable manner that balances risk and long-term costs.

Asset Management Policy

Powerco's vision is to be a reliable partner, delivering New Zealand's energy future.

Effective asset management is the cornerstone for the delivery of our vision and underpins our approach at all levels of the organisation.

We will strive to achieve the following asset management outcomes:

- Positioning the safety of the public, our staff and contractors as paramount
- Developing our networks in a way that reflects the evolving needs of our customers
- Delivering a cost-effective service by optimising asset cost and performance
- Be proactive, transparent and authentic in our interactions with our stakeholders
- Meeting all statutory and regulatory obligations

We will achieve these asset management outcomes by:

- Aligning corporate and asset management governance to ensure a singular focus
- Underpinning asset management decisions with structured processes and systems
- Ensuring asset management decisions are supported by accurate information / data
- Managing data as an asset through structured development over time
- Continually enhancing our asset management capability and skills over time
- Aligning to the best international approach through ISO55000
- Recognising the importance of people and their development to the process

We strive to be New Zealand's leading asset manager, enabling us to provide excellent customer service and a consistently safe, reliable and cost-effective service.

5.4 ASSET MANAGEMENT STRATEGY

5.4.1 OVERVIEW

Our Asset Management Strategy sets the strategic direction for managing our electricity network assets. It has been developed to achieve the following aims:

- Describe how our Asset Management Policy is used to develop asset management objectives.
- Support the delivery of best value to our customers while sustaining an appropriate commercial return for our shareholders.
- Help us achieve our core function as a lifeline utility by safely and reliably delivering electricity to our customers.
- Drive our continuous improvement programme to ensure we continue to be an efficient, forward-thinking network business.

A set of five Asset Management Objectives sit at the heart of our asset management strategy. They reflect our life cycle asset management approach. This approach considers all aspects of asset decision-making and activities from inception to decommissioning. These objectives are illustrated in **Figure 5.2** and are discussed in the sections below.

Figure 5.2: Our Asset Management Objectives

5.4.2 SAFETY AND ENVIRONMENT

Our Asset Management Policy reaffirms the safety of the public, our staff and service providers is paramount. We are committed to developing the leadership, culture and systems to support us in our drive for zero harm.

We also see ourselves as custodians of our environment. As part of this we ensure possible damage to the environment from our electricity assets and our operations is kept as low as reasonably possible. We encourage the efficient use of energy and strive to minimise our carbon footprint.

Safety and Environment objectives

Our safety objective is to safeguard the public and ensure an injury free workplace.

Our environmental objective is to cause no lasting harm to the environment.

To help achieve these objectives we have adopted a set of goals as set out in the following tables. Various initiatives to support the goals have also been defined.

Table 5.2: Safety goals

GOAL	SUPPORTING INITIATIVES
Zero fatalities to staff and contractors	Develop and implement plans to manage critical risk areas. Enhance service provider approval processes to ensure we utilise the right delivery partners. Mitigate arc flash hazards for high risk assets.
Zero lost time injuries to staff and contractors **10% year-on-year reduction in Lost Time Injury Frequency Rate**	Ongoing development of safety culture maturity with our service providers. Continual improvement in recording and reporting of safety-related issues. Fully embed safety-in-design principles in all our planning and design work. Enhancement of service provider management systems. Phasing out assets that no longer meet modern safety standards or are no longer safe to operate and maintain.
Zero public harm incidents resulting from our network	Regular public safety communication with our customers and communities. Remove defected assets, especially those in areas of high public safety risk. Targeted renewal programmes to ensure appropriate levels of asset health.
Full compliance with the Health and Safety Reform Bill	Training for Board members and staff regarding the requirements of the Health and Safety Reform Bill.

Table 5.3: Environmental goals

GOAL	SUPPORTING INITIATIVES
No significant, avoidable environmental incidents caused by our assets	Continual improvement in measuring and reporting incidents that have a real or potential environmental impact.
Designing networks and working with customers to promote efficient delivery and use of electricity	Develop and implement energy efficiency campaigns that help moderate our impact on the environment.

5.4.3 CUSTOMERS AND COMMUNITY

Good customer service is an essential requirement for any successful business. For an electricity lines business this includes delivering a reliable, resilient electricity supply. But it also covers delivering 'softer' measures such as responsiveness to customer requests, timely completion of works, effective communication about and during outages, and making it easy to deal with us.

Another core element of our asset management strategy is to engage effectively with our customers and the communities we serve. This ensures our asset management decisions reflect the level of service they desire and at a cost they find acceptable.

We are also aware that emerging technologies will provide our customers with energy alternatives. To be their energy partner of choice, we will have to thoroughly understand their requirements if we are to support them in enabling their energy choices.

Finally, our assets cross private and public land, which has an impact on our customers and communities. It is important that we mitigate this impact, while also optimising our operational costs. This requires effective communication and the support of our communities.

Customers and Community objective

Build a deep understanding of our customers' requirements and preferences. We will then reflect this through excellent customer service, and the types and quality of service we offer.

To support our customer and community objective, we have adopted the following set of goals. Various initiatives have also been defined, which will help us achieve these goals.

Table 5.4: Customers and Community goals

GOAL	SUPPORTING INITIATIVES
Effective, regular consultation about price and service quality requirements	Expand our customer focus groups to widen representation in our regular surveys and discussions.
Excellence in customer service, tested against objective performance measures	Targeted surveys of customers after outages or interactions with us to understand and enhance customer experience.
Enabling our customers' future energy choices	Increased monitoring and analysis of local and international customer trends and preferences. Transition to a Distribution System Integrator via targeted technology development.
Build effective long-term relationships with landowners and community groups	Regular communication with communities affected by our assets to discuss their rights and their experience. Professional and empathetic communication with landowners where new builds or renewal works are required.
Proactively communicate planned and unplanned power cuts to our customers	Improve access to network status information for customers through different communication channels, such as web, mobile apps and social media.
Improving our outage response, especially in remote areas	Targeted improvements in areas of low network performance providing alternative options where high network reliability cannot be economically maintained.

5.4.4 NETWORKS FOR TODAY AND TOMORROW

Our networks provide a lifeline service to communities. Reliable electricity is essential and we will maintain this supply to our customers now and in the future.

For today's network it means we have to provide electricity supply at a level of service that balances customers' quality requirements with their willingness to pay. Looking forward, this means ensuring that we are able to support those customers who choose to utilise new energy solutions such as rooftop PV and energy storage, as well as those who wish to continue taking supplies as they do today.

In addition, overseas and local studies have shown that effective planning and application of appropriate emerging technologies on our networks is essential to realise the opportunities these bring for improved services and cost-efficiency, or to moderate the cost of accommodating new distributed energy solutions. This topic is further discussed in **Chapter 13.**

Networks for Today and Tomorrow objective

We will continue to provide our customers with a cost effective, reliable electricity service that will reflect their preferences and meet their needs today and in the future.

To help us achieve our Networks for Today and Tomorrow objective, we have adopted a set of goals and associated initiatives, as set out below.

Table 5.5: Networks for Today and Tomorrow goals

GOAL	SUPPORTING INITIATIVES
At least maintain overall and disaggregated network reliability at historical levels[5] (unless specific customer requirements indicate otherwise)	Targeted asset renewals and security reinforcements to maintain historical network reliability levels.
Provide a service that reasonably balances our customers' quality expectations and willingness to pay	Refine our network security standards to reflect customer needs, in light of emerging customer requirements and willingness to pay.
In a transforming energy environment, continue to provide safe, reliable and cost-effective energy solutions by optimally mixing traditional investments with innovative network and non-network solutions	Develop a detailed future network strategy that sets out our plan for developing the network of the future.
Encourage innovative fresh approaches to traditional issues	Expand our capability and incentives for innovation, including encouraging innovation from staff.
Adopt prudent asset investment approaches given uncertain future energy demand patterns	Improve our demand forecasting approach to better reflect demographic, weather and economic trends, and the likely increased complexity of future networks. Review our network architecture based on detailed scenario analysis and adopt the least-regret outcome.
Ongoing improvement in network resilience reflecting changing community needs	Enhance our networks and communications infrastructure to support future network resilience.

5 As discussed later in this AMP, we intend to significantly expand our asset renewal programme over the planning period, partly to ensure future network reliability. During these works we expect planned outages on the network to increase, despite adopting all reasonable measures to limit the impact.

5.4.5 ASSET STEWARDSHIP

Our electricity network is extensive and made up of assets of varying age and condition. Looking after these assets efficiently is essential to the ongoing delivery of a safe, reliable and cost-effective electricity supply.

To be a good steward of long-life assets requires a thorough understanding of their performance and condition. We need to monitor and maintain assets to ensure they deliver to their required specification over their life and replace them at the appropriate time. It also requires us to be prudent operators, ensuring an asset does not operate outside capacity limits or be used in ways that are unsafe or could shorten its life.

While our network performance appears relatively stable when considered at a summary level, there are increasing signs of poor underlying asset performance driven by asset deterioration. This is evidenced by, among other things, increasing defect rates and asset health indices that are trending unfavourably.

Maintaining stable asset health is a key focus. To stabilise and reverse deteriorating performance trends we need to accelerate investment in asset renewal and on our maintenance programmes. We also have to improve our asset management support systems and processes to ensure we get the benefits of modern information technology to optimise asset investments. This will allow us to get the most value from our assets, minimise risk and ensure continuing prudent investment.

Asset Stewardship objective

Through effective management and operation our assets deliver a reliable supply to customers in a cost-effective manner, over their expected lives.

To support this objective we have adopted a set of goals, as set out below. Various initiatives have also been defined.

Table 5.6: Asset stewardship goals

GOAL	SUPPORTING INITIATIVES
Our assets perform at their designed capacity over their expected lives	Continue to develop our holistic fleet management approach to asset maintenance and renewal. Expand our preventive maintenance programme for each asset fleet, including collecting expanded asset health assessments and defect records.
Well targeted asset renewal plans to cost-effectively ensure safe and reliable performance of our network, also reflecting the needs of the future network	Improved prioritisation of asset renewals based on comprehensive condition and risk assessment. Improved prioritisation of maintenance based on a comprehensive risk framework.
Effective vegetation management around our networks, with the support of private landowners, councils and roading authorities	Adoption of good practice vegetation management.
Increasing asset standardisation, supported by a group of specifications and guidelines that ensure optimal asset life cycle performance	Continue to standardise on the minimum number of assets required to ensure the cost-effective, safe and reliable operation of our networks, and maintain appropriate commercial tension between suppliers. Maintain a comprehensive set of asset standards and guidelines for all asset classes on the network, representing best industry practice.

5.4.6 OPERATIONAL EXCELLENCE

Operational excellence is a broad concept that covers many of our activities. From an asset management perspective, striving for operational excellence has particular relevance to the following areas:

- Putting in place the skills, capacity and supporting systems need to achieve good practice asset management and service delivery (including network operations, asset maintenance and construction).
- Cost-effectively delivering services to customers in accordance with their needs.
- Effective engagement with stakeholders, including providing accurate performance reports and asset information, supporting regulatory submissions and preparing high quality material to aid company governance.
- Excellence in asset and network data collection, the management and safekeeping of this data, and the processing and analysis of data and information to support effective decision-making.
- Increasing efficiency within our planning and delivery processes to ensure the best value is achieved from our operations.

Operational Excellence objective

Ensure we have the skills, capacity, systems, and processes in place to cost effectively and reliably deliver to our asset management strategy.

To support this objective we have adopted a set of goals, as set out below. Various initiatives have also been defined.

Table 5.7: Operational excellence goals

GOAL	SUPPORTING INITIATIVES
Implement leading asset management information processes	Identify and adopt cost-effective information systems and tools that are appropriate and effective to support asset management and network operations.
Ensure cost efficient, valuable services to our customers	Supplement our risk framework to better quantify risk and ensure an appropriate balance between mitigation and cost. Enforce a transparent, commercially competitive approach to all our procurement and contract activities, adhering to best industry practice.
Comprehensive and accurate asset and network data is available to our asset managers and service delivery staff	Develop and implement an asset data quality strategy that will ensure our asset managers and operations staff are provided with comprehensive and accurate asset and network performance data.
Our electricity network and databases are secure against cyber-attacks	Improve the security of our databases, ‘intelligent’ assets, and SCADA network.
A structured risk framework is applied to our asset management decisions	Grow our asset management capability through judicious recruitment and development of staff, ensuring appropriate competency levels and range of skills.
Employ motivated, competent technical staff to look after our assets	Encourage a culture of continuous learning and innovation.
Achieve ISO55000 certification	Identify and address the necessary steps to achieve (at least) level three maturity on all measures by 2020.

5.4.7 PERFORMANCE AGAINST OUR OBJECTIVES

We have developed a group of targets against which progress towards our goals and the success of the supporting initiatives can be measured. These are set out in Chapter 9. Progress against these targets will be reported in future AMPs (or AMP updates).

6.1 OVERVIEW

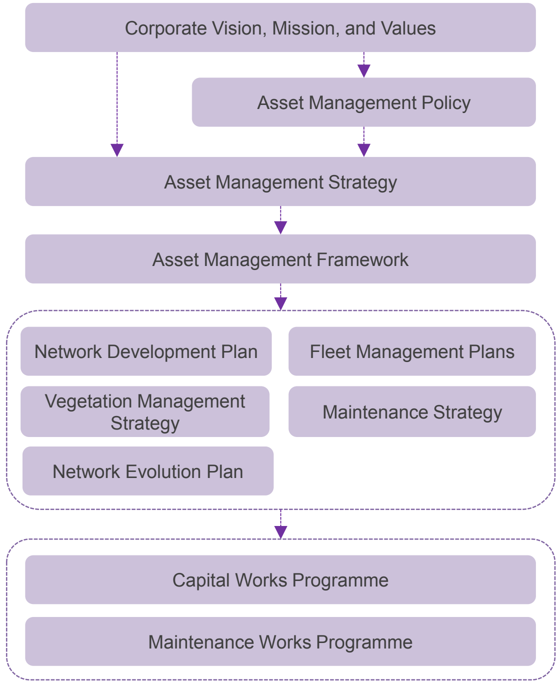
This chapter discusses our asset management governance structures and responsibilities. It considers those processes that apply to effective management of expenditure and covers the following key topics:

- Corporate responsibilities
- Our lifecycle approach to asset management
- Expenditure governance processes
- AMP Development and approval processes
- Non network asset governance processes
- Risk management processes

Our asset management thinking is aligned with leading practice as described in the ISO 55000 standard. This emphasises the importance of maintaining a 'line-of-sight' between an organisation's corporate objectives with asset management objectives and strategies through to the on-the-ground daily activities.

The way our Asset Management System is supported by our hierarchy of asset management documentation is shown in **Figure 6.1**. The concept of having a clear link between corporate objectives and daily activities is a key feature of effective asset management and underpins our governance approach.

Figure 6.1: Our asset management documentation hierarchy



6.2 CORPORATE RESPONSIBILITIES

6.2.1 OVERVIEW

Our asset management decisions are undertaken using a structured process with commensurate oversight. The level of oversight reflects the cost, risk and complexity of the decision being considered.

Our asset management decision-making occurs at various levels in our organisation, from the Board to field staff. This system of responsibilities and controls is in place to ensure decisions are made in line with our overall Corporate Vision and associated asset management policy, strategy and framework.

In this section we describe the principal governance responsibilities.

6.2.2 THE BOARD

The Powerco Board provides strategic guidance, monitors management's effectiveness and is accountable to shareholders for the company's performance.

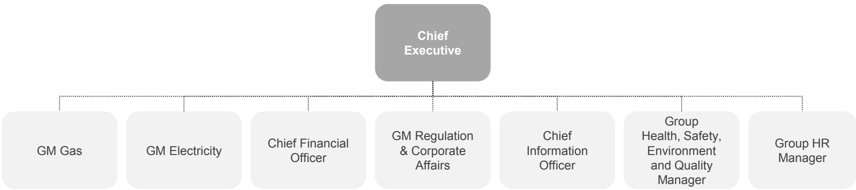
From an asset management perspective, it does this by endorsing key documentation (including this AMP), establishing our objectives and strategies for achieving those objectives. The principal asset management responsibilities of the Board are listed below.

- The Board has overall accountability for maintaining Powerco as a safe working environment and ensuring public safety is not compromised by our assets and operations
- The Board reviews and approves our AMP, which includes our medium term (10-year) investment forecasts, and our shorter term expenditure plans. The Board's Regulatory and Asset Management Committee is responsible for ensuring that our AMP is appropriate, and regulatory requirements are met
- The Board sanctions operational or capital projects involving expenditure greater than $2 million, and the divestment of any assets with a value greater than $250,000. One of the main factors the Board uses when considering projects is its alignment with the Asset Management Plan
- The Board receives monthly reports that include performance reports regarding the status of key work programmes, key network performance metrics, updates on high-value and high-criticality projects, and the status of our top 10 risks. It also receives audit reports against a prescribed audit schedule. It uses this information to provide guidance to management on improvements required, or changes in strategic direction
- The Board's Audit and Risk Committee is responsible for overseeing risk management practices and to review audit findings

6.2.3 THE EXECUTIVE TEAM

Our organisational structure is based on two asset management focused units (electricity and gas divisions), with the support of five functional units. The makeup of our executive team, which reflects this organisational structure, is illustrated in **Figure 6.2**. This structure allows the Electricity Division to focus on core activities and decisions and access specialist skills and advice as required.

Figure 6.2: Executive team structure



The **Electricity and Gas** divisions hold overall responsibility for asset investment, operational management and commercial management of each business line. A detailed breakdown of roles and responsibilities for the Electricity business line is provided in Section 6.3. Support provided from each of the specialist functional units is set out below:

The technical overlap between the gas and electricity divisions is limited, although we believe there will be opportunities for dual-energy delivery and optimal energy substitution in the future. Asset management ideas and information are increasingly being shared between the groups to help ensure a consistent approach across the company as well as learning from each other.

The **Information business unit** manages IT related non-network assets, as these are normally shared between the electricity and gas divisions. This includes asset information, Information Communications and Technology (ICT) infrastructure and telecommunications systems. It provides ICT and systems support for systems that the electricity network relies on, such as the geographical information system (GIS), outage management system (OMS) and network analysis software.

The **Finance group** is responsible for overseeing our financial affairs, as well as arranging the necessary financing to keep operations going. It works closely with the Electricity Division on areas such as expenditure forecasting and budgeting, tracking expenditure, invoicing and accounts payable. It also provides specialist legal and internal audit support.

The **Human Resources group** assists the asset management function with capability development, recruitment, training, day-to-day human resource management and advice, and performance frameworks.

The **Health, Safety, Environment and Quality team** supports the asset management function by providing direction, framework and targets for managing these critical aspects of our operations. It also assists with investigation of incidents, root cause analysis, and assessing overall health, safety and environment performance. It initiates corrective action as required.

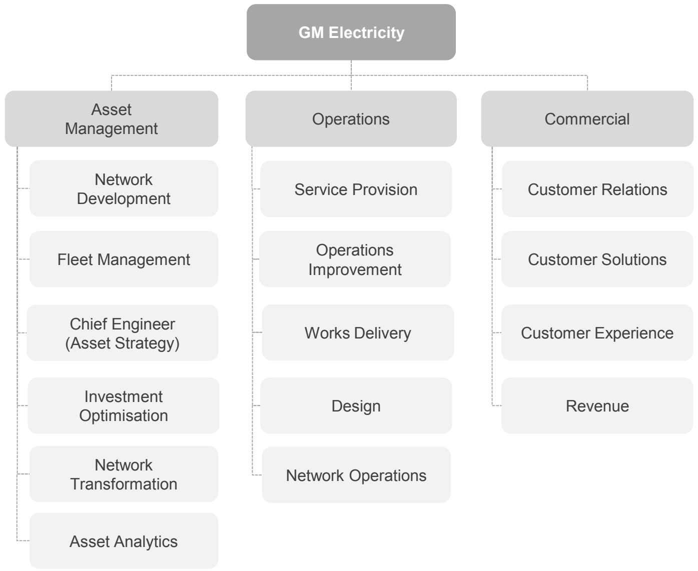
The **Regulatory and Corporate Affairs group** manages the interface with our regulators, including making regulatory submissions and disclosures (of which the AMP forms part) and engaging in the rule-setting processes. There is close interaction between this team and the asset management functions to ensure that we understand and comply with regulatory requirements, and also to obtain inputs for engagement with our regulators. The group also guides external brand and media interaction.

6.3 ELECTRICITY DIVISION RESPONSIBILITIES

6.3.1 OVERVIEW

The Electricity Division is structured to support delivery of the main asset management functions. The General Manager (GM) for electricity manages the division and acts as primary custodian of the network. The division is split into three areas with specialised teams, as depicted in **Figure 6.3**.

Figure 6.3: Electricity Division structure[6]



6.3.2 ASSET MANAGEMENT TEAM

The asset management team is responsible for translating the Asset Management Policy into a practical asset management strategy and plan. It then details the short term activities required to meet this strategy and plan, and works with the Operations team to ensure its delivery.

The team has recently been restructured to support our drive towards enhanced asset management practice, and increasing work volumes.

The functions of the Asset Management group are:

6 Noting that we regularly refine or add functions that will not necessarily be shown in organisational charts.

Network Development

The Network Development team is responsible for planning augmentations to the electricity network. This includes developments driven by increasing customer connections and demand, changing demand patterns, or increased network functionality, including increased automation and network communications. The planning processes culminate in the delivery of asset management strategies and documentation, Capex plans, concept designs, project briefs (scope and specification of capital projects) and annual work plans.

Fleet Management

The Fleet Management team is responsible for the asset management of our existing electricity network assets which are divided into several fleets. This involves the preparation of renewal and maintenance plans based on performance and condition assessment, conducting specialised engineering studies, preparing asset management strategies and documentation, Capex plans, concept designs, project briefs (scope and specification of capital projects) and annual work plans.

Investment Optimisation

The Investment Optimisation team is responsible for ensuring that our electricity investment plans (capital and operating expenditure) achieve an optimal balance in meeting the requirements of our customers, our shareholders, the regulators and the technical needs associated with running a safe, reliable network. Outputs from the team will include network investment analysis, asset risk management, the annual investment plan (network capex and opex) and the optimised 10-year investment plan.

Network Transformation

The Network Transformation team leads network activities that are aimed at readying our electricity networks for a changing energy environment. Outputs from the team include scenario development and the associated network impact assessment, emerging consumer trend analysis, research and development of emerging network and non-network solutions, coordinating pilot programmes and proofs of concept for new solutions.

Asset Analytics

The Asset Analytics team supports our asset management, by providing analytical support to the various investment and planning functions in the electricity team. This includes the development and support of network and asset analytical tools and models, managing the data required to ensure the effectiveness of these, and analysing asset and network performance information to guide asset management decisions.

Chief Engineer

The Chief Engineer’s team is responsible for network asset strategy, asset risk management guidelines, technical reviews and arbitration, and technical support for regulatory submissions, investment policies and design. This team is also responsible for overseeing the introduction of new asset types onto the network, and the development and maintenance of our asset standards.

6.3.3 OPERATIONS TEAM

The Operations team is responsible for the delivery of our AMP work programmes and operating the network. This includes overseeing field crews that undertake construction and maintenance work.

The team has been recently restructured to support the increased scale of delivery associated with CPP.

Network Operations

Day-to-day operation and access to the network is managed by the Network Operations Centre (NOC). This includes controlling network shutdowns and switching, coordinating the response to network outages, managing the load control process, maintaining the SCADA system, and ensuring adherence to contractor competency requirements.

Works Delivery

Our field service operations, including maintenance and construction, are fully outsourced. The Works Delivery group manages the day-to-day execution of contracts with our prime field service providers, as well as with further suppliers that are accessed via contestable tender markets.

Service Provision

The Service Provision Team leads the management of the various contracts with our service providers and monitors contractor performance.

Operations Improvement

The Operations Improvement function exists to lead and oversee improvements across the Electricity Operations Group and to provide leadership and mentoring to management within Electricity Operations.

Design

The Design team provides an engineering design service, preparing detailed documents for issuing to our service providers. It is also responsible for preparing suites of standard design drawings, protection designs and preparing specified capital project designs.

6.3.4 COMMERCIAL TEAM

The Commercial team is our main link with our electricity customers. It maintains our relationships with major connected customers and retailers, as well as other interested parties, such as distributed generators. It ensures all services and solutions are meeting expectations by engaging directly with customers and feeding information back into both the asset management and operations teams.

It also manages customer-initiated works (new connections or augmenting existing ones), and new customer solutions (providing alternatives or additions to conventional electricity connections).

Customer Relations

The Customer Relations team is responsible for managing relationships with key electricity customers and managing commercial agreements. It provides advance information on customers' growth intentions, to support effective planning.

Customer Solutions

The Customer Solutions team manages the connection of new customers to our network. This includes the planning of customer solutions, concluding commercial arrangements and managing contractors who do the physical connection work.

Customer Experience

The Customer Experience team is the link with the bulk of our customers, excluding key accounts. It responds to queries and resolves complaints. It is also responsible for collecting mass customer information.

Revenue

The Revenue team is responsible for structuring our pricing to ensure we obtain the income permitted under regulatory settings. It oversees our electricity revenue, including connections income.

6.4 LIFE CYCLE APPROACH

6.4.1 OVERVIEW

Effective asset management governance relies on a holistic approach that considers the full asset life cycle. This includes the creation of the asset, ease and safety of use during its life, the cost involved at all stages, and the ability to efficiently decommission and remove it at the end of its life.

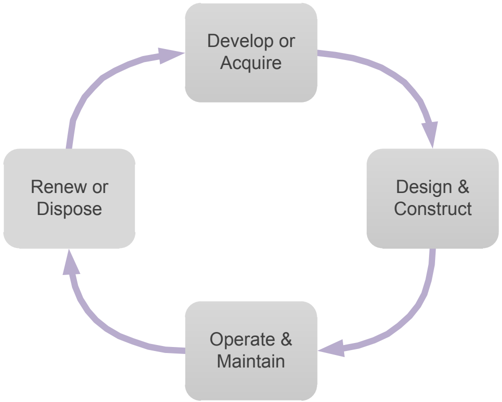
There are a number of key life cycle-based considerations when undertaking asset management activities. These are considered in detail in our Asset Management Framework and addressed as part of our fleet management plans and processes. They include:

- Decisions made at the concept and planning stages of an asset's life that will have a major bearing on its practical and safe operation
- The value of an asset being maximised if it has a lifetime of safe, reliable operation. This requires sufficient maintenance, together with appropriate operation of the asset
- The cost of an asset involving more than the initial Capex. When comparing investment options, ongoing operational, maintenance and refurbishment costs, as well as the expected life of the asset, need to be considered
- The complex decommissioning and removal of assets which can burden future asset managers if it is not considered and prepared for from the outset

6.4.2 OUR ASSET LIFE CYCLE

Our interpretation of the life cycle is shown below in **Figure 6.4**.

Figure 6.4: Asset management life cycle



The four stages of the asset life cycle and where they are addressed in our asset management processes (and the AMP) are described below. Effectively managing assets over their full life cycle requires close coordination of decisions and activities across the Electricity Division.

Develop or acquire

This covers the creation of an asset through development or acquisition, spanning the identification of the initial need, assessing options and preparing the conceptual designs. At this point it is handed over to our Design and Works Delivery teams. New assets are mainly constructed to address:

- Network growth and security (discussed in Chapter 11)
- Network reliability enhancements (discussed in Chapter 12)
- New customer connections and relocations of existing assets (addressed in Chapters 24 and 25)
- Future network needs (discussed in Chapter 13)

Design and construct

This covers detailed design, tendering, construction and project management, commissioning and handover of new assets to the operational teams. How this is done for our asset fleets is discussed in Chapters 15-21.

Operate and maintain

This covers the operation and maintenance of our electricity assets. It aims to ensure the safe and reliable performance of our assets over their expected lives. This is discussed in detail in Chapter 23.

Renew or dispose

This covers the process to decide when to renew and/or dispose of assets. Generally, the decision to renew or dispose of existing assets is needed when an asset becomes unsafe, obsolete, or would cost more to maintain than to replace. How this is undertaken for our asset fleets is addressed in Chapters 15-21.

6.4.3 LIFE CYCLE APPROACH TO GOVERNANCE

Effectively managing assets over their full life cycle requires close coordination of decisions and activities across the Electricity Division. Some of the more important activities are summarised below:

Developing asset strategies

Developing our assets involves broad collaboration. This includes decisions about the services and service levels we wish to provide, how we will manage our assets, the network architecture and other performance goals. This requires a long-term view, with the whole-of-life cost and performance of assets the central consideration.

Effective asset management relies on quality information about how assets and networks are performing. This information, which is largely provided by our field staff and operations teams, is key to good life cycle-based decision making.

Planning and design

Once the need for new electricity services or assets has been identified, we conduct a thorough review of the options available to achieve this. These options are considered based on full life cycle considerations. This involves close cooperation by the Asset Management team with the Service Delivery and Operations teams for input on the operability and safety implications of solutions, as well as deliverability.

Safety-in-design is a key consideration during planning and design. It is recognised that the intrinsic safety of our installations is heavily influenced by decisions made at this early stage.

Construct

During construction, further opportunities arise to influence the whole-of-life performance of assets. This not only relates to the quality of work, but also factors such as ensuring good records are created and asset specifications are incorporated into our maintenance procedures.

Our technical standards provide an essential guide for construction that ensures we are able to deploy standardised assets of a consistently high quality. This helps optimise the cost during the operational phase.

Operate

The manner in which assets are operated is a key factor in how they perform and how long they remain serviceable. Our operations procedures aim to ensure our assets perform as designed. This includes operating assets within acceptable operating parameters, which may change over the life of an asset as they degrade.

Feedback is sought from the operations teams during the planning process to ensure operational issues are identified and avoided in future installations.

Maintain

Our maintenance standards are developed by the asset management team, taking into account feedback from the operations teams. The manner in which assets are maintained is another key factor in how assets perform and how long they remain serviceable. Our maintenance procedures are designed to ensure assets remain safe and serviceable over their expected lives in a cost-effective manner.

Feedback from maintenance crews is invaluable for operations and planning purposes. This is where most of the information about operating conditions and asset performance is acquired. This is essential if we are to continually improve our planning and operations practices.

6.5 EXPENDITURE GOVERNANCE

6.5.1 OVERVIEW

We have processes to approve all Opex and Capex. This ensures our governance objectives are met and we make prudent and efficient decisions.

Each year the budget and focus of our expenditure is approved by our Board. The annual Electricity Works Plan (EWP) is approved by the GM Electricity under delegation, reflecting the board’s direction.

Once the EWP is approved, the projects it contains are subject to further individual approval based on our delegated financial authority (DFA) policy. Any changes to project scope requiring additional expenditure triggers further review which is subject to original DFA limits.

This section describes how asset management decisions are made and approved in line with our governance framework.

6.5.2 EXPENDITURE PLANNING

We broadly have eight levels of asset management expenditure planning, ranging from strategic decisions by the Board and CEO, to approval of operations and maintenance decisions by operations staff or field crew. Each layer of governance is proportionate to the significance of the decision being made. These layers have been developed to mirror and support ‘line-of-sight’ between our Corporate Objectives and asset management activities.

Table 6.1 provides an overview of these expenditure planning governance levels.

Table 6.1: Asset Management Expenditure Planning Responsibilities

LEVEL	PURPOSE	RESPONSIBLE	DOCUMENTATION
Corporate strategy	Setting high-level objectives and targets for the company	CEO, Executive	Vision, Mission, Values, Corporate objectives, AM Policy, Business plan
Asset Management Strategy	Supports corporate objectives, sets asset management objectives, goals and targets	Asset Manager	Asset Management Strategy, Asset Management Framework
Asset Management Plan	The plan to implement the asset management strategy. It sets out the 10-year investment plan, drawing on the short-, medium- and long-term planning documents.	Asset Manager	Asset Management Plan
Long-term planning	The plan for developing and structuring the network and its bulk supply points to meet the needs of customers in the long (up to 20 years) term.	Network Development Manager, Asset Manager	Long-term Network Development Plan
Medium term planning	Fleet, network development and operating activity specific plans to support meeting our network targets, for the next 10 years. This includes the required expenditure on these activities.	Asset Manager, Network Development Manager. Asset Fleet Manager, Investment Optimisation Manager, Network Transformation Manager	Network development plan; Fleet Management Plans; Maintenance strategy; Network evolution plan; Deliverability Plan
Annual plans	Planning of capex and maintenance delivery programmes	Asset Manager, Network Development Manager, Asset Fleet Manager, Operations Manager	Electricity works plan; Annual maintenance plan

LEVEL	PURPOSE	RESPONSIBLE	DOCUMENTATION
Detailed project plans	Detailed planning of project and activity delivery	Network Development Manager, Asset Fleet Manager	Project briefs, business cases and board papers
Works Delivery and Field Operations	Oversight of capital project and maintenance delivery	Works Delivery Manager, Project Managers, Network Operations Manager	Detailed construction schedules, detailed maintenance schedules, outage schedules, tendering material

6.5.3 DELEGATED FINANCIAL AUTHORITY

DFAs are allocated in accordance with our corporate governance charter and group delegations of authority. They set out the limits to which managers are allowed to authorise expenditure. The DFA policy also sets out the process for approving payments, and the cross-checks built into this. Application of the DFA policy is externally audited on an annual basis.

Applicable limits reflect whether it is Capex or Opex, network or non-network, and budgeted or reactive. The typical DFAs for our Electricity Division are as listed in **Table 6.2**. The limits are set out within our sub delegation standard which is a controlled document approved by the CEO.

Table 6.2: Delegated Financial Authority limits

LEVEL	CAPEX LIMIT	OPEX LIMIT
Board	>$2m	>$2m
CEO	$2m	$2m
GM Electricity	$1m	$1m
Senior managers[7]	$600k	$600k
Other managers	$300k	$300k

[7] The Operations Manager may approve budgeted network Capex and Opex up to $750k.

6.5.4 APPROVAL STAGE GATES

6.5.4.1 OVERVIEW

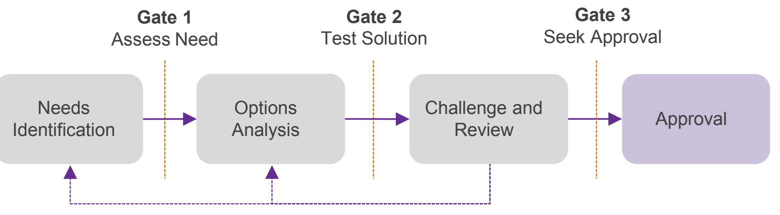
Our decision-making approach for approving network investments uses a stage-gated challenge and approval process (see **Figure 6.5**). This ensures appropriate governance is applied and challenges are posed at appropriate stages as investment plans are developed and refined.

This section describes our generalised stage-gate process for network expenditure. While Opex and Capex undergo similar approval processes, these differ based on the complexity of the works and whether the work is routine.

The degree to which we use this process is also commensurate with the size of the works. For example, small routine projects may be approved as a large bundled programme.

The discussion below focuses on network expenditure, with non-network investment governance covered in **section 6.8**.

Figure 6.5: Network Capex approval stages



Projects pass through stages of assessment and challenge up to the point where they gain final approval according to our DFA policy.

This process also applies to volumetric asset renewal, routine growth works, and to reactive replacement work. In these cases, works may not require full options analysis and may not be subject to Gate 2.

Projects are identified by the members of the various electricity teams, in line with their areas of responsibility. This ‘needs identification’ occurs before entry to the stage-gate process.

6.5.4.2 GATE 1 – ASSESS NEED

The first approval stage-gate is a review of identified investment needs, generally by the relevant team leader. This is a detailed review of the underlying need and the assumptions underpinning the timing of the investments. The approach taken to assessing the need will vary by investment type and size. Some examples of these assessments are:

- **Growth and security** – initial assessment is generally undertaken by the relevant engineering team leader, with needs mainly arising from demand growth or new developments. Growth and security needs are assessed on whether the technical analysis is sound; and whether work is aligned with customer requirements and/or reasonable demand growth expectations.
- **Renewal** – needs are identified from a range of sources of which condition (defects) data is one of the most important. Needs are assessed based on the factors put forward as justification (eg asset condition or safety risk), the long-term need for the asset, and the proposed solution. These assessments are generally undertaken by the relevant engineering team leader.
- **Customer connection and relocation** – needs arise from requests for works from customers or other stakeholders such as the New Zealand Transport Agency (NZTA). The need for investment following these requests is assessed by the Commercial team following advice from the Asset Management team.
- **Future technology** – research or proof-of-concept needs are assessed on their alignment with our future network strategy and the robustness of the proposal.
- **Reactive works** – relate to assets that are damaged by third parties, other external factors, or fail during operation. Actual projects are not identified in advance. These works are usually moved directly to the approval stage.

Once needs have been identified and assessed they pass on to the options analysis stage and then Gate 2.

6.5.4.3 GATE 2 – TEST SOLUTION

The second gate occurs after options analysis and is a review of the chosen solution. It also reviews the initial decision made at Gate 1. This review assesses the proposed solution against a range of criteria, including consistency with our overall asset management objectives, cost effectiveness, technical feasibility and its deliverability. Cost estimates for projects are also assessed.

The approach taken to test the proposed solution will vary by investment type and scope. Some examples are:

- **Renewal** – solutions are generally tested by the Asset Fleet Manager. This review assesses whether renewing the asset(s) and its timing will support our overall asset management objectives. Cost effectiveness and deliverability are important considerations. This may include testing against non-network and/or Opex solutions.
- **Growth and Security** – solutions are generally reviewed and tested by the Network Development manager. This review assesses whether the proposed solution and its timing support our overall asset management objectives. Solutions are challenged based on whether the supporting technical and costing analysis is sound, the solution will meet future demand growth projections and it represents the least cost technically feasible solution. The degree to which non-network solutions were considered is also tested.
- **Consumer connections and asset relocations** – solutions are generally reviewed by the Commercial Manager. However, since these projects are driven by third party requirements and they generally pay for most of the work, the extent of options available is limited...
- **Network Evolution**– proposals are generally reviewed by the Network Transformation Manager. Research-based investments are tested to assess the expected learning, potential network benefits, and the practicality of the activity proposed.

Approved solutions form the basis of our overall portfolio forecasts and are included in our draft EWP. Certain works are then subject to further challenge and review in Gate 3. The remainder go for final approval at a level aligned with our DFA policy (see Section 6.5.3 above).

Briefs are prepared for projects and programmes at a level of detail consistent with the size and complexity of the work. These are completed by the various Asset Management teams, and are subject to a deliverability review by the Works Delivery team.

6.5.4.4 GATE 3 – SEEK APPROVAL

The seek approval gate (Gate 3) is the final pre-approval challenge for projects. At this stage, projects are subjected to more detailed planning, cost estimation and final consideration of options than at the early gates. This final step provides further opportunity to challenge individual projects on additional information that became available following more detailed planning.

This gate has two main aims. The first is to further challenge significant expenditure or complex works at a governance level aligned with our DFA policy. This is to ensure they are ready for formal approval. This process will refer to earlier stage gates so that any concerns or feedback can be addressed.

The second aim is to prioritise and optimise expenditure across our expenditure portfolios. This includes considerable interaction through workshops across the various teams in the Electricity Division. Works are subjected to a prioritisation process (which takes into account available funding and internal resources), a works integration review (ensuring growth and renewal projects are complementary) and a constructability review (ensuring the necessary construction and commissioning resources are in place and that outage windows will be available). Expenditure optimisation is discussed in more detail in Chapter 7.

Capex works are prioritised and integrated (by timing or location) with our maintenance programmes to achieve synergies from simultaneous and sequential works. Benefits of this include reduced outages and lower costs. Three main constraints considered in the works integration process are:

- **Deliverability** – workloads by portfolio are adjusted to account for potential deliverability constraints. This allows us to more effectively allocate sometimes scarce resources across portfolios.
- **Forecast resources** – we forecast the resource requirements of the works plan and make adjustments to ensure efficient use of internal and external resources.
- **Required outages** – when scheduling works, we seek to minimise outages and planned interruptions to customers.

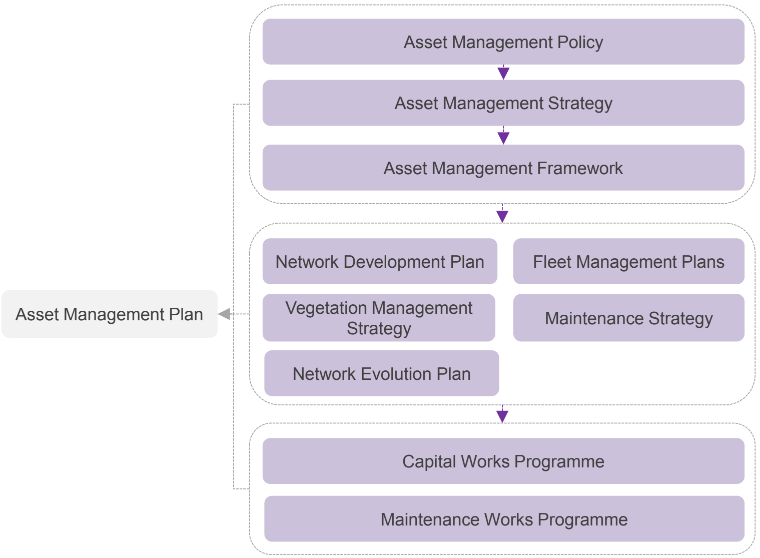
Once approved, delivery of the project becomes the responsibility of the Works Delivery team, with the project manager having overall responsibility. During execution of a project, there are several further governance steps relating to procurement and progress measurement, scope changes, and works acceptance.

6.6 AMP DEVELOPMENT AND APPROVAL

Our AMP captures the key elements of our asset management document suite in a summarised form. It is an important means of explaining our approach to managing our assets to internal and external stakeholders. It aims to meet our Information Disclosure obligations.

It summarises our internal asset management documentation as depicted in **Figure 6.6**.

Figure 6.6: Internal asset management documentation



Our AMP summarises our strategic asset management documents (our policy, strategy and framework). These documents form the basis of our asset management objectives and are approved at Board and CEO level.

The AMP includes our prioritised 10-year network investment plans, with associated capex and opex forecasts. Year 1 of the investment plan in the AMP forms the initial basis of our electricity works plan.

The portfolio plans include our area plans, fleet management plans and our network Opex strategies. These are approved by the GM Electricity and form the basis for our long-term forecasts. All forecasts are challenged by the GM Electricity before inclusion in the AMP. In addition, our AMP forecasts are tested against funding arrangements prior to commitment. This includes comparisons to revenue allowed under the DPP.

Our works programmes for capital projects and maintenance form the basis of our short-term forecasts. These are also approved by the GM Electricity and reflect our asset fleet expenditure forecasts, customer connections forecast, and network Opex forecasts.

The AMP is developed with oversight and input from our regulatory team, which advises on relevant Information Disclosure and certification requirements.

Reflecting its role as a key stakeholder document, the AMP is reviewed by our Executive Team and ultimately approved by the Board. As part of this process, proposed expenditure plans are again scrutinised and challenged. This may include obtaining the opinion of external independent reviewers and advisors.

6.7 ASSOCIATED PLANNING DOCUMENTATION

The suite of planning documents and processes that underpin our network capital and operating expenditure investment plans are shown in **Table 6.3**. The outputs of the various plans are consolidated in the Asset Management Plan.

Responsibility for preparing the draft EWP – where the actual work to be executed in the year is consolidated - lies with our Network Development, Fleet Management, and Works Delivery teams. The former two owns the plan, while the latter provides advice on deliverability, outage planning and resource availability. Inclusion of projects into the draft plan is tested using our stage-gate process.

Following the gating process, the plan is submitted to the GM Electricity for formal approval. As part of this approval, the rest of the executive team can provide further challenge and feedback. Ultimately the EWP is approved by the GM Electricity in discussion with the CEO.

The annual electricity budgets are a key input into the EWP. This budget is subject to challenge by the Board, which ultimately approves it. Typically the budget reflects the commitments set out in our AMP and the budgets are discussed and challenged by the Board in this context.

Network maintenance and vegetation management plans are prepared for a 10-year window. By their nature, these activities do not lend themselves to the same detailed long-term planning as larger capital projects. Maintenance planning is therefore generally done on a portfolio basis, with only activities or programmes that represent material changes to existing practices separately identified in the 10-year plan.

Table 6.3: Capital works plans and horizons

PLAN	HORIZON	PURPOSE	REVIEW FREQUENCY
Long-term Network Development Plan **(under development)**	20-year	Describes our long-term network development needs, particularly relating to bulk-supply points, major long-term network upgrades and re-architecture plans.	Two-yearly full update Summary update in between
Network Development Plan	10-year	Sets out growth and security plans, broken down into the 13 planning areas. It also covers network augmentations for automation, reliability and communications.	Annual update; two-yearly comprehensive review
Fleet Management Plans	10-year	Sets out the renewal and maintenance requirements for each of our 25 asset fleets (grouped into 7 main portfolios), and the associated projects and programmes.	Annual update; two-yearly comprehensive review
Network Evolution Plan **(under development)**	10-year	Sets out our plan to evolve to a Distribution System Integrator, covering the intended research, development and proof of concept work to support this. Also addresses innovative applications that are being implemented, but are not yet mainstream planning solutions.	Annual comprehensive review and update[8] Annual programme update
Deliverability Plan	five-year	Sets out our approach to ensuring that sufficient resources (contracting and material) are available to undertake the proposed network construction and maintenance works for the next five years.	Two-yearly comprehensive review Annual programme update
Annual works-plan (Capex)	one-year	Details the construction works planned for a financial year, drawing from the AMP and longer-term plans. Reactive replacements (renewal required as a result of unforeseen asset damage) are separately allowed for in the works-plan, based on historical run-rates.	Yearly
Business cases and board papers	Project-specific	Details the proposed major project solutions. Formal board papers are prepared for projects requiring board sign-off.	Per project
Project briefs and designs	Project specific	Describes capital projects in sufficient detail to allow detailed designs to be prepared, or in some cases to issue construction tenders. In most cases designs are prepared before issuing tenders.	Per project

8 As new technology and customer applications are continually evolving at an increasing pace, it is essential to review and update the network evolution strategy more regularly than the conventional business plans.

6.8 NON-NETWORK ASSETS

6.8.1 OVERVIEW

We use separate but similar processes to govern our non-network investments. These include assets that support the operation of the electricity business, such as information and technology systems and asset management systems.

Similar to network governance, strong and committed governance of non-network projects is critical to the success of change initiatives undertaken.

Good governance structures and processes help avoid poor project and programme selection at the portfolio level and minimise poor execution at the project and programme level. Our non-network governance and delivery model is consistent with practices used by peer utilities.

All non-network investment decisions are undertaken within a structured and considered process with proportionate oversight. At a high level our governance process is responsible for addressing the following key questions:

- Which initiatives complement our strategic direction?
- What are the right programmes/projects to do?
- How much change can the organisation absorb?

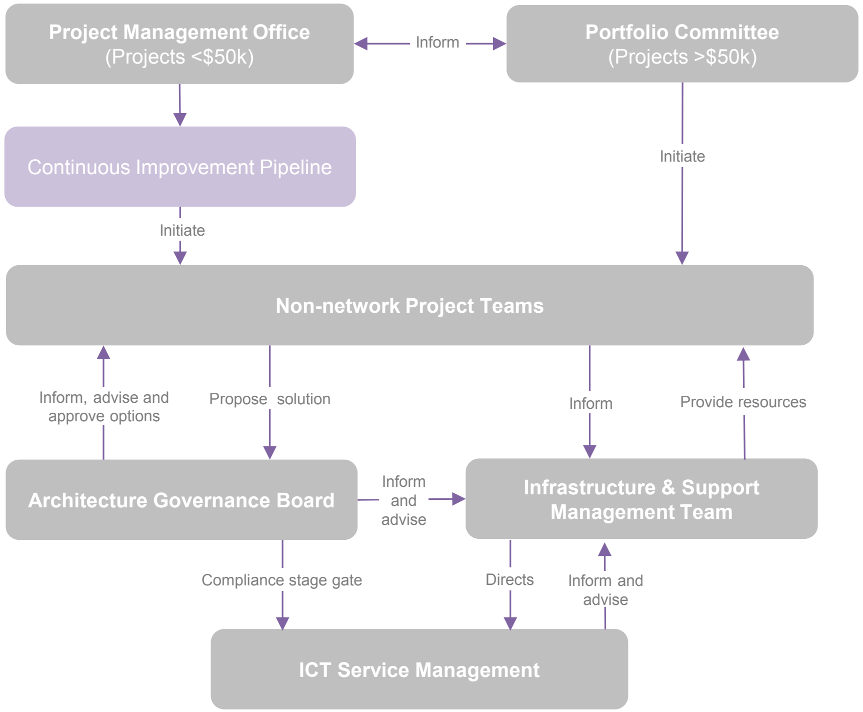
- Which initiatives are the most beneficial?
- What can the organisation resource?
- What can we afford?
- What are the risks and impacts?

The remainder of this section explains how our governance function oversees our processes to identify and deliver non-network initiatives and associated investments.

6.8.2 NON-NETWORK GOVERNANCE GROUPS

We have established a number of internal governance groups to ensure a prudent approach to delivering non-network assets. The interactions between these groups and our operational and project teams are summarised in **Figure 6.7**. Their roles are explained in the remainder of this section.

Figure 6.7: Overview of non-network governance groups



Project Management Office (PMO)

The PMO is our main authority and competency centre for project, programme and portfolio management. Its key roles include guiding projects and programmes to a successful conclusion and providing advice to the project and portfolio committees. It also provides technical support and advice to the Portfolio Committee.

Portfolio Committee

The Portfolio Committee is made up of senior managers across our business. Its key function is to review and approve projects. It assesses and manages the impact of change on the company and ensures effective controls are in place. The committee also ensures appropriate project controls are in place.

Architecture Governance Board

This board is an essential element of our ICT governance. It ensures consistent alignment with business strategies, and provides strategic and tactical direction on ICT investments. It fulfils a key technology governance role supporting the GM Operations Support in setting and implementing our strategic technical architecture.

In addition, the Architecture Governance Board assesses the impact of technology change against the following criteria:

- Degree of alignment with our technical strategies and ICT principles
- Impact on cost of service, security, health and safety, and other operational concerns
- Constraints that may impact the delivery of the proposed scope
- Whether solutions should be flagged as obsolete, and monitored to ensure replacement by the agreed disposal date

6.9 RISK MANAGEMENT

All asset management decisions are linked, in various degrees, to managing risk. For an EDB this includes minimising safety risks, avoiding capacity constraints, managing asset failure risk through maintenance and renewals, managing procurement and delivery to ensure financial prudency, and assessing and mitigating possible High Impact Low Probability (HILP) events. Managing risk requires sound governance processes to direct effective procedures and controls.

Consequently we have a dedicated Risk and Assurance team to oversee the application of our risk management policy and framework.

These together with our legal compliance programme align with relevant standards.[9]

[9] These standards include AS/NZS ISO 31000:2009, NZS/AS 3806:2006, NZS 7901:2014 and AS/NZS ISO 14001:2004.

6.9.1 RISK MANAGEMENT FRAMEWORK

Risk management is applied at all levels of our organisation – from decisions in the field through to discussion at our Board. The purpose of risk management is twofold:

- To understand the types and extent of risks our business and operations face
- To respond effectively to these through appropriate mitigation approaches

To achieve this, our approach is to identify and understand the cause, effect and likelihood of adverse events occurring. We then develop and implement strategies to manage such risks to an acceptable level. These efforts are supported by a comprehensive risk monitoring and reporting regime, based on a company-wide set of risk assessment criteria and a risk matrix.

These processes encompass all aspects of our business including:

- Health and safety
- Environmental
- Asset integrity and performance
- Operational continuity
- Regulatory and legal compliance
- Financial and commercial

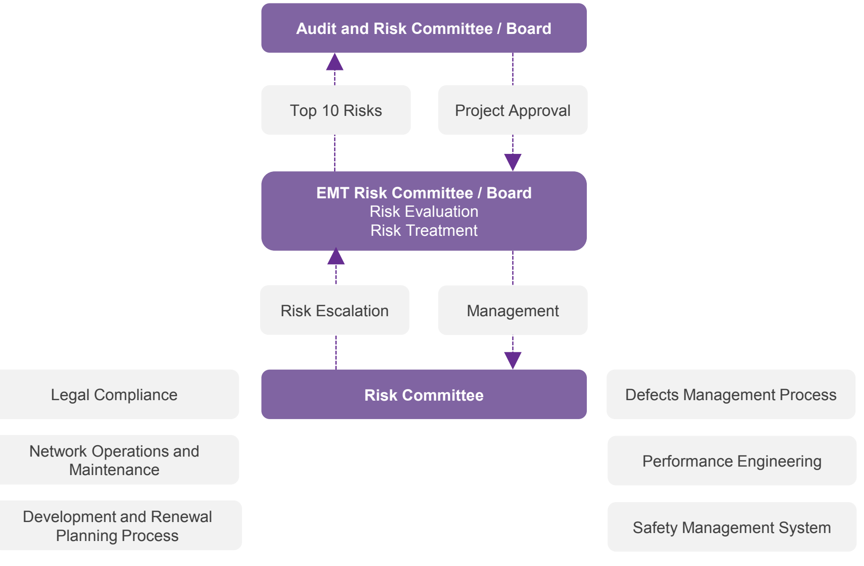
The framework we apply to identify, assess, treat, monitor and review risks is consistent throughout the business. The risk management process includes the following activities:

- **Identification** of risks throughout the business takes place via workshops in which a variety of techniques are used eg SWOT analysis. The Risk and Assurance team manage this process.
- **Analysis** of risk involves developing an understanding of the causes and sources of the risk, its likelihood and consequences, and existing controls. Our risk management application, Methodware, allows the risks, controls and action plans to be monitored and updated.
- **Evaluation** and ranking of risk is based on the results of the analysis phase. Decisions are made on which risks require treatment and in which priority.
- **Treatment** options are deliberated by management and depend on severity and ranking. The options to treat risk include risk avoidance, reduction of likelihood or consequence, elimination, acceptance, or sharing.

Our management has responsibility for establishing the risk management framework. The Risk and Assurance team assists across all levels of the business. For example, departmental managers and employees are responsible for risk identification and the operation of mitigating controls. Managers also ensure staff are aware of their risk management obligations through training and assessment.

Our Board is accountable for the effectiveness of the risk management framework and its practices. This helps to ensure risk management extends throughout the hierarchy of the organisation. The Board is responsible for governing risk policy development and has an Audit and Risk Committee (ARC) that oversees risk management practices. The executive team reviews risk and audit issues regularly to determine possible changes to the strategic and operational environment. Our risk management process is illustrated in **Figure 6.8.**

Figure 6.8: Our risk management process



6.9.2 RISK REGISTER, MONITORING AND REPORTING

We use a risk register to record and monitor risks. The register is regularly maintained, updated and audited, as well as being reviewed by senior management. The highest risks are reported to senior management on a monthly basis. These, together with Electricity Division risks, are reported to the ARC at least quarterly.

Our risk monitoring process aims to:

- Ensure risk controls are effective and efficient
- Identify improvement opportunities from risk assessment and incidents
- Detect and facilitate responses to changes in internal and external environments
- Identify emerging risks in a timely manner

Examples from our risk register have been included in Appendix 6.

6.9.3 ASSET RISK MANAGEMENT

Risk management is an important component of good asset management. The consideration of risk plays a key role in our asset management decisions. These range from network architecture planning and asset replacement decisions, through to operational decisions. The assessment of risk and the effectiveness of options to minimise it is one of the key factors in our investment choices.

Asset strategy and planning processes as risk management tools

Our asset management systems and our core planning processes are designed to manage existing risks and to ensure emerging risks are identified, evaluated and managed appropriately. Our approach is to seek specific instances where features of our network which should make us resilient, do not suffice or apply. In particular, the following assessments are used:

- **Capacity and Security standards assessment** – our demand forecasting works development process includes formal evaluation of forecast loads on our networks against our security criteria. We formally assess every instance where security standards are not met, consider the associated risk, and make an informed decision regarding risk treatment.
- **Maintenance and renewal strategy** – our maintenance and renewal planning processes, as set out in our fleet management plans, are designed to ensure we effectively manage the risks associated with fleets of assets over their lifecycle.
- **Formal risk review and signoff** – material deviation from targeted security standards, design operating condition, or standard designs are evaluated as part of the annual works prioritisation process. Our processes include formal requirements to manage the risks identified, including mandatory treatment of high risk items and formal management signoff where acceptance of moderate risks is recommended
- **Generic risk management** – we use structured risk capture and management processes, including Bow Tie HAZID assessments, to ensure key residual risks arising from our planning process are visible and signed off at an appropriate level.

6.9.4 HILP EVENTS

Our governance processes are designed to effectively manage the implications of High Impact Low Probability (HILP) events on our networks. We achieve this via a focus on the following key areas:

- **Creating resilient networks** by designing them in a way that makes them easy to repair and reconfigure
- **Considering HILP in our design process** to improve resilience where we know specific HILP risks exist eg creating independent physical routes for redundant circuits feeding important loads
- **Taking an active role in CDEM activities** associated with any failure in order to reduce vulnerability eg establishing contingency plans to deal with the consequences of (as yet) unknown modes of failure

6.9.4.1 CREATING RESILIENT NETWORKS

Our networks are designed to minimise the potential for high impact events to occur. We design our networks in a way that, as much as possible, makes them easily repairable and easily reconfigurable when events occur. Key features that help minimise the impact of events include:

- **Geographically diverse** networks mean that natural disasters will impact only part of our networks.
- **Multiple supply points** on our networks, from multiple grid exit points, limit the impact of upstream failure to localised areas.
- **Overhead construction** means a high proportion of our network is overhead, which is more resilient to natural disasters and easier to reconstruct than underground networks.
- **Standardised equipment** utilised on our network can be reallocated/rebuilt easily in the event of failure.
- **Earthquake resilient** facilities have been progressively upgraded to ensure resilience to earthquakes.
- **Multiple control options** mean that we have alternative control and emergency management capability available in the event that the New Plymouth facility is disabled.

6.9.4.2 CONSIDERING HILP FOR SPECIFIC SENARIOS

The nature of our networks make them resilient to HILP events, and with few exceptions (typically related to seismic strength) our sites comply with all applicable legislative requirements and provide levels of security appropriate to the types of loads they supply.

We are conscious, however, that some installations require specialist designs given that known HILP risks that exist. In these cases we apply specific risk treatments as part of our project development and design process. Some recent examples are noted below to illustrate this process:

Example 1: Essential services reviews. We pay particular attention to essential services such as sewage and town water supply pumps. For example Whanganui District's water supply comes from a series of bores and pumps in a rural location fed by a single cross country subtransmission line. In association with the local council, we decided that an effective, economical means of mitigating the risk of power supply failure was to install a diesel generator at one of the water supply sites.

Example 2. Lessons from other networks. We consider HILP events highlighted by other operators. For example we are currently assessing the risk and consequences of termination failures in the cable joints at the Kinleith GXP in the light of the 2014 Penrose cable fire incident. Any resulting design changes here will be coordinated with forthcoming cable and GXP 11kV switchboard replacements

Example 3. Implementing industry guidelines. We review and adopt industry best practice guidelines where they apply to HILP. For example. we are currently working through risk mitigation for arc flash assessments which are also based on HILP assessment.

6.9.4.3 AN ACTIVE APPROACH TO INCIDENT RESPONSE

As a Lifelines Utility we have responsibilities under the CDEM Act for maintaining the services provided by our essential infrastructure.

We have an active and formal process of response management in place that covers the full range of natural events which impact our network. Scenario testing has been completed through a range of studies to understand the impact on our networks including modelling the effect of a volcanic eruption and understanding the susceptibility of essential assets (such as our depots) to liquefaction.

However it is not enough to consider only our own assets. Many HILP events have outcomes that involve a complex web of different kinds of infrastructure. We take part in Lifeline Advisory Group meetings where different infrastructure representatives meet to discuss response readiness. At semi-regular intervals we take part in regional exercises to act out response to major events, and participate in actual events.

Recent examples include the flooding along the banks of the Whanganui River where we had to isolate around 160 affected customers from power supply. Another example was where a substation was flooded due to blockages in the storm water system nearby. This caused the substation to be out of service for several days while it was cleaned up and active management via the local CDEM group was a critical part of our response.

The contingency plans we have in place are discussed in more detail in section 6.9.5 below.

6.9.5 CONTINGENCY PLANNING

6.9.5.1 OVERVIEW

Our primary overarching emergency plan and procedures are set out in our Electricity Supply Continuity Plan (ESCP). The ESCP sets out the composition, authority, responsibilities and the reporting structure for electricity emergency response teams and resource allocation. Individual risks are not the focus as procedures are designed to ensure the support structure mobilised is appropriate to the particular emergency situation. Testing of the ESCP and training of staff is ongoing.

The aim of this plan is to sustain electricity network capabilities through abnormal, emergency situations by effective network management and practices.

The plan is designed for emergencies, ie events that fall outside of the ordinary operation of the network.

Table 6.4 provides an overview of the main plans and procedures that support the effective operation of the electricity network in emergency situations.

Table 6.4: Emergency plans and procedures

OBJECTIVE	DESCRIPTION
Incidents (non-ESCP)	Incidents are relatively common but unpredictable events that can be managed within the normal operating framework of the NOC. These would be handled by personnel as virtually a routine job and would normally not require the presence of a supervisor on-site for the full duration of the operation. Examples include: – Reported lines down or pole fires – 'No-power' calls – Network faults
Emergencies (ESCP)	An emergency is an unplanned event that presents or has the potential to present a major disruption to the normal operation of the network. An emergency is too big a problem to be handled effectively using business-as-usual resources and capabilities, eg without bringing in extra staff who are not on call. Events that may cause, or be lead indicators for, emergency situations include (but are not limited to): – Natural disasters (flooding, earthquake, volcanic eruption, cyclone, tsunami) – Major transmission network or generation failure – Significant natural or human threat or impact to the NOC A network emergency would require the presence on-site of a supervisor and, depending on the situation, a senior manager at the emergency control centre. General guidelines for classification of an event as an emergency situation are set out below: – Loss (or potential loss) of 10,000 customers or 20MVA of load (or greater) where this is likely to be sustained for more than six hours – Loss (or potential loss) of between 5,000 and 10,000 customers or between 10 and 20MVA of load where this is likely to be sustained for more than 10 hours – The declaration of a civil defence emergency – The evacuation of the NOC other than for a fire alarm

Other plans and procedures that support the ESCP include:

- Generic emergency procedures, such as the major network incident and severe weather event procedures.
- Specific emergency plans, such as the Pandemic Preparedness Plan and the Volcanic Ash Recovery Guidance, which outline tailored responses that are appropriate to a specific type of emergency.
- Support systems contingency plans, including the Operational Communications Contingency Plan, SCADA Contingency Plan and the Load Management Contingency Plan, which provide guidance on how to support these critical functions when a failure occurs.
- Civil Defence emergency management and liaison standards, which guide the relationships with the Civil Defence authorities.

A comprehensive set of site-specific substation contingency plans are in place. These identify known local risks and operational options for dealing with local network problems that could arise.

6.9.5.2 MAJOR NETWORK EVENT PROCEDURES

Major network incident and severe weather event procedures outline the generic emergency response process that is used to respond to a wide range of emergencies. They provide guidelines for assessing the extent of the damage or threat, making necessary preparations, and responding to severe weather events and major incidents that cause extensive loss of supply to customers. They provide a basis for communicating and establishing a common understanding of the specific roles, responsibilities and activities to be undertaken in response to incidents.

The procedures scale up to and connect with the more comprehensive ESCP. Depending on the event and its effect or likely effect on the network, the NOC will announce an appropriate storm response level (categorised in terms of an R – Readiness, L1 – Level 1, L2 – Level 2, or L3 – Level 3). Based on the storm response level, the procedures provide further guidance on the types and level of activities deemed appropriate in responding to the event.

The procedures provide guidance on three emergency response processes:

- The restoration process
- The strategic management process
- The stakeholder communication process

6.9.5.3 PANDEMIC CONTINGENCY PLANS

We have developed a plan to respond to an influenza pandemic occurring in New Zealand. This plan provides a basis for establishing a common understanding of the roles, responsibilities and activities to be undertaken in response to the pandemic to ensure the operational integrity and continuity of our networks. Due to the unpredictable nature of pandemics, the plan also considers the wider implications for the company beyond its obligations as a lifeline utility provider.

7.1 CHAPTER OVERVIEW

This chapter discusses the governance processes which apply to capital planning and delivery. We provide an overview of the frameworks and processes which apply with a focus on the following key Capex portfolios:

- Growth and Security (with proposed projects described in Chapters 11 and 12)
- Renewals (with proposed projects described in Chapters 15-21)

We follow by describing the associated budgeting and works delivery processes.

7.2 GROWTH AND SECURITY

7.2.1 OVERVIEW

Growth and security works are intended to ensure the capacity of our network is adequate to meet the peak demand of our customers at appropriate levels of reliability, now and in the future.

We broadly classify our growth and security investments into the following portfolios:

- **Major projects:** Over $5m, generally involving subtransmission or GXP works.
- **Minor growth and security works:** which includes
  - Minor projects between $1m - $5m that typically involve zone substation works and small subtransmission projects
  - Repetitive routine projects below $1m, including distribution capacity and voltage upgrades, distribution back-feed reinforcements (supports automation), smaller zone substation upgrades, distribution transformer upgrades, and LV reinforcement.
  - Communications projects, to support improved control and automation of the network, and provide voice communications to our field staff.
- **Reliability:** Includes network automation projects to help manage the reliability performance of our network.

This section outlines the process we use to determine our growth and security related investments. The specific projects we anticipate are required over the planning period are detailed in Chapter 11 and 12.

7.2.2 GROWTH AND SECURITY INVESTMENT PLANNING

Planning for growth and security investments requires we anticipate potential shortfalls of capacity, or breaches of our security criteria under forecast demand conditions. We plan for efficient and timely investment in additional capacity and security before reliability is adversely affected.

These developments need to fit within the context of our wider asset management activities (eg renewal plans), such that investments are optimised across all business objectives and constraints.

The considerations in this planning include security of supply, network architecture, asset capacities and how future demand is forecast. From these considerations we produce a growth and security plan for each network area. We refer to these as our area plans. Our approach considers:

- Demand forecasting
- Asset capacity ratings
- Our security criteria
- A focus on local needs and issues
- Risk based options analysis
- Consideration of non-network options
- Network wide optimised investment timing

Ensuring appropriate security of supply is a key focus of this process. Security drives the larger investments related to the subtransmission system and zone substations, which directly impact reliability to large numbers of customers.

7.2.3 DEMAND FORECASTING

Growth and security planning is essentially a comparison of asset capacity against forecast demand in the context of security (ie the degree of redundancy required to minimise outages arising from credible contingent events).

Demand changes with time, both in terms of the reasonably predictable and repeatable patterns of daily and seasonal load profiles, but also the longer term trends in population, economic activity and consumer behaviour.

Because of the long lead time for major projects, it is essential to forecast the expected demand on all parts of the network several years ahead. This allows us to identify potential security issues well before they occur and schedule timely investments to address these. Demand forecasts are also used to identify the most efficient investment options which involves considering the longer term demand outlook.

7.2.3.1 APPROACH

We have recently improved our demand forecasting methodology. We now model down to a feeder level (more granular than in the past) and model population and new connection trends. This improves the robustness of our forecasts, especially for loads dominated by residential and small commercial customers.

We also introduced scenario modelling which will be important as we will increasingly rely on probabilistic network development planning. We will continue to refine our forecasting approach as we need to understand at an early stage the potential impacts of new technology and increased customer choice.

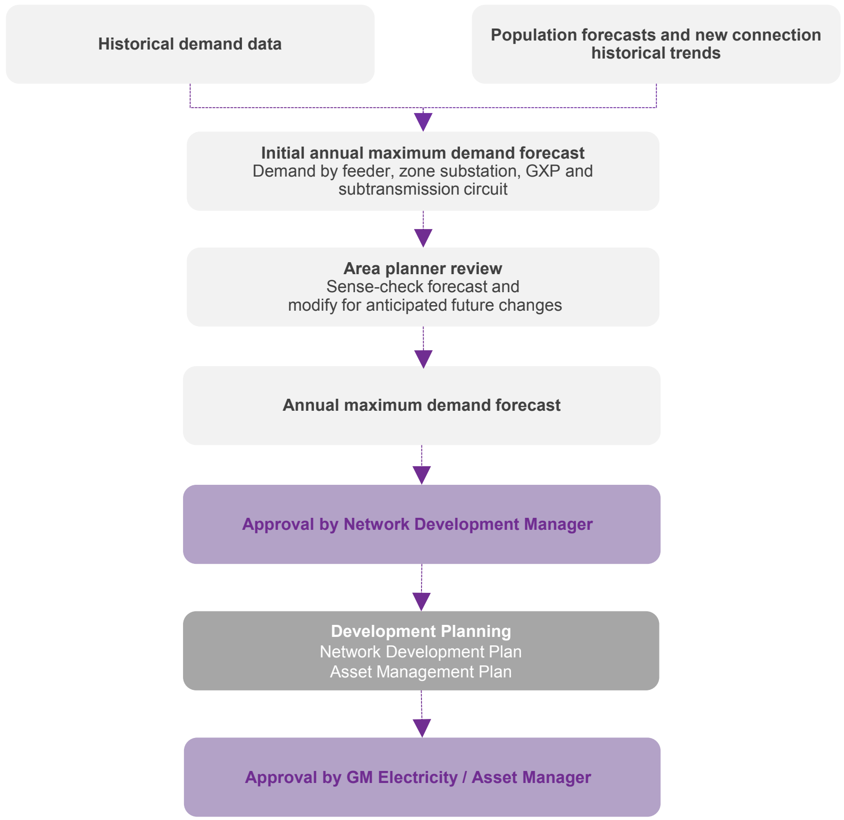
Growth and security planning requires demand forecasts at different network levels:

- 11kV distribution feeders
- Zone substations
- GXP and subtransmission circuits

We use the load forecasts we develop at the feeder level to create aggregate demand forecast at zone substation, GXP and subtransmission level. We estimate existing peak demand based on 90th percentile of filtered and trended historical peaks.

Figure 7.1 shows the key elements of our current demand forecasting approach.

Figure 7.1: Demand forecasting approach



The starting point for our demand approach is distribution (11kV) feeder level forecasts. Our modelling combines NZ Statistics census area population forecasts mapped to each feeder and historical trends in new customer connection trends. This approach works especially well with feeders serving numerous residential and small commercial customers.

Feeders serving one or a few large industrial customers are assumed to have zero growth. If customers indicate a demand increase, with a high degree of certainty, we reflect these as step changes in our base forecasts. No commitment for customer investments is made until formal customer agreements are concluded.

Predicting growth of feeders that serve a mixture of commercial and residential customers is subject to greater uncertainty than other feeder types. We plan to refine our forecast in future by introducing economic activity modelling at the commercial/industrial level.

Once growth rates for feeder forecasts are established, we assess the growth rate for zone substations, GXPs and subtransmission circuits based on the weighted average of feeder growth rates. Existing maximum demand is used as the weighting factor.

We estimate current peak demand based on modelling historical data. For zone substations and more aggregate demand categories, we adjust historical annual peak demands for distortions due to load transfers, both temporary and permanent. We assess current maximum demand as the 90th percentile of these filtered and trend adjusted demand series. This allows for a 1-in-10-year exceedance of the forecast demand peak, a level of risk considered appropriate. Feeders use a different approach that is tailored to their planning process and risk.

We generally consider a 10-year historical period in any analysis to determine trends or establish existing demand levels. This is considered a reasonable balance between stability (a shorter period can create excessively volatile outcomes) and responsiveness, such as to step changes in underlying, customer, demographic or economic activity.

We are considering the future use of our ripple control plant (to control hot water storage heaters) and other potential demand-side resources which may become available through new technology and communication capabilities. For now our demand forecasts assume that deployment of ripple capability has the same impact as in the past.

Our demand forecast approach introduced scenario analysis to consider alternative future growth scenarios, building on MBIE's Electricity and Demand and Growth Scenarios (EDGS). Scenario modelling will become more important as we will increasingly rely on probabilistic network development planning, which will consider the impact of new technologies and future customer choices (including when faced with different electricity pricing structures).

7.2.3.2 EMBEDDED GENERATION

Historical demand data includes the net impact of embedded generation and existing ripple control. Over the planning period, embedded generation is expected to be below the threshold of significance to peak demand, with a few exceptions that are adjusted manually. Most small scale embedded generation, which is generally PV, does not affect our demand peaks which mostly occur on winter evenings. Chapter 13 discusses future PV uptake which may impact future peak demand if combined with energy storage.

Wind generation development on our network has been very infrequent but substantial in capacity when it does. Small hydro generation is also very limited in terms of physical opportunities. There is some activity around gas turbine peaking units in Taranaki, subject to the relative economics of the fuel sources. Larger scale generation for any of these sources tends to be connected directly to the transmission grid and therefore does not impact our growth and security planning directly.

Almost all renewable embedded generation (PV or wind) is intermittent by nature, and without associated storage has minimal impact on our predominantly winter peaking demand.

7.2.4 ASSET RATINGS

The ratings (ie capacities) assigned to circuits and transformers impact growth and security planning.

While all assets are assigned a specific standard or nominal rating, actual capacities vary in real time, depending on environmental conditions. Recognising load profiles and fault occurrences are also statistical variables, the management of load against capacity is effectively an exercise in risk management.

Standard ratings are therefore assigned at a level of risk that triggers analysis and planning, with sufficient lead time available to ensure network risk can be managed until upgrades are commissioned.

The principles behind asset ratings are universal, but the actual approach is tailored more specifically to the asset characteristics and thermal environment:

- **Zone substation transformers:** Our standard assigns a maximum continuous rating and a four-hour rating, which applies to post contingent load transfer in an N-1 context. Our standard ratings for transformers often vary considerably from nameplate manufacturer ratings. This is done to ensure all our transformers are rated according to consistent and appropriate conditions for the New Zealand environment.
- **Overhead lines:** Our standard assigns a nominal continuous rating that is used to systematically identify potential future overloads. Short-term ratings (ie a four-hour rating) are not appropriate for overhead lines because of their limited thermal capacity. Because of the influence of environmental parameters, our standard provides a framework for implementing dynamic rating schemes if a risk assessment confirms this is appropriate.
- **Underground cables:** Ratings are being reviewed and we will soon issue a new standard. This will assign consistent, systematic standard ratings for planning analysis, and will also set a framework for dynamic or monitored rating schemes using distributed fibre temperature sensing.

7.2.5 CUSTOMER SERVICE LEVELS

The objective of growth and security planning is to provide a cost-effective service to customers in the form of:

- Adequate capacity to meet demand (and generation)
- Maintaining adequate voltage

- A reliable quality of supply

Our asset management practices ultimately seek to reflect the price/quality preferences of our customers. Through surveys and focused discussions with representative groups (eg Federated Farmers, local councils) we regularly consult on the price and quality of our services. We also maintain regular contact with major customers and discuss their specific service level and capacity requirements. Consultation will be an increasing focus area with our expected increase in investment to address the deteriorating reliability of ageing assets.

Our network is inherently a shared resource. Specific price/quality preferences for individual customers can generally only be provided for larger customers with dedicated assets. In most cases, the reliability we provide must reflect the general, or averaged, preferences of our customers.

7.2.6 NETWORK SECURITY STANDARDS

Security standards are normally defined in terms of N-x, where x is the number of coincident outages that can occur during periods of peak demand without extended loss of supply to customers. At the quantum of load encountered at most of our zone substations, N-1 is the optimal consideration (ie an outage on the single largest circuit or transformer can occur without resulting in supply interruption).

Zone substation security levels can also be ‘qualified’ by the time allowed to restore supply by network reconfiguration after an asset has failed. Three of our five security classes are qualified by the allowable switching time before all load is to be restored.

We also consider the size of load at risk in our security standards – with higher levels of redundancy or back-feed capacity required where more customers could be affected by an outage.

As noted above, effective tailoring of security standards for individual customers, especially mass market is impractical. Our security criteria therefore are defined at zone substation level and above only.

To gauge whether our security criteria are effective in achieving our customers’ desired service levels, we need to interpret their feedback on the more general price/quality trade-off, and also consider any other industry benchmarks, trends or comparisons.

For example, we have aligned our security standards with the industry’s guideline document produced by the Electricity Engineers Association (EEA). In turn, this EEA guide seeks to set security levels aligned with the UK standard P2/6, while recognising the particular characteristics of the New Zealand industry and networks.

The EEA Guide to security of supply introduces two approaches to security, and the underlying issue of reliability:

- A deterministic N-x security classification
- A probabilistic, reliability-based approach

In applying our security criteria, we have used a combination of these approaches. Our security standard is essentially a deterministic approach. It provides a consistent and systematic N-x criterion against which we can analyse the performance of all of the subtransmission system and zone substations. This identifies any potential needs or issues that can then be ranked according to risk. The subsequent analysis of possible options to resolve these constraints then adopts a more probabilistic, or reliability based approach. This helps determine the most cost effective solution.

We use this two-stage approach since the sole application of N-x security criteria, while simple, does not address the subtleties of network architecture, asset performance and the inherently variable nature of key reliability parameters. Fully adhering to the deterministic criteria could result in significant additional capacity investment, without necessarily achieving equivalent benefits for our customers.

In particular, deterministic security classes are a highly simplified representation of all possible fault scenarios and responses. They can only consider criticality (ie the consequence or cost) of an outage if it occurs at peak demand, but not the probability (ie likelihood or frequency of outages). However, they are simple and systematic to apply from a planning or operational perspective, and therefore well suited as a screening tool that identifies all potential needs or constraints above a threshold of risk.

In cases where there is clearly no economic option, we generally do not invest to provide higher than N security. Rural substations fed by a single circuit or with a single transformer, serving a small load, often fall into this category. For these the outage consequences can usually be managed operationally.

The probabilistic approach to options analysis also allows us to consider multiple different demand scenarios. We have recently introduced an upper and lower variant to our base forecast growth rate, drawing off variance seen in national demand growth forecasts published by MBIE. In future, we intend to develop this scenario forecasting and analysis further so we can model the possible different uptake of new technologies, alongside the more traditional variances in economic and demographic drivers.

Our zone substation security classifications start with the 11kV feeder type (F1, F2, etc) at each substation. The feeder types are determined from the predominant type of customer on each 11kV feeder (see **Table 7.3**). The zone substation security classes are then determined from **Table 7.1**, which is a function of both 11kV feeder type and amount of load involved. These classes are shown in demand forecast tables throughout this AMP.

Table 7.1: Substation security class

FEEDER (LOAD) TYPE	ZONE SUBSTATION MAXIMUM DEMAND			
	< 1 MVA	1 – 5 MVA	5 – 12 MVA	>12 MVA
F1	AA	AA	AA+	AAA
F2	A1	AA	AA+	AAA
F3	A2	AA	AA	AA
F4	A2	A1	A1	n/a
F5	A2	A2	A1	n/a

The restoration targets assigned to each of the security classes are set out in **Table 7.2**.

Table 7.2: Security class restoration targets

SECURITY CLASS	TARGETED RESTORATION CAPABILITY FOR	
	1ST EVENT	2ND EVENT
AAA	100% - without break	> 50% in < 60 mins, remainder in repair time
AA+	100% - restored in < 15 secs	> 50% in 60 mins, remainder in repair time
AA	100% - restored in < 60 mins	Full restoration only after repairs
A1	100% - unlimited switching time	Full restoration only after repairs
A2	Full restoration only after repairs	Full restoration only after repairs

The first four classes (AAA to A1) all require either full or switched N-1 capacity. This means that it must be possible to supply the peak load on the substation even with the loss of the single largest normal supply circuit or transformer. The different security classes simply mandate different restoration times.

The A2 class requires only N security. Supply can therefore be via a single circuit or transformer with limited or no backup. This class only applies to a few remote rural zone substations where alternative supply cannot be economically justified.

7.2.7 INVESTMENT TRIGGERS

Investment triggers are prompted by network needs identified through analysis that signals if certain criteria have been met. This prompts a review of options to invest in the network, or non-network options, to restore appropriate levels of capacity or reliability. Growth and security investment triggers (by voltage level) include:

- **GXPs/transmission spurs** that exceed security criteria, effectively N-1.
- **Subtransmission and zone substation** that exceed security criteria, effectively a qualified or switched N-1.
- **Distribution feeders** that exceed guidelines or planning parameters related to voltage profile, thermal capacity of any given section of feeder, and number of connections.

The identification of an investment trigger does not automatically mean a project will be included in the EWP. For growth and security planning, we prioritise the identified needs according to the risk exposed by the constraint. This assists with the ranking and timing of related investments. Given capital and capacity constraints, low risk projects, or projects with low economic value are often deferred.

7.2.8 OPTIONS ANALYSIS

Options analysis is carried out on identified needs. The complexity of the analysis is kept in proportion to the level of risk and cost. We have developed a systematic and objective process to consider potential options. As an example, overhead line upgrade needs have several options, including thermal re-tensioning, re-conductoring, or the installation of new lines or circuits (ie dual circuit). We currently do not use duplexing.

Option analyses assess costs over a 20-year period. A life cycle approach involves consideration of all appropriate cost elements, including Capex, maintenance and losses. The analysis models the economic cost of reliability, where this reflects the cost of unserved energy to customers in the event that supply cannot be maintained. Based on these factors, we identify the most cost effective, long-term solution overall.

We have developed a formal tool and guidelines for undertaking options analyses. This helps ensure that the assumptions and approach remain consistent between options, traceable and documented. The tool also provides built-in unit rates and helps estimate the cost of different options. These rates are aligned with our cost estimation systems.

7.2.9 NON-NETWORK SOLUTIONS

Increasingly we are considering non-network solutions as alternatives to, or in conjunction with, network investments. Evolving technology and economies of scale are expected to make such solutions more practical and cost effective in the future. Examples that are likely to become more prevalent in future include:

- **Embedded renewable generation**:
  - PV, especially at a residential level
  - Wind, generally large installations in rural areas
  - Hydro and micro hydro, though there are limited viable locations
  - Biomass, some specialist possibilities
- **Embedded non-renewable generation**:
  - Diesel peaking or backup generators (very low utilisation)
  - Gas fired, typically in an industrial cogeneration context
- **Energy storage:** At present the most practical energy storage options for distribution networks are large or small scale batteries, although other options such as heat, water or flywheel energy storage systems are also being considered. Storage offers several potential benefits, especially related to the ability to shave daily peaks therefore reducing the network's effective peak demand and/or increasing utilisation. Possible widespread EV uptake is a potential complementary storage facility, although depending on usage patterns, could also add to peak demand.
- **Demand-side management:** Technology offers emerging possibilities ranging from simple variable thermostats through to smart appliances and home energy management systems. Small scale distributed energy storage (eg home batteries) can effectively be treated as a demand- side resource.
- **Power flow:** involves Management/automation involves techniques to improve utilisation and use special protection schemes (SPS), dynamic ratings and voltage/phase management devices.

New technology can complement more traditional demand-side options, such as ripple control and this is an area we continually review to ensure we identify opportunities as they emerge. Our planning and approval process for larger projects includes a formal review of non-network solutions.

7.2.10 DISTRIBUTION PLANNING

Distribution planning ensures the capacity and voltage profile of 11kV feeders are adequate to meet existing and future needs of our customers.

We use five 11kV feeder classifications, each of which represents the predominant type of load, or consumer, served by that feeder. This load type is a proxy for the economic impact of lost supply, and therefore the targeted reliability standards for each feeder type differ according to the significance of reliable supply to customers.

Table 7.3: Feeder classifications

FEEDER CLASSIFICATION	PREDOMINANT CUSTOMER DESCRIPTION
F1	Large industrial
F2	Commercial/CBD
F3	Urban residential
F4	Rural (dairy or horticultural)
F5	Remote rural (extensive agricultural)

In several cases feeders serve a mix of load types. Where necessary, a mixed classification is applied. Feeder classifications also determine the upstream zone substation load type, from which we work out the zone substation's security classification.

For distribution feeders there is no systematic contingency analysis, as is the case when considering subtransmission and zone substation security. This is because feeders have smaller loads and generally multiple back-feed options. There are some elements of reliability considered but the focus of analysis for distribution planning is predominantly the capacity and performance of the network under normal configuration.

All 11kV feeders are modelled at regular intervals using the latest demand forecast to assess if there are any breaches of:

- The thermal capacity of any section of the feeder, particularly the first section of the feeder (with the heaviest loading).
- Voltage levels, especially whether the most remote point is below 95% of nominal.

Feeders are also assessed in terms of the number of ICPs as part of our reliability planning process. We aim to optimise the deployment of switches, reclosers and sectionalisers to improve quality of supply. Feeders or switched sections with too many ICPs may lead to lower reliability.

It is of note that our strategy to increase automation (in the form of automatic switching schemes) often triggers the need to increase back-feed capacity (in the circuits themselves). This triggers additional development expenditure. For more information on our reliability and automation plans, see Chapter 12.

Other drivers for investing in distribution feeders are:

- Specific back-feed investigations, including inter-substation transfer, which identify opportunities for useful back-feed enhancements.
- Operational field experience, which also identifies practical opportunities to provide additional back-feed to 11kV feeders or substations.

- Customer feedback and complaints that identify localised voltage deviations – sometimes these are symptomatic of high voltage feeder capacity constraints.
- Customer inquiries for increased capacity, if these impact feeder loading. This is especially true if more than one customer is affected (ie irrigation or dairy).
- Our guideline that feeder backbone loading is kept below 2/3 of capacity in urban meshed areas so that the load can be split over no more than two other feeders.

Distribution growth and security planning typically results in the following projects:

- Line upgrades and new sections of line (tie lines or new feeders)
- New cables, usually of larger capacity, or to provide new 11kV feeders
- Specific back-feed initiatives (increased capacity or new tie lines)
- Distribution transformer upgrades
- Feeder voltage support (ie regulators or capacitor banks)

7.2.11 DISTRIBUTED GENERATION POLICY

Our distributed generation policy has been developed to comply with the Electricity Industry Participation Code (EIPC) 2010, Part 6. It details our relevant internal policies, along with pertinent industry rules, regulations and standards.

Our policy is intended to support and facilitate the appropriate development of distributed generation. Two categories of generation capacity are recognised. Less than 10kW can usually be connected with minimal cost and administrative requirements, while larger than 10kW generally requires more detailed review of possible safety and technical issues. All connections must meet all regulatory, safety, and technical requirements. We must be assured that the connection will not interfere with other customers or adversely affect the safe and reliable operation of the network.

Pricing methodologies are in accordance with the EIPC. For smaller generators, costs are similar to any other standard small capacity (eg domestic) network connection, generation or otherwise. For larger generators, there is scope to assess any potential benefits in terms of reducing our distribution or transmission costs.

The policy describes the application process, time frames applicable, disputes resolution process, terms of connection, and applicable fees. It also outlines requirements for the recovery of network support or avoided cost of transmission payments available to generators.

The policy, together with application forms, links to relevant standards and detailed advice, is published on our website[10].

10 http://www.powerco.co.nz/Get-Connected/Distributed-Generation/

7.3 RENEWALS

7.3.1 OVERVIEW OF ASSET RENEWALS

This section explains our approach to managing our asset fleets and provides an introduction to our fleet plans in Chapters 15-21.

Renewal investment is triggered from the Renew or Dispose stage of the asset life cycle, discussed in Chapter 6. The Renew or Dispose stage includes:

- **Asset renewal:** Includes the replacement of assets with like-for-like or new modern equivalents
- **Asset refurbishment** : Extends the useful life or increases the service potential of an existing asset
- **Disposal:** Occurs following the decision to remove assets from our network

7.3.2 FLEET CATEGORIES

To support our approach to effective asset renewal and disposal we have defined a set of asset fleets which form the basis for our intervention strategies and associated expenditure forecasts. For expenditure planning and to inform our Information Disclosures (ID) we have grouped similar fleets into Asset Portfolios. These are set out in **Table 7.4**.

Table 7.4: Portfolio and asset fleet mapping[11]

PORTFOLIOS	ASSET FLEET
Overhead structures	Poles Crossarms
Overhead conductors	Subtransmission overhead conductors Distribution overhead conductors Low voltage overhead conductors
Cables	Subtransmission cables Distribution cables Low voltage cables
Zone substations	Power transformers Indoor switchgear Outdoor switchgear Buildings Load control injection Other zone substation assets
Distribution transformers	Pole mounted distribution transformers Ground mounted distribution transformers Other distribution transformers
Distribution switchgear	Ground mounted switchgear Pole mounted fuses Pole mounted switches Circuit breakers, reclosers and sectionalisers
Secondary systems	SCADA and communications Protection DC supplies Metering

7.3.3 RENEWAL AND REFURBISHMENT

7.3.3.1 OVERVIEW

Addressing asset deterioration is necessary to ensure they remain in a serviceable and safe condition. As the level of deterioration increases, the asset reaches a state where ongoing maintenance becomes ineffective or excessively costly. Once assets reach this stage we look to renew (replace) or refurbish them. Our fleet management plans describe how we make these decisions and explain our approach to renewing fleets over the long-term. Examples include proactively replacing wooden poles with more reliable concrete poles.

Renewals Capex includes replacing assets with like-for-like or new modern equivalents. Refurbishment Capex is expenditure that extends an asset's useful life or increases its service potential. These works are generally managed as programmes focused on a particular asset fleet such as power transformers.

There are a number of drivers for asset renewal or refurbishment including:

- Safety
- Environmental
- Asset health
- Reliability
- Legislative compliance
- Equipment failure
- Obsolescence
- Overall life cycle cost

Below we provide further detail on some of the renewal drivers.

7.3.3.2 SAFETY

Safety is our fundamental organisational value and is a key driver for renewal Capex during the planning period. Investments are sometimes required to ensure that assets do not pose safety risks to staff or the general public. We ensure that such risks are isolated or minimised as much as reasonably possible.

Safety is addressed by both the timing of investments and the design of our assets. Safety risks can also arise from degrading asset condition or environmental factors such as vegetation encroachment.

The need to ensure safety for staff and the general public will lead to the need for new, replacement or refurbished assets. One example is the plan to replace oil-filled switchgear, which could pose an arc flash risk.

7.3.3.3 ASSET HEALTH

Asset health reflects the expected remaining life of an asset and acts as a proxy for likelihood of failure. We have used asset health to inform our asset management approach for a number of our asset fleets. Using Asset Health Indices (AHI) we can estimate the required future volume of asset renewals and forecast the health outcomes of our investment scenarios.

AHI has been used to inform our Capex forecasts over the planning period for a number of fleets. The design of an AHI model is based on factors relevant to the particular asset fleet and may include:

[11] These portfolios differ from the asset categories specified by Information Disclosure as they better reflect the way we manage these assets and plan our investments.

- The condition of the asset
- Output from survivor models
- Factors affecting the rate of degradation such as the environment
- Failure and outage rates – historical and projected
- Known defects in certain assets or groups of assets
- Issues that limit expected life such as compliance with safety or environmental regulations
- Asset age and the life expectancy of the asset

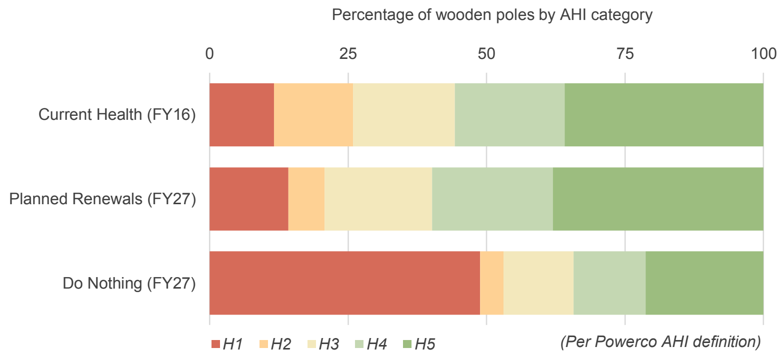
Table 7.5 sets out our AHI categories, including the basis for the category and the expected replacement period.

Table 7.5: AHI categories

AHI	CATEGORY DESCRIPTION	REPLACEMENT PERIOD
H1	Asset has reached the end of its useful life	Within one year
H2	Material failure risk, short-term replacement	Between 1 and 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
H4	Normal deterioration, regular monitoring	Between 10 and 20 years
H5	As new condition, insignificant failure risk	Over 20 years

Figure 7.2 shows an example of the projected future asset health based on different intervention options.

Figure 7.2: Example of current and projected asset health (wooden poles)



For fleets with AHI, it is possible to use scenario analysis to compare the future health of fleets based on alternative investment scenarios. Asset health is therefore a key input into the timing of asset renewal.

This approach assigns higher replacement priority to assets with lower remaining life. It identifies these as being more likely to require an intervention due to their higher relative failure risk. In some fleets, we further prioritise projects based on relative criticality and associated performance targets.

Power transformer – asset health

An asset health model has been developed to estimate the remaining life of our power transformer fleet.

Power transformer condition assessment data is used to inform the AHI model. This includes dissolved gas analysis (DGA) results, oil temperature records, tank condition and degree of polymerisation (DP) results. The model also takes type and obsolescence issues into consideration.

Every transformer is assigned an expected renewal year. The forecast is based on the number of power transformers expected to reach their renewal year during the forecast period.

We have informed our power transformer asset health model with work conducted by the EEA, with additional developments based on our experience and information.

Asset criticality

We have developed an asset criticality framework as a proxy for the consequence of asset failure, and are currently implementing it within our information systems. It is based on consumer impact (calculated from load at risk or number of customers affected), public safety, environmental impact, and financial cost.

While we do not anticipate the approach will alleviate the need to increase renewal expenditure as set out in this asset management plan, asset criticality frameworks will help us target asset renewal in an appropriate sequence. This minimises safety and reliability related risks over the planning period.

Future improvements

The design of the AHI and criticality approaches is still maturing. The approaches will be continually refined as our asset management improves and we obtain more consistent and higher-quality condition data. Additional improvements will include extending the use of AHI to other fleets and further embedding the models and their outputs into our planning and asset information systems.

We have targeted our approach on those asset fleets where asset health must be most carefully managed over the next five years. We believe our analysis provides appropriate estimates of required volumes over this period. Future enhancements will help ensure appropriate forecasting and asset replacement in the longer term.

7.3.3.4 RELIABILITY

We undertake renewals investment to manage reliability levels experienced by our customers. This includes renewal of poor condition assets, and assets with known failure modes / type issues such as where a particular asset type / model are found to fail prematurely. We regularly review the performance of our network feeders in order to target asset renewal in areas of worst performance, ensuring our customers all receive a fair level of service.

7.3.3.5 OBSOLESCENCE

Renewal may be warranted due to the existing assets being obsolete, such as when incompatible with our modern systems and standards, lack significant functionality (when compared to modern equivalent assets), or spares may no longer available and the asset may no longer be supported by the manufacturer. Obsolescence is the primary driver of renewal in the secondary assets portfolio. In this case, modern assets using standardised designs provide improved functionality, serviceability and performance. This allows us to more efficiently control and operate the network, providing better value to our customers.

7.3.3.6 OVERALL LIFE CYCLE COST

In some instances it may cost more to retain an asset in service than to replace it. In these cases it will be renewed (with an asset for which the life-cycle cost is lower). New assets often have reduced maintenance costs compared to legacy assets. We often use life cycle cost analysis to determine asset specifications – specifying assets with the lowest life cycle costs even when the initial cost may be higher.

7.3.4 OPTIONS ANALYSIS

Our Fleet Management Plans set out our renewal programmes. Many needs are recurring and can be addressed as part of ongoing work programmes. In such cases our chosen approach is generally informed by specific, long-standing strategies.

The range of viable options considered in these programmes will vary based on the asset fleet and the originating need. In general the issues can be addressed through one of the following options:

- Replace the asset
- Refurbish the asset
- Continue maintaining the asset

Potential options always consider safety implications and likely performance impacts, including support for our asset management objectives. Where fleets have asset health indices, our analysis includes estimating the future health of assets against each of the options.

Life cycle cost is an important consideration. In addition to Capex it is necessary to assess the cost of maintenance and other operational costs incurred over the life of the asset. We assess the extent to which the need, eg failure risk, is addressed by each option, including a status quo or ‘do nothing’ option.

7.3.5 DISPOSAL

Asset disposal activities are required when an asset is approaching the end of its useful life. There are a number of triggers for disposal decisions including the requirement to replace an asset due to poor condition, reactive replacements or changes to safety or environmental standards.

In general, the approach and timing of asset disposal is considered during the planning phase for those assets. As part of our decision-making process we take into account the required disposal activities.

While some assets, for example underground cables, may be left in situ, most of our assets are removed at end-of-life, and safely disposed of. In some cases useful components are salvaged. Site clean-up and restoration also form part of the disposal activity.

Maintenance activities can trigger disposal of equipment and materials, such as the need to dispose of hazardous materials (eg contaminated oil) following servicing. Consistent with our Safety and Environment objectives we ensure waste materials are disposed of in a responsible manner. **Table 7.6** gives an overview of the types of waste materials we manage.

Table 7.6: Potential waste materials from asset disposals

DISPOSED ASSET	POTENTIAL WASTE MATERIAL
Overhead line assets	Steel, aluminium, copper, soil, porcelain/glass, copper chrome arsenic (CCA) treated poles
Underground cables	Cross-linked polyethylene insulation (XLPE), copper, lead, oil and oil impregnated paper
Buildings	Building materials, asbestos and contaminated soil
Switchgear/circuit breakers	SF_6, oil, recyclable metals, porcelain
Power transformers	Oil, steel and copper

In the majority of cases, disposal of assets is a relatively low cost activity. However, if special disposal requirements exist, these are considered at an early stage. Disposal costs are considered as part of the overall life cycle costing.

7.4 NETWORK CAPEX BUDGETING PROCESS

We use the first year of the AMP as the basis of works plans for the year, and a detailed works plan developed that sets out the specific investments and projects to be completed over the year. We term this plan the Electricity Woks Plan (EWP).

The EWP is developed based to reflect as closely as possible the specific investments and investment mix set out in the AMP, taking into account the latest possible information on network needs and construction status.

We also prepare forecasts for work that is reactive in nature, for example new connections, reactive network replacement, and network relocations. We apply historical run rate forecasts to set the budget.

The full year budget is compiled using the EWP and reactive capital forecasts as a basis, and is compiled by our finance team. It is reviewed by the General Manager Electricity and the CEO and then approved by our Board.

7.5 NETWORK CAPEX WORKS DELIVERY

7.5.1 OVERVIEW

The delivery process is managed by our Works Delivery team, which specialises in procurement and project management of external service providers. The increase in work on our network has required improvement of our end-to-end delivery approach. This has improved the way we coordinate and communicate the impact of planned customer outages, and also manages workflow to allow our service providers to deliver at the lowest cost.

The capital works delivery process includes:

- **Works planning:** Integrates our works plan to optimise the work by area and timing. Project managers are assigned to each project to manage the end-to-end process.
- **Detailed design:** Converts conceptual designs completed in the planning stage to detailed designs for construction.
- **Procurement:** Manages the tendering of work and negotiating and awarding of contracts.
- **Construction and commissioning:** Includes managing of service providers to deliver to time, scope and budget. It also includes commissioning new assets, handover to operations and project close-out.

7.5.2 WORKS PLANNING

Once projects are prioritised in the final stage of the annual planning cycle, an important process of works integration and planning takes place. This focuses on when each project should begin based on its priority, location, size, complexity and the availability of resources. These discussions involve planning, design, operations, customer relations and service delivery.

Resources needed for delivery depend on:

- The level of design work required
- Access and consents issues
- If a planned outage is needed and the impact on customers
- Availability of operations to manage work on the network
- Service provider availability

Projects are coordinated where possible to minimise disruption to customers. It is also important to manage a smooth work flow to service providers to allow them to be as efficient and effective as possible.

7.5.3 DETAILED DESIGN

Our design approach aims to standardise our network assets by following a suite of design standards. This helps to simplify delivery and achieve long-term consistency across our network. Safety-in-design is also a central driver for our designs.

We build on pre-design work and design concepts to create a complete detailed design for large projects. This includes budget breakdowns, tender drawings, material lists, estimated SAIDI impact and a general project overview. The Design team is involved for the duration of the project to take care of tasks such as design variations during construction.

Detailed design is not required in many cases such as standard installations and smaller defect jobs. In these cases we use the design build services of our construction contractors. They use our design standards to ensure appropriate specification of components.

Design work is performed by our in-house design, design consultants, or contractors in line with defined standards. We maintain a standards library, which comprises a suite of design, construction, maintenance and policy documents. These are made available online to our approved service providers. The documents are continually reviewed and updated.

Safety-in-design

Safety-in-design is a key philosophy applied throughout our standards. It is continually reviewed through our standards review process. Our technical standards are developed to include health and safety requirements, environmental risk identification, and network risk management requirements.

7.5.4 PROCUREMENT

7.5.4.1 SERVICES

Our construction process is an outsourced activity.

We operate a long-term contract model for faults, maintenance and minor capital works. The most recent iteration of the field services delivery strategy has involved development of a tender panel sized to deliver appropriate scale, resource certainty and effective price competition. We have worked with our key providers to tailor their resourcing and delivery to future work volumes.

We operate a more traditional principal contractor model for major capital works, which are tendered job by job. We run a closed tender process, offering work to only those contractors who are pre-approved. We use a FIDIC[12] template for the tender process and a standard evaluation form is used to assess each tender.

We limit tenders to those companies who are approved under our approved contractor process. For the majority of our approved contractors, the general terms and conditions under the FIDIC contract have been pre-negotiated. This aims to streamline the tender process so significant negotiation is avoided with each tender release.

7.5.4.2 MATERIALS

As part of the tender process, service providers break their bid into the costs of materials and labour. This allows us to assess material costs in the tender and negotiate if needed. It also provides a base against which project costs can be monitored. For high cost items, we directly procure them to ensure we manage their cost, quality and delivery.

Our technical standards are also designed to ensure efficient and streamlined materials procurement by grading the level of specification in a way that helps balance the benefits of standardisation with the benefits of competitive tension between suppliers. This approach is set out in **Table 7.7**.

Table 7.7: Approach to asset specification

EQUIPMENT CLASS	SPECIFICATION REQUIREMENTS
Class A Item-focused	Items within this class are critical to supporting the reliability and performance of the network. Examples are 33kV and 11kV switchgear and power transformers. Class A equipment must be chosen from specific type lists within standards published in our Contracts Works Manual. No discretion is allowed when choosing these items.
Class B Standards-focused	Class B is a standards-focused group of materials and equipment. These items of equipment must be chosen in compliance with our standards. Examples include overhead conductors and underground cable and poles.
Class C Functionality-focused	Class C items can be selected in compliance with functional requirements published in our Contract Works Manual. Examples of Class C equipment types include bolts and crossarm braces.

7.5.5 CONSTRUCTION AND COMMISSIONING

Once all the activities above have been completed, the construction process can begin. Service providers must first be approved to work on our network. This ensures an appropriate level of competency at the firm level through their systems and processes. At an individual level it ensures they are competent to complete the tasks and work on the network as safely as possible.

Works management

Our project management processes are highly structured, with strong oversight of progress against plans and contracts. We have formal KPIs for works delivery and these are closely monitored. Overall, we have been successful in recent years at delivering volumes of work in line with targets. Our Works Delivery team is responsible for the works programme. Its staff is competent and experienced at the management of works delivery in the field.

We use various methods to monitor our service providers' efficiency while meeting our construction and materials standards. We use professional project managers who monitor cost outcomes against contract conditions and approved budgets.

Commissioning

Commissioning is the formal process of handover from the construction phase to the operational state. It represents the point in time at which the network assets become recognised as assets for the purposes of operation and valuation. The

12 Based on material from the International Federation of Consulting Engineers.

commissioning process is controlled by NOC, with the support of the Works Delivery team and the service provider. We have a commissioning standard that defines the process for commissioning before livening on the network.

The commissioning process includes conducting pre-commissioning tests, confirming these tests have been successfully completed, conducting a pre-conditioning inspection and creating a ready-for-go-live notice.

Works close-out

Once all works are complete, we undertake a number of project close-out activities, including final capitalisation of the project in our financial system. This confirms asset information systems have been updated (archiving relevant documentation), and a review of lessons learned including a review of safety performance.

The review process is modified in line with the complexity and risk associated with the project.

8.1 OVERVIEW

This chapter describes the types of activities that are required to successfully operate and maintain our electricity network. It sets out how we plan and budget for those activities in order to meet the needs and requirements of our shareholders, regulator and customers.

The chapter is structured as follows:

- Section 8.2 – outlines the planning process for maintenance, vegetation management and System operations and Support (SONS) activities
- Section 8.3 – outlines how we establish our budgets
- Section 8.4 – describes how we deliver our operations and maintenance tasks

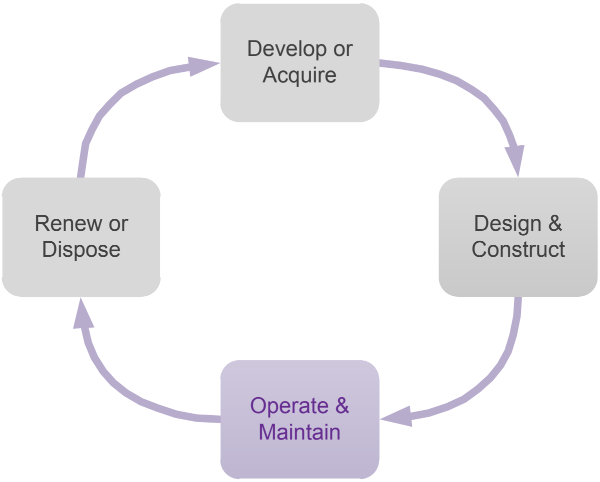
8.2 NETWORK OPEX PLANNING

8.2.1 OVERVIEW

We manage our asset fleets using an asset life cycle approach. **Figure 8.1** depicts the four life cycle stages within our Asset Management process. Operate and Maintain is a key stage in this cycle. It lasts for the duration of the asset's life and impacts the timing and scope of other stages (eg need for renewal).

Competent operation and maintenance form part of our obligations under the Electricity Safety Regulations.

Figure 8.1: Asset management life cycle



The term 'operations' refers to the activities necessary to ensure the day-to-day safe and reliable operation of our network. Operations is primarily about keeping the electricity supply flowing to customers through monitoring, switching and load control. It centres on our 24/7 NOC and a separate dispatch centre that communicates with retailers and the public.

'Maintenance' is the care of assets to ensure they operate safely and effectively at their designed capacity and performance. Maintenance involves monitoring and managing the condition of an asset over time, and restoring the asset to a safe working condition in the event of a failure.

Maintenance activities include tasks such as routine inspections and asset testing, transformer and switchgear earth inspections, inspection of lines, and safety checks of field work. Our maintenance standards and work schedules have been developed to ensure that testing, inspections and other activities can be undertaken safely.

Network operating expenditure (Opex) includes three categories of work:

- **Maintenance** (preventive, corrective and reactive)
- **Vegetation management**
- **System operations and network support** (SONS)

The planning around each of these aspects is discussed below.

8.2.2 MAINTENANCE PLANNING

In planning maintenance activities we use our maintenance standards, which prescribe the required inspections and routine activities, and the frequency at which these are to be carried out. We also use information obtained during inspections to guide our corrective maintenance programme and inform renewal decisions.

Maintenance involves monitoring and managing the deterioration of an asset in operation, or in the case of a defect or fault restoring the condition of the asset. Maintenance activities may also include minor modifications to assets to improve performance and reliability.

Our maintenance activities are categorised into three portfolios:

- **Preventive Maintenance and Inspection[13].** This portfolio deals with routine maintenance activities like testing, inspecting and asset servicing
- **Corrective Maintenance.** This portfolio is mainly concerned with fixing defects (after they are identified and scheduled appropriately), through activities such as replacement of defected asset components or minor assets

[13] Our Preventive Maintenance and Inspection portfolio was previously named Routine Corrective Maintenance and Inspections (RCI). The corrective maintenance component of this work is now part of our Corrective Maintenance portfolio. This change has been made to better reflect the drivers for these activities and the way we plan and deliver these works. Our information disclosure schedules reflect the RCI definitions, also consistent with our historical disclosures.

- **Reactive Maintenance**. This portfolio is about responding to faults and other network incidents, including immediate work to make a situation safe, or to repair broken assets

Historically, our maintenance approach has been a combination of time-based interventions for asset inspections and low cost renewal items, minor asset renewals based on age or condition, and reactive response to faults.

Over the planning period, we intend to introduce a more sophisticated risk and condition-based approach to provide an improved balance between investment in maintenance and investment in renewals.

Maintenance strategy summary

Our current maintenance strategy provides a solid foundation to build on, with well-structured asset inspections, comprehensive routine maintenance standards, and effective approaches to manage assets requiring intervention or reaching the end of their lives.

Historically, our maintenance has been a combination of time-based interventions for asset inspections and routine servicing of major components, minor asset repairs or renewals based on age or condition, and reactive response to faults. This approach has served us well in the past.

However, as part of our improvement journey, we recognise that there is room for improving how we maintain our assets. An optimised maintenance approach identifies the optimal maintenance strategy for each asset, rather than treating all assets in a category the same. It requires a more targeted approach, with a focus on longer term outcomes – not just in terms of safety and whole-of-life cost, but also quality.

We aim to improve our maintenance approach over time, increasingly adopting predictive maintenance elements. In the interim we will evolve our existing approach, finding the right balance between different maintenance intervention types. Over the next ten years we aim to move to a 'reliability-centred maintenance' approach. This will lead us to carry out an increasing portion of our work using preventive and predictive strategies.

The maintenance practices we employ will evolve our approach, while ensuring stable network outcomes and supporting efficient expenditure (Opex and Capex) over the planning period.

8.2.3 VEGETATION MANAGEMENT PLANNING

Vegetation management is an essential activity that supports safe and reliable networks. Ensuring appropriate clearances from our lines is also a regulatory requirement.

Trees and other vegetation growing near our network are a hazard. Vegetation coming into contact with our assets can lead to safety and reliability issues such as fires, asset failures and outages. We must manage it to ensure the security of supply and safety of the public. It involves tree trimming and removal, inspections to determine the amount of work required, and liaising with tree owners regarding the work needed on their property.

Vegetation management is planned on a portfolio basis – individual tree sites are not (currently) identified in the annual or longer term plans. This identification happens in the detailed planning stage, and is presently carried out by the vegetation service providers.

In line with our vegetation strategy, in future we will to move away from our current largely reactive vegetation management approach (addressing issues as they occur), to a more planned approach. This will involve more cyclical inspections, whereby all trees will be inspected at pre-determined intervals (typically three years). We will adopt a risk-based approach to vegetation outside statutory clearance zones – where this is likely to pose a safety or reliability risk in the foreseeable future. In addition, we are also considering separating the works identification function from the works execution function.

While these changes will enhance our operational efficiency, they will not change our planning processes, other than to better inform our portfolio expenditure levels.

8.2.4 SYSTEM OPERATIONS AND NETWORK SUPPORT

SONS relates mainly to our people – salaries, wages and supporting expenditure. It also covers related network support expenses such as professional advice, engineering reviews, quality assurance, and network running costs.

SONS planning is generally done on a portfolio level. Annual planning is based on a combination of historical costs and trends supplemented to reflect the future effort associated with projected network growth and renewal.

Where new initiatives or substantial changes to existing work approaches or volumes are identified, these are added to the underlying base and trend plans. This also applies to situations where new work-types require the introduction of new skills.

8.3 NETWORK OPEX BUDGETING PROCESS

Our network operating budgets are based on the forecasts set out in our AMP. These forecasts consider historical long run costs and update these to reflect targeted changes in strategy, and known emerging issues with our asset fleets.

The process we use to set our network opex budgets each year included the following key steps:

- The process starts with the 10-year portfolio forecasts (maintenance, vegetation and SONS); these forecasts are updated as part of our AMP update process to reflect updated assumptions, changes in maintenance strategies, or known one of items for the year.

- We load the specific schedules of activities into our GEM scheduling tool to validate the cost of the preventative maintenance budgets and refine the detailed scheduling to reflect the top level AMP assumptions.
- Reactive maintenance, vegetation management, and SONs budgets are set based on the AMP assumptions and adjusted to reflect any one offs or known issues for the financial year.
- The budgets are compiled, reviewed by the Asset Manager and GM Electricity, and presented to the Board for discussion and approval. Once approved the budgets are released within our financial systems for execution.

Capex-Opex trade-offs

A life cycle based asset management approach requires a holistic view of asset expenditure. The investments we make in the Opex space play a material role in enabling efficient delivery of capital projects and our subsequent ability to manage them.

Reflecting this, we consider both Capex and Opex requirements as part of our decision-making, including:

– The impact of maintenance activities on asset life and performance
– Total life cycle costs, including disposal, when commissioning new assets or replacing/refurbishing existing assets.

In many cases, longer term maintenance and operation costs will be a significant proportion of the life cycle cost in present value terms. It is important, therefore, that Capex decisions are not made based solely on the up-front capital costs.

8.4 OPERATIONS AND MAINTENANCE DELIVERY

8.4.1 OVERVIEW

Operations and Maintenance activities comprise:

- **Network operations** – includes real time network control, monitoring and event response.
- **Outage planning** – involves planning for equipment outages to enable safe access to network assets.
- **Network maintenance** – is the care of assets to ensure they provide the required capability in a safe and reliable manner from commissioning through to their replacement or disposal.
- **Vegetation management** – includes monitoring and trimming of vegetation growing in close proximity to our assets.

Operational and maintenance activities are introduced below. Further discussion on Network Opex including our planned expenditure is included in Chapter 23.

8.4.2 NETWORK OPERATIONS

Network operations is a real time function and is undertaken through our NOC. Network operators monitor network status and system load, and take actions as necessary including planned and unplanned switching and load control to maintain supply through our HV network.

Outage Management System

Our Outage Management System (OMS) is a core tool used in managing the NOC workload. OMS derives network status data from SCADA. OMS is used to manage calls and outage restoration efforts, track interruptions to customers, and provide relevant information to customers through retailers, our website or an interactive voice recording system.

Using a statistical inference model, OMS produces a predictive outage location based on customer calls and provides NOC staff with geospatial views of these affected customers. This tool is used to improve fault responsiveness.

Switching

Switching is undertaken to disconnect sections of the network for safety isolation to enable maintenance or new connections to be undertaken, or to restore supply in the event of a fault. Most switching involves the 11kV distribution network but at times subtransmission switching at 33 and 66kV is also undertaken.

There are two principal switching methods – remote switching, which is done by the NOC via SCADA, and field switching, which is undertaken by our service provider under the direction of the NOC. Switching is planned and managed through our OMS. Expenditure related to field switching is included within our ARR portfolio.

Dispatch

The NOC also incorporates a dispatch function, where dispatch operators communicate with retailers and customers. They communicate with our service provider service management centre to dispatch field staff where work is necessary to maintain or restore power supply. Dispatch operators also manage all LV outages.

8.4.3 OUTAGE PLANNING

Our NOC has a team of release planners who coordinate the release of our high voltage network for planned work. They ensure that the work being done can be clearly understood by all concerned and that all recognised measures are in place to ensure safety of personnel and the public.

Outage planning follows a process of release procedures. The procedure is documented and follows operational rules designed to promote system stability and security, and to ensure personnel have sufficient time to safely consider permits and switching instructions necessary for work to occur.

An important focus is to become more responsive to our customers. A key part of this is outage planning with customers, while also enabling reasonable access to the network for work to occur. This includes providing adequate notice of an outage, explaining why the outage is needed and responding to queries and concerns. The process also considers the impact on critical customers, such as schools, hospitals, transportation, and industry.

8.4.4 NETWORK MAINTENANCE

8.4.4.1 OVERVIEW

The bulk of our maintenance activities are completed by Downer (as part of Electricity Field Services Agreements), our approved vegetation contractors or other external specialists. The work programme is sourced from:

- The GEM schedule of Preventive Maintenance and Inspection work[14]
- The defect database, which provides a comprehensive record of all outstanding defects, from which individual Corrective Maintenance jobs or packages of work are issued
- The Network Operations Centre (NOC), which issues urgent Reactive Maintenance fault work on an individual job basis to our Service Providers Service Management Centre (SMC).

Our Service Providers and external specialists are responsible for ensuring that they have sufficient expertise and resources to undertake the assigned works in line with our requirements. They are also responsible for ensuring that their staff are trained and qualified to undertake the assigned works. We monitor their compliance with these requirements.

8.4.4.2 QUALITY MANAGEMENT

Our Service Providers have to manage quality for all works that they undertake. Quality management includes supervision and auditing of works to ensure compliance with standards and with contractual conditions.

We independently monitor the completion of Service Provider and specialist works and undertake sample audits to ensure compliance with our technical and quality standards.

8.4.4.3 FEEDBACK AND MONITORING

Our Electricity Field Services Agreement (EFSA) provides a mechanism for feedback both from and to our Service Providers. When undertaking physical works, Service Providers identify issues or ways to improve specific maintenance tasks. Similarly, we identify and advise of technological changes that can assist the Service Providers to undertake work more effectively and efficiently. Feedback improves our understanding of maintenance requirements and assists with keeping standards relevant and up to date.

Feedback from external specialists helps with planning renewals or operational changes for specialist equipment such as load control plant.

8.4.4.4 ENABLERS

Planning and delivery of maintenance activities are dependent on having skilled and specialised personnel, particularly in our field workforce, engineering, planning and analytical functions. It also requires having the systems in place to efficiently manage the flow of information to support the work processes. In general, engineering, planning and analytical roles are in-house functions, while field work is a Service Provider function.

[14] GEM is our Gas and Electricity Maintenance management system. It includes a database of scheduled inspection activities.

9.1 CHAPTER OVERVIEW

This chapter sets out our Network Targets for the planning period. We use these to gauge our performance in delivering our asset management objectives.

- Sections 9.2 and 9.3 provide the context for our performance targets, and the focus we will apply over the planning period.
- Remaining sections set out our targets for each year of the planning period, our historical performance.

We have designed our targets framework to drive improvement in the way we run our business, our networks, and the services we provide to our customers.

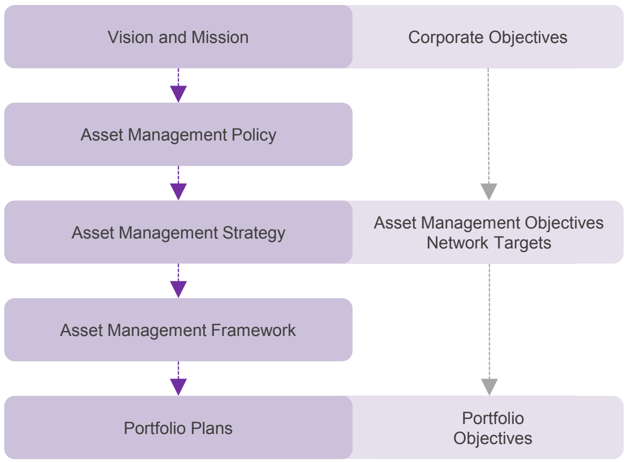
Our detailed plans, such as Network Development and Fleet Management Plans, then define what we plan to do to deliver these targets.

9.2 CONTEXT FOR OUR TARGETS

9.2.1 ASSET MANAGEMENT LINE-OF-SIGHT

In Chapters 5-8 we described our corporate objectives, asset management policy, asset management strategy, and asset management framework. This chapter outlines the performance targets against which we measure our success. Refer to **Figure 9.1** for context.

Figure 9.1: Our asset management 'line-of-sight'



9.2.2 ASSET MANAGEMENT OBJECTIVES

Our five Asset Management Objectives sit at the heart of our asset management strategy. These objectives are illustrated in **Figure 5.2**, and are discussed in more detail in Chapter 5.

Figure 9.2: Our Asset Management Objectives

Our Network Targets set out specific measures and timing to be achieved in delivering our Asset Management Objectives.

Targets play a critical role in our delivery as they translate directional and aspirational objectives to definitive, time-bound outcomes to be achieved.

9.2.3 FOCUS AREAS FOR TARGET IMPROVEMENT

We group our targets to provide effective measurement of progress in each of our objective areas, effectively a 'dashboard' to measure our performance.

In many cases, interdependencies exist between targets and the achievement of some supports achievement across multiple objectives. Understanding these independencies helps us focus our efforts on the areas which will have the biggest impact and help ensure we meet the full range of targets over time.

The targets which have the maximum impact on the achievement across our objectives, and where we will place particular focus, are set out below:

- **Asset Health**: Our targets seek to stabilise asset health and drive appropriate management of end of life assets
- **Asset Fault Rates**: Our targets seek to stabilise asset fault rates and restore fault rates to industry average levels
- **Asset Utilisation**: Our targets seek to ensure appropriate utilisation of assets over time to moderate the cost of energy delivery
- **Asset Management Maturity**: Our targets seek to enhance our asset management effectiveness over time

9.3 SUMMARY BY OBJECTIVE AREA

9.3.1 OVERVIEW

In this section we discuss the context of our targets in each of our Asset Management Objective areas and provide a summary of current performance.

9.3.2 OPERATIONAL EXCELLENCE

As an asset management organisation, the outcomes we ultimately achieve are heavily influenced by our asset management capability, processes and practice. We define our effectiveness in this area as Operational Excellence.

Operational Excellence allows us to manage our projects and assets effectively and efficiently.

The key areas of focus are:

- **Asset Team**: Effective fleet investment planning, network development and maintenance strategy
- **Operations Team**: Quality installations and delivery of works at an efficient price, to maximise asset life and minimises lifecycle cost
- **Commercial Team**: Customer experience and effective relationship management to enable us to tailor our approach to customer needs

Our focus on Operational Excellence drives the development of sufficient capacity and capability to be an effective Asset Manager and the associated targets are designed help us improve this capability over time.

Operational Excellence targets summary

– Our targets in this area focus on improving asset management maturity over time, which supports ongoing efficiency gains and an overall lift in performance.

– We have self-assessed our asset management maturity at 2.4, which falls short of the standard we believe is needed in the longer term, and the standard we consider appropriate to deliver efficient outcomes for our customers.

– Our targets are set to drive improved performance in this area over time. We aim to achieve an asset management maturity level of 3.0 by 2020

9.3.3 ASSET STEWARDSHIP

Our assets play a critical role for our customers and communities. It is therefore essential our assets are well managed to ensure they are appropriate and fit for purpose over the long term. We term this concept Asset Stewardship.

There are a range of network performance measures which help us manage our assets prudently. These include measures such as asset health, fault rates and network utilisation.

A focus on asset stewardship helps us to plan in a long term and sustainable way and gives us clear and early warning of emerging issues on our networks.

Asset Stewardship targets summary

– Our targets in this area help us maintain appropriate asset condition and performance. They include asset health, fault rates, and asset utilisation.

– We are concerned that the health of some of the assets we operate, as well as the in-service fault rates of these assets, are at the limit of the acceptable range and deteriorating rapidly. We consider it important that we lift investment in the maintenance and renewal of these assets to manage their condition.

– Our targets in this area are designed to arrest deteriorating trends, and stabilise the health of our assets in the longer term.

9.3.4 SAFETY AND ENVIRONMENT

We consider safety and environmental protection to be a non-negotiable.

The asset stewardship targets (as set out above) play a critical role in supporting safe outcomes and protection of the environment. In addition we utilise a range of strategies and management systems to ensure safety including the following:

- Public Safety Management System
- Technical standards
- Health and Safety Strategy

- Environmental Management Strategy
- Network access and permitting system
- Field auditing system
- Contractor approval system

Appropriate oversight and management of these key safety related strategies helps us to protect the safety of the public, our staff, and our service providers at all times.

Safety and Environment targets summary

- Our targets in this area are designed to prevent harm, protect the environment and drive continuous improvement in our performance over time.
- We have made good progress in advancing our health and safety approach in recent years and our targets in this area are designed to ensure ongoing improvement to our strategies and management processes over time.

9.3.5 NETWORKS FOR TODAY AND TOMORROW

Ultimately our networks need to perform at a level that meets the needs and expectations of our customers.

The number of outages experienced each year, the total time without access to electricity, and the impact of localised outages are all key indicators of the service experience of our customers.

The ability of our networks and systems to effectively support customer choice and integrate effectively with an evolving energy system are also key measures of customer experience.

Our focus is on tailoring the performance of our networks to the needs of our customers, now and in the future.

Networks for Today and Tomorrow targets summary

- Our targets in this area cover network reliability and our readiness in enabling and utilising technologies which are impacting energy markets.
- We are concerned that the reliability of our networks as measured by SAIDI and SAIFI is unfavourable in comparison with our peers, and when measured at a feeder level performance on some parts of our networks is well outside the levels considered acceptable. It is also of concern that leading indicators of reliability performance, such as network faults, are degrading over time.
- Our targets in this area have been set to stabilise network reliability and ensure an improvement focus in the worst performing areas of our network.

9.3.6 CUSTOMERS AND COMMUNITIES

Ultimately, the test of our success across all of our Asset Management Objective areas is the satisfaction of our customers.

Effectively consulting with customers to understand their requirements, being responsive when events do occur, and delivering an appropriate quality of supply are areas of critical focus.

Customers and Community targets summary

- Our targets in this area cover customer satisfaction, response times and power quality.
- A small proportion of our customers are not satisfied with the services they receive and we share their desire to see targeted improvement.

9.4 OPERATIONAL EXCELLENCE

9.4.1 OVERVIEW

This section sets out the specific targets we have set ourselves for operational excellence over the planning period. We also consider the basis for these targets and our historical performance against these targets.

9.4.2 TARGETS

The table below sets out our targets for operational excellence.

Table 9.1: Operational Excellence targets

Indicator	TARGET FY17-FY27
Asset Management Maturity	
Self-assessed maturity level	Achieve a self-assessed AMMAT score of at least 3.0 by 2020
ISO 55000 certification	Achieve ISO 55000 certification by 2020
Efficiency	
Efficiency gains	Achieve projected efficiency gains

9.4.3 COMMENTARY

The table below explains the basis for our targets and a summary of our historical performance.

Table 9.2: Operational Excellence target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Asset Management Maturity	
We have proven ourselves as capable asset managers. However, we recognise there is more to do as asset management approaches mature. We consider ISO55000 certification to be an appropriate good practice target and 2020 an appropriate transitional window.	The AMMAT scope proves a proxy for a transition towards ISO55000 certification. Our approach has matured progressively from a self-assessed average AMMAT score of 1.9 in 2013 to 2.4 in 2017. Details and associated 'spider' diagrams are included in Chapter 10.
Efficiency	
Our delivery plans involve a material increase in investment volumes over the planning period. Our plans include specific efficiency assumptions. Our efficiency targets have been set on a portfolio by portfolio basis to reflect an achievable, but stretch target over and above current performance.	We have not specifically tracked efficiency improvement in prior periods; however industry benchmarking on a cost-per-connection basis demonstrates our performance has been strong.

9.4.4 IMPROVEMENT INITIATIVES

The table below sets out our improvement initiatives for the planning period.

Table 9.3: Operational Excellence improvement initiatives

FOCUS AREA	INITIATIVES
Investment targets	Our fleet and network development plans include specific efficiency targets to be achieved over the period.
Organisation redesign	We are currently in the process of reshaping our asset and operational teams to align them to the nature and volume of work to be delivered over the planning period.
Process refinement	Our business plans include a focus on process refinement to support efficient delivery. We anticipate this will include a move from annual to rolling works plan delivery and enhancements to portfolio optimisation.
Field delivery refinement	We are currently in the process of resetting our field delivery arrangements to deepen competition and ensure appropriate resources are available. These arrangements will be progressively refined over the planning period.
Enterprise resource planning	Implementation of an Enterprise Resource Planning system within the next three years. This initiative will include refinement and rationalisation of associated business processes.

9.5 ASSET STEWARDSHIP

9.5.1 OVERVIEW

This section sets out the specific targets we have set ourselves for asset stewardship over the planning period. We also consider the basis for these targets and our historical performance against these targets.

9.5.2 TARGETS

The table below sets out our targets for asset stewardship.

Table 9.4: Asset Stewardship targets

INDICATOR	TARGET FY17-FY27
Asset health	
Asset health	Deliver asset renewal volumes/asset health targets as per fleet management plans.
Asset failure rates (Faults/interruptions per 100 km)	
6.6, 11, 22 kV overhead lines	<16 faults <10 interruptions
6.6, 11, 22 kV underground cables	<4 faults <4 interruptions
33, 66 kV overhead lines	<9 faults <5 interruptions
33, 66 kV underground cables	<1.7 faults <1.5 interruptions
Asset utilisation (%)	
Distribution transformer utilisation	30%
Zone transformer utilisation (zone substation peak demand divided by zone substation total capacity)	50%
Network energy losses versus energy entering network	6%
Vegetation Management	
Cyclical trimming programme	Cyclical trimming programmes implemented in all regions by 2022

9.5.3 COMMENTARY

The table below explains the basis for our targets and a summary of our historical performance.

Table 9.5: Asset Stewardship target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Asset Health	
Asset Health Indices (AHI) help ensure both appropriate and stable health of our asset fleets. We have set targets to ensure appropriate outcomes in our fleet management plans as per Chapter 15-21.	The use of AHI techniques is a relatively new initiative for Powerco. For details of current asset health for our key fleets see Chapters 15-21.
Asset Failure Rates	
Fault and interruption rates are a useful indicator of the effectiveness of our renewal plans ans. We have set our targets to reflect levels typically considered good practice within the industry. The selected fault rates also reflect, on average, performance achieved by similar networks in NZ.	Figure 9.7 to Figure 9.9 show how our failure rates compare against other EDBs.
Asset Utilisation	
Asset utilisation provides useful top level indicators of the balance between network security and asset use. Our targets are set to reflect the midpoint of the accepted good practice range in the industry, noting all network development projects are subject to project by project scrutiny.	Our current distribution transformer utilisation is 28.5% against a target of 30%. Figure 9.10 shows how this compares with the industry averages. Our FY17 zone transformer utilisation was 52.6% against a target of 50%. Our current energy loss has been measured at 5.1%, near our target of 6%. Figure 9.11 shows how this compares with the industry averages.

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Vegetation Management	
Tree regulations require us to ensure appropriate vegetation clearances from lines. We do not currently have full assurance of this position. Our target of moving to a full cyclical trimming regime is designed to ensure full compliance. Associated reductions in fault rates reflect our current view on the impact of this approach.	Our vegetation-related faults history is shown in Figure 9.12. Currently only a small part of our network is subject to cyclical trimming. Our target to reduce tree-related faults will be reported in subsequent AMPs.

9.5.4 IMPROVEMENT INITIATIVES

The table below sets out our improvement initiatives.

Table 9.6: Asset Stewardship improvement initiatives

FOCUS AREA	INITIATIVE
Fleet management plans	Our fleet management plans and associated investment proposals are designed to ensure appropriate health outcomes over the planning period. They are also designed to arrest deteriorating fault rate trends, and achieve improvements towards the end of the planning period.
Defect backlog resolution	Our plans include targeted initiatives to address defect backlogs. This approach will help ensure proactive replacements of components with a high risk of failure, which will help stabilise and ultimately reverse current unfavourable fault rate trends.
Network development	Our specific network development plans are designed to ensure an appropriate balance between network security and asset utilisation. More information is in Chapter 11.
Future network initiatives	The technologies we will trial as part of our future networks programmes should help enhance long term utilisation. This included LV monitoring, battery storage, real time asset ratings, and state estimation. More information is in Chapter 13.
Vegetation strategy	Our improved approach to vegetation management is designed to support a shift to cyclical trimming and reduce vegetation related faults over time. The approach is described in Chapter 23.

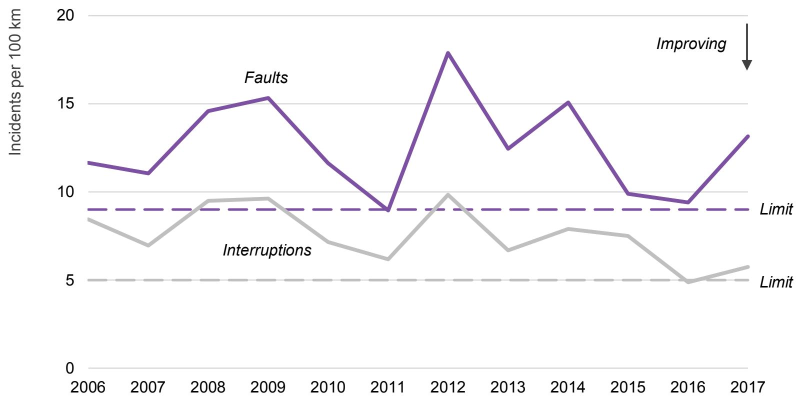
9.5.5 HISTORICAL TRENDS AND BENCHMARKS

9.5.5.1 ASSET FAILURE RATES

Failure trends

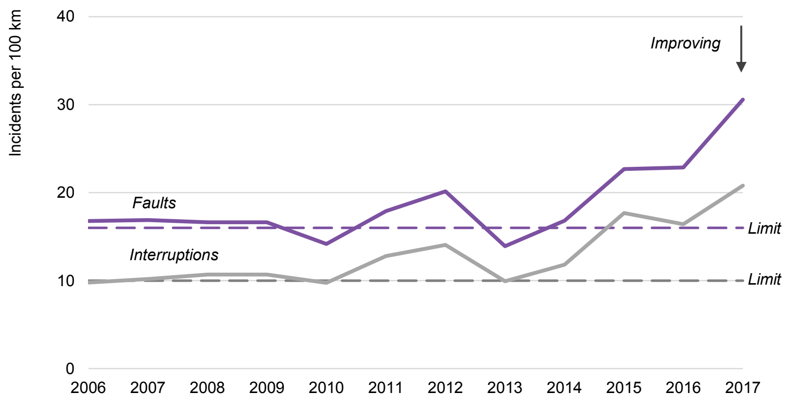
The figures below show our historical fault and interruption performance on our subtransmission and distribution networks.

Figure 9.3: Subtransmission overhead faults and interruptions per 100km



As shown above, subtransmission overhead faults and interruptions have consistently been above target over the past decade. The irregular shape of the trend line reflects inclement weather conditions from year to year. Our targets are designed to improve asset health and decrease the number of subtransmission overhead faults we are experiencing.

Figure 9.4: Distribution overhead faults and interruptions per 100km



As shown above, the number of distribution overhead line faults has significantly increased over the past five to seven years, indicating deteriorating asset health. Our targets are designed to improve health, reduce the number of defects and reduce failure rates.

Figure 9.5: Subtransmission underground faults and interruptions per 100km

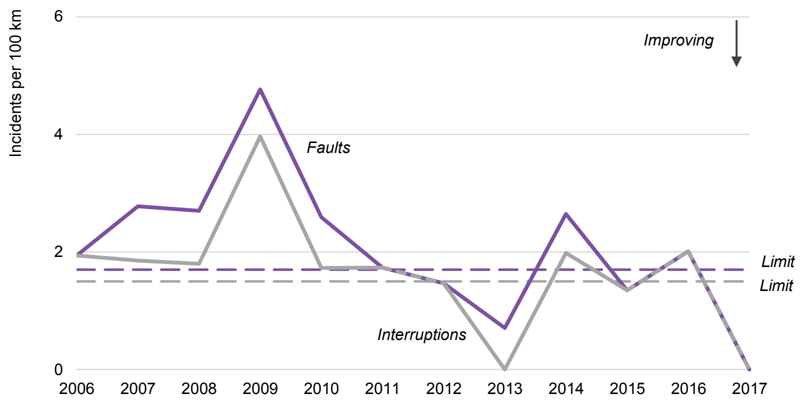
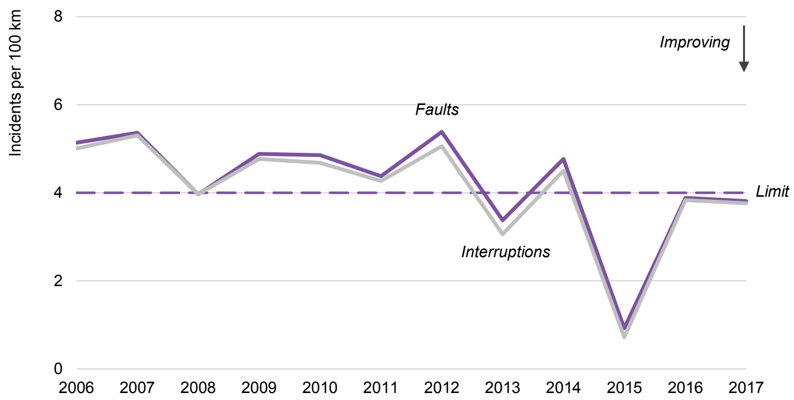


Figure 9.6: Distribution underground faults and interruptions per 100km

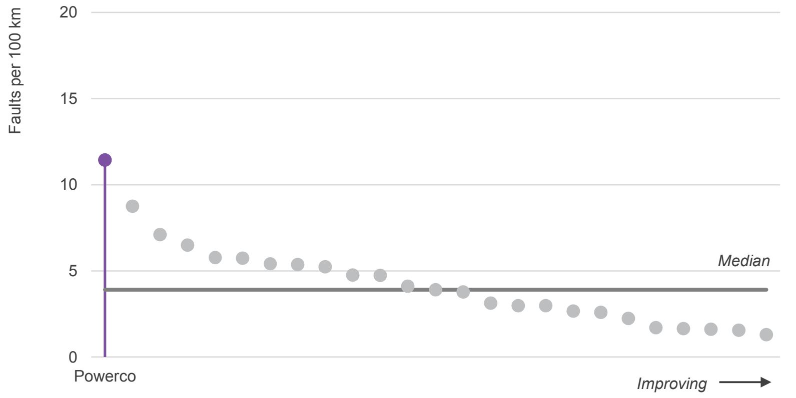


As indicated in the foregoing two figures, the performance of our underground circuits is satisfactory.

Benchmarking

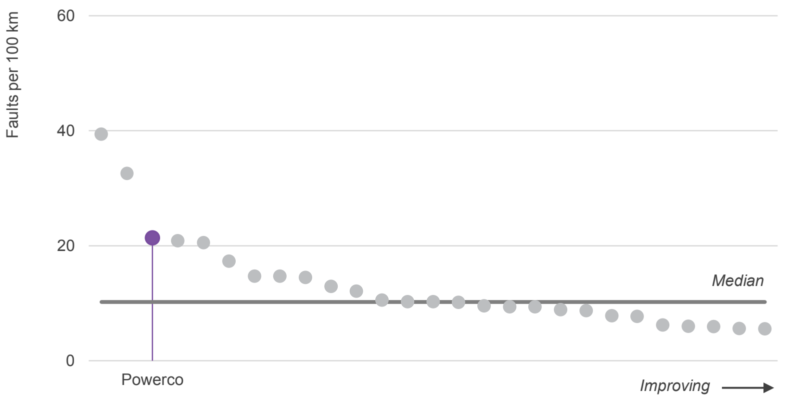
The following graphs show where we sit among our peers in terms of faults per unit length of circuit, asset utilisation and network losses.

Figure 9.7: Subtransmission overhead line benchmarking (2013-2016 average)



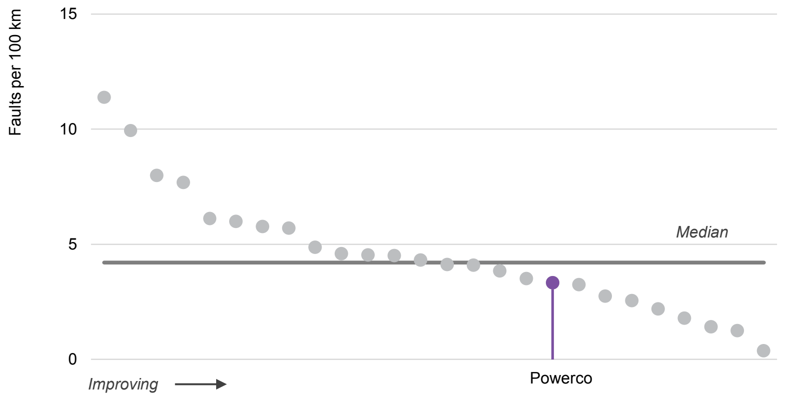
As shown above, the frequency of faults on our subtransmission lines is more than double the industry median. As seen in Figure 9.3, our subtransmission overhead faults have been unfavourable over the past 10-year period, further emphasising that our performance in this area has been poor for some time. Our targets are designed to reduce the number and duration of overhead line faults.

Figure 9.8: Distribution overhead line benchmarking (2013-2016 average)[15]



As shown above, the frequency of faults on our distribution overhead lines is almost double the industry median. Our performance has substantially deteriorated over the past five years (Figure 9.4). Our targets are designed to reduce the number and duration of these types of faults.

Figure 9.9: Distribution cable benchmarking (2013-2016 average)



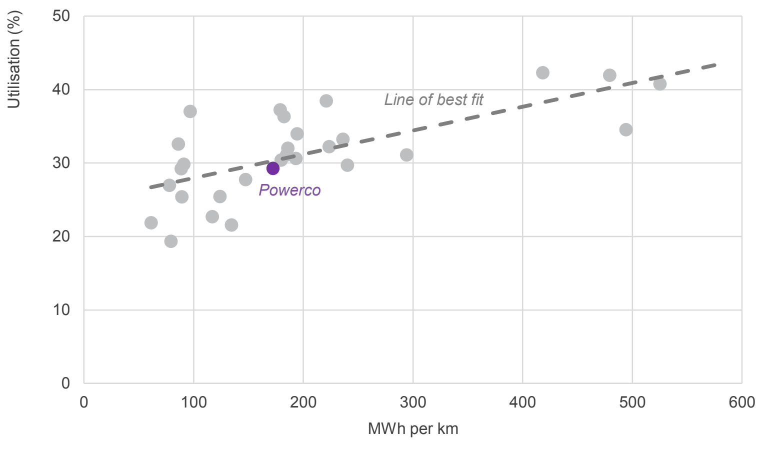
As shown above, we compare favourably against industry averages with respect to faults on distribution cable networks.

9.5.5.2 ASSET UTILISATION

Distribution transformer utilisation

The following figure shows our distribution transformer utilisation against network load density.

Figure 9.10: Comparison of NZ EDB distribution transformer utilisation and network load density



15 Our average also includes FY17 data. FY17 information from other EDBs is not yet publically available.

We sit close to the line of best fit for us. We use this relationship to inform our distribution transformer utilisation target of 30%.

Zone substation transformer utilisation

Our FY17 zone transformer utilisation was 52.6%. Consistent with previous AMPs, this has been calculated by dividing total zone substation peak demands by the total zone transformer capacity. Zone substation peak demands have generally been recorded in MW. They have been adjusted by a nominal power factor and, where possible, to restore transferred loads.

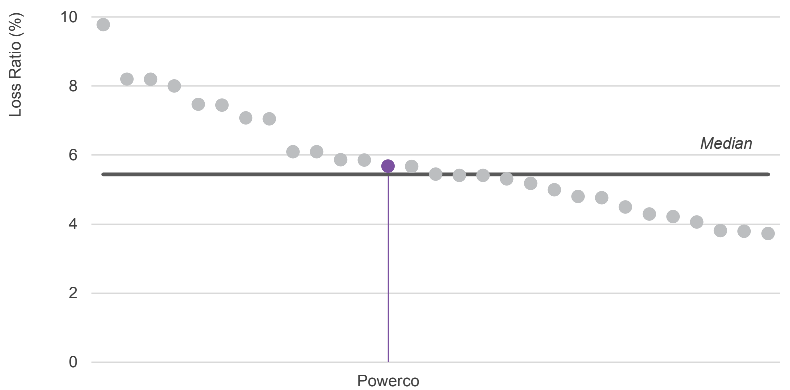
In general, higher transformer utilisation means less operational flexibility. When zone transformer utilisation exceeds 60% it can constrain ability to shut equipment down for maintenance work. As such, 60% is a high level indicator for the need to upgrade capacity. Our utilisation target of 50% is an average and reflects that some sites, particularly newer ones, need to have spare capacity to allow for future demand growth.

We do not compare ourselves with other distributors' zone substation transformer utilisation because of large variations in the use of zone substations within the industry. Networks rely to a greater or lesser extent on Transpower for their distribution supply. This is further complicated as some zone substations are required to have extra capacity to provide backup services for other zones.

Network losses

The figure below shows our network loss ratio compared to other EDBs.

Figure 9.11: Benchmarking of average network loss ratio (2013-2016)

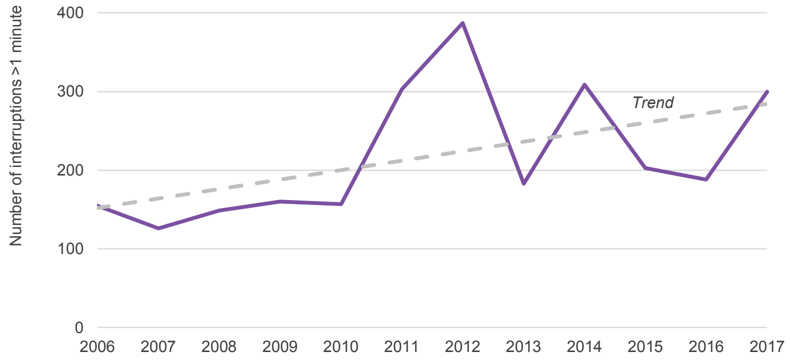


Our network losses are at industry median level and considered satisfactory and appropriate for our network.

9.5.5.3 VEGETATION MANAGEMENT

The figure below shows our historical vegetation related interruptions.

Figure 9.12: Number of vegetation related events causing >1 min outages



The irregular shape of the trend line reflects inclement weather conditions from year to year. However one can see the overall trend is increasing, indicating an underlying increase in vegetation-related failure risk. Our targets are designed to drive a decrease in the number of vegetation-related faults.

9.6 SAFETY AND ENVIRONMENT

9.6.1 OVERVIEW

This section sets out the specific targets we have set ourselves for safety and the environment over the planning period. We also consider the basis for these targets and our historical performance against these targets. Lost Time Injury Frequency Rate (LTIFR)[16] is our primary measure of safety performance, but we also have a number of supporting measures.

9.6.2 TARGETS

The table below sets out our targets for safety and environment

Table 9.7: Safety and Environment targets

INDICATOR	FY17	18	19	20	21	22	23	24	25	26	27
Personnel safety											
LTIFR (LTIs per million hours worked)	1.76	1.76	1.58	1.43	1.28	1.15	1.04	0.94	0.84	0.76	0.68
High Potential Incidents (HPIs) reported and investigated using full ICAM within 28 working days						100%					
Safety programme delivery						To plan					
Environmental responsibility											
Medium or higher consequence environmental incidents investigated using ICAM						100%					
Enviro-Mark standard certification						Diamond					
Environmental programme delivery						To plan					
SF**6** leak rate (% of stock)						<2%					
Legislative compliance											
Legislative compliance						Full					

9.6.3 COMMENTARY

The table below explains the basis for our targets and a summary of our historical performance.

Table 9.8: Safety and Environment target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Safety	
Our targets have been set to reflect progressive reduction of harm over time, with the ultimate objective of achieving a zero harm environment, and to ensure we remain vigilant via targeted review of our processes and systems.	We have achieved consistent improvement in lagging targets over time. Figure 9.13 shows our historical LTIFR performance. LTIFR has improved over the historical period, but we did not achieve our target in FY17. We completed 95% of our safety programme initiatives in FY16.

[16] LTIFR is calculated as the 12-month rolling number of lost time injuries per 1,000,000 hours worked.

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Environment	
We consider a structured and formal approach to the improvement of environmental performance is appropriate. We have selected the Enviro-Mark Programme (see www.enviro-mark.co.nz) as a suitable framework to guide our progress.	We achieved Enviro-Mark Diamond level in July 2016, a significant improvement compared to our 2013 AMP where the majority of our sites were certified as Bronze Level. The SF6 leak rates for 2014, 2015 and 2016 were 0.32%, 0.33% and 0.46% of total stock respectively. These are all well below the legislative compliance level of 2%.
Legislative compliance	
We are committed to achieving full legislative compliance.	We consistently achieve appropriate compliance outcomes.

9.6.4 IMPROVEMENT INITIATIVES

The table below sets out our improvement initiatives.

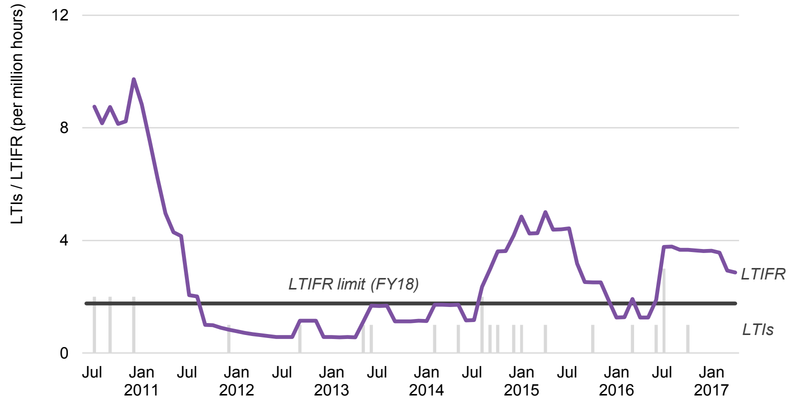
Table 9.9: Safety and Environment improvement initiatives

FOCUS AREA	INITIATIVE
Phasing out unsafe assets	We are seeking to phase out assets that no longer meet modern safety standards. This is described in more detail in our fleet management Chapters (15-21).
Service provider relationships	We will continue to work with in collaboration with our service providers in order to achieve the highest levels of safety for their staff.
Critical risk assessment	Over the planning period we will continue to refine our approach and methodologies to ensure optimal condition of safety-critical assets.
Safety governance	Our work programmes include a focus on the new Health and Safety Reform Act, including training for directors and all levels of the organisation.
Fully embedding safety-in-design processes	Our safety programmes include further development of our standards and processes into all our planning and design activities.
Power transformer oil containment	We will install oil containment and separator systems for power transformers which do not have these systems.

9.6.5 HISTORICAL TRENDS

The figure below shows our LTFIR for the past five years, along with associated lost time injuries (LTIs).

Figure 9.13: LTIFR historical performance[17]



We have made appropriate improvements over the past six years, however we continue to experience higher than desirable rates of LTI's given our commitment to a harm free workplace.

[17] Note this chart covers safety performance for all our staff, including our gas business. Our safety management system currently reports combined LTIFR for electricity and gas. We plan to separate these out in future AMPs.

9.7 NETWORKS FOR TODAY AND TOMORROW

9.7.1 OVERVIEW

This section sets out the specific targets we have set ourselves for our Networks for Today and Tomorrow objectives for the planning period. We also consider the basis for these targets and our historical performance against these targets.

9.7.2 TARGETS

As part of our CPP proposal, we are proposing a new quality (SAIDI/SAIFI) path. Increased levels of investment on our network will require an increase in the number of planned outages in the short term, to ensure stable unplanned outage performance in the longer term.

We are therefore proposing a new quality path that removes the planned outage component, and re-baselines the unplanned component on our last 10 years' performance[18]. All other aspects of the quality path are to be maintained. The targets will apply from FY19. Until then we remain under our existing DPP quality path. More information on our proposed quality path for CPP is contained in our CPP Main Proposal.

The table below summarises our Networks for Today and Tomorrow targets. Subsequent sections provide more detail on the network reliability and feeder reliability targets.

Table 9.10: Networks for Today and Tomorrow targets

INDICATOR	FY17	18	19	20	21	22	23	24	25	26	27
Overall Network Reliability											
Unplanned SAIDI	DPP		173.3								
Unplanned SAIFI	DPP		2.15								
Feeder Reliability											
% of feeders compliant with FIDI standard	70	70	71	73	75	77	79	81	83	85	85
Networks of the future											
Complete Network Evolution strategy and 10-year roadmap	Complete by end of FY18										

[18] The new quality path will need to be approved as part of our CPP proposal, and therefore is only presented here as 'proposed'.

9.7.2.1 NETWORK RELIABILITY

Table 9.11 shows our proposed CPP reliability targets for SAIDI and SAIFI (with 0% weighting given to planned SAIDI and SAIFI).

Table 9.11: Proposed CPP reliability targets

	SAIFI	SAIDI
CPP target	2.15	173.3
CPP cap	2.32	195.9
CPP collar	1.97	150.6
Unplanned boundary value	0.065	11.7

The table below includes our SAIDI and SAIFI forecasts.[19] We have developed separate models to forecast unplanned and planned SAID and SAIFI. They are based on modelling our historical fault data, and our planned work.

Table 9.12: Reliability forecast for the planning period

INDICATOR	FY17	18	19	20	21	22	23	24	25	26	27
SAIDI											
Planned	45.9	54.6	71.0	75.4	82.0	87.2	88.2	83.0	79.1	80.1	78.8
Unplanned (Not normalised)	196.2	208.8	210.8	205.5	201.1	199.8	197.4	195.0	195.4	197.3	198.5
SAIFI											
Planned	0.21	0.24	0.31	0.34	0.36	0.38	0.38	0.35	0.34	0.34	0.33
Unplanned (Not normalised)	2.30	2.29	2.32	2.29	2.28	2.28	2.27	2.25	2.26	2.28	2.31

Unplanned SAIDI and SAIFI targets reflect our focus on arresting deterioration and maintaining network reliability at current levels.

Planned SAIDI and SAIFI are forecast to increase, reflecting the increase in planned works over the period.

[19] These are consistent with the forecasts in schedule 12D.

9.7.2.2 FEEDER RELIABILITY

Table 9.13 shows the feeder reliability performance targets by feeder type.

Table 9.13: Reliability performance standards by feeder (consumer type)[20]

MEASURE	LARGE INDUSTRIAL F1	COMMERCIAL F2	URBAN F3	RURAL F4	REMOTE RURAL F5
Customers on feeder	5	100	800	500	250
SAIFI (average)	0.33	0.33	0.5	2	3
SAIDI (average)	15	15	23	180	450
Annual auto-recloses	-	-	4	16	24
Annual Interruptions	0.5	1.0	1.5	4	6
FIDI	30	60	180	600	1080

9.7.3 COMMENTARY

The table below explains the basis for our targets and a summary of our historical performance.

Table 9.14: Networks for Today and Tomorrow target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Network Reliability	
Reliability on our networks has been generally degrading over time and we are committed to arresting this trend. Our targets therefore reflect a stabilisation of unplanned SAIDI and SAIFI over the planning period (recognising that planned SAIDI and SAIFI will need to increase). We will maintain SAIDI and SAIFI in line with the DPP target levels up until 2019.	SAIDI was 203.9 which is above the DPP target but below the cap (210.63) SAIFI was 2.48 which is above the DPP target but below the cap (2.52) Our SAIDI performance (adjusted for weather variability) has been degrading. SAIFI has been generally within target.
Feeder Reliability	
Reliability on some parts of our networks falls outside of our desirable range. We are committed to addressing poor performance over time. Our targets reflect the anticipated improvement based on the levels of targeted renewals without our plans.	F1-F4 feeder performance was favourable against our target level of 70% in FY17, but F5 performance declined to 48%. Further analysis on our worst performing feeders is included in Table 9.13.
Networks for the Future	
We are committed to ensuring our networks are able to meet the needs of our customers into the future. The first milestone of this programme is to develop a detailed future technology strategy with an associated 10-year roadmap.	This initiative will commence in FY18.

9.7.4 IMPROVEMENT INITIATIVES

The table below sets out our improvement initiatives.

Table 9.15: Networks for Today and Tomorrow improvement initiatives

FOCUS AREA	INITIATIVE
Asset Stewardship	The initiatives listed in the Asset Stewardship area will flow through to network reliability.
Network automation	Our network automation plans are designed to help support stable reliability outcomes. More information is contained in Chapter 12.

9.7.5 HISTORICAL TRENDS

9.7.5.1 NETWORK RELIABILITY

Figure 9.14 and **Figure 9.15** set out historical trends for SAIDI and SAIFI against our regulatory targets. The figures reflect weather normalisation of unplanned SAIDI/SAIFI, with planned SAIDI/SAIFI weighted at 50% from 2015.

[20] The reliability performance in the table is for distribution feeders only, and excludes the performance of the network upstream of the feeder.

A clear pattern of deterioration is apparent over time for SAIDI, noting that the change in measurement of planned SAIDI from 2015 reduces the disclosed result (grey dots) by around 20 SAIDI minutes per year. The SAIFI result has been relatively stable.

The material differences in reliability results between years relates to the impact of storms and severe weather on our networks.

Figure 9.14: Historical SAIDI performance against regulatory targets

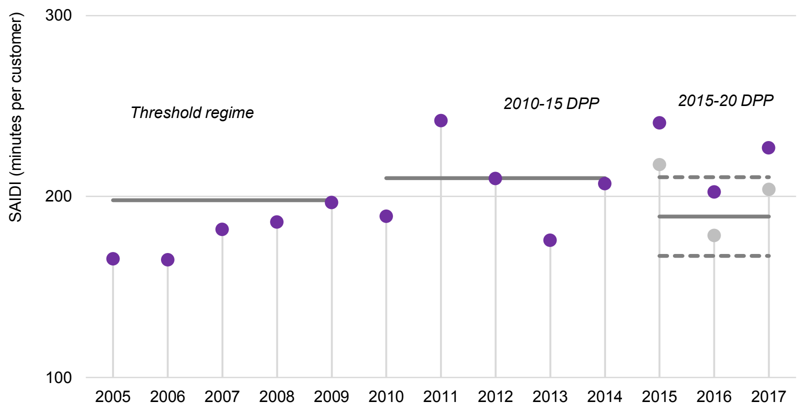
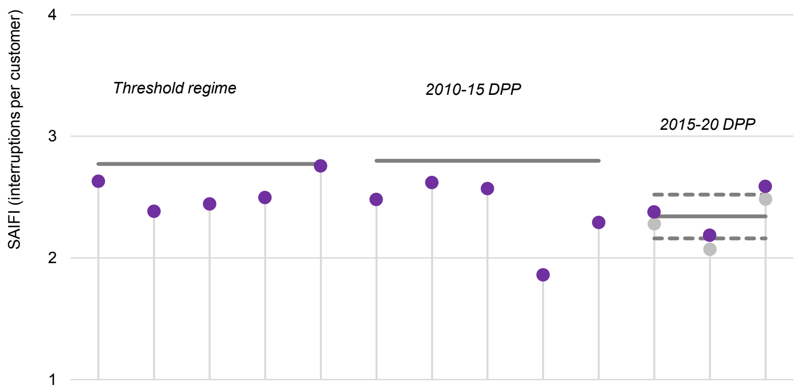


Figure 9.15: Historical SAIFI performance against regulatory targets



9.7.5.2 FEEDER RELIABILITY

We analyse our feeder performance using the Feeder Interruption Duration Index (FIDI) reliability standard. FIDI represents the average number of minutes per year that a customer on a particular feeder experiences without supply. Below we summarise our 2017 FIDI performance.

Table 9.16: Feeder Reliability Performance in 2017

TYPICAL CONSUMER TYPE	LARGE INDUSTRIAL	COMMERCIAL	URBAN	RURAL	REMOTE RURAL
Feeder class	F1	F2	F3	F4	F5
FIDI Limit (mins)	30	60	180	600	1080
Feeders above limit[21]	23	31	48	53	13
Total Feeders[22]	76	117	215	214	20
% compliant with standard	70%	74%	78%	75%	35%

Feeder classes F1-F4 met or exceeded our target of 70% in 2017, improving from 2016. Feeder performance for our remote rural customers however declined from 2016. Detailed descriptions of our worst performing feeders is contained in Appendix 11.

[21] This is influenced by feeders with multiple feeder types, where we assess all feeders against the highest feeder class. For example, a feeder with F2 and F4 sections may have interruptions on the F4 section only, but this is included in the F2 results. We intend to improve the granularity of this analysis to better reflect the performance of feeders with different class sections.

[22] Feeders exclude those for our zone substation local service supplies.

9.8 CUSTOMERS AND COMMUNITY

9.8.1 OVERVIEW

This section sets out the specific targets we have set ourselves for customers and communities over the planning period. We also consider the basis for these targets and our historical performance against these targets.

9.8.2 TARGETS

The table below shows our targets for the planning period

Table 9.17: Customers and Community targets

INDICATOR	TARGET FY17-27
Customer Satisfaction	
% of customers that consider their supply reliability is acceptable or better	>90%
% of customers that consider their overall electricity supply quality meets expectations	>95%
Fault response	
Response times (% meeting target)	>90%
Resolution times (% meeting target)	>85% (F1-F3) >95% (F4-F5)
Power quality	
Voltage within 6% of nominal (% compliance)	100%
Total harmonic voltage < 5% at Point of Common Coupling (% compliance)	100%
Power quality customer complaints investigated (% investigated within 24 hours)	>90%

9.8.3 COMMENTARY

The table below explains the basis for our targets and a summary of our historical performance against targets.

Table 9.18: Customers and Community target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Customer Satisfaction	
Targets reflect our commitment to engaging with our customers to understand their needs. Target levels reflect focused improvement over time, in particular during planned and unplanned power cuts.	More than 90% of surveyed customers consistently consider their electricity reliability acceptable. The responses from our quality survey indicate that more than 95% of customers are satisfied with supply quality.
Fault Response	
Fault response performance reflects our commitment to public safety and our desire to minimise incurred SAIDI. Our targets for fault response reflect our view on acceptable standards, which are aligned to generally accepted practice in the industry.	Fault response performance has improved significantly since 2014, when only 70% of faults were responded to within specified times. Recent performance has been close to or at target levels. Our average fault resolution performance on urban HV assets was 73% in 2017, a drop in performance compared to 2016 figures, and significantly below target. Our average fault resolution performance for rural HV assets remained at same, at 90%, slightly below target.
Power Quality	
Our power quality targets are set to reflect industry requirements, and where these are not prescribed normal industry practice industry guidance. Our Power quality target reflects increased focus and a level we consider to demonstrate proactive management.	At the end of March 2017 we had 109 quality complaints that we were monitoring, pending resolution, or awaiting customer acceptance. We are improving our information systems to allow reporting of the timeliness of power quality investigations.

9.8.4 IMPROVEMENT INITIATIVES

The table below sets out our improvement initiatives.

Table 9.19: Customers and Community improvement initiatives

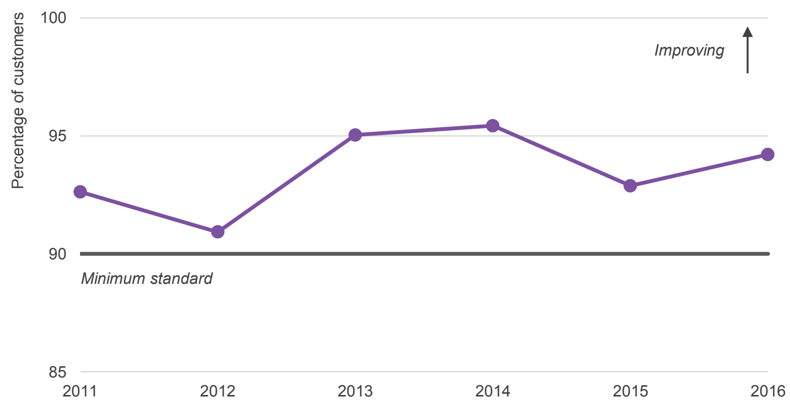
FOCUS AREA	INITIATIVE
Customer strategy initiatives	During 2016 we reshaped our customer teams as a first step in refining our approach with customers. We subsequently sought feedback from our customers about what aspects of our service are most important to them. These are described in Chapter 4. This feedback will shape our customer approach during the planning period.
Powerco Outage Application	During 2017 we will be rolling out an outage application to provide our customers with mobile technology and updates regarding power outages.
Worst performing feeders' improvement	We will continue to prioritise renewal and maintenance work to improve performance on poor performing feeders, as described in Section 0. Examples of this analysis are in Appendix 11.
Service level agreements	Our service provider contracts contain financial incentives for fault response, and we will continue to work collaboratively with our service providers and retailers to ensure the best possible response service.
OMS improvements	We plan to extend the functionality of our OMS with features such as distribution management, storm management and automated switching.
Field mobility and communications	We plan to extend radio communications and provide field staff with mobile access to real time information relevant to their task. This will improve fault response times and allow for more timely and informed decision-making
LV network visibility	We are investing in improved oversight and monitoring on our networks to assist in fault identification and resolution. More information on this programme is provided in Chapter 13.

9.8.5 HISTORICAL TRENDS

9.8.5.1 CUSTOMER SATISFACTION

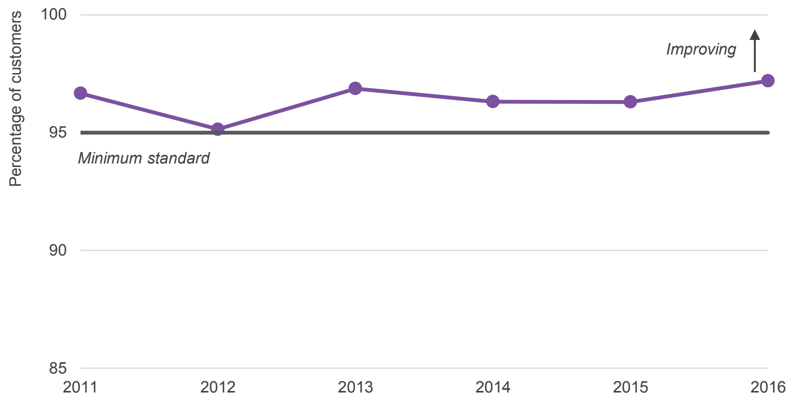
The following figures indicate how our customer satisfaction measures have performed historically.

Figure 9.16: % of customers that told us their electricity supply reliability is acceptable or better



More than 90% of surveyed customers consistently consider their electricity reliability acceptable. While this is a good result, anything less than 100% shows that some customers are not satisfied with their reliability levels. We therefore need to work harder to ensure that areas of the network with poorer performance are improved in line with our customers' expectations.

Figure 9.17: % of customers that told us their overall electricity supply quality meets expectations



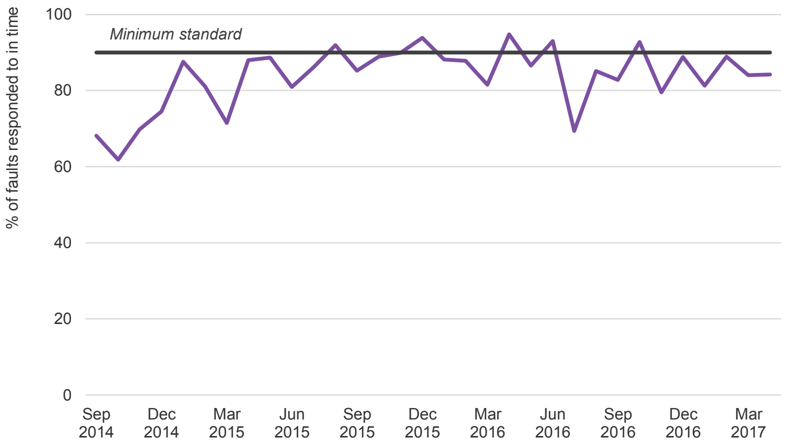
The responses from our quality survey are also positive. In each year, more than 95% of customers told us their supply quality meets their expectations. But there is room for improvement and we will continue to focus on improving our customer service and communication, in particular during planned and unplanned power cuts.

The 2012 results were the lowest of the past five years. We believe this was due to field days being held shortly after a major weather event that caused significant disruption. These results reflect a good baseline for our customer service. Even when our network came under stress our good performance was largely maintained.

9.8.5.2 FAULT RESPONSE

The figure below shows our fault response performance since EFSA began. Amongst other drivers, EFSA was put in place to improve our fault response performance.

Figure 9.18: % of faults responded to within target response time



Fault response performance has improved significantly since 2014, when only 70% of faults were responded to within specified times. Recent performance has been close to or at target levels.

10.1 CHAPTER OVERVIEW

Our investment plans include a progressive lift in total investment over time. To enable this it is appropriate we lift our internal and external capability to deliver.

This chapter describes the work that is underway to support this increased volume of delivery, in particular the following:

- Section 10.2 sets out work underway to lift external field resource
- Section 10.3 sets out work underway to lift internal capacity and capability
- Section 10.4 describes the work underway to improve our information management systems
- Section 10.5 sets our work underway to lift asset management maturity

We also include a high level description of our asset management maturity self-assessment, considering how these measures are used to prioritise the improvement initiatives needed for the organisation to perform more efficiently, and adequately deliver the planned increase in work volumes.

10.2 EXTERNAL CAPABILITY

10.2.1 OVERVIEW

We have consistently demonstrated our ability to plan, release and execute 100% of our annual work plans in conjunction with our contracting partners. We have increased total network capital expenditure year-by-year from $73m in FY12 to $104m in FY16, $20m of that increase being asset renewal projects alone.

In large part our success has been underpinned by the strategic decision made 10 years ago to outsource all of our field work to external service providers. This strategy was designed to minimise cost, deliver efficiencies and enable scalability. It also allowed us to benefit from innovation and competition associated with tender markets.

The rates we pay have been proven efficient, having been tested against the market three years ago in a tender invitation for 100% delivery of fault response, corrective maintenance and minor works services.

10.2.2 RECENT DEVELOPMENTS

Over the past 12 months our field services delivery strategy has been refined to incorporate a tender panel for larger planned works, sized to deliver appropriate scale, resource certainty and effective price competition. We have worked with our key providers to tailor their resourcing and delivery to future work volumes including the following steps:

- Calculated the specific field resources needed to construct and maintain the network;
- Conducted commercial negotiations with external field service providers to provide assurance that the required levels of field resources will be available;
- Assessed the impact that the service providers increased field resource requirements will have on the market for these resources in the various regions in which they operate;
- Analysed and addressed the constraints associated with inputs factors related to the delivery of network investment, such as materials, planning/resource consents and land use rights.

We are moving to further deepen our contracting markets over the CPP period to ensure ongoing efficient pricing and resource flexibility.

10.2.3 PLANT AND MATERIALS

Increased investment in the network will drive a corresponding increase in the amount of input material that will be needed.

We have assessed the availability of key equipment such as poles, crossarms, conductor, cable, switchboards, power transformers, voltage regulators, reclosers and ground-mounted switchgear. This assessment concluded that there are many national and international suppliers, and that our share of the market is small enough that planned increases are readily achievable.

We have also confirmed that our procurement processes are appropriate to ensure we pay a competitive price, commiserate with the volume of purchases.

10.3 INTERNAL CAPABILITY AND CAPACITY

10.3.1 OVERVIEW

The section discusses our plans to grow our internal capability and capacity to support enhanced asset management processes and work volumes.

Over 2017 we will restructure the Powerco Electricity business to ensure we can deliver our work plans efficiently and effectively. Key focus areas are as follows:

- Lifting capability in our asset management teams to enable us to deliver work programmes with targeted levels of efficiency;
- Lifting capacity to enable us to deliver a higher number of projects and investment programmes; and
- Enhancing our asset information processes to support improved asset management practices.

Our approach in this area is consistent with our focus on achieving ISO 55000 asset management standard certification by 2020.

10.3.2 CAPABILITY

10.3.2.1 CAPABILITY REQUIREMENTS

In order to deliver our network investment programmes, we require targeted capability enhancements in the following areas:

- Managing and effectively analysing increasing volumes of network and asset data, building an information basis for sound asset management and network operational decision making
- Building our skills related to innovation, research and development, piloting new solutions and developing these to a state suitable for incorporating as business-as-usual
- Enhancing our ability to understand customer requirements and emerging trends, and how these could be addressed effectively in our service offerings, and better responding to their requirements
- Future scenario development and analysis – ensuring that we make informed investment decisions that would lead to least-regret outcomes in light of changing load patterns on our networks
- Enhancing our asset management practices, with the aim of being ISO 55000 compliant by 2020
- Optimising our long-term investment plans, balancing technical, customer, regulatory, risk-management and shareholder considerations

10.3.2.2 ASSET MANAGEMENT CAPABILITY IMPROVEMENT INITIATIVES

Our plans include a range of initiatives designed to guide development of capability over time. These are set out in **Table 10.1.**

Table 10.1: Asset Management Capability Improvement Initiatives

AREA	INITIATIVE	DESCRIPTION	TIMING
ISO 55000	ISO 55000 Certification	We will identify and address the necessary steps to achieve ISO 55000 certification by 2020.	FY20
Asset Strategy	Refined delivery structures	Aligns our asset management activities and network outputs with our overall organisational objectives including a shift from generalist planning to focused fleet and network development based planning.	FY18
Asset Strategy	Enhanced planning analytics	Lift approach to compiling, processing and mining asset data to inform operational, maintenance and investment decisions.	FY18
Asset Strategy	Enhance team capability	Develop our asset management capability through effective recruitment and development of our staff, ensuring appropriate competency levels and breadth of skills.	Ongoing
Asset information	Asset information strategy	Develop and implement an asset data quality strategy that will ensure our asset managers and operations staff are provided with comprehensive and accurate asset and network performance data	FY19

10.3.3 CAPACITY

10.3.3.1 CAPACITY REQUIREMENTS

In order to deliver our network investment programmes, we require targeted capacity enhancements in the following areas:

- Planning, design and project management of network growth and renewal projects
- Planning and management of increased network maintenance programmes
- Planning and management of increased vegetation control programmes
- Management of an increased number of services providers, which will be required to deliver the proposed increased work volumes
- Managing the day-to-day operation of our electricity network, especially in the face of increased demand for network outages and switching

The capacity uplift will largely involve adding personnel with skills similar to those already present in the company.

10.3.3.2 ASSET MANAGEMENT CAPACITY INITIATIVES

Our plans include a number of specific initiatives to help streamline delivery and focus delivery. These initiatives will supplement additional resources, and ensure capability enhancements are implemented efficiently. These are set out in **Table 10.2**.

Table 10.2: Deliverability Improvement Initiatives

AREA	INITIATIVE	DESCRIPTION	TIMING
Works planning	Works plan process	Enhancement of works planning to enable an extended delivery pipeline.	FY18
Health and Safety	Safety in Design	Update quality and project management framework to ensure that safety in design principles are included	FY18
Facilities	NOC	Construction of a new Network Operations Centre building to allow expanded capability	FY19

10.4 ASSET INFORMATION MANAGEMENT

10.4.1 OVERVIEW

This section considers our approach to Asset Information management, and enhancements we are planning to make in this area.

We treat information as an asset with the understanding that quality, timeliness, accessibility and analysis determine the value of that information. From an asset management perspective, the value is derived from being able to make well informed decisions.

We have made some significant advances in terms of data collection, processing, and mining in recent years. That said, our systems and controls to manage data quality and accuracy are still relatively immature and improvements in this area will be a particular focus for our new Asset Analytics team.

10.4.2 ASSET DATA

We identify the data needs through consultation with our teams and stakeholders, and by mapping out the business functions and required inputs and outputs. This information is then made available to the business through the systems described Chapter 22.

Much of the data we use is collected via our asset inspections. We have standards that prescribe the information that has to be gathered (including asset condition). .

As part of our ongoing asset management journey (discussed in Chapters 5-8) we will complete targeted enhancements to our asset management information) as we move from making predominantly time based or reactive decisions to decisions that are based on condition and criticality-based analytics.

In the last three years, we have focused on improving data on key assets such as distribution transformers and overhead lines. We have also integrated information on ancillary assets and all available historical construction information into our GIS system. We continue to update any new information we receive from field work on existing assets.

The biggest asset information gap we still need to address is with respect to our LV networks, which will be dealt with as part of our long-term information management strategy. Asset data deficiencies are reflected in our AMMAT assessment (see next section and Appendix 2.7), which has shown the feedback loops for information, data quality and structures are sub-optimal.

Initiatives designed to improve the availability or completeness of asset data are listed in **Table 10.3**.

Table 10.3: Asset Data Improvement Initiatives

AREA	INITIATIVE	TIMING
Preventive maintenance inspections	Pole top photography to improve the quality of our overhead line asset information (eg hardware condition). Acoustic testing of overhead line components (conductor, insulators, terminations etc.) to locate defects and to diagnose potential faults on key feeders. Acoustic resonance pole testing to determine internal condition of wooden poles.	FY19
Investment modelling	Refine asset health assessment methods to support maintenance and renewal investment decisions.	FY20

10.4.3 INFORMATION MANAGEMENT

We recognise that to improve our delivery capability we will need to improve the management of business information.

Table 10.4 lists the particular aspects of information management that we are progressing. These are supported by the enabling ICT systems described in Chapter 22.

Table 10.4: Information Improvement Initiatives

AREA	INITIATIVE	TIMING
Capture	Develop comprehensive data standards to ensure we capture correct, quality information once, and at source.	FY19
Accessibility	Develop systems for near real-time storage and retrieval of critical information in a range of locations including supplier and customer portals, cloud systems and with customers.	FY20
Security	Our approach to system security will match information criticality to security and detection measures, so that the more sensitive the information the more layers of security protect it.	FY20
Analytics	This will have significant focus in the period, both with respect to organisational structure and business systems. This will provide tools for analysts and 'knowledge workers' across the business to use asset information to enhance business decision-making.	FY20
Capability	The shift from paper-based to electronic information delivery and the need for more sophisticated data mining is driving a change in the skills required from our people. These are reflected in our recruitment plans and our competency framework development.	FY19

10.5 IMPROVING OUR ASSET MANAGEMENT MATURITY

10.5.1 AMMAT ASSESSMENT

Our plans are designed to ensure ongoing development of our asset management approach over time.

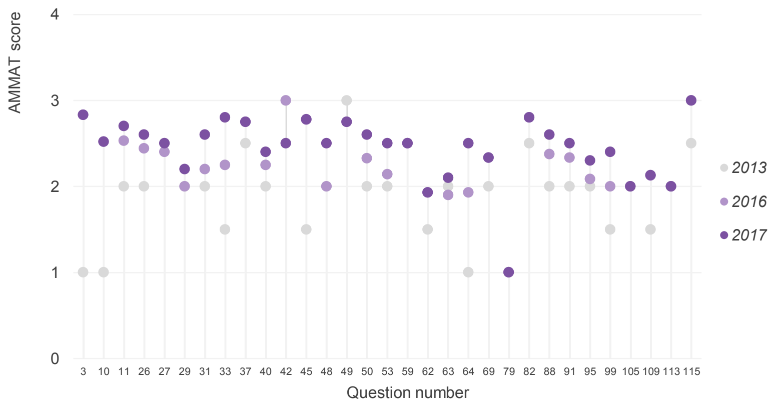
This is consistent with seeking continuous improvement against the Asset Management Maturity Assessment Tool (AMMAT), a self-assessment tool set out by the Commerce Commission for Information Disclosure purposes.

We published our first assessment in the 2013 AMP, and have repeated the assessment in this AMP.[23] Overall, we have found the repeated use of the AMMAT approach useful, and some of the improvement initiatives we are implementing originated from the AMMAT assessment.

The figure below shows the AMMAT results from this year's assessment and compares them to prior scores. Scores range from 0 ('innocent' maturity level) to 4 (excellent maturity level).

[23] As an electricity distributor we are required to undertake and publicly disclose the AMMAT self-assessment results.

Figure 10.1: Asset Maturity Self-Assessment Scores for 2017, 2016 and 2013



We apply a very conservative methodology when evaluating ourselves against the AMMAT criteria. The scores above should be viewed in this context. We believe that asset management is a professional discipline. Therefore we will only score ourselves at maturity level 3 if we believe the item assessed is developed to a level reflecting advanced asset management practice and is widely embedded within our organisation.

10.5.2 SCORING

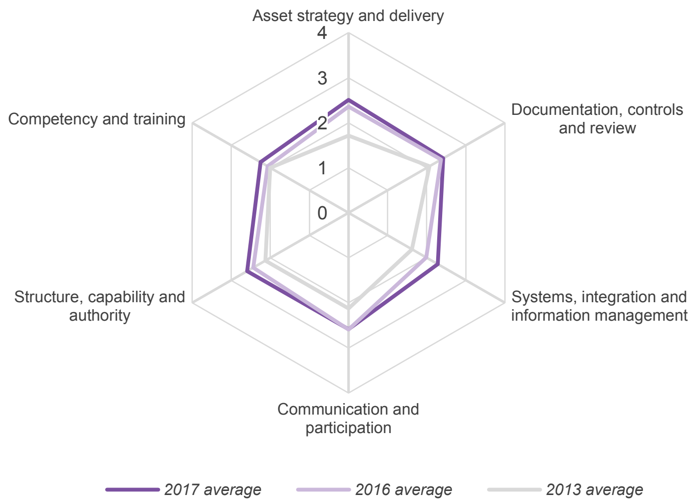
We have seen consistent improvement of our asset management maturity over time, a reflection of the increased importance we have given to this aspect of our business.

Changes in our measured maturity since the last edition of our AMP are:

- On 16 questions our maturity score increased compared to 2016;
- On 14 questions our score is the same as in 2016; and,
- On one question our score decreased slightly.
- Our average score is 2.4 against a 2016 average score of 2.3.

Below we show the scores grouped by assessment areas. Our maturity improved significantly in one area, improved marginally in three areas, and stayed virtually the same in two areas.

Figure 10.2: Summary of Asset Maturity Self-Assessment Scores by Assessment Area



Most of the changes reflect positive trends in our asset management approach. For example our Asset Management Group restructure will allow better linkages between corporate strategy and team functionality.

However some differences are a result of our improving understanding of the AMMAT self-assessment process. We undertook the assessment for the first time in 2013. We had contributed to the development of the EEA's AMMAT guide in 2012 but our subsequent experience enabled us to materially contribute to the subsequent update in 2014.[24]

Other differences reflect increasing self-awareness. For example in 2013 we assessed ourselves as reasonably advanced on the availability of asset information. However, the corporate ERP initiative revealed the need for richer, more detailed information to support the level of competence we aspire to.

10.5.3 IMPROVEMENT INITIATIVES

As well as the initiatives set out in Table 10.1 and Table 10.2, we have started to develop the relevant additional documentation, systems and processes needed for ISO 55000 certification as outlined in **Table 10.5**.

[24] Electricity Engineers' Association, AMMAT — Revised Guide (May 2014) www.eea.co.nz/tools/products/details.aspx?SECT=publications&ITEM=2564

Table 10.5: Asset Management Maturity Improvement Initiatives

INITIATIVE	OUTCOME	TIMING
Communications Plan	Will set out how we communicate with stakeholders involved in activities such as developing asset management strategies, objectives and plans, ensuring we communicate them effectively and help lift the profile of the Asset Management System across the company.	FY18
Competency Framework	Expanding our people competency framework will benefit and strengthen linkages to the asset management system	FY19
Asset Information management improvements	The ICT infrastructure and the way we use it will be areas of particular focus in the planning period	FY19

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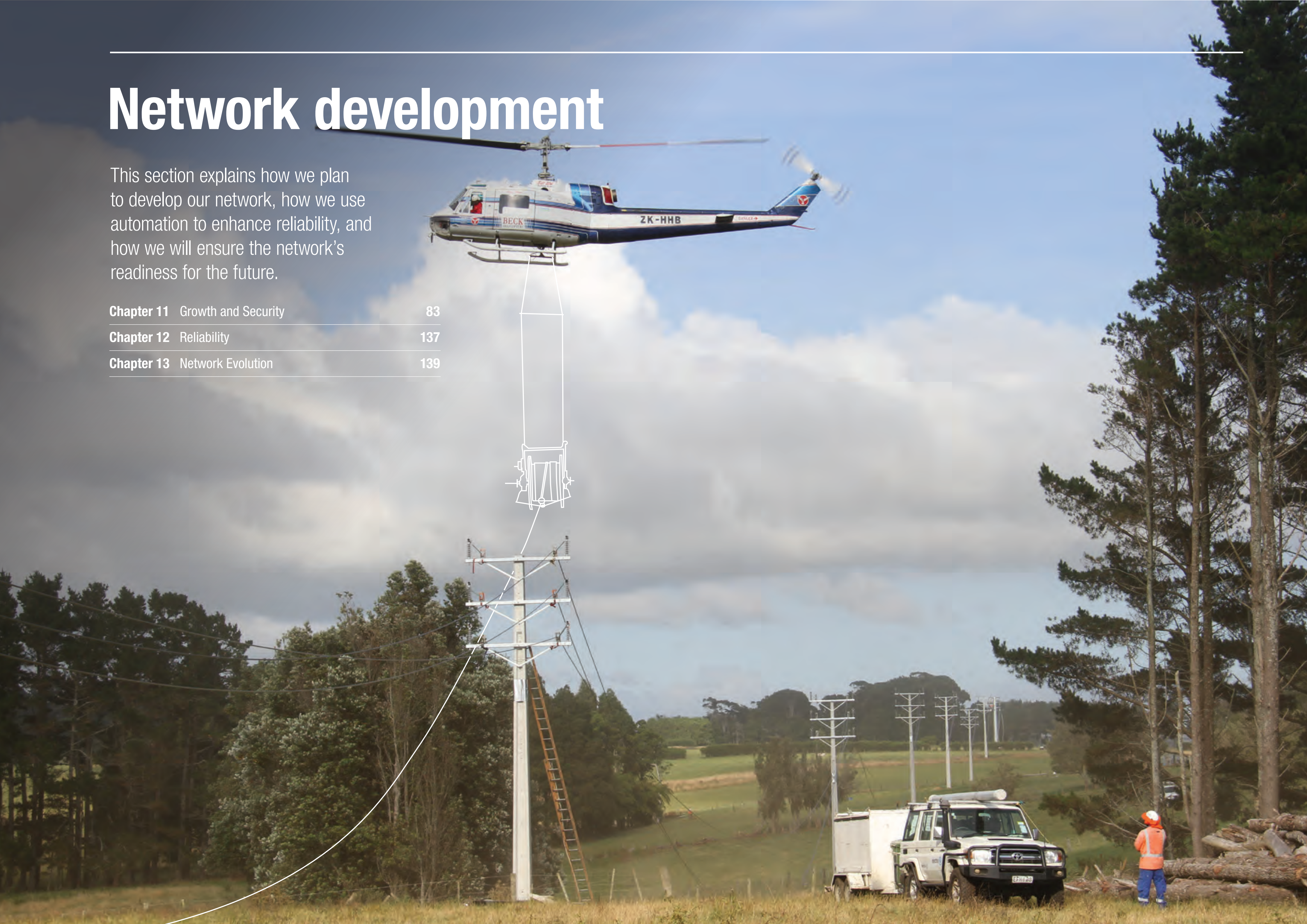
Network development

This section explains how we plan to develop our network, how we use automation to enhance reliability, and how we will ensure the network's readiness for the future.

Chapter 11	Growth and Security	83
Chapter 12	Reliability	137
Chapter 13	Network Evolution	139



11.1 CHAPTER OVERVIEW

This chapter builds on the introduction to Growth and Security provided in Chapter 7 which summarised our approach to forecasting demand growth and how we invest to maintain supply security. It provides a summary of the resulting area investment plans, our investment in communications infrastructure and ongoing routine growth investments on the distribution network.

Growth and security investment is forecast to grow during the planning period, driven by increasing ICP numbers and demand across our network. In contrast to the reported national trend, the majority of our network continues to experience sustained demand growth. This is mainly driven by residential growth in areas such as Tauranga, and dairy and industrial growth in the Waikato and Taranaki.

We are forecasting a need to significantly lift our investment in growth and security from current levels. This investment is specifically targeted at supporting residential and industrial growth, and addressing security related issues. This is informed by the concerns of the customers and communities we serve. We are fortunate to operate in regions where our customer base continues to grow and expand, and we believe we play a critical role in supporting this growth.

We do our network planning based on 13 discrete areas. These are described in this chapter, along with our main planned investments in each area.

11.2 GROWTH AND SECURITY

We use the term growth and security to describe capital investments that increase the capacity, functionality, or size of our network. These include the following five main types of investments.

- **Major projects:** Over $5m, generally involving subtransmission or GXP works.
- **Minor projects:** Between $1m - $5m that typically involve zone substation works and small subtransmission projects
- **Routine projects:** Below $1m, including distribution capacity and voltage upgrades, distribution back-feed reinforcements (supports automation), smaller zone substation upgrades, distribution transformer upgrades, and LV reinforcement.
- **Communications projects:** To support improved control and automation of the network, and provide voice communications to our field staff.
- **Reliability:** Includes network automation projects to help manage the reliability performance of our network. These are discussed in Chapter 12.

11.2.1 GROWTH AND SECURITY STRATEGY AND OBJECTIVES

To guide our strategy for network development we have defined a set of objectives, as listed below. They are linked with our overall asset management objectives in Chapter 5.

Table 11.1: Growth and Security objectives

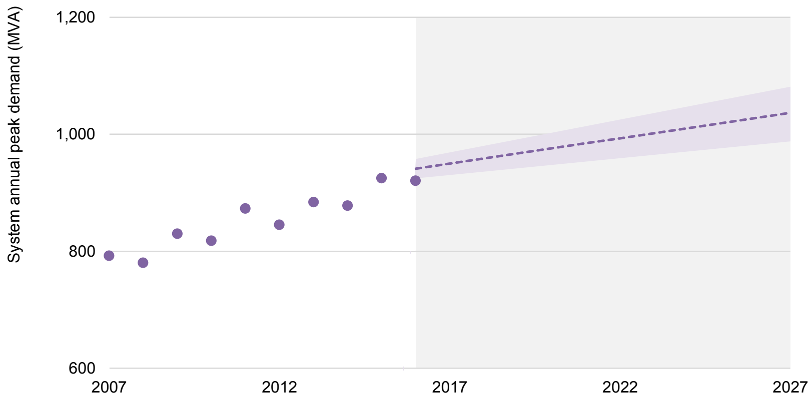
ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Use safety-in-design to ensure appropriate design of the network to provide for alternate supply during maintenance, reducing the need for high risk live line work. These principles also help ensure the intrinsic safety, ease of maintenance, operations and accessibility of our assets.
	Consider the impact on the environment of our large-scale development projects in our access and consenting approach.
Customers and Community	Minimise planned interruptions to customers by coordinating network development with other works.
	Consult with our customers in regard to price/quality trade-offs for major projects. Better align our planning processes and decision criteria with evolving customer needs.
	Adapt to the changing needs of our customers to understand the possible implications of widespread uptake of new technology.
	Work with land owners during our access and consents process.
	Ensure our customer contribution policies are fair, in that they reflect the unrecovered cost of progressing a connection.
Networks for Today and Tomorrow	Prudently introduce new technology on our network, including technology that facilitates innovative customer solutions. Undertake appropriate trial programmes to understand how new technology can assist in more effectively providing our core service of delivering reliable energy.
	Continue with our strategy of using appropriate levels of network automation and remote control to reduce outage times following faults, as well as the number of ICPs affected.
	Continue to review our demand forecasting, security criteria and network architecture to optimise our investment in network infrastructure.
Asset Stewardship	Improve our use risk-based analysis and life cycle cost modelling in our development planning.
	Improve our feedback procedure so that field and construction experience is used to help future planning in a more systematic and thorough manner.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Operational Excellence	Obtain more comprehensive, accurate data to aid high quality options analysis, so the most cost effective, long-term solutions can be consistently identified.
	Continue to refine our area plans to holistically consider all network priorities (renewal, development, customer needs and reliability).
	Continue to update core design standards, which will improve safety and efficiency. Standardisation of components and materials will improve spares and stock efficiency.

11.3 DEMAND TRENDS

A flat or reducing peak demand has been reported in many sectors of the industry lately, most notably the grid operator. In contrast, our network has continued to experience steady and sustained growth. **Figure 11.1** shows both the historical trend and our forecast of total system demand for the whole network.

Figure 11.1: System demand trend and forecast



The consistent growth exhibited is mainly a result of:

- Steady residential subdivision activity, especially in key areas such as Tauranga and Mt Maunganui
- Significant changes in the demand of some larger industrial customers, especially from the dairy industry, and the oil and gas industry in Taranaki
- Smaller contributions from irrigation developments, cool stores, and other agricultural loads

Growth in each area of our network varies according to demographic changes and economic activity. The maps in **Figure 11.2** and **Figure 11.3** indicate annual forecast growth rates by planning area for the western and eastern regions.

Figure 11.2: Forecast demand growth in western planning areas

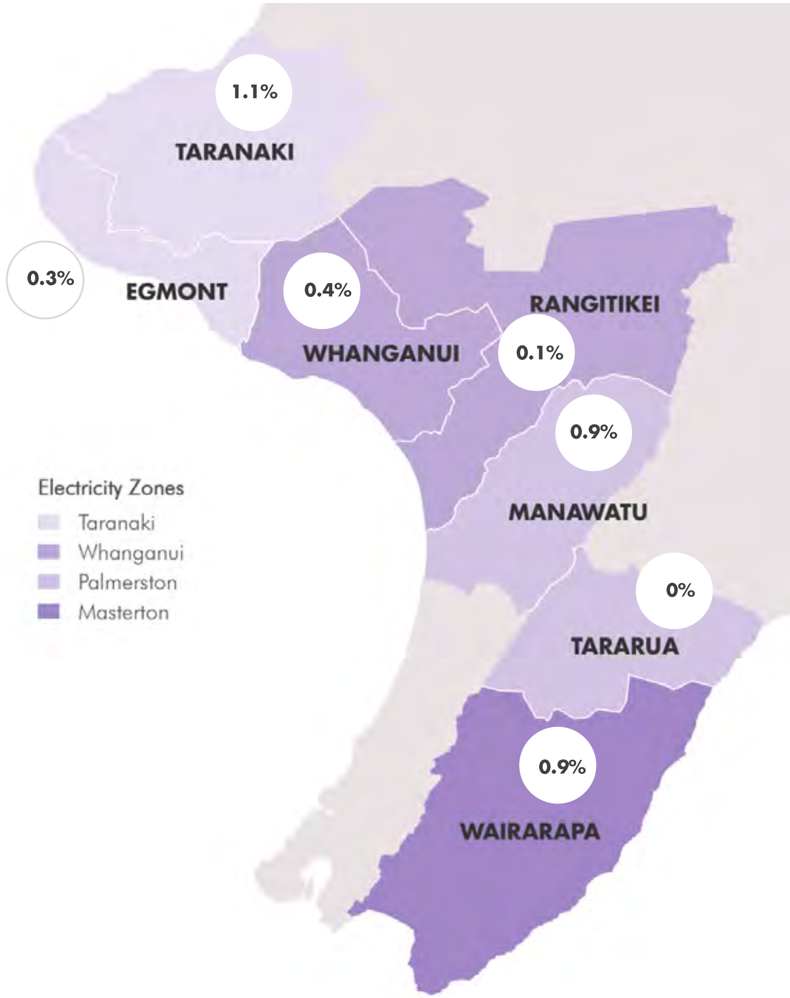
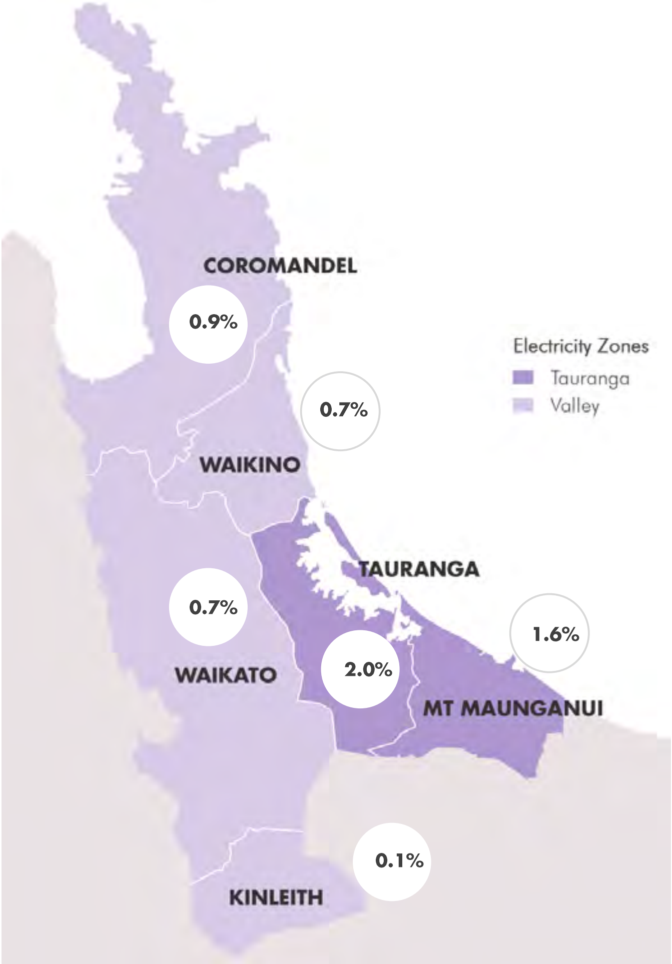


Figure 11.3: Forecast demand growth in eastern planning areas



Higher growth is evident in areas such as:

- Tauranga and Mt Maunganui – population increase driving residential subdivisions and commercial/industrial developments.
- Coromandel – increased holiday and tourism activity in Coromandel and popular coastal areas.
- Taranaki – industrial, often associated with oil and gas.

11.4 AREA PLANS

To best manage our investment planning, and to improve our focus on local needs and issues, we have divided our network into 13 planning areas. We then produce a comprehensive and integrated development plan for each area.

These area plans are summarised in the following sections.

For more detailed descriptions of the options considered for our large growth and security projects, refer to Appendix 8.

11.4.1 COROMANDEL

Strong growth in the Coromandel area has created legacy security issues, which is coupled with increasing consumer expectations around the reliability of supply, particularly from holiday home owners on the Coromandel Peninsula. As a result, in 2011 we completed the construction of a new 66kV line (110kV enabled), which has increased the security and reliability of specific substations. However the existing lines and substations face significant capacity restraints and additional investment is required to improve both network security and reliability. Major and minor project spend related to growth and security over the next 10 years is $65.9m.

11.4.1.1 AREA OVERVIEW

The Coromandel area plan covers the Coromandel Peninsula as well as a northern section of the Hauraki Plains. The main towns in the area are Thames, Coromandel, Whitianga, Tairua, and Ngatea.

The economy is largely tourism based, with some agriculture and forestry. The population is highly seasonal and the annual demand profile is peaky.

The appropriate level of security is also a source of debate given the nature and duration of peak loads, and the inherent economic cost of reliable supply.

The region is characterised by rugged, bush-covered terrain, with minimal sealed road access for heavy vehicles. This makes access to lines for construction, maintenance and faults difficult and costly. Sensitive landscape and heritage areas also restrict our options for upgrading and building new lines.

Seasonal weather extremes and cyclones can impact the quality of supply. The demand for electricity peaks in the summer when the thermal ratings of overhead lines are limited by the higher ambient temperatures.

The subtransmission circuits in the Coromandel area are supplied from the Kopu GXP, just south of Thames. The area uses a 66kV subtransmission voltage, which is unique across our networks.

The subtransmission is dominated by a large overhead ring circuit, serving Tairua and Whitianga, with a teed radial line feeding Coromandel. A further interconnected ring serves the Thames substation.

These ring circuits have protection issues that prevent us operating the rings closed. Voltage constraints and, in places, thermal capacity constraints, also severely limit our ability to provide full N-1 security to all substations.

Matatoki substation is directly adjacent to the Kopu GXP. Kerepehi substation is fed from a single radial circuit.

Our subtransmission and distribution networks in the Coromandel area are predominantly overhead, reflecting the rural nature of the area. Some of the original transmission circuits are very old but we have been working through a programme of upgrading and renewing the circuits during the past decade.

11.4.1.2 DEMAND FORECASTS

Demand forecasts for the Coromandel zone substations are shown below, with further detail provided in Appendix 7.

Table 11.2: Coromandel zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Coromandel	AA	0.0	4.7	4.9	5.1	5.3
Kerepehi	AA+	0.0	10.1	10.4	10.8	11.1
Matatoki	AA+	0.0	5.6	5.8	6.1	6.3
Tairua	AA	7.5	8.6	8.8	9.1	9.4
Thames T1&T2	AAA	0.0	13.4	13.6	13.8	13.9
Thames T3	AA	6.9	3.4	3.4	3.4	3.4
Whitianga	AAA	0.0	17.2	18.3	19.6	21.0

Growth is forecast to be steady, especially on those substations that supply popular holiday towns. This is, to a degree, linked to national economic prosperity, since demand here grows in response to additional holiday accommodation.

Shaded years indicate that the demand exceeds the capacity we can provide with appropriate security. Several of the Coromandel substations already exceed our security criteria in 2016. Our plans are therefore focused more on improving security and reliability for the existing load base as much as catering for additional future load growth.

Thames T3 is part of Thames substation and is a dedicated transformer serving one industrial customer with customer-specific security requirements.

11.4.1.3 EXISTING AND FORECAST CONSTRAINTS

None of the Coromandel area's substations fully meet our standard security criteria. This is, in part, because of the legacy security criteria used by previous network owners, which reflected the low criticality of the consumer load because of its short peak duration (i.e. mostly during peak holiday periods/weekends).

Major constraints affecting the Coromandel area are shown below:

Table 11.3: Coromandel constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Coromandel, Whitianga and Tairua substations	Kopu-Parawai and Parawai–Kauaeranga sections of 66kV line are insufficient to supply all three substations for a Kopu-Tairua 66kV circuit outage.	New Kopu-Kauaeranga line
Coromandel, Whitianga, Tairua and Thames substations	Kopu-Parawai 66kV circuit needs to supply all of Thames when the direct Kopu-Thames circuit is unavailable. Overloading occurs when supplying Whitianga, Coromandel and part of Thames.	New Kopu-Kauaeranga line
Coromandel, Whitianga and Tairua substations	Kaimarama-Whitianga 66kV line has insufficient capacity to supply all three substations for a Kopu-Tairua 66kV circuit outage.	New Kaimarama – Whitianga circuit
Coromandel, Whitianga and Tairua substations	Kopu-Tairua 66kV line has insufficient capacity to supply all three substations for a Kopu-Whitianga 66kV circuit outage.	Kopu-Tairua line upgrade
Coromandel, and Whitianga substations	Tairua-Coroglen 66kV line has insufficient capacity for a Kopu-Whitianga circuit outage.	Note 1
Whitianga substation, Matarangi feeders	Two existing 11kV feeders supplying Matarangi are overloaded at times, have excessive ICP counts and insufficient back-feed capability.	New Matarangi substation
Whitianga substation, Whenuakite feeders	Two existing 11kV feeders supplying Coroglen, Cooks Beach, Hahei and Hot Water Beach are overloaded at times, have excessive ICP counts and insufficient back-feed capability.	New Whenuakite substation
Coromandel, Whitianga and Tairua substations	Low voltages during outages of either Kopu-Whitianga or Kopu-Tairua circuits.	Kaimarama-Whitianga, Kopu-Tairua, Kopu-Kauaeranga, Whitianga and Tairua voltage support
Kerepehi substation	Single circuit – insufficient 11kV back-feed to meet security criteria.	Backup supply to Kerepehi
Kerepehi substation	Demand exceeds secure capacity of the two transformers.	Kerepehi Transformers upgrade
Coromandel substation	Single 66kV circuit with minimal 11kV back-feed.	Kaimarama-Whitianga circuit, Coromandel substation alternate supply
Matatoki substation	Single transformer. 11kV back-feed capacity does not provide the required security.	Note 2
Tairua substation	Demand exceeds secure capacity of the two transformers.	Note 2
Whitianga substation	Demand exceeds secure capacity of the two transformers.	Matarangi and Whenuakite subs
Coromandel substation	Demand exceeds secure capacity of the two transformers.	Note 2
Coromandel substation	SWER in rural parts of the network. Low voltages and high unbalance issues seen during high load periods.	Upgrade of SWER systems

Notes:

1. Tairua-Coroglen section has insufficient capacity for a Kopu-Whitianga outage. This issue is managed operationally. Once the Kopu-Tairua section upgrade is completed this section may be addressed.

2. The risk of lost supply with these transformers is minimal and can be managed operationally until future transformer upgrades can be scheduled.

11.4.1.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Coromandel area.

NEW KAIMARAMA–WHITIANGA CIRCUIT	
Estimated cost (concept):	$6.1m
Expected project timing:	2021-2023

This investment addresses a number of constraints and needs, especially the tee connection of the Coromandel line and the capacity constraint between Kaimarama and Whitianga.

Options considered are detailed in Appendix 8.

The current preferred solution is a new 66kV circuit between Kaimarama and Whitianga, using an 110kV capable cable along existing public road routes. This will allow the Coromandel tee to be removed, and eliminate capacity constraints during Kopu-Tairua outages.

While the proposed solution removes the tee connection of the Coromandel circuit, none of the options would economically address the single 66kV circuit to Coromandel. The costs for a second dedicated 66kV circuit over difficult terrain would be prohibitive.

KOPU–TAIRUA LINE UPGRADE	
Estimated cost (concept):	$9.2m
Expected project timing:	2019-2021

This project addresses the limitations imposed by the capacity of the relatively small conductor on the 66kV line between Kopu GXP and Tairua substation. This is constrained at peak loads when the Kopu to Whitianga circuit is out of service. The conductor size also adversely impacts voltage quality under contingencies.

Options considered are detailed in Appendix 8.

The proposed solution is to reconductor the existing line. This will be designed for a higher capacity and operating temperature, and will remove the existing thermal capacity constraints. The voltage performance will be addressed by separate projects to install reactive support at Whitianga and Tairua.

NEW KOPU–KAUAERANGA LINE	
Estimated cost (consenting):	$10.2m
Expected project timing:	2016-2024

The existing 66kV line between Kopu and Kauaeranga is constrained in several sections, especially between Kopu and Parawai, which also serves as a backup supply to Thames. The conductor between Parawai and Kauaeranga is also overloaded when used to supply the Tairua, Coromandel and Whitianga substations on the 66kV ring during an outage of the Kopu-Tairua circuit. Furthermore, the conductor between Kopu and Parawai can overload when supplying the Thames, Coromandel and Whitianga substations during an outage of the Kopu-Thames circuit.

Options considered are detailed in Appendix 8.

The proposed solution is to install a new 110kV capable line from Kopu GXP to Kauaeranga. This allows the existing line to Parawai to be dedicated to Thames substation and provides additional capacity for the 66kV ring serving Whitianga and Coromandel, plus Tairua also under contingencies. The new line also provides a 110kV capable circuit from Kopu GXP through to Kaimarama (close to Whitianga). This is part of our strategy to accommodate long-term growth.

Given that construction of the line is expected to be delayed as a result of a Treaty land settlement claim, the interim solution is to reconductor the section from Parawai to Kauaeranga, and thermally upgrade the section from Kopu to Parawai. These projects will allow the proposed line construction to be deferred until the settlement claim is resolved.

WHENUAKITE SUBSTATION	
Estimated cost (concept):	$7.2m
Expected project timing:	2022-2023

The two 11kV feeders supplying the coastal area south and east of Whitianga, including the holiday townships of Coroglen, Cooks Beach, Hot Water Beach and Hahei, are severely constrained. The feeders experience high loads (and voltage constraints) during holiday periods and have very limited back-feed. These feeders also contribute to potential overloading of Whitianga substation. Growth rates in this area have been relatively high and are expected to continue. Due to the long feeder lengths, supply restoration times are typically long as field crews attempt to fault-find and fix network faults.

Options considered are detailed in Appendix 8.

The proposed solution is to construct a new Whenuakite zone substation. It is proposed to supply this substation from the existing 66kV Tairua to Whitianga line using a new dual circuit 66kV line with ‘in and out’ configuration. The new zone substation will supply a number of new 11kV feeders. This will reduce the length of the existing feeders, decrease customer numbers per feeder, and provide adequate capacity for normal configuration, back-feeds and future growth. It will also offload Whitianga substation.

MATARANGI SUBSTATION	
Estimated cost (concept):	$8.2m
Expected project timing:	2021-2023

The 11kV feeders supplying the holiday townships of Matarangi and Kuaotunu (north of Whitianga) are constrained and have very limited back-feed capacity. These feeders also contribute to potential overloading of Whitianga substation. Growth rates in this area have been relatively high and are expected to continue.

Due to the long feeder lengths, supply restoration times are typically long as field crews attempt to fault-find and fix network faults.

Options considered are detailed in Appendix 8.

The proposed solution is to construct a new 66/11kV Matarangi zone substation. A new 66kV capable circuit may be constructed before the substation and used initially as an additional 11kV feeder. Later, the line would be energised at 66kV to supply a new zone substation with 11kV feeders supplying the immediate area. This project also alleviates future constraints on Whitianga substation, although the Whenuakite substation is expected to provide this same benefit as well.

BACKUP SUPPLY TO KEREPEHI	
Estimated cost (concept):	$6.2m
Expected project timing:	2021-2022

Kerepehi has a single 66kV supply circuit. This means that supply is limited to 11kV back-feeds when the 66kV is out of service. The existing 11kV back-feed is not sufficient to meet our security standards.

Options considered are detailed in Appendix 8. We propose to refurbish and reinstate an old 50kV line that runs between Kerepehi and Paeroa and provide a 33kV back-feed via Paeroa. However, this option rests on the successful negotiation of consents and property rights in order to gain permission to upgrade the line. If the initial assumptions around these prove invalid, we may need to re-visit the project scope and options.

11.4.1.5 MINOR GROWTH AND SECURITY PROJECTS

There are no minor growth and security projects identified for the Coromandel area over this period.

11.4.1.6 OTHER DEVELOPMENTS

We are planning to install reactive support at Tairua and Whitianga to address the existing voltage constraints when feeding all of Whitianga, Coromandel and Tairua substations from one side of the 66kV ring out of Kopu GXP.

Protection issues have also limited our ability to operate the 66kV ring permanently closed. With improved communication capabilities it is planned to install protection systems that will allow future closed ring operation.

The Kopu-Tairua and Kopu-Kauaeranga circuits, in addition to being capacity constrained, are also in need of major renewal work. Pole replacements have already been designed to allow for the future capacity increase of the line.

The future long-term strategy for development in the Coromandel area is to provide for 110kV supply from Kopu GXP to Whitianga (or alternatively Kaimarama).

Operation at 110kV is unlikely to occur until beyond the next decade. However, projects to date and those identified above provide 110kV capable circuits in anticipation of this significant potential voltage change.

To address the lack of alternative supply for Coromandel substation, we are investigating the possibility of installing feeder-based distributed generation/energy storage systems (DG/ESS) spread across the distribution network.

Some remote parts of the network north of Coromandel are supplied via single wire earth return (SWER) reticulation. Low voltages are seen on the SWER network during high loads and leads to increased unbalance on the 11kV network. Further load growth will worsen these issues. We propose to progressively upgrade the SWER network to a three-wire three-phase supply over time but will consult with customers on their price-quality preferences.

Transpower's dual circuit 110kV lines from Hamilton to Kopu (known as the Valley Spur) are forecast to exceed N-1 capacity in about 2022. This has some impact on Kopu security but the scope of any future upgrades is likely to be outside the Coromandel area.

Longer term developments in the area may include a new substation dedicated to Thames Timber and increased capacity on the section of 66kV line from Tairua to Coroglen.

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Coromandel Substation Alternate Supply	Security of supply at Coromandel is vulnerable due to the long single circuit subtransmission line. A second line is impractical due to terrain and cost. A distributed Energy Storage Solution is likely to be a preferred solution.
Tairua Area Voltage Support	The subtransmission network around the Coromandel peninsular is voltage constrained. Although reconductoring projects are planned, the area will still need voltage support in the form of either STATCOM or capacitor banks at key substations.
Kerepehi Substation Transformer Capacity Upgrade	Firm capacity at Kerepehi substation is exceeded. Additional transformer capacity will be required. A third transformer is the probable solution.

PROJECT	SOLUTIONS
Upgrade of Single Wire Earth Return (SWER) Systems	The capacity of the SWER circuits north of Coromandel town is at its limits. As load increases, the situation will worsen. Conversion of the SWER lines to three phase is the most likely solution but non network alternatives are being considered.
Whitianga Area Voltage Support	The subtransmission network around the Coromandel peninsular is voltage constrained. Although reconductoring projects are planned, the area will still need voltage support in the form of either STATCOM or capacitor banks at key substations.

11.4.2 WAIKINO

The Waikino area includes the popular holiday town of Whangamata, which is supplied by a single 33kV circuit from Waihi. The main growth and security project in this area is to add a second 33kV line from the Waikino substation to Whangamata once consenting issues are resolved. In the interim, we plan to install an energy storage system comprising batteries and diesel generators to provide emergency supply to the critical loads in the central business district of Whangamata. Major and minor project spend related to security over the next 10 years is $21.4m.

11.4.2.1 AREA OVERVIEW

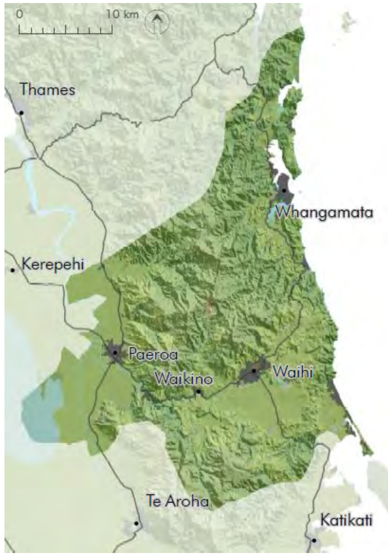
The Waikino area plan covers the southern end of the Coromandel Peninsula and a small section of the eastern Hauraki Plains.

As with the Coromandel area, much of the Waikino area is rugged, hilly and covered with native bush. It is not heavily populated and road access is quite limited in some parts.

The region has a temperate climate with mild winters and warm summers. Rainfall can be high and storms often come in from the Pacific Ocean, which can affect network operation.

The main towns in the Waikino area are Paeroa, Waihi and Whangamata. The region's economy is based on tourism, particularly seasonal holidaymakers, with some primary agriculture. The Waihi mine also has a significant bearing on the electrical demand in the area.

This area takes grid supply from the Waikino GXP at 33kV. Zone substations are located at Paeroa, Waihi, Waihi Beach and Whangamata. The subtransmission system has a ring configuration between Waikino GXP and Waihi. A single circuit supplies Whangamata from Waihi. A single circuit also supplies Waihi Beach, with a tee connection to the Waikino GXP-Waihi ring. There are two dedicated circuits supplying Paeroa from Waikino.



The subtransmission and distribution networks are mainly overhead. Occasional extreme weather and rugged, bush-covered terrain make line access and fault repair challenging. Of particular concern are those substations supplied by single circuits.

11.4.2.2 DEMAND FORECASTS

Demand forecasts for the Waikino zone substations are shown below, with further detail provided in Appendix 7.

Table 11.4: Waikino zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Paeroa	AA+	6.0	8.3	8.5	8.6	8.8
Waihi	AAA	16.0	18.3	18.7	19.4	20.0
Waihi Beach	AA	3.3	5.9	6.2	6.6	7.0
Whangamata	AA+	0.0	10.5	10.7	10.9	11.1

Growth in the area has been modest in recent years, except on those substations that supply popular holiday towns. Demand growth in holiday locations is linked to general economic prosperity. The development of the mine is more a function of market prices. Strong economic conditions could be expected to drive higher growth rates than those shown.

Shaded values in the table indicate that demand exceeds the capacity we can provide with appropriate security. Of note is that all of the Waikino substations already exceed the secure class capacity. Development plans are therefore focused on improving security and reliability for the existing load base rather than specifically catering for load growth.

11.4.2.3 EXISTING AND FORESEEN CONSTRAINTS

Major constraints affecting the Waikino area are shown below.

Table 11.5: Waikino constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Waikino GXP	TP Waikino supply transformers are close to end-of-life. Low voltages during 110kV Hamilton-Waihou circuit contingency.	Note 1
Whangamata substation	Loss of supply to Whangamata for an outage on the single Waihi-Whangamata 33kV circuit. Main 11kV backup line shares same poles as 33kV.	Whangamata single 33kV circuit
Waihi Beach substation	Single circuit to Waihi Beach. Insufficient 11kV back-feed when this 33kV circuit is out of service.	Note 2
Waihi Beach substation	Waikino to Waihi Beach tee connection: Outages on the Waikino to Waihi line cause an outage at Waihi Beach. Overloading can occur under some scenarios.	Waihi Beach 33kV tee supply
Waihi substation	Demand exceeds secure capacity of the two transformers.	Note 3
Whangamata substation	Demand exceeds secure capacity of the two transformers.	Whangamata single 33kV circuit
Waihi Beach substation	Single transformer, which does not provide sufficient security.	Waihi Beach supply transformers
Paeroa substation	Demand exceeds secure capacity of the two transformers.	Note 4
Paeroa substation	Expected end-of-life of transformers (x2).	Note 4

Notes:

1. Transpower Transmission Planning Report 2015 – Transpower plans to replace the transformers about 2020. The new units will have on-load tap changers, which will also address the voltage problems.

2. The amount of load at risk is small and the section of line affected is short. Therefore outages are infrequent. It is not cost effective to provide an alternative second 33kV circuit. Options to improve 11kV back-feed or reliability will be considered.

3. Waihi substation supplies the Waihi mine. This customer does not require security to all load. Demand side arrangements exist to shed load at the mine if the Waihi substation transformers or supply system upstream has insufficient capacity.

4. Expenditure for this work is allowed for in the renewal forecasts, and capacity will be considered so as to economically provide for expected long-term load growth.

11.4.2.4 MAJOR GROWTH AND SECURITY PROJECTS

Below we set out summaries of the major growth and security projects planned for the Waikino area.

WHANGAMATA SINGLE 33KV CIRCUIT	
Estimated cost (consenting):	$18.7m
Expected project timing:	2016-2025

The popular holiday town of Whangamata is supplied from the Waihi substation by a single long 33kV line.

This line is constrained at peak loads. During faults on this line, the 11kV back-feed is very limited and most of Whangamata remains without power until repairs are completed. The 11kV back-feed and 33kV circuit share poles for most of the route, exposing a high risk of common types of failure causing both circuits to be unavailable. Options to increase 11kV back-feed capacity are therefore very limited. Options considered are detailed in Appendix 8.

The interim solution we propose is to introduce an energy storage with backup generation system, sized to support the critical load in the town during emergencies. Depending on the outcome of consultation with customers, this could in the longer term future be followed by the construction of a new 33kV line from Waikino substation to Whangamata substation. We are working closely with the relevant parties to secure a suitable route as the line would cross conservation land. The new 33kV line would resolve the security issues at Whangamata and improve the overall reliability to Waihi and Whangamata substations.

The proposed energy storage solution provides an ideal platform for Powerco to test a wide variety of concepts in a real-life situation to determine their impact on the wider network.

11.4.2.5 MINOR GROWTH AND SECURITY PROJECTS

Below we set out summaries of the minor growth and security projects planned for the Waikino area.

WAIHI BEACH SUBSTATION SUPPLY TRANSFORMERS	
Estimated cost (concept):	$1.2m
Expected project timing:	2022-2023

The Waihi Beach substation contains a single transformer. The demand has exceeded the transformer's capacity. There is also limited 11kV back-feed, so it does not meet security requirements.

The solution is to upgrade to a two-transformer bank substation, ensuring that the capacity will provide for future demand.

Alternatives such as increased 11kV back-feed would be costly as Waihi Beach is quite remote from other substations and the 11kV network requires manual switching, during which time the remaining transformer could trip on overload.

WAIHI BEACH 33KV TEE SUPPLY	
Estimated cost (concept):	$2.4m
Expected project timing:	2022-2023

The Waihi Beach substation is supplied via a spur teed off one of the Waikino-Waihi 33kV circuits.

Supply for Waihi Beach is lost if a fault occurs anywhere on the overhead Waikino-Waihi Beach-Waihi 33kV circuit. Conversely, a fault on the 33kV spur line to Waihi Beach will result in Waihi substation running on N (single redundancy) security.

The proposed solution is to build a new 33kV indoor switchroom at Waihi substation and route a new 33kV cable from the new switchroom to the existing tee-off to create a dedicated Waihi-Waihi Beach 33kV circuit. This also allows supply to be maintained to Waihi Beach even if the Waikino-Waihi circuit is out of service.

11.4.2.6 OTHER DEVELOPMENTS

Transpower's dual circuit 110kV lines from Hamilton to Kopu (known as the Valley Spur) are forecast to exceed N-1 capacity in about 2022. This has some impact on Waikino security but the scope of any future upgrades is likely to be outside the Waikino area.

11.4.3 TAURANGA

The Tauranga region has historically had high-demand growth driven by population increases, and we are expecting this to continue.

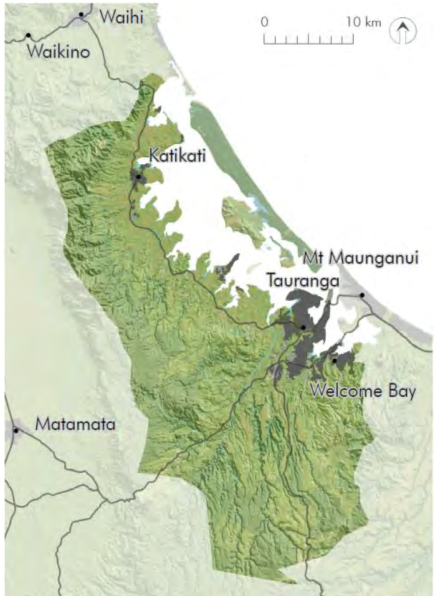
Security in the area is generally good with twin circuits supplying most of our substations in the area.

The major projects are driven by increasing demand, which is forecast to exceed the existing capacity on our network.

Major and minor project spend related to growth and security over the next 10 years is $48.7m.

11.4.3.1 AREA OVERVIEW

The Tauranga area covers Tauranga city and the northern parts of the Western Bay of Plenty district. Mt Maunganui is considered in a separate area plan.



Tauranga area comprises two different terrains or environments. Tauranga city includes industrial, commercial and residential land use, while the northern rural landscape tends to consist of rolling country, predominantly used for rural and lifestyle dwellings.

The region has a temperate, coastal climate with mild winters and warm humid summers. Peak demand is in winter, but increased summer activities, including greater use of air conditioning, could see this change to a summer peak in future.

The popularity of this region as a place to live, reflecting the good climate, terrain and coastal setting, is the single biggest reason for development, and is reflected in the high demand growth rates.

Tauranga is a major city and is the economic hub of the area. The recent upgrade of major transport links and continued land development signals confidence in population growth and commerce and industry. Primary production, including horticulture, is also a significant economic activity, with many kiwifruit orchards in the Aongatete and Katikati areas.

The area is supplied from the Tauranga and Kaitemako GXPs. Tauranga GXP is a grid offtake at both 11kV and 33kV.

The Tauranga GXP supplies ten zone substations: Bethlehem, Tauranga, Waihi Rd, Hamilton St, Otumoetai, Matua, Omokoroa, Aongatete, Katikati and Kauri Pt. The Kaitemako GXP only supplies Welcome Bay substation.

The region uses a 33kV subtransmission voltage. Twin dedicated circuits feed each of the critical inner city substations of Hamilton St and Waihi Rd.

Twin 33kV high capacity circuits link Tauranga GXP with a major subtransmission interconnection point at Greerton switching station. From this, two circuits supply the northern substations (Omokoroa and Aongatete) via dual circuits, and Katikati and Kauri Point on single circuits from Aongatete. A 33kV ring from Greerton also supplies Bethlehem via Otumoetai. Otumoetai is now supplied from twin radial subtransmission circuits from Greerton, with a single 33kV radial circuit from Otumoetai supplying Matua. The Bethlehem/Otumoetai ring and the twin Omokoroa circuits share poles for several spans out of Greerton, which raises common types of failure risks and protection issues.

Trustpower's Kaimai generation scheme also feeds into the Greerton switching station. Some smaller generation, mainly at the fertiliser works, feeds into the 11kV network.

The subtransmission and distribution networks in the Tauranga area are mainly overhead, although there are also large areas of underground cable, particularly in the inner city or newer subdivisions. Environmental and urban constraints require most of our new circuits to be underground.

11.4.3.2 DEMAND FORECASTS

Demand forecasts for the Tauranga zone substations are shown below, with further detail provided in Appendix 7.

Table 11.6: Tauranga zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Aongatete	AA+	7.2	8.4	9.2	10.2	11.2
Bethlehem	AA+	8.0	9.4	10.9	12.7	14.6
Hamilton St	AAA	22.4	15.5	16.2	17.2	18.1
Katikati	AA	5.3	8.3	8.8	9.5	10.1
Kauri Pt	A1	2.0	3.1	3.2	3.3	3.4
Matua	AA	7.2	10.2	10.3	10.5	10.6
Omokoroa	AA+	13.2	11.5	12.1	12.8	13.6
Otumoetai	AA	13.6	14.0	15.1	16.6	18.0
Tauranga 11	AAA	30.0	30.3	33.8	38.2	42.6
Waihi Rd	AAA	24.1	21.9	22.2	22.6	22.9
Welcome Bay	AA	21.4	22.6	24.3	26.5	28.7

The Tauranga area continues to have high growth rates. Substantial investment has been undertaken recently but considerably more is needed, particularly if, as expected, growth rates remain higher than those of a decade ago.

High growth substations - Tauranga 11kV, Bethlehem, and Welcome Bay - are those supplying the major subdivisions. A new substation at Pyes Pa is intended to offload Tauranga GXP by supplying the large industrial and residential developments. Bethlehem is a new substation, which offloads Tauranga and Otumoetai, and where high growth is likely to be concentrated in future.

Omokoroa still has substantial areas of land zoned for urban development on the peninsula, and increased growth in this area is expected once developments closer to the city are filled.

Substations supplying the inner city and established urban areas continue to be subject to steady growth from infill and intensification. This growth is expected to be higher than the past decade, during which economic conditions were subdued. Also, the tight Auckland property market has the potential to result in considerable growth in Tauranga and Mt Maunganui.

Aongatete demand is dominated more by significant increases from cool-store loads, which are being driven by the kiwifruit market. This market has been subdued in recent years but is likely to increase.

11.4.3.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tauranga area are shown below.

Table 11.7: Tauranga constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Tauranga GXP	An outage of one of the two Kaitemako-Tauranga 110kV circuits can overload the other circuit.	Note 1
Tauranga GXP	The firm capacity of the two 110/11kV transformers will be exceeded in about 2019.	Pyes Pa substation
Kaitemako GXP	Single transformer at Kaitemako GXP provides no firm capacity.	Note 2
Omokoroa, Aongatete, Kauri Pt and Katikati	An outage on one of the two Greerton-Omokoroa 33kV circuits will, in future, cause overloading on the remaining circuit supplying these four substations.	Northern Tauranga reinforcement
Katikati and Kauri Pt substation	An outage on one of the two Greerton-Omokoroa 33kV circuits causes low voltages at Katikati and Kauri Pt.	Northern Tauranga reinforcement
Kauri Pt substation	Single Aongatete-Kauri Pt 33kV circuit with insufficient 11kV back-feed to secure all load at Kauri Pt.	Note 3
Matua substation	Single Otumoetai-Matua 33kV circuit with limited 11kV back-feed to secure all load at Matua.	Note 4
Welcome Bay substation	An outage on one of the Kaitemako-Welcome Bay 33kV circuits can cause overloading on the remaining circuit.	Note 5
Matua substation	Demand exceeds secure capacity of the two transformers.	Note 6
Katikati substation	Single transformer provides no firm capacity.	Katikati second transformer
Kauri Pt substation	Single transformer provides no firm capacity.	Note 7
Welcome Bay substation	Demand exceeds secure capacity of the two transformers.	Note 7
Omokoroa substation	Demand exceeds secure capacity of the two transformers.	Note 7
Bethlehem substation	Single transformer provides no firm capacity.	Note 7

Notes:

1. We are in preliminary discussions with Transpower about possible long-term solutions. Risk in the near term is mitigated by SPS, plus the availability of generation from Kaimai Hydro scheme.

2. The old Welcome Bay circuits from Tauranga GXP provide sufficient back-feed so that the Kaitemako GXP load is secure even with one supply transformer. When load exceeds this back-feed capacity, we will need to investigate a second 110/33kV transformer.

3. The installation of a second circuit for Kauri Pt is not economic. Future planning will consider 11kV back-feed upgrades where cost effective.

4. A 33kV cable has been installed between Otumoatai and Matua and is operating at 11kV to provide sufficient backup. Once the smaller transformer is upgraded, the circuit will be reconfigured to form the second 33kV to Matua.

5. Risk is minimal since overloading would only be at peak loading and the circuits are short and have low probability of faults. Pyes Pa will assist in taking some load off Welcome Bay.

6. 11kV support provides sufficient security at present, but further growth will warrant an upgrade of the 5MVA transformer.

7. Because of low probability of failure, there is only small risk with single transformer substations or dual transformer substations where firm capacity is marginally exceeded. Options will be considered to increase capacity or install new units as appropriate, in conjunction with transformer relocations and refurbishment, and as is economically cost effective. A second transformer at Bethlehem is planned once load growth exceeds the 11kV back-feed capability.

11.4.3.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major projects planned for the Tauranga area.

NORTHERN TAURANGA REINFORCEMENT (OMOKOROA ADDITIONAL 33KV CIRCUITS)	
Estimated cost (concept):	$12.3m
Expected project timing:	2019-2022

This project addresses security of supply to four zone substations – Omokoroa, Aongatete, Katikati and Kauri Pt. These four substations are fed from two 33kV circuits from Greerton to Omokoroa. The lines have been thermally upgraded but this only defers investment in more capacity for 5-6 years. An outage of one circuit already causes voltage problems near the end substations, Katikati and Kauri Pt.

Options considered are detailed in Appendix 8. These also include 110kV solutions, which were part of a wider analysis that considered the grid supply to the whole Tauranga region.

The proposed long-term solution is the installation of a third 33kV Greerton-Omokoroa circuit. The circuit will be partly overhead line but mostly underground cable. The solution makes use of an existing overhead line crossing the Wairoa River. The third circuit will require a new switchboard at Omokoroa and a reconfiguration of the 33kV circuits into Omokoroa. Voltage constraints can be addressed through reactive support.

PYES PA SUBSTATION	
Estimated cost (design):	$5.4m
Expected project timing:	2018-2019

Pyes Pa substation has been planned for some time to provide supply to a very large area of high growth industrial development and residential subdivisions. Existing supply is through long and heavily loaded 11kV feeders from Tauranga 11kV. The 11kV supply was only ever an interim measure and makes use of the 33kV cables at 11kV to defer the substation construction for as long as possible. In addition to the heavy loading on the 11kV feeders, the Tauranga 110/11kV transformers also exceed firm capacity.

Options considered are detailed in Appendix 8.

The scale or size of these subdivisions means that 11kV feeders from the existing substations would not have been a viable long-term option. The loading on the 11kV has now reached the stage where the new Pyes Pa substation needs to be constructed soon. This substation will be fed by two 33kV circuits from Kaitemako GXP via the Tauranga 33kV switchboard using the existing 33kV capable cables.

11.4.3.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor projects planned for the Tauranga area.

KATIKATI SUBSTATION SECOND TRANSFORMER	
Estimated cost (design):	$1.2m
Expected project timing:	2022

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings. The substation is a single supply transformer bank substation.

The size and nature of the load connected to the Katikati substation at risk from non-supply in the event of a transformer outage is significant. Some load can be back fed from neighbouring substations, such as Aongatete and Kauri Point substations, but it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance has to be limited to low load times, for which appropriate windows are increasingly difficult to achieve.

Options considered are detailed in Appendix 8.The preferred solution is to install a matching second 33/11kV supply transformer. This option will provide full (no break) N-1 security to the Katikati substation (together with the Katikati second circuit, refer to section 11.4.3). This option will cater for future growth and development without introducing unusual operating configurations.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required back feeding capacity are not favoured due to the complexity of upgrading the mix of conductors on some of the lines. In addition, the switching required on the 11kV network can take a considerable amount of time to restore supply after a substation outage.

KATIKATI SUBSTATION SECOND SUBTRANSMISSION CIRCUIT	
Estimated cost (design):	$1.5m
Expected project timing:	2021

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings.

The substation is supplied via a single 33kV overhead line from Aongatete substation.

The size and nature of the load connected to the Katikati substation at risk from non-supply in the event of a 33kV line outage is significant. Some load can be back fed from neighbouring substations, such as Aongatete and Kauri Point substations, but it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance is limited to low load times.

Options considered are detailed in Appendix 8. The preferred solution is to install a second 33kV circuit to the Katikati substation by laying a cable from the Katikati substation and connecting onto the Aongatete – Kauri Point overhead line, creating a hard tee to Kauri Point. This means that for an outage on one subtransmission circuit, supply can be maintained at the Katikati substation (n-1 security). With this solution, the Katikati substation will meet our required security level.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required back feeding capacity are not favoured due to the higher overall cost and the complexity of upgrading the mix of conductors on some lines. In addition, the switching required on the 11kV network can take a considerable amount of time for a substation outage.

11.4.3.6 OTHER DEVELOPMENTS

There are very significant constraints pending on the 110kV circuits from Kaitemako to Tauranga. The Poike tee also causes operational difficulties and reduced security. Because of the complexity and cost of solutions, detailed projects have not yet been formulated but expenditure of the order of $30m or more is expected to be needed, starting in the early 2020s. Possible ownership changes also complicate the final decisions on who will invest, on what and when. Because of the long lead times and consenting issues, planning work needs to commence soon.

We will continue to monitor land development in this high growth area. Several additional zone substations are nominally identified in our longer term planning. These include Hospital, Judea, Oropi and Omokoroa urban. Investment is not expected for these until after 2025, but this will depend on growth and subdivision development.

In the long-term, Sulphur Pt is an additional substation that is planned. This would be dedicated to the port and timing is largely related to the port's development plans. The new substation is not expected to be needed until the mid-2020s. A 33kV cable is in place to a nominated substation site, although the cable is being used at 11kV.

The larger planned developments detailed above cover most of the significant risks exposed by the subtransmission constraints. A number of transformer constraints exist at zone substations, with growth rates determining when these will occur. As appropriate, these transformers will be upgraded, which may involve using refurbished/existing units from other substations. Specific projects are not identified here because of the fluidity of timing and the interdependence with other drivers. Some replacements can also be done for less than $1m, meaning we can fund these from our routine project allowance.

Growth and security expenditure on 11kV feeder upgrades and new 11kV feeders will be needed throughout the planning period. A substantial part of the routine project allowance (for projects less than $1m) is expected to be needed in the Tauranga area. New subdivisions must contribute towards the 11kV feeders directly serving those sections, but additional growth and security investment is needed to maintain security in the upstream network. Infill growth also drives new or upgraded feeders in existing parts of the network.

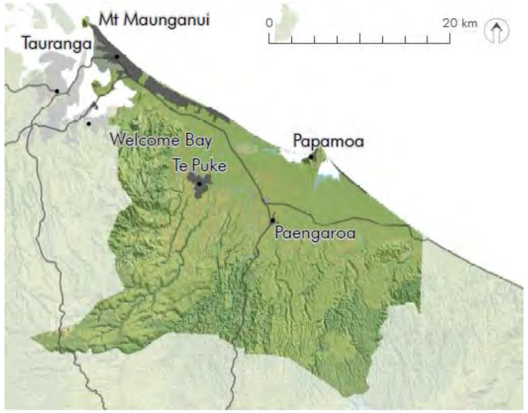
The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Northern Tauranga voltage support	Post contingent voltage constraints at Aongatete, Katikati and Kauri Point will eventuate with increasing load. Voltage support at Aongatete substation resolves the constraint
Apata Area Capacity Reinforcement	Large customer growth at Aongatete (cool stores) has resulted in capacity issues on the 11kV network. If load continues to increase, a local zone substation at Apata will be required.
Bethlehem Substation Transformer Capacity	Load growth around Bethlehem will eventually overcome the ability to support the single bank substation through 11kV interties. A second transformer is planned to maintain security of supply levels.
Oropi Capacity Reinforcement	Residential load growth in the Oropi area will be constrained by the 11kV capacity out of Welcome Bay substation. The preferred solution is to accommodate the growth by commissioning a new substation in the Oropi area.
Tauranga Port Capacity Reinforcement	As the port load grows, it will become difficult to meet the load demands off the existing 11kV supplies. It is proposed to commission a substation at Sulphur Point to provide adequate supply for the port's expansion.
Tauranga GXP High Fault Level	Fault levels at Tauranga 11kV GXP are too high. Most mitigation strategies have already been exhausted. The preferred solution is to create a new zone substation in the industrial area, to offload the 110/11kV supply at Tauranga.
Matua Substation Transformer Capacity	Matua substation second transformer is a 'hot standby' spare, capable of only partial substation backup. 11kV support provides the rest. As load increases, and the existing express feeder converts to 33kV to form the second subtransmission circuit, a larger transformer will be required if security of supply levels are to be maintained.

11.4.4 MT MAUNGANUI

The Mt Maunganui area has historically had a high growth rate, also driven by population growth and residential expansion. We have recently built the Te Maunga substation to reduce the load on the Papamoa substation, but it is expected to exceed secure capacity again as load grows. We intend to undertake a major project to build a substation at Wairakei to further reduce load on the Papamoa substation and to link the two GXPs in the area. Major and minor project spend related to growth and security over the next 10 years is $34.8m.

11.4.4.1 OVERVIEW



The Mt Maunganui area covers the urban parts of Mt Maunganui as well as the developing Papamoa and Wairakei coastal strip.

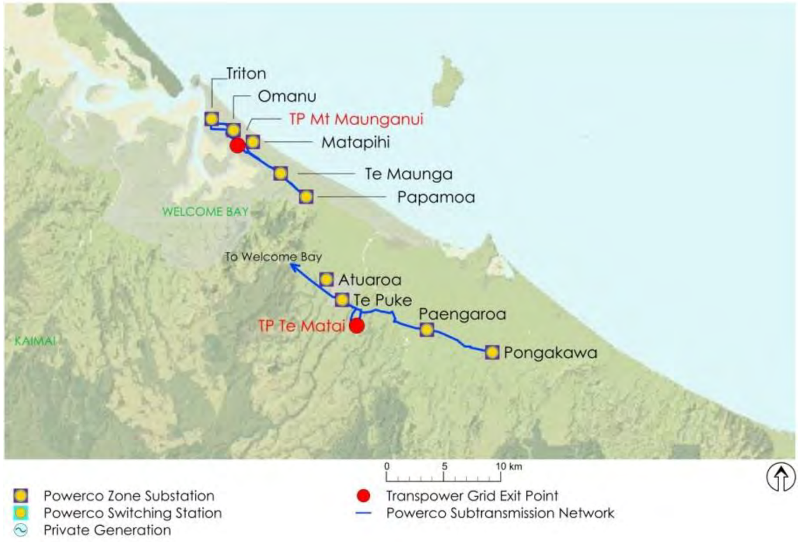
Our Mt Maunganui area also encompasses Te Puke and surrounding rural areas down to Pongakawa and the inland foothills. This is because the planned developments will link the Mt Maunganui and Te Puke electricity supplies and it is easier to consolidate the planning in one area.

The Mt Maunganui area shares many of the features of the neighbouring Tauranga area, including terrain, climate and land use. The region contains a long coastal strip and some rugged terrain inland. The coastal area contains severely deteriorated network equipment, which has had an impact on reliability and performance. The inland area is more rugged and presents the usual difficulties in terms of access and maintenance.

The Mt Maunganui CBD is the economic hub, with expansion along the coast to accommodate population growth driven by the attractive lifestyle and climate. In the rural areas, horticulture dominates. Around Te Puke there are a large number of kiwifruit orchards, which use cool stores and pack-houses. The Port of Tauranga is also a major economic driver.

The area is supplied from the Mt Maunganui and Te Matai GXPs.

The Mt Maunganui GXP supplies five zone substations - Matapihi, Omanu, Papamoa, Te Maunga and Triton. The Te Matai GXP supplies three zone substations - Te Puke, Atuaroa and Pongakawa. The region uses a 33kV subtransmission voltage.



Our subtransmission and distribution in the Mt Maunganui area is predominantly through overhead lines, especially in rural areas, with all new intensive subdivision being supplied through underground networks.

The subtransmission network from Mt Maunganui GXP is predominantly twin circuit architecture. Two dedicated circuits directly feed each of the Triton, Matapihi (adjacent to Mt Maunganui GXP), Omanu and Te Maunga substations. Twin circuits from Te Maunga continue on to Papamoa substation.

The 33kV subtransmission from the Te Matai GXP has a meshed architecture. Dual circuits supply the Te Puke substation. Atuaroa is a new urban substation, installed to offload Te Puke, and is supplied through a single 33kV cable teed off the Kaitemako to Te Matai line. Pongakawa is supplied by a single circuit, which until recently shared a 33kV feeder from Te Matai with Atuaroa. A new Paengaroa substation is being completed and is initially connected to the Pongakawa line.

An old transmission grid line links Te Matai GXP and Kaitemako GXP (Tauranga area) at 33kV with connections to Atuaroa and Welcome Bay substations. This provides limited backup to Atuaroa and Te Matai itself.

11.4.4.2 DEMAND FORECASTS

Demand forecasts for the Mt Maunganui zone stations are shown below, with further detail provided in Appendix 7.

Table 11.8: Mt Maunganui zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Atuaroa Ave	AA+	0.0	8.1	8.3	8.7	9.0
Matapihi	AAA	24.1	14.4	14.9	15.6	16.3
Omanu	AAA	24.3	15.6	15.9	16.3	16.8
Paengaroa	AA	2.3	4.1	4.1	4.1	4.1
Papamoa	AAA	21.3	19.5	24.1	29.8	35.4
Pongakawa	A1	2.1	7.4	7.5	7.7	7.8
Te Maunga	AA	9.1	8.4	8.8	9.5	10.1
Te Puke	AAA	22.9	20.4	20.9	21.5	22.2
Triton	AAA	21.3	21.4	22.1	23.0	23.9

The Mt Maunganui area has the highest growth rates in our network. Substantial investment has been made recently to provide new substations and to expand our subtransmission and 11kV feeder networks.

High load growth rates are expected to continue as subdivision development extends down the coast from Papamoa to Wairakei and eventually to Te Tumu. Property section sales have been subdued since the global financial crisis, but appear to have accelerated rapidly in the past few years. This acceleration is not reflected in the base growth rates in the table above, which mostly come from longer term historical trends. The local council has signalled section capacity in the Te Tumu area will be lower than originally anticipated, but this only affects the final saturated electrical load density, not the immediate growth rate.

The existing urban areas of Mt Maunganui are also expected to have high growth from infill and intensification. This shift from urban spread to greater intensification of urban areas is a key element of recent strategic development planning by the council. The ensuing potential for higher demand growth of the existing urban Mt Maunganui substations (Matapihi, Triton and Omanu) is additional to the base growth rates reflected in the table above.

The Rangiuru Business Park has been a focus of past long-term planning. Recent indications are that this will not start to be developed until about 2022, following uptake of land closer to the city. However the potential for development to start earlier remains a planning risk.

The Te Puke and surrounding rural load continues to grow steadily. An acceleration in this growth rate is foreseeable as the kiwifruit industry recovers from the implications of the PSA virus.

11.4.4.3 EXISTING AND FORESEEN CONSTRAINTS

Major constraints affecting the Mt Maunganui area are shown below.

Table 11.9: Mt Maunganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Mt Maunganui GXP	The N-1 capacity of the 110kV transmission into Mt Maunganui GXP will be exceeded in about 2020. The 110/33 kV supply transformer firm capacity will be exceeded in about 2028.	Papamoa project
Papamoa and Te Maunga substations	An outage on one of the two Mt Maunganui-Te Maunga 33kV circuits causes overloading of the remaining circuit.	Papamoa project
Papamoa substation	Demand will exceed the secure capacity of the two transformers in about 2020.	Papamoa project
Triton substation	An outage on one of the two Mt Maunganui-Triton 33kV circuits can cause an overload of the other circuit.	Note 1
Te Maunga substation	Single transformer. Has insufficient back-feed to secure all load by about 2018.	Te Maunga second transformer
Te Matai GXP	The 110/33 kV transformer firm capacity will be exceeded. An outage on the Kaitemako-Te Matai 110kV circuit will cause low voltages at Te Matai GXP.	Papamoa project
Pongakawa and Atuaroa substations	Single feeder from Te Matai GXP serves both Pongakawa and Atuaroa – both subs affected by single outage.	Papamoa project
Pongakawa substation	Single 33kV circuit supplies Pongakawa – insufficient back-feed to secure all loads.	Note 2
Pongakawa	Demand exceeds secure capacity of the two transformers.	Note 2

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Atuaroa substation	Single transformer. Insufficient back-feed to secure all load at Atuaroa by about 2022.	Note 3
Atuaroa substation	Atuaroa subtransmission. Single 33kV cable from tee to substation. Tee connection to Kaitemako tie line. Insufficient back-feed via Kaitemako to supply all Atuaroa.	Note 3
Te Puke substation	An outage on one of the two Te Matai-Te Puke 33kV circuits can cause overloading on the other (about 2026).	Note 4

Notes:

1. Thermal upgrade and reconductor of light conductor sections commences 2017.

2. The small load at Pongakawa cannot justify dual 33kV circuits. The recently established Paengaroa substation will offload Pongakawa and several long 11kV feeders from Pongakawa and Te Puke, improving reliability to customers affected. Transformer capacity will also be adequate following load transfer to Paengaroa. In the longer term, a subtransmission ring incorporating Rangiuru Business park and Paengaroa would be established to improve security of supply.

3. Atuaroa was recently built to offload Te Puke substation. Load growth within Te Puke township will progressively increase load on Atuaroa, including transfer from Te Puke substation. As demand grows and exceeds 11kV back-feed capability, the increasing risk will need to be addressed through improvements to Atuaroa subtransmission security and to provide a second transformer. This is not expected before 2022.

4. The constraint is a low risk, assuming only modest growth rates. The 33kV lines are quite short and fault rates are not high. Some load can be transferred to Atuaroa.

11.4.4.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Mt Maunganui area.

PAPAMOA PROJECT (WAIRAKEI SUBSTATION)	
Estimated cost (design):	$16.2m
Expected project timing:	2016-2018

The greenfield subdivision development along the Papamoa coastal strip requires a large increase in the capacity and footprint of our network. Steady growth in the past decade resulted in the Papamoa substation's security being exceeded, which triggered the construction of the new Te Maunga substation to offload Papamoa.

Major imminent security constraints relate to the capacity of the 110kV circuits into Mt Maunganui GXP, the transformers at the GXP and the capacity of the 33kV circuits from the GXP to Te Maunga. Papamoa substation will also exceed its secure capacity again as it picks up new load in the Wairakei area.

The options for the Papamoa project encompass a number of analyses over a period where the project evolved from a planned new GXP into the proposed 33kV solution with GXP upgrades. Further details are included in Appendix 8.

The proposed solution reflects a new strategy adopted two years ago when investigations into a new GXP determined this to be unachievable. As such, and anticipating the extremely high cost to address the pending Mt Maunganui 110kV circuit constraints, the strategy is now to extend the 33kV from Te Matai GXP into the greenfield areas of Papamoa, Wairakei and Te Tumu.

Two new high capacity 33kV cables are to be installed from Te Matai to Wairakei. These will initially supply a new Wairakei zone substation, which will in turn further offload Papamoa substation. The new strategy allows for future connection of a Te Tumu substation and, after further reinforcement of the subtransmission, a possible Rangiuru substation. Papamoa substation will ultimately be transferred off Mt Maunganui GXP and on to Te Matai GXP. We will retain the ability to transfer load between the GXPs to optimise the timing of future developments and minimise risk.

Te Matai GXP had both capacity and renewal issues to address even before the transfer of load was planned. The lack of 33kV feeder bays restricted security for Atuaroa and Pongakawa, and one of the GXP 110/33kV transformers was already too small and lacked online tap changing capability. Therefore, the Papamoa project includes a new 33kV switchboard and we will talk with Transpower to upgrade the transformers to the best possible capacity for long-term growth.

11.4.4.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor projects planned for the Tauranga area.

PAPAMOA SUBSTATION 33KV SWITCHBOARD	
Estimated cost (design):	$1.9m
Expected project timing:	2019

The Papamoa substation supplies the growing residential and lifestyle load of South East Mount Maunganui. Strong growth has meant that both the firm transformer capacity and sub-transmission capacity has been exceeded by the peak demand at this substation . The drivers for this project are the same as for the Papamoa Reinforcement project and are discussed above.

The solution involves the construction of a new 33kV indoor switch room at Papamoa, and transferring the Papamoa substation load to the Te Matai GXP (following the completion of the Papamoa and Wairakei substation projects).

11.4.4.6 OTHER DEVELOPMENT

As with the Tauranga area, the high growth from infill and greenfield developments will require continued investment in 11kV feeder backbone capacity and new 11kV feeders. These projects are not specifically identified but will be scoped when required in our programme of smaller routine growth and security projects.

Voltage and capacity constraints on the 110kV grid circuits supplying Te Matai GXP have been signalled by Transpower. This is partly because of the additional load transferred from Mt Maunganui. We will talk with Transpower about options to address these constraints. Investment would not be expected before 2022.

We will also continue to monitor the load on the 110kV into Mt Maunganui GXP. While our strategy for the Papamoa project is to avoid upgrades to these circuits, if growth because of infill is higher than anticipated, constraints may develop in the next 10-15 years. Costs for additional capacity are extremely high if this is still needed. Securing routes early is essential to mitigating such costs.

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Atuaroa Sub-Transmission Reinforcement	Atuaroa substation is supplied by a single subtransmission cable. 11kV backup is insufficient at peak times. It is proposed to install a second subtransmission cable from Te Puke substation to provide an appropriate level of security.
Atuaroa Substation Transformer Capacity Upgrade	Atuaroa is a single transformer substation. The 11kV backup support is insufficient at peak times. It is proposed to install a second transformer at the substation to provide appropriate security.
Rangiuru Business Park Capacity Reinforcement	A new zone substation will be required to meet the demand of the proposed industrial park. Timing is dependent on customer load growth.
Pongakawa Substation Transformer Capacity Upgrade	Load at Pongakawa substation exceeds the firm capacity of the transformers. It is proposed to upgrade the transformers to restore adequate security of supply.
Te Tumu Capacity Reinforcement	As residential growth continues at pace in eastern Papamoa, a new zone substation will be required to supply the new load for the Te Tumu growth area.
Triton Substation Transformer Capacity Upgrade	Load at Triton substation exceeds firm capacity of the transformers. It is proposed to upgrade the transformers to ensure the appropriate security of supply is achieved.

11.4.5 WAIKATO

Our Waikato area covers the eastern Waikato region and does not include Hamilton or the Western Waikato. It is largely an agricultural area, with a strong dairy industry. There are a number of locations supplied by single circuits that don’t meet our security criteria. Our largest project in this area is to construct a new GXP at Putaruru to improve security. We also have a number of other projects to increase security and capacity. Major and minor project spend related to growth and security over the next 10 years is $63.7m.

11.4.5.1 OVERVIEW

The Waikato area extends from the Hauraki Plains north of Morrinsville and Tahuna, through the rural land of the Eastern Waikato and to rural areas south of Putaruru.

The Kaimai Range runs the length of its eastern boundary. The supply area covers parts of the Matamata-Piako and South Waikato districts.

The terrain is flat to rolling pasture land, sprinkled with towns and settlements.

The environment is generally favourable to network construction, maintenance and operations. Peat lowland areas can provide challenges to structural foundations and thermal rating of cables.

The climate is typical of the Waikato region with mild winters and warm humid summers. Being inland the region is relatively sheltered from extreme weather and coastal influence.

The key element of the region’s economy is primary production, with most of the region being high-production dairy country. A number of important industrial and food processing facilities are located within the area. These have been quite instrumental in driving recent demand and network developments.

The significant population centres are Morrinsville, Te Aroha, Matamata and Putaruru. Population growth is modest to static, although associated economic activity brings modest demand growth. The industrial park at Waharoa has had considerable growth in primary and supporting industries. Tirau is subject to tourism activity and the dairy plant is the largest single load.

The area is supplied from the Waihou, Piako and Hinuera GXPs.

Waihou GXP supplies four zone substations - Mikkelsen Rd, Tahuna, Waitoa and Inghams. Waihou is an older GXP and much of the equipment needs replacing or upgrading. Piako GXP was built with the intention of offloading Waihou and helping refurbishment projects.

The new Piako GXP supplies six zone substations - Piako, Morrinsville, Tatua, Farmer Rd, Walton and Waharoa.

The Hinuera GXP supplies six zone substations - Waharoa[25], Browne St, Tower Rd, Lake Rd, Putaruru, and Tirau.

All subtransmission in the region is at 33kV, and mainly via overhead lines. The architecture could best be described as interconnected radial. Very few substations have two dedicated circuits. Most substations rely on switched 33kV back-feeds, often from different GXPs. Therefore, parallel operation of supply lines is often not possible.

The two new dedicated customer zone substations at Tatua and Inghams have security that is specific to the customer, with just single zone transformers. Also at Waharoa the security is a balance between our nominal security standards and the specific requirements of large customers.

Tahuna and Putaruru are notable in that they are supplied via long, single, 33kV circuits, with no alternative source other than limited 11kV back-feed. For Putaruru, particularly, this is well below our security standards.

The other notable characteristic of this area relates to the 110kV circuits, owned by Transpower that feed the GXPs. The Hinuera GXP is supplied from a single 110kV circuit from Karapiro. This is a legacy of historical grid development and severely limits security to Matamata, Putaruru and Tirau. The Piako and Waihou GXPs, along with Kopu and Waikino, are supplied from dual 110kV circuits on a single tower structure line originating in Hamilton. The capacity of this line impacts the longer term development.

11.4.5.2 DEMAND FORECASTS

Demand forecasts for the Waikato zone substations are shown below, with further detail provided in Appendix 7.

Table 11.10: Waikato zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Browne St	AA	10.6	9.9	10.4	11.0	11.6
Farmer Rd	AA+	0.0	5.9	6.0	6.1	6.1
Inghams	AA	3.6	3.8	3.8	3.8	3.8
Lake Rd	A1	0.0	5.9	6.0	6.1	6.3
Mikkelsen Rd	AAA	19.2	15.2	15.3	15.5	15.7
Morrinsville	AA+	0.0	10.7	10.9	11.2	11.4
Piako	AAA	15.2	15.0	15.6	16.3	17.0
Putaruru	AA+	0.0	11.6	11.9	12.2	12.4
Tahuna	A1	0.8	5.7	5.8	5.9	6.0
Tatua	AA	1.2	4.5	4.5	4.5	4.5
Tirau	AA+	0.0	9.5	9.7	9.9	10.1
Tower Rd	AA+	0.0	9.8	10.4	11.1	11.8
Waharoa	AA+	0.0	7.8	8.4	9.2	10.0
Waitoa	AAA	18.8	12.7	12.7	12.7	12.7
Walton	AA+	0.0	5.9	5.9	6.0	6.0

[25] At present the supply to Waharoa substation is shared between two GXPs, Piako and Hinuera.

Major industrial customers have the most significant impact on demand growth through specific plant or process upgrades.

Recent and imminent activity for major industrial customers includes:

- New zone substations at Inghams and Tatua are dedicated to industrial consumers and have recently resulted in significant changes in demand.
- Waitoa substation is a dedicated supply to the Waitoa dairy factory. Possible load increases and generation changes have been signalled.
- Waharoa and Tirau substations each supply a dairy factory. Waharoa has experienced significant changes in load because of other industries.
- Mikkelsen Rd substation supplies Richmond's meat processing plant.
- Piako substation supplies the De Gussa chemical plant.

Demand growth is generally from small gains in population in urban centres and also from increased dairy activity in some rural areas. Much of the area is historically a dairy stronghold, but some pockets of more recent conversion to dairy farming have increased the loading on our 11kV feeders. We are monitoring the impact from potential changes to dairy refrigeration requirements on farms.

From the demand forecast table it is evident that several of the Waikato substations already exceed our security criteria requirements. Rather than future growth, several larger investments relate to these legacy security risks, which impose unacceptable economic costs either in terms of the high value load at risk, or the large number of customers impacted by poor reliability.

11.4.5.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikato area are shown below.

Table 11.11: Waikato constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Hinuera GXP	Single 110kV circuit from Karapiro to Hinuera.	Putaruru GXP and other projects. Note 1
Hinuera GXP	N-1 capacity of the transformers is exceeded.	Putaruru GXP
Waihou GXP	N-1 capacity exceeded in ~ 2025.	Note 1
Waharoa and Browne St substations	Small conductor between Kereone and Walton constrains back-feed capacity to Browne St and Waharoa substations.	Kereone-Walton upgrade
Waharoa substation	Insufficient capacity for growing demand at Waharoa.	Kereone-Walton upgrade and Waharoa transformer upgrade
Browne St and Tower Rd substations	Single 33kV circuits from Hinuera supply each of these two substations in Matamata. The 11kV inter-tie capacity is not sufficient or fast enough to meet security standards.	Matamata subtransmission
Putaruru substation	Single 33kV Hinuera-Putaruru circuit. Insufficient 11kV back-feed to supply all load.	Putaruru-Tirau upgrade
Morrinsville substation	Single 33kV Piako-Morrinsville 33kV circuit.	Morrinsville second circuit
Tahuna substation	Single 33kV circuit. Insufficient 11kV back-feed to meet security standards.	Tahuna back-feed capacity upgrade, Note 2
Piako 11kV feeders	Long, heavily loaded feeders from Piako substation. Voltage and capacity constrains both normal supply and back-feeding.	Piako-Kiwitahi feeder
Putaruru substation	Demand exceeds secure capacity of the two transformers.	Note 3
Lake Rd substation	Single transformer. Insufficient 11kV back-feed to meet security standards.	Lake Rd second transformer
Tower Rd substation	Demand exceeds secure capacity of the two transformers.	Tower Rd second transformer
Walton substation	Single transformer. Insufficient 11kV back-feed to meet security standards.	Note 4
Tirau substation	Single transformer. Insufficient 11kV back-feed to meet security standards.	Tirau second transformer
Inghams substation	Single transformer does not meet security standards.	Note 5
Maungatautari and Horahora	Single long 11kV spur feeder prone to long duration outages. Low voltages during high load.	Maungatautari area reinforcement

Notes:

1. Putaruru GXP is the main project to address Hinuera's lack of security (ie. single circuit). Putaruru-Tirau and Kereone-Walton projects are also needed to fully secure all Hinuera load, but these projects

are also driven by local subtransmission constraints. As Putaruru GXP will utilise the existing 40MVA transformer at Piako GXP, a new 60MVA unit will be procured for Piako GXP to replace it.

2. Options to establish a second circuit into Tahuna were considered during the analysis of options for Morrinsville, but none of these proved economic for the small load at risk.

3. In conjunction with the construction of the new Putaruru GXP, a number of renewal and upgrade projects will be carried out on the existing 33/11kV Putaruru substation.

4. A second transformer is not economic. Risk of a transformer failure is low, especially given reasonable levels of 11kV back-feed.

5. Customer-specific security level is acceptable.

11.4.5.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Waikato area.

PUTARURU GXP	
Estimated cost (design):	$25.4m
Expected project timing:	2016-2022

Hinuera GXP is supplied by a single 110kV circuit (25km) from Karapiro. There is limited back-feed capability to support the load should an outage occur on the 110kV supply. The remaining load suffers a lengthy outage during any maintenance or faults on this line or at the associated substation plant.

In addition, the Putaruru GXP project addresses a number of associated constraints:

- The supply transformers at Hinuera GXP have exceeded their secure capacity. Demand growth has been steady.
- Scheduling regular maintenance work on both the supply transformers and the 110kV line has been difficult and the condition of the assets is not well understood.
- A long, single 33kV circuit supplies Putaruru substation from Tirau substation.

More details of the options considered are set out in Appendix 8.

The proposed solution is to construct a new 110kV circuit from Arapuni power station to a new GXP located at Putaruru (110/33kV substation). A new 110kV cable will connect the north bus at Arapuni to the new 110/33kV substation, which will have just a single transformer relocated from Piako GXP. Our future strategy is that Putaruru and Hinuera will support each other and therefore do not require full N-1 capability at each.

This solution not only provides additional back-feed in the case of a Hinuera GXP outage but improves security to the Putaruru and Tirau substations.

The Putaruru to Tirau second circuit, although a separate project, is mainly driven by the overall strategy adopted for the Putaruru GXP. This project will provide sufficient capacity to fully supply Tower Rd from the new Putaruru GXP.

In conjunction with the new Putaruru 110/33kV substation, we will need to relocate, renew and upgrade much of the existing Putaruru substation 33/11kV assets. These are treated as separate projects to the new Putaruru GXP.

KEREONE-WALTON UPGRADE	
Estimated cost (concept):	$6.3m
Expected project timing:	2021-2023

Part of the strategy with the Putaruru GXP is that the Browne St and Waharoa substations will be transferred to Piako during an outage of the Hinuera GXP. The capacity of the existing network tie lines is not adequate to fully secure all this load and maintain adequate voltage.

Waharoa substation has faced rapid demand growth through significant changes in load from larger customers, which is expected to continue. The 33kV supply circuits from either the north (Piako GXP) or south (Hinuera GXP) no longer have adequate capacity to supply all Waharoa on their own. As an interim strategy, we have had to split the load at Waharoa across two transformers, each connected off different supply circuits and different GXPs. This effectively leaves customers on N security and exposed to the risk of brief outages following a fault on either circuit or transformer. The limiting constraint is a relatively long section of small conductor 33kV line between Kereone and Walton.

Options considered are detailed in Appendix 8.

The proposed solution involves a new 33kV cable from Kereone to Walton. This is the most economic option that fully secures all load. In conjunction with Putaruru GXP and associated upgrades, it also secures all Hinuera load. The solution improves flexibility by offloading Walton substation on to the Waihou GXP. This will enable the Piako GXP to supply all of Waharoa substation normally, plus Browne St during contingencies in the area.

PUTARURU-TIRAU UPGRADE	
Estimated cost (concept):	$6.7m
Expected project timing:	2020-2021

The Putaruru and Tirau substations are supplied by a single 33kV line from Hinuera. Expansion of local industries has resulted in load growth at both these substations. An outage on this line will cause a loss of supply to Putaruru and Tirau. There is very limited 11kV back-feed capability from substations further north, such as

Browne St and Lake Rd. Because of these constraints, both substations do not meet our required security levels.

The proposed solution involves building a new 33kV underground cable between Putaruru and Tirau substations. This will provide high reliability and capacity between Putaruru and Tirau. It will also form part of a project to provide a backup supply to the Hinuera GXP, via the proposed Putaruru GXP. As a result of this project both the Putaruru and Tirau substations will achieve our security requirements.

11.4.5.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Waikato area.

HINUERA OUTDOOR-INDOOR (ODID) CONVERSION	
Estimated cost (concept):	$1.4m
Expected project timing:	2020

At Hinuera GXP, a single circuit breaker currently supplies both Lake Rd and Tower Rd substations. The Tirau and Putaruru supply also comes off a single circuit breaker at Hinuera GXP.

The proposed Putaruru GXP is required to support the Hinuera GXP loads should an outage occur on the 110kV Hinuera supply. Protection systems will suffer from slow protection trip times when Putaruru GXP supports the Hinuera GXP loads as Putaruru GXP is a weaker infeed.

The proposed solution is to partially convert the 33kV outdoor assets into an indoor solution to enable fast bus protection schemes. This will also accommodate the recently installed Hinuera to Tirau cable and separate out the Lake Rd and Tower Rd circuits.

MATAMATA SUBTRANSMISSION (TOWER-BROWNE 33KV CABLE)	
Estimated cost (concept):	$2.1m
Expected project timing:	2019-2020

The Browne St and Tower Rd substations are each supplied through a single 33kV line from Hinuera GXP. Together these substations supply all of the Matamata Township, including the CBD. Outages on either of the 33kV lines will cause an immediate loss of supply to both substations. The 11kV inter-tie capacity between the substations does not provide appropriate security.

The proposed solution is to build a 33kV underground cable circuit between Tower Rd and Browne St substations. This will create a secure 33kV subtransmission ring. This is more cost effective and provides more flexible operational capability than increased 11kV inter-tie and automated switching. The cost of duplicate 33kV circuits to each substation would be prohibitive.

MATAMATA SUBTRANSMISSION (HINUERA-TOWER RD 33KV LINE UPGRADE)	
Estimated cost (concept):	$1.5m
Expected project timing:	2020-2022

Once the Tower Rd to Browne St tie is complete, there will be a 33kV ring between Hinuera GXP, Tower Rd and Browne St substations. At peak loading, the existing Hinuera-Tower Rd line does not have sufficient capacity to supply both substations. In order to provide the required security levels the Hinuera-Tower Rd 33kV line will need to be upgraded.

The proposed solution is much cheaper than an additional circuit to Matamata. There are no practical 11kV back-feed options. Non-network solutions such as demand side response and load shedding may be possible but only as a risk management strategy to defer the upgrade.

MORRINSVILLE SECOND CIRCUIT	
Estimated cost (concept):	$3.9m
Expected project timing:	2021-2023

The Morrinsville substation is fed by a single 33kV circuit from the Piako GXP. If there is a fault on this circuit there will be an immediate loss of supply to all Morrinsville, including the dairy factory. Some back-feed from Piako and Tahuna is available but does not meet our security criteria.

The proposed solution is to construct a second 33kV circuit from Piako GXP to Morrinsville substation and upgrade the transformers at Morrinsville. This second circuit will ensure supply can be maintained at Morrinsville substation during a subtransmission outage.

Options to create a 33kV ring between Morrinsville and Tahuna (also supplied by a single circuit) were considered but proved too expensive for the risk involved.

PIAKO KIWITAHI NEW 11KV FEEDER	
Estimated cost (concept):	$1.7m
Expected project timing:	2023

There are eight 11kV feeders supplied from the Piako zone substation. Two of these, Kereone and Kiwitahi, are long feeders (Kereone is 114km in length). During peak periods there can be low voltage at the end of the feeders. Back-feed capability is severely restricted, which reduces reliability. There is steady growth in the area so the performance of these feeders will deteriorate over time.

The proposed solution is to construct a new 11kV feeder from the Piako substation to supply part of the area fed by the existing Kereone and Kiwitahi feeders. This will offload these feeders by reducing their length, thereby improving the voltage and performance.

TOWER RD SUBSTATION SECOND SUPPLY TRANSFORMER	
Estimated cost (concept):	$4.1m
Expected project timing:	2019-2020

Tower Rd substation has only one 33/11kV transformer. The 11kV back-feed from Browne St is not sufficient to meet our security standards.

Tower Rd substation has a programme of upgrades to improve performance and security including the addition of a second transformer. The substation has been designed to house a second transformer to bring it up to the required security levels.

LAKE RD SUBSTATION SECOND SUPPLY TRANSFORMER	
Estimated cost:	$2.4m
Expected project timing:	2019

Lake Rd substation has only one 33/11kV transformer. Back-feed at 11kV is very limited and does not meet our security standards.

The proposed solution is to upgrade to two transformers. Additional 11kV back-feed is possible but limited by the large distances to other substations.

11.4.5.6 OTHER DEVELOPMENTS

Associated with the larger projects identified previously to secure the load at Hinuera GXP, we plan to upgrade the 33/11kV transformers at Putaruru substation and install a new indoor 33kV switchboard when building Putaruru GXP.

The transmission serving the Waikato area is particularly pertinent to our development plans and strategies. As noted already, Putaruru GXP and a number of associated projects are primarily driven by the lack of security of the single Karapiro to Hinuera 110kV circuit. Piako GXP was built specifically to offload Waihou GXP. With Putaruru GXP coming off the north bus at Arapuni, the GXP is unlikely to be affected by network constraints on the wider transmission system, hence ensuring its off-take capacity is not compromised.

The Valley Spur 110kV line’s N-1 capacity is forecast to be exceeded about 2022. Before this occurs, and as demand increases, the line will be voltage constrained during single circuit outages.

In addition there are several causes for renewal of specific GXP assets. In particular, much of the Waihou GXP is original and will need refurbishment and upgrade.

The Valley Spur is subject to ownership transfer discussions. Regardless of this, the investment to maintain security could be by either party. If Transpower undertakes grid upgrades they will need clear and substantial support from us to establish the case. Since a long-term solution is expected to require significant investment, planning for this needs to begin urgently. Investment is not expected before about 2024, but if deferment strategies are not effective, including possible non-network approaches, investment may be required earlier.

The Waihou GXP is also subject to ownership transfer discussions. We expect that this site will require a major overhaul. Should this transfer happen, Piako GXP will need to have sufficient security to carry much of the Waihou load during the upgrades.

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Tahuna Substation Subtransmission Supply	Tahuna substation is supplied via a long single subtransmission circuit. 11kV backup is limited. A second subtransmission circuit is likely to be economic due to the distance involved. Increased 11kV interconnection is the most likely solution.
Tirau Substation Transformer Capacity	Tirau substation does not meet Powerco's security of supply standards. The substation consists of a single transformer and 11kV support is limited. A second transformer is proposed.
Waharoa Substation Transformer Capacity	Waharoa substation consist of two transformers of different sizes. The two transformers do not share load evenly. Each transformer is fed from a different GXP for operational reasons. The proposal is to upgrade the smaller transformer to match the larger unit and install an indoor 33kV switchboard to alleviate the operational issues.

PROJECT	SOLUTIONS
Maungatautari Area Reinforcement	Maungatautari and Karapiro are areas on the fringes of Powerco's network. Supply to the area is from Tirau substation. The ability to provide a secure supply to the area is hampered by distance and terrain. The likely solution to improve quality of supply will be via distributed energy storage solutions.

11.4.6 KINLEITH

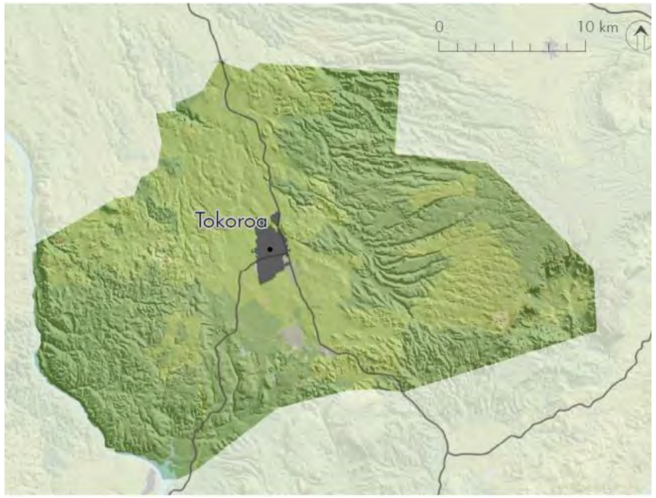
The Kinleith area includes Tokoroa and a major pulp and paper mill at Kinleith. There is only one minor project - to create a ring circuit for the two substations supplying Tokoroa to ensure the network meets our security criteria. There will be no project spend in the Kinleith area over the next 10 years..

11.4.6.1 OVERVIEW

The Kinleith area covers the southern stretch of the South Waikato district. The northern part of the South Waikato district falls within our Waikato area.

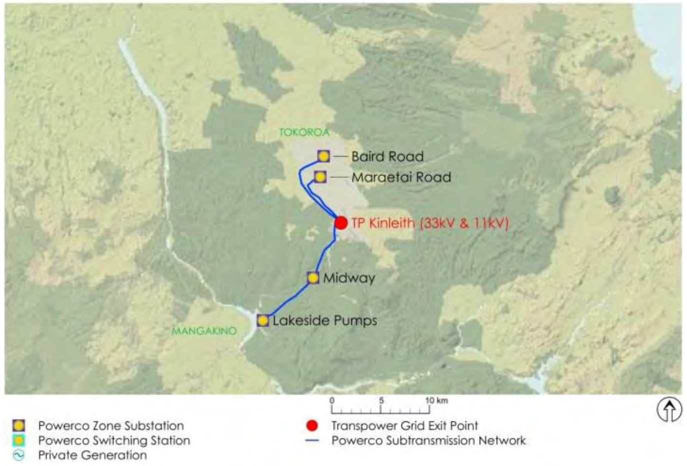
The largest town in the Kinleith area is Tokoroa, which has a population of 13,600.

The area includes the large pulp and paper mill at Kinleith, which has a significant influence on the local economy, industry and employment. Other keys to the district's economy are primary production (dairy farming) and forestry.



The terrain varies from rolling pasture land around Tokoroa to large expanses of pine forests around the Kinleith mill. The climate is similar to other parts of the Waikato, although it is slightly cooler as the area is on the fringes of the central North Island plateau.

The subtransmission and distribution networks in the Kinleith area are mainly overhead.



Kinleith GXP is the sole grid supply point for the area. There is no 33kV interconnection with other areas and only limited 11kV back-feed.

Kinleith GXP provides offtake at both 33kV and 11kV. The 33kV supply feeds our Tokoroa substations Baird Rd and Maraetai Rd. There is one 33kV line to each substation. There is also a radial 33kV line feeding Kinleith's Midway and Lakeside pump stations.

The 11kV offtake from Kinleith serves the mill, owned by Oji Fibre Solutions. There are multiple 11kV busses, with some limited degree of interconnection. The mill also operates a cogeneration plant feeding into one of the 11kV transformers.

11.4.6.2 DEMAND FORECASTS

Demand forecasts for the Kinleith zone substations are shown below, with further detail provided in Appendix 7.

Table 11.12: Kinleith zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Baird Rd	AA+	0.0	10.3	10.6	10.9	11.2
Maraetai Rd	AA+	0.0	11.2	11.3	11.5	11.7
Midway / Lakeside	AA	0.0	4.4	4.4	4.4	4.4

Economic growth in Tokoroa is modest. There have been some inquiries regarding a possible industrial park or primary industry near the Kinleith mill, but with no commitment yet these proposals are not reflected in the base forecast.

We are in contact with the Kinleith mill regarding any future development plans. This has been particularly pertinent in the past two years as Transpower plans a major overhaul of the GXP because of ageing equipment and operational constraints.

There is existing generation and some possible future developments, both of significant importance. However, these are likely to be directly connected to the grid and do not significantly impact the development of our network.

11.4.6.3 EXISTING AND FORECAST CONSTRAINTS

The electricity supply in the area is dominated by demand from the Kinleith mill. This has four 11kV busses at which supply is taken, and two additional supplies at 33kV serving river pump substations. The security provided to the mill and pumps is determined through consultation with the customer, Oji Fibre Solutions.

The two substations supplying Tokoroa township do not fully meet our security criteria because of the single circuit architecture.

Major constraints affecting the Kinleith area are shown below.

Table 11.13: Kinleith constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Kinleith GXP	Firm capacity for 110/11kV supply transformers is exceeded.	Note 1
Kinleith GXP	The 110/33kV supply transformers are not able to operate in parallel because of incompatible vector groups. Therefore 33kV supply capacity does not meet the security standard.	Note 2
Baird Rd substation	Single 33kV circuit. The 11kV back-feed capability does not meet security standard.	Baird-Maraetai ring
Maraetai Rd substation	Single 33kV circuit. The 11kV back-feed capability does not meet security standard.	Baird-Maraetai ring
Lakeside and Midway substations	Single circuit to Midway and Lakeside pump substations. An outage on either 33kV circuit will cause loss of supply until repairs are completed.	Note 3
Lakeside and Midway substations	Single supply transformer (in each respective substation). No security provided.	Note 3

Notes:

1. The security for the Kinleith mill is determined by the customer, Oji Fibre Solutions, not our security standard. During discussion with Transpower, we have considered possible improvements to security that can be carried out during the proposed replacement work. In particular, an additional 11kV winding on T4 is planned to provide additional security to the Cogen and PM6 plant load. Increased capacity on the 110/11kV T1 to T3 transformers will also improve operational flexibility.

2. No break N-1 security for the 33kV bus supplying Tokoroa township would not be possible without replacing both T4 and T5 transformers with identical vector groups. The cost of this is prohibitive for the minimal benefits. The existing configuration requires a short break between changeover of transformers, which can be managed operationally.

3. The single circuits and single transformers provide no security to the mill's pump stations (Lakeside and Midway) but this level of security is acceptable to the customer.

11.4.6.4 MAJOR GROWTH AND SECURITY PROJECTS

There are no major growth projects planned for the Kinleith area

11.4.6.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Kinleith area.

BAIRD-MARAETAI 33KV CABLE RING	
Estimated cost:	$2.6m
Expected project timing:	2016-2018

Both substations supplying Tokoroa (Baird Rd and Maraetai Rd) are supplied by a single 33kV circuit. While they have considerable 11kV inter-tie, this is not sufficient to meet our security criteria.

Options considered to address this include increased 11kV back-feed, new dedicated second 33kV circuits to each substation, and a 33kV tie circuit between the two, providing a ring configuration. The most cost effective solution is the ring circuit. The proposed solution requires a new 33kV cable between the two substations plus switchgear upgrades, which have been coordinated with renewal work at the substations.

11.4.6.6 OTHER DEVELOPMENTS

Transpower is working on detailed designs for a major refurbishment of the Kinleith GXP. As part of this, the 11kV feeders to the mill will need to be re-routed to new switchgear. Protection upgrades will be carried out at the same time. This work will be coordinated with the customer.

As part of the upgrade we will consider improvements to the 33kV switchboard, which may help to reduce the impact of future outages. Transpower's replacement of one of the 33kV supply transformers will also improve voltage quality at our 33kV bus.

Kinleith GXP is also affected by the grid capacity constraints on the 110kV between Tarukenga and Arapuni..

11.4.7 TARANAKI

The largest development issue in the Taranaki area is the need to maintain supply to our Moturoa substation if Transpower decides to exit the New Plymouth substation. Major and minor project spend related to growth and security in the region over the next 10 years is $18.7m.

11.4.7.1 OVERVIEW

The Taranaki area covers the northern, central and some southern parts of the Taranaki region.

The Taranaki area overlaps three territorial authority areas – New Plymouth district, Stratford district and South Taranaki district.

Taranaki's terrain and climate is generally quite favourable to asset construction, access, maintenance and life expectancy. The exception is the coastal areas, where additional corrosion can affect assets as far as 20km inland.

Severe weather events such as storms can have a significant impact on the network. Tornadoes can also occur, although these are infrequent and their impact is localised.

Agriculture, oil and gas exploration and production, and some heavy industry are the backbone of the Taranaki economy. Agriculture is dominated by intensive dairying suited to the temperate climate and fertile volcanic soils.

The area is supplied from four grid exit points (GXPs). These are at New Plymouth (ex the power station), Carrington St, Huirangi and Stratford.

The subtransmission and distribution networks in the Taranaki area are mainly overhead.

There are some underground networks in the newer urban areas, particularly New Plymouth city.

Subtransmission is mainly meshed or interconnected radial. The notable exception is in New Plymouth, where the five main urban substations are supplied from twin 33kV circuits, and all but one are dedicated circuits directly from the GXP.

11.4.7.2 DEMAND FORECASTS

Demand forecasts for the Taranaki zone substations are shown below, with further detail provided in Appendix 7.

Table 11.14: Taranaki zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Bell Block	AAA	22.9	18.4	20.0	22.0	24.0
Brooklands	AAA	27.0	15.3	15.8	16.5	17.1
Cardiff	A1	4.1	1.6	1.6	1.7	1.7
City	AAA	20.1	19.1	19.5	20.0	20.6
Cloton Rd	AA+	13.0	10.7	10.9	11.2	11.5
Douglas	A1	1.7	1.7	1.7	1.7	1.7
Eltham	AA+	8.6	9.9	9.9	10.0	10.0
Inglewood	AA	6.2	5.4	5.6	5.9	6.2
Kaponga	A1	3.0	3.7	3.7	3.7	3.8
Katere	AAA	24.3	13.5	14.9	16.7	18.4
McKee	AA	1.6	1.4	1.5	1.6	1.7
Motukawa	A1	0.6	1.2	1.3	1.3	1.3
Moturoa	AAA	21.4	22.5	23.5	24.7	25.9
Oakura	AA	4.2	3.5	3.7	3.9	4.1
Pohokura	AA	9.2	5.2	5.2	5.2	5.2
Waihapa	AA	1.4	1.2	1.2	1.2	1.2
Waitara East	AA	10.1	6.3	6.6	6.9	7.3
Waitara West	AA	6.4	6.9	6.9	7.0	7.1

Major industrial customers in the area can have a significant impact on the demand forecast. In the Taranaki area the major industrial loads are:

- Port Taranaki supplied by Moturoa substation.
- Riverlands freezing works and the Fonterra pastoral foods plant supplied by Eltham substation.
- The Pohokura natural gas plant supplied by Pohokura substation.
- The Waihapa petroleum production station supplied by Waihapa substation.
- ANZCO food processing plant supplied by Waitara West substation.

We are not aware of any significant changes in demand for any customers. However such changes usually appear at relatively short notice. We will continue to talk with our larger customers to establish as much lead time as possible for any future developments.

The oil and gas industry impacts demand, both directly and indirectly, and can also drive upgrades for generation opportunities. The 100MW gas plant planned in the Mangorei Rd area will feed directly into the grid, and therefore does not affect our network development. Numerous smaller gas generators have been proposed around the Stratford area, but recent market and economic conditions mean these have been postponed indefinitely.

Although overall demand growth in Taranaki has historically been quite high, this has been mainly driven by significant changes at specific large customers. Forecast growth from other sectors in the Taranaki area is relatively modest. The oil and gas industry has experienced a relatively flat period in the past few years. It is hard to predict how long this will last. There is steady population growth in the major population centres, with some new subdivision activity in and around New Plymouth.

Several of the Taranaki substations already exceed our security criteria. This is largely symptomatic of the manually switched radial interconnected architecture, where full N-1 in the switching times specified by our security classes is difficult to obtain. These constraints on security are often quite low risk in terms of the impact on supply quality.

11.4.7.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Taranaki area are shown below.

Table 11.15: Taranaki constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
New Plymouth GXP	Transpower need to exit the New Plymouth site and to upgrade the 220/110kV interconnection capability. This has implications on our subtransmission for the Moturoa substation. As Moturoa is the only substation supplied by the New Plymouth GXP, Powerco will need to secure an alternative source of supply.	Moturoa subtransmission
Stratford GXP	N-1 capacity exceeded.. Two new supply transformers provide sufficient firm capacity, however a metering accuracy constraint prevents these transformers from operating to their full capability.	Note 1
Carrington St GXP	N-1 transformer capacity exceeded - secondary assets. Limitations of secondary equipment mean that firm transformer capacity is exceeded.	Note 2
Huirangi GXP	Transformer's firm capacity will be exceeded.	Note 3
Bell Block and Katere substations	Carrington St GXP to Bell Block | Katere Tee N-1 circuit capacity exceeded. Outage on one Carrington St to Bell Block Katere 33kV circuit causes loss of supply at Bell Block and Katere substations due to circuit capacity being exceeded on the 2nd 33kV circuit.	Note 4
Waitara West, Waitara East and Pohokura	An outage on the Waitara West 33kV line can overload the Waitara East circuit supplying Waitara East, Pohokura and Waitara West.	Waitara East | McKee 33kV
McKee substation (generation)	The tee connection to McKee means capacity is limited when the Huirangi to McKee section is out of service.	Waitara East | McKee 33kV
Oakura substation	The new Oakura substation is supplied by a single 33kV circuit. The 11kV back-feed does not meet the security standard.	Note 5
Eltham substation	The transformer's firm capacity and substation security have been exceeded.	Eltham transformers
Cardiff substation	The single supply transformer does not provide sufficient security. Renewal is scheduled for 2023.	Note 6
Kaponga substation	Demand exceeds secure capacity of the two transformers. Transformers are scheduled for replacement.	Note 6
McKee substation	Transformer is scheduled for replacement.	Note 7
Motukawa substation	The single transformer does not provide sufficient security and is scheduled for replacement.	6
Waihapa substation	Transformer is scheduled for replacement.	Note 7
Oakura substation	Transformer does not provide sufficient security.	Note 5
Douglas substation	Transformer does not provide sufficient security.	Note 6
Waitara West substation	Demand exceeds secure capacity of the two transformers.	Note 6
Inglewood Substation	6.6kV network. Non-standard Powerco zone substation	Inglewood 6.6kV to 11kV Conversion Project

Notes:

1. Constraint is minor (metering accuracy) - new 2 x 40MVA transformers recently installed provide ample N-1 capacity.

2. Constrained by limitations of secondary equipment (not the transformers) and will be resolved by future load transfer and other proposals (i.e. ODID).

3. Once Bell Block is transferred the demand forecast for Huirangi needs to be confirmed. The plan is to operationally manage the risk (ie via load transfer).

4. This constraint is being addressed by the Huirangi project which is expected to be completed before 2017.

5. Oakura is a new N security substation. Reinforcement of 11kV backfeeding capability to meet security requirements has been conducted.

6. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.

7. Expenditure for this work is allowed for in the renewal forecasts, and detailed options will be considered closer to the time.

11.4.7.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Taranaki area.

MOTUROA SUBTRANSMISSION	
Estimated cost (concept): Project funding yet to be confirmed	$8.8m
Expected project timing:	2018-2019

Transpower's New Plymouth GXP is on land that now belongs to Port Taranaki. There have been discussions regarding Transpower possibly leaving the substation site so that the port can use it for other purposes.

In conjunction with this, Transpower needs to address constraints with the 220/110kV interconnecting transformer capacity in North Taranaki regionally. The preferred option involves two higher capacity transformers at Stratford, allowing New Plymouth to be converted to a simple 110/33kV offtake GXP.

Moturoa substation is the only load connected to this GXP and the capacity does not justify the scale of high voltage assets at the site. Transpower has identified further economic benefit if it can leave the site. This would require that Moturoa substation was supplied from a different GXP.

We have therefore done some preliminary analysis to consider options for subtransmission supply to Moturoa. Further details are in Appendix 8.

The proposed concept solution is to install two new 33kV underground cables from Carrington St GXP to Moturoa substation (about 7km). Whether this work proceeds depends on the outcome of Transpower's analysis and consultation regarding the grid developments. The ownership and funding of the 33kV cables is also still to be resolved.

INGLEWOOD 6.6KV TO 11KV CONVERSION PROJECT	
Estimated cost:	$5.9m
Expected project timing:	2019-2020

The Inglewood zone substation supplies power to Inglewood Township and the surrounding rural areas at 6.6kV. The substation contains two 33/6.6kV supply transformers. These two feeders are supplied as transformer feeders from Huirangi and Stratford GXPs , respectively.

As this is a non-standard Powerco zone substation, the Inglewood substation does not presently meet our required security and performance quality levels.

We have conducted some analysis to consider options for the Inglewood zone substation conversion. Further details are in Appendix 8.

The proposed solution is to replace all of the 6.6/0.4kV distribution transfomers in the Inglewood area with dual winding transformers (11/6.6kV-0.4kV) over a 2-3 year period.

11.4.7.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Taranaki area.

WAITARA TO MCKEE 33KV LINE	
Estimated cost (concept):	$1.9m
Expected project timing:	2020

If the Waitara West line is not available during peak periods, the single 33kV Waitara East circuit from Huirangi GXP has insufficient capacity to supply all four substations - Waitara East, Waitara West, Pohokura and McKee. The tee configuration of the Waitara East/McKee lines also causes protection issues and limits power transfer levels and network security.

The proposed solution is to construct a second 33kV line from Huirangi GXP to the Waitara East substation. This will provide sufficient backup capacity to all four substations on the Waitara ring. It will also allow the Waitara East 33kV circuit to operate independently of the McKee 33kV circuit, enabling generation injection even during an outage on the Huirangi to Waitara East circuit.

ELTHAM SUBSTATION SUPPLY TRANSFORMER	
Estimated cost:	$2.1m
Expected project timing:	2021

The Eltham substation supplies Eltham town, the surrounding rural areas, and two significant industrial loads. The substation contains two transformers. The demand has exceeded the secure capacity of the transformers (ie the capacity that can be supplied by one transformer plus available 11kV back-feed).

The solution is to replace the existing transformers with two larger units. This will secure the load at Eltham and provide adequate capacity for anticipated future demand. To meet the desired security, further improvements will be needed to the subtransmission and protection systems.

11.4.7.6 OTHER DEVELOPMENTS

Transpower's grid developments can have a significant impact on network development, as seen with the Moturoa proposal.

Gas fired generation opportunities can arise. Larger generation (30MW+) typically feeds directly into the grid, but smaller units can often be embedded in our network. These generation proposals are highly dependent on gas, oil and electricity markets, and are therefore difficult to predict in terms of location and size. Lead time is usually very short, meaning we have to quickly reconsider some of our network development plans.

Taranaki has a lot of spot load increases driven by industrial customers - either those associated with agriculture or with the oil and gas industry. These have limited lead time and are unpredictable in terms of location and capacity.

At the distribution level we will continue to routinely complete lower cost feeder upgrades and, where required, install new feeders. Upgrades are often driven by the need to reinforce feeders for growth or for better performance through improved back-feeding schemes. Long rural feeders often need voltage support, which requires regulators or more permanent conductor upgrades.

11.4.8 EGMONT

The subtransmission configuration in this area consists of ring circuits providing adequate security, except the Manaia substation, where we are looking to rectify the short section of single 33kV circuit. A new substation is planned at Mokoia to replace the Whareroa substation - this being a replacement project. Major and minor project spend related to growth and security over the next 10 years is $3.2m.

11.4.8.1 OVERVIEW

The Egmont area covers the southern Taranaki region and is part of the South Taranaki District Council area.

The main urban areas are Hawera, Manaia, Opunake and Patea. Hawera is the largest of these and its population figures are reasonably stable. Smaller towns rely more on tourism now that their historical function of being rural service centres has been reduced.

The terrain is mostly rolling open country, although there are some remote and steep back country areas with long distribution feeders. There is reasonable access to most parts of the network.

The southern Egmont area is prone to storms off the Tasman Sea, which can impact severely on the network. As in northern Taranaki, equipment in coastal areas corrodes quickly.

Agriculture and associated support and processing industries drive the economy, with dairy a long established and strong sector. There are also large food processing operations, including Fonterra's Whareroa site and Yarrows The Bakers. Some oil and gas processing is also present.

The Egmont area is supplied from the Hawera and Opunake GXPs through two independent 33kV subtransmission systems. Opunake GXP supplies Pungarehu, Ngariki and Tasman substations through two 33kV ring circuits. Ngariki is common to both rings. Hawera GXP supplies Kapuni, Manaia, Cambria, Whareroa, and Livingstone substations. A 33kV ring supplies Whareroa and Livingstone. A separate 33kV ring supplies Kapuni and Manaia, although Manaia has a short section of single circuit teed off the ring.

Cambria substation is supplied by two dedicated 33kV oil-filled cables. Cambria, which is the main substation serving Hawera township, has recently been upgraded.

Historically, two different power companies owned the Opunake and Hawera networks. The two subtransmission networks are both operated at a 50Hz frequency but with different phase angles so cannot be interconnected. The subtransmission and distribution networks are mainly overhead.

The Whareroa substation has the same name as the adjacent major Fonterra plant but does not connect to the plant, which is connected directly to the 110kV grid.

11.4.8.2 DEMAND FORECASTS

Demand forecasts for the Egmont zone substations are shown below.

Table 11.16: Egmont zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Cambria	AAA	17.0	15.6	15.9	16.3	16.7
Kapuni	AA+	7.0	6.8	6.8	6.7	6.6
Livingstone	A1	3.1	3.2	3.3	3.3	3.3
Manaia	AA	5.0	7.8	7.8	7.8	7.9
Ngariki	A1	3.8	3.7	3.7	3.8	3.8
Pungarehu	A1	4.5	4.5	4.5	4.6	4.7
Tasman	AA+	6.4	7.1	7.1	7.2	7.2
Whareroa	A1	3.0	4.5	4.6	4.7	4.9

Major industrial customers in the area have the biggest impact on the demand forecast through occasional and largely unpredictable significant increases in demand. Apart from this, the forecast demand growth in other sectors in the Egmont area is relatively low.

As with the Taranaki area, generation proposals can also drive capacity upgrades, which tend to be unpredictable and, from a planning perspective, arise at short notice. Proposals also tend to depend on market conditions.

A number of substations already exceed our security standards. As with other areas, our development plans seek to improve our security for existing loads as well as catering for demand growth.

11.4.8.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Egmont area are shown below.

Table 11.17: Egmont constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Hawera GXP	i) An outage on the 110kV supply circuit to the Hawera GXP can cause low voltages at the substation ii) Supply transformer firm capacity exceeded due to bus section capacity limitations.	(i) Note 1 (ii) Note 2
Manaia substation	Section of single circuit from the tee to Manaia substation and the tee connection itself do not meet security criteria.	Manaia subtransmission
Kapuni substation	For a Kapuni 33kV circuit outage, the Manaia 33kV feeder will not in future supply both substations at peak demand.	Manaia subtransmission
Manaia substation	Single transformer. The 11kV back-feed does not meet security criteria. Transformer is scheduled for replacement in 2018.	Note 3
Pungarehu substation	Demand exceeds secure capacity of the two transformers. Transformer is scheduled for replacement in 2022.	Note 4
Tasman substation	Transformer firm capacity has been exceeded. Transformer is scheduled for replacement in 2023.	Note 4
Livingstone substation	Transformer firm capacity has been exceeded. Transformer scheduled for replacement in 2018.	Note 4
Ngariki substation	Single transformer. The 11kV back-feed does not meet security criteria.	Note 5
Whareroa substation	Single transformer. The 11kV back-feed does not meet security criteria. Transformer is scheduled for replacement in 2018.	Note 3

Notes:

1. Transpower is investigating possibilities for additional reactive support, for use during 110kV outages. Only constrains with no generation.2. Capacity is limited by a bus section, and can be managed operationally using the adjoining the Kupe transformer in emergencies.

3. Managed operationally. Low risk as back-feed capacity is adequate and transformer failure is a very low probability. Where replacement occurs, the new transformer capacity will incorporate future development needs.

4. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.

5. Managed operationally.

11.4.8.4 MAJOR GROWTH AND SECURITY PROJECTS

There are no major growth and security projects planned for the Egmont area.

11.4.8.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Egmont area.

MANAIA SUBTRANSMISSION	
Estimated cost (concept):	$3.2m
Expected project timing:	2022-2023

Manaia substation is supplied by a short section of single 33kV circuit that tees off the Manaia-Kapuni 33kV ring. The tee connection and single circuit expose Manaia to reduced security and higher risk of outages. In addition, the capacity of the Manaia feeder is not sufficient to supply future peak demand for both Manaia and Kapuni (ie if the Hawera-Kapuni circuit is out of service).

Options considered are detailed in Appendix 8.

The proposed solution is a direct circuit between Manaia and Kapuni using a second circuit from Manaia to the tee and reconfiguring as a full ring connection.

While it may not be economically justified to upgrade the Manaia-Kapuni circuits to supply full N-1 security, we will keep options open in terms of future development. A relatively low cost thermal upgrade may be justified if demand increases more quickly than expected. The upgraded support structures on the line will be designed to accommodate a larger conductor if it is required in the future.

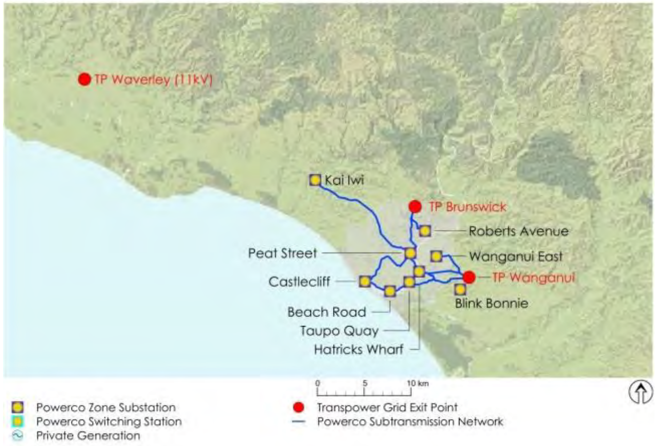
11.4.9 WHANGANUI

The subtransmission network architecture in Whanganui city is different to our other areas and does not easily align with our security criteria. Minor projects in the area include a second 33kV circuit to the Taupo Quay and Peat St substations. Minor project spend related to growth and security over the next 10 years is $12.9m.

11.4.9.1 OVERVIEW

The Whanganui area covers the city of Whanganui and its surrounding settlements, which form the Whanganui district.

Whanganui city lies on the north-western bank of the Te Awa O Whanganui – the Whanganui River.



The small South Taranaki town of Waverley is also part of the Whanganui area.

Much of the land outside the city is rugged, hilly terrain surrounding the river valley. A large proportion of this is within the Whanganui National Park. This means that access to these regions, especially following major weather incidents, is difficult, and can result in lengthy outages for remote customers.

The Whanganui district has a temperate climate, with slightly higher than the national average sunshine - 2100 hours per annum - and about 900mm of annual rainfall. The Whanganui River is prone to flooding in heavy rain.

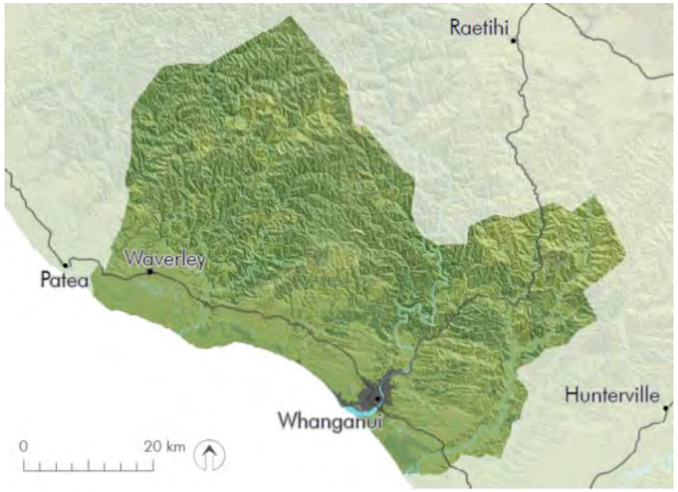
The Whanganui area also gets hit by occasional storms off the Tasman Sea. High winds cause the main disruption as they can fell trees and throw debris into lines, which leads to widespread and prolonged outages.

The district's economy is driven by agriculture, forestry and fishing. Whanganui city is both the main service centre for the rural district and a self-sustaining commercial entity.

There are several industrial and commercial customers of significance within Whanganui city. However, none are of sufficient size to warrant a dedicated substation.

The area connects to the grid through three Transpower GXPs. Whanganui and Brunswick GXPs supply Whanganui city and surrounding areas. Waverley GXP supplies the town of Waverley, in the South Taranaki district.

There are nine zone substations in the Whanganui area, five of which (Blink Bonnie, Taupo Quay, Beach Rd, Hatricks Wharf and Whanganui East) are supplied from the Whanganui GXP, and four (Peat St, Roberts Ave, Kai Iwi, Castlecliff) from the Brunswick GXP. Waverley GXP directly supplies the Waverley township and surrounding areas via 11kV distribution feeders.



Whanganui has a unique and highly meshed subtransmission architecture. Most substations in the city are supplied from single radial lines, often more than two substations per 33kV feeder, but with some alternative switched 33kV capacity. Often the alternative 33kV line is from a different GXP, complicating operations and switching. Protection systems are also a challenge.

With this architecture it is difficult to provide the breakless or quick switching required to comply with our security criteria. From a purely risk of supply perspective, the architecture is quite robust and cost effective.

The zone substation architecture is also unique. Several urban substations have a single transformer of relatively modest capacity, but are supported by higher than usual capacity 11kV feeder interconnections. Taupo Quay and Hatricks Wharf are unique in our network as they are essentially operated in parallel using a high capacity 11kV cable that ties the two 11kV busses.

The subtransmission and distribution networks are mainly overhead, even in most urban areas.

11.4.9.2 DEMAND FORECASTS

Demand forecasts for the Whanganui zone substations are shown below, with further detail provided in Appendix 7.

Table 11.18: Whanganui zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Beach Rd	AA+	13.6	10.9	11.1	11.4	11.7
Blink Bonnie	A1	2.3	4.4	4.5	4.6	4.6
Castlecliff	AA+	8.7	11.5	11.7	12.0	12.3
Hatricks Wharf	AA+	0.0	11.5	11.5	11.6	11.6
Kai Iwi	A1	1.0	2.4	2.5	2.6	2.6
Peat St	AAA	0.0	19.4	19.9	20.4	21.0
Roberts Ave	AA	5.7	8.4	8.5	8.6	8.8
Taupo Quay	AA+	0.0	11.4	11.5	11.6	11.6
Wanganui East	AA	3.1	8.6	8.7	8.7	8.8

Recent underlying growth in demand has been modest throughout the Whanganui area. Major industrial customers in the area can have a big impact on the demand through significant changes in load. This is in part behind the high growth rate signalled at Beach Rd in the table above.

The Springvale Structure Plan[26], if fully realised, will be expected to add up to 2 to 3MW of demand to the Peat St or Castlecliff substations. However, this demand increase is expected to occur over the longer term, and some of it could be perceived as being incorporated into the estimated underlying growth rates.

Shaded years indicate that the demand exceeds the capacity we can provide with appropriate security. Of note is that all but one of the Whanganui substations already exceeds our security criteria. Growth and security plans are focused on improving security and reliability for the existing load base rather than specifically catering for future new load.

Growth and security plans also need to take into account the unique characteristics of the network architecture in the city. This means we do not always seek to fully comply with all security criteria but rather focus on the most cost effective investments that improve overall reliability. This approach is consistent with our probabilistic consideration of development options.

11.4.9.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Whanganui area are shown below.

[26] Springvale Structure Plan, Whanganui District Council, April 2012.

Table 11.19: Whanganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Whanganui GXP	Firm capacity of the 110/33kV transformers is exceeded. Transformers are due for replacement.	Note 1
Brunswick GXP	Single 220/33kV transformer – no N-1 security.	Whanganui GXP to Taupo Quay New Circuit Whanganui Subtransmission Reinforcement
Waverley GXP	Single 110/11kV transformer – no N-1 security.	Note 2 Waverley GXP Single Transformer
Castlecliff Substation	**Whanganui GXP to Taupo Quay 33kV circuit**: Insufficient capacity to supply Castlecliff substation, when normal supply, via the Brunswick GXP to Peat St and Peat St to Castlecliff 33kV circuits, is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Peat St Substation	**Whanganui GXP to Hatricks Wharf 33kV circuit**: Insufficient capacity to supply Peat St substation, when normal supply via the Brunswick GXP to Peat St 33kV circuit, is unavailable..	Roberts Ave to Peat St 33kV Circuit
Taupo Quay Substation	**Whanganui GXP to Hatricks Wharf 33kV circuit**: Insufficient capacity to supply Taupo Quay substation when Whanganui GXP to Taupo Quay 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Hatricks Wharf Substation	**Whanganui GXP to Taupo Quay circuit**: Insufficient capacity to supply Hatricks Wharf substation when Whanganui GXP to Hatricks Wharf 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Peat St & Kai Iwi Substation	**Hatricks Wharf to Peat St 33kV circuit**: Insufficient capacity to supply Peat St. and Kai Iwi substations when Brunswick GXP to Peat St 33kV circuit is unavailable.	Roberts Ave to Peat St 33kV Circuit
Beach Rd and Taupo Quay Subs	**Peat St to Castlecliff 33kV circuit**: Insufficient capacity to supply Beach Rd & Taupo Quay substations when Whanganui GXP to Taupo 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Castlecliff Substation	**Taupo Quay to Beach Rd 33kV circuit**: Insufficient capacity to supply Castlecliff substation when normal supply, via the Brunswick GXP to Peat St and Peat St to Castlecliff 33kV circuits, is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Beach Rd and Taupo Quay Substation	**Beach Rd to Castlecliff 33kV circuit**: Insufficient capacity to supply Beach Rd and Taupo Quay substations, when Whanganui GXP to Taupo Quay 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Beach Rd and Taupo Quay Substation	**Brunswick GXP to Peat St 33kV circuit**: Insufficient capacity to supply Beach Rd and Taupo Quay substations, when Whanganui GXP to Taupo Quay 33kV circuit is unavailable.	Whanganui GXP to Taupo Quay New Circuit
Roberts Ave Substation	Outage on Brunswick GXP to Roberts Ave single 33kV circuit can cause a loss of supply to Roberts Ave substation.	Roberts Ave to Peat St 33kV Circuit
Whanganui East Substation	Outage on Whanganui GXP to Whanganui East single 33kV circuit can cause a loss of supply to Whanganui East substation.	Whanganui East Substation Second Transformer and Subtransmission Supply
Kai Iwi Substation	Outage on Peat St to Kai Iwi single 33kV circuit can cause a loss of supply to Kai Iwi substation.	Note 6
Roberts Ave Substation	The single supply transformer does not provide sufficient security to the substation	Roberts Ave Substation Second Transformer
Hatricks Wharf Substation	The single supply transformer does not provide sufficient security to the substation	Note 5
Taupo Quay Substation	The single supply transformer does not provide sufficient security to the substation	Note 5

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Whanganui East Substation	The single supply transformer does not provide sufficient security to the substation	Whanganui East Substation Second Transformer and Subtransmission Supply
Kai Iwi Substation	The single supply transformer does not provide sufficient security to the substation.	Note 6
Blink Bonnie Substation	The single supply transformer does not provide sufficient security to the substation.	Note 7

Notes:

1. Transpower Asset. Transpower has scheduled a renewal of the transformers in the next 10 years. Load can be transferred to Brunswick to manage the constraint.

2. Transpower Assets. The N security issue of single transformer GXP was recently identified as significant risk due to the stated long lead time (33 days) for restoration of supply by Transpower.

3. The Whanganui area has highly meshed 33kV circuits with cross GXP backfeeding capability. Several constraints interact, and need to be grouped in one analysis.

4. The Whanganui network architecture relies on a strong 11kV backfeeding capability with single transformer zone substations.

5. Taupo Quay and Hatricks Wharf are linked by a high capacity 11kV bus tie. Hatricks Wharf has adequate capacity to back feed Taupo Quay, in the case of single transformer outage. Taupo Quay sub does not have adequate capacity to back feed Hatricks Wharf, so currently the changeover scheme is on manual.

6.. A second circuit to Kai Iwi was considered during options analysis, including interconnection with possible new Castlecliff circuits. These options did not prove viable. Instead we will look at opportunities to further reinforce the 11kV inter-tie capacity and any possible non-network options, such as backup generation for critical sites.

7. Expenditure for this work is allowed for in the renewal forecasts and detailed options will be considered closer to the time, including the appropriate capacity of the replacement units.

11.4.9.4 MAJOR GROWTH AND SECURITY PROJECTS

The substations in Whanganui city are supplied through a highly meshed network of essentially radial interconnected circuits. Many of the back-feeds cross GXP boundaries. Multiple substations are often fed from single circuits. The GXPs are not fully N-1 secure and rely on subtransmission back-feeds.

As is notable in the table above, circuit outages on one side of the network can expose constraints on the other side. Constraints on the same circuit can be exposed by multiple contingency scenarios (i.e. different line outages) and any given line outage can expose multiple constraints on different lines.

In considering network development options we had to consider multiple constraints in one overarching analysis. This essentially determined a high level future strategy – or set of growth and security projects – that would address all the high risk constraints.

11.4.9.5 MINOR GROWTH AND SECURITY PROJECTS

There are two significant minor growth and security projects in the Whanganui area. These are detailed below. It is expected these will be further refined by more detailed and focused options analysis closer to the proposed timing of the projects.

WHANGANUI GXP TO TAUPO QUAY SECOND CIRCUIT	
Estimated cost (concept)	$4.3m
Expected project timing:	2018-2020

This project addresses a number of network constraints but most particularly:

- Taupo Quay and Hatricks Wharf are each fed by single 33kV circuits but the substations are paralleled at 11kV. There is insufficient capacity in either single 33kV circuit to supply both substations.
- The 33kV to Taupo Quay also supplies increasing demand at Beach Rd. This 33kV also needs to supply Castlecliff when the normal supply through Brunswick and Peat St is interrupted. The network capacity is inadequate.
- There are multiple limitations in capacity if trying to back-feed Taupo Quay through Brunswick, Peat St, Castlecliff and Beach Rd. Additional security at Taupo Quay in the form of another circuit would mean such back-feed scenarios would not be needed.
- Peat St is the most critical substation in Whanganui, but if the single 220/33kV GXP transformer at Brunswick is unavailable, Peat St and all other Brunswick load must be supplied from Wanganui GXP. Significantly greater capacity is required, especially on the Taupo Quay circuit, to enable secure supply under such contingencies.

Options considered are detailed in Appendix 8.

The proposed solution is to install an additional 33kV circuit from Whanganui GXP into Taupo Quay. This would operate in parallel with the existing circuit and vastly improve security to Taupo Quay and the dependent substations of Beach Rd and Castlecliff. Even Peat St and Hatricks Wharf would benefit. The solution also helps mitigate the risks exposed by only a single 220/33kV transformer at Brunswick GXP.

Variations to this option will be explored as more detailed analysis takes place closer to the proposed project implementation. Essentially this project sets out our development path for the whole city through establishing much greater security and capacity from the Wanganui GXP. Brunswick can then remain an N secure GXP without compromising reliability.

ROBERTS AVE TO PEAT ST 33KV CIRCUIT	
Estimated cost (concept)	$3.1m
Expected project timing:	2020-2021

This project addresses a number of development constraints but most particularly:

- Peat St is the most critical substation in Whanganui but is supplied by a single circuit, meaning security is dependent on back-feed from Wanganui GXP substations. Such cross GXP back-feed arrangements also require break-before-make changeover, which is inappropriate for a substation serving the city's CBD.
- When existing circuits from Wanganui GXP are unavailable there is insufficient capacity through Peat St to secure all substations.
- Kai Iwi is sub-fed from Peat St and loses supply when Peat St does.

Options considered are detailed in Appendix 8.

The preferred project involves the construction of a new 33kV circuit between Roberts Ave and Peat St substations and upgrading the existing 33kV circuit between Brunswick GXP and Roberts Ave substation. This option will create a secure supply to Peat St and Roberts Ave substations, enabling them to meet our security levels.

In conjunction with the Whanganui GXP to Taupo Quay new circuit project, Option 2 will ensure that all of the key Whanganui city substations, including Taupo Quay, Hatricks Wharf, Peat Street as well as Beach Road, Castlecliff and Roberts Ave substations, will meet our required security levels.

The other option, which involves the construction of a new circuit between Brunswick GXP and Peat St substation while providing a secure supply to Peat St substation, will not resolve the security of supply issue at Roberts Ave substation. Hence this option was not favoured.

11.4.9.6 OTHER DEVELOPMENTS

Transpower is replacing the 33kV switchboard at Whanganui GXP and has been proposing to replace the 110/33kV supply transformers. The capacity of the new units will be determined by considering the future load growth and the need to support Brunswick GXP.

The cross GXP subtransmission back-feeds and meshed nature of the network mean good protection and automation is required, which in turn relies on good communication links. We have recently upgraded these through direct microwave links. The proposed new subtransmission projects will offer more opportunities to improve the communication systems by the installation of fibre cables on some key communication links.

The single transformer and single subtransmission circuit architecture means Whanganui relies on strong 11kV interconnection to ensure reliable supply. We will continue to provide 11kV distribution feeder upgrades to ensure capacity meets any demand growth.

Rural distribution is more focused on performance (i.e. reliability). We will continue to look for opportunities to improve back-feed capacity, especially for long and heavily loaded feeders.

Waverley GXP has only N security and would benefit from improved 11kV inter-tie to Whanganui and South Taranaki networks.

We are upgrading some LV and distribution transformers serving the central commercial district of Whanganui.

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

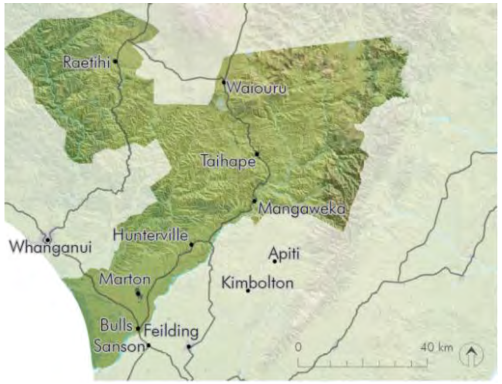
PROJECT	SOLUTIONS
Whanganui subtransmission Reinforcement	The second Whanganui to Taupo Quay line will improve the supply security of zone substations off Brunswick GXP, however, the subtransmission circuit between Taupo Quay and Peat St is expected to come close to being overloaded considering the future growth in the area. The preferred solution involves re-tensioning the overhead line and replacing some cable sections with larger capacity conductor.
Whanganui East Substation Second Transformer and Subtransmission Supply	The substation is supplied by one single 33kV circuit from Whanganui GXP and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. There is limited backfeed capability from distribution network. The solution is to install a second subtransmission circuit and a second transformer at the substation. This will improve the substation's security level.
Roberts Ave Substation Second Transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.

11.4.10 RANGITIKEI

Rangitikei has low historical and forecast growth. Other than the Taihape substation, our substations in the area are supplied by single circuits and do not strictly meet our security criteria. These security issues are considered low risk because of their relatively low impact and are mitigated by the available 11kV back-feed capability. Major and minor project spend related to security over the next 10 years is $16.1m.

11.4.10.1 OVERVIEW

The area covers towns in the Rangitikei district, including Bulls and Marton, and follows the state highway up to Hunterville and Mangaweka. It also includes the towns of Waiouru, Taihape and Raetihi, and the surrounding rural areas.



The terrain is varied with rolling country in Rangitikei changing to more rugged, mountainous terrain in the Ruapehu area where the central plateau and mountains of the Tongariro National Park dominate.

The climate in this region ranges from temperate in the Rangitikei district to sub-alpine in the Ruapehu district. Snow can settle in locations over 400m above sea level, such as Raetihi, Waiouru and Taihape. Extreme weather occurs frequently and has a widespread impact on the network, making it difficult to access faults.

The Rangitikei economy is based on primary production and downstream processing. In the Ruapehu district, tourism and primary production drive the economy. Ohakune, with its proximity to the world heritage area of the Tongariro National Park, attracts many visitors for outdoor activities such as skiing. Taihape, Marton and Bulls are significant urban centres in the Rangitikei district. Waiouru is dominated by a large armed forces camp.

The Rangitikei area is connected to the grid through Marton, Mataroa and Ohakune GXPs. Both Mataroa and Ohakune GXPs have only a single offtake transformer.

From Mataroa GXP, two 33kV lines supply Taihape substation, while a single 33kV overhead line serves Waiouru. Ohakune is a shared GXP and supplies directly at 11kV.

Marton GXP supplies Pukepapa, Arahina, Rata and Bulls substations through radial 33kV overhead lines. Pukepapa substation is directly beside Marton GXP. Arahina substation supplies the Marton township. Rata is sub-fed from Arahina through a single 33kV line and services the upper Rangitikei or area around Hunterville.

There is little or no interconnection at 33kV. The subtransmission and distribution circuits are almost exclusively overhead, with long lines and sparse connections reflecting the highly rural nature of the area. Loads and conductors are generally quite small. Voltage constraints are generally more significant than thermal capacity constraints.

Between Pukepapa and Rata there is a 22kV distribution tie that serves as a backup for Rata. The 22kV operating voltage helps mitigate voltage drop over the long distances.

Isolating and restoring the network after a fault can be challenging and often time-consuming. Switching points and lines can be hard to access, and there are very limited back-feed opportunities, especially on long spur lines.

11.4.10.2 DEMAND FORECASTS

Demand forecasts for the Rangitikei zone substations are shown below, with further detail provided in Appendix 7.

Table 11.20: Rangitikei zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Arahina	AA	2.9	8.9	9.0	9.1	9.2
Bulls	AA	4.0	5.7	5.7	5.7	5.8
Pukepapa	A1	3.4	9.0	9.1	9.2	9.4
Rata	A1	0.7	2.3	2.3	2.3	2.3
Taihape	A1	0.7	5.1	5.1	5.1	5.1
Waiouru	A1	0.6	3.0	3.0	3.0	2.9

Growth in the Rangitikei area has historically been low. These are mature rural communities with a relatively static electricity requirement. Our forecast is that growth will remain subdued or flat as energy efficiency offsets any small increase in connection numbers. No significant load increases are anticipated from either residential or industrial development.

There have been indications of possible increases in irrigation in the Parewanui area, which could create a significant change in the demand from the Bulls substation. This is not represented in the base substation forecast above, as the developments are still uncertain in timing and size.

As with other rural parts of our network, a lot of substations do not meet our security criteria, even with existing load. Therefore our growth and security plans are focused on improving security and reliability for existing customers, rather than catering for growth.

11.4.10.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Rangitikei area are shown below.

Table 11.21: Rangitikei constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Mataroa GXP	The single supply transformer does not provide sufficient security to the substation	Note 1 Mataroa GXP Single Transformer
Ohakune GXP	The single supply transformer does not provide sufficient security to the substation	Note 1
Parawanui and Lake Alice feeders	Heavily loaded feeders have limited backfeed and high growth due to irrigation.	Parewanui Zone Substation
Waiouru substation	Outage on single Mataroa GXP to Waiouru 33kV circuit will cause loss of supply to Waiouru substation	Note 2
Waiouru substation	The single supply transformer does not provide sufficient security to the substation	Note 2
Taihape substation	Mataroa GXP to Taihape 33kV circuits: Old manually operated switchgear limits parallel operation so security to substation is not met.	Note 3
Taihape substation	The single supply transformer does not provide sufficient security to the substation	Taihape Substation Second Transformer
Marton GXP	Firm capacity for 110/33kV supply transformers is exceeded. Low supply voltages for outage of one supply transformer.	Note 4
Arahina and Rata substations	Outage on singe Marton GXP to Arahina 33kV single circuit will cause loss of supply to Arahina and Rata substations.	Arahina Substation Second Transformer and Subtransmission Supply
Arahina substation	The single supply transformer does not provide sufficient security to the substation	Arahina Substation Second Transformer and Subtransmission Supply
Rata substation	Outage on single Arahina to Rata single 33kV circuit will cause loss of supply at Rata substation.	Note 2
Rata substation	The single supply transformer does not provide sufficient security to the substation	Note 2
Bulls substation	Outage on Marton GXP to Bulls single 33kV circuit will cause loss of supply at Bulls substation.	Note 5
Bulls substation	The single transformer does not provide sufficient security to the substation + Renewal transformer replacement (scheduled for 2023)	Note 6
Pukepapa substation	The single supply transformer does not provide sufficient security to the substation	Pukepapa Substation Second Transformer

Notes:

1. Transpower Assets. The N security issue of single transformer GXP was recently identified as significant risk due to the stated long lead time (33 days) for restoration of supply by Transpower. Mataroa TX is approaching end of life.
2. N-1 for 33kV circuits or zone transformers are not economic. Options to improve 11kV backfeed will be considered under routine planning.
3. These constraints will be addressed through the fleet renewal planning process.
4. Transpower Asset. Auxiliary components are the limitation. Transformers are due for renewal soon. Other projects (Sanson-Bulls) may drive upgrade sooner.
5. Options to improve Sanson security may also bring improvements to Bulls, via a new Sanson - Bulls tie line (refer to option discussion under section 11.4.11).
6. N-1 for Zone transformers are not economic. Options to improve 11kV backfeed will be considered under routine planning.

11.4.10.4 MAJOR GROWTH AND SECURITY PROJECTS

Although there are numerous issues (ie sections of network that do not strictly meet our security standards) they are all relatively low risk. Many are related to single zone substation transformers, for which the probability of failure is low and is mitigated by 11kV back-feed capability. Single circuits expose consumer loads to a higher probability of outage, but restoration times are generally reasonable given the network is all overhead. The network architecture is a reflection of the small loads involved and widely dispersed connections. The cost of improvements to fully comply with the security standards can rarely be justified. As such, there are no major growth and security projects planned on the subtransmission or zone substations during the next decade.

Under our renewal programme we plan to replace the transformers at Bulls and Arahina and the switchgear at Arahina, Pukepapa and Rata.

A project in the Palmerston North area will improve security to Bulls. This project proposes a 33kV interconnection between Bulls and Sanson substations. Refer to section 11.4.11 for further details.

11.4.10.5 MINOR GROWTH AND SECURITY PROJECTS

There are no minor growth and security projects planned for the Rangitikei area.

11.4.10.6 OTHER DEVELOPMENTS

We will continue to monitor distribution feeder loading and voltages, and schedule any upgrades needed for growth. We will also focus on improving existing reliability, especially through back-feeding and automation. This can require increased capacity of tie circuits.

To improve security performance, even if not fully meeting our standards, increased substation inter-tie capacity is being investigated for Waiouru, Bulls, Arahina and Rata substations.

We will also monitor possible irrigation developments, especially in the Parewanui region. We are working towards a long-term development strategy that would enable us to construct a Parewanui substation if required. In the interim we will build a distribution feeder from Bulls. This feeder will operate at 11kV but will be capable of uprating to 33kV if a new substation is required.

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Mataroa GXP Single Transformer	The Mataroa GXP supplies tow zone substations, Taihape and Waiouru. These areas are sparsely populated with long, high impedance conductors, and very low capacity backfeeds from other substation feeders. The preferred solution is to deploy a mobile substation for outage periods, and to provide 33kV supply from 110kV.
Parewanui Zone Substation	The Parewanui and Lake Alice areas are presently supplied by the Bulls and Pukepapa substations via 11kV feeders. The strong growth in this area signals that these feeders will reach their capacity in the future. The preferred solution is to construct a new Parewanui zone substation at the corner of Parewanui and Forest Road.
Taihape Substation Second Transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.
Arahina Substation Second Transformer and Subtransmission Supply	The substation is supplied by one single 33kV circuit from Marton GXP (N security) and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. The solution is to install the second subtransmission supply and transformer at the substation.
Pukepapa Substation Second Transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.

11.4.11 MANAWATU

Palmerston North CBD has a meshed network supplied from two high capacity GXPs and uses several 33kV underground oil-filled cables. Some of our transformers at the CBD substations, and the 33kV cables feeding these, have exceeded or are approaching their secure capacity.

The largest single growth and security project currently planned involves addressing these security issues by building two new 33kV circuits and a new inner city substation at Ferguson St, with a total estimated cost of $27.4m. There are also a number of other projects planned to upgrade the transformers in existing substations..

Major and minor project spend related to growth and security over the next 10 years is $57.6m.

11.4.11.1 OVERVIEW

The Manawatu area is dominated by the city of Palmerston North but also includes Feilding and smaller inland and coastal settlements and surrounding rural areas.

Palmerston North city and surrounding areas to the north and west lie on the Manawatu plains.

More rugged, hilly terrain is found to the east of Palmerston North on the Tararua Range and to the northeast on the Ruahine Range.

The Palmerston North area has a temperate but windy climate, with consistent wind in the Tararua and Ruahine ranges. Network equipment close to the sea is prone to corrosion.

Wind generation is a major feature in the Manawatu area with three major wind farms to the east of Palmerston North. Tararua Wind Farm has two generation sources feeding into our network at 33kV and has a significant impact on protection and operation of the 33kV network.

Access of the area for fault repair and maintenance is good, especially on the Manawatu plains.

Primary production, such as dairying, is significant to the local economy, although less dominant than in other planning areas.

Palmerston North is the economic hub of the area. The city has had steady growth, with areas such as Kelvin Grove, Kairanga and Summerhill popular for residential development. Further development in these locations is noted in local council planning documents.

Industry and commerce are also strong in the city. The North East Industrial zone recognises Palmerston North's position as a transport and warehouse hub – the city being centrally located with immediate access to major transport facilities. In recent times the CBD has had a relatively high growth rate. This is expected to continue given the city's popularity, size and the considerable distance to the next major commercial centres.

Two of New Zealand's major military bases are also in the Manawatu area - Ohakea air base (near Sanson) and Linton army camp (south of Palmerston North). The Massey University complex and associated research centres are also significant contributors to the city's vitality.

The Manawatu area is connected to the grid through the Bunnythorpe and Linton GXP substations.

Bunnythorpe GXP supplies seven zone substations - Keith St, Kelvin Gr, Main St, Milson, Feilding, Kimbolton and Sanson.

The Linton GXP supplies three zone substations - Kairanga, Pascal St and Turitea.

Both subtransmission networks supplied by these GXPs have 34MW generation feed from the Tararua Wind Farm.

The subtransmission and distribution networks in the rural areas are mainly overhead. Within Palmerston North city there are some overhead lines but predominantly circuits are underground.

The 33kV subtransmission network is mostly meshed. The two subtransmission networks from each GXP are operated independently but can be interconnected at several points across the city. City substations generally have full N-1 circuits in either twin circuit or ring circuit configurations. Some ring connections are open because of protection issues or they cross GXP boundaries. The two rural substations, Kimbolton and Sanson, are on single radial spurs.

The 11kV distribution in the city is mainly underground cable, which is a legacy of earlier local council objectives. The network operates independent feeders with multiple manually switched open points to other feeders (ie interconnected radial). One unique feature in Palmerston North is the legacy of tapered capacity, where feeders reduce in capacity from the substation out to the extremities. This can severely limit back-feed and protection settings. We have been addressing this through a consolidated upgrade programme.

11.4.11.2 DEMAND FORECASTS

Demand forecasts for the Manawatu zone substations are shown below, with further detail provided in Appendix 7.

Table 11.22: Manawatu zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Feilding	AAA	23.7	22.0	22.8	23.9	24.9
Kairanga	AAA	19.1	19.6	20.0	20.5	21.0
Keith St	AAA	21.9	19.1	19.5	19.9	20.3
Kelvin Grove	AAA	17.2	18.9	20.6	22.7	24.8
Kimbolton	A1	0.6	3.1	3.1	3.1	3.2
Main St	AAA	17.0	29.4	30.0	30.7	31.4
Milson	AAA	18.1	18.9	20.1	21.4	22.8
Pascal St	AAA	17.0	23.4	23.7	24.0	24.4
Sanson	AA+	0.0	8.9	9.2	9.7	10.2
Turitea	AAA	0.0	16.0	16.9	18.0	19.1

Palmerston North city has had steady growth throughout the past decade, reflecting its importance as a major central North Island city. The growth outlook for the CBD and commercial centre is strong.

The NEI industrial area has been planned as a transport and warehouse hub because of its strategic location in the national transport infrastructure. While initial demand has been modest, we need to plan for the eventual full scale development.

The council’s urban development planning anticipates strong residential growth on the southern side of the city around Kairanga. Kelvin Grove is also expected to continue following recent historical growth trends. Summerhill and Massey have also been popular areas for residential and lifestyle development and more expansion is expected, within the bounds of land availability and zoning.

Massey University, the research centre and the Linton and Ohakea defence force bases are significant large capacity customers. We maintain contact with them to ensure the best possible planning of security and supply. It was suggested that the armed forces may consolidate at Ohakea, but that is yet to be decided.

Demand from rural customers has been relatively static, other than in areas where irrigation may develop. Oroua Downs is one area we are monitoring closely as it has the potential to impact on proposed growth and security projects.

11.4.11.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Manawatu area are set out below.

Table 11.23: Manawatu constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Bunnythorpe GXP	Firm capacity of the GXP transformers has been exceeded.	Palmerston North CBD
Keith St, Kelvin Gr and Main St substations	The N-1 capacity of the 33kV Keith St and Kelvin Gr subtransmission circuits is exceeded.	Palmerston North CBD
Feilding, Sanson and Kimbolton substations	The N-1 capacity of the two 33kV Bunnythorpe-Feilding circuits has been exceeded.	Sanson-Bulls 33kV
Sanson substation	Single circuit from Feilding to Sanson. There is insufficient 11kV back-feed to meet the security criteria.	Sanson-Bulls 33kV
Main St substation	N-1 capacity of 33kV oil-filled cables is exceeded. Oil-filled cables are a security and environmental risk.	Palmerston North CBD
Pascal substation	Under-rated cable from Manawatu River to Pascal St cannot meet N-1 security criteria.	Palmerston North CBD
Pascal substation	Demand exceeds firm capacity of the two transformers. Substation is highly constrained for space.	Palmerston North CBD
Kairanga substation	Protection issues with operating a closed 33kV ring. A section of cable from Pascal to Kairanga limits N-1 capacity.	Note 1
Kimbolton substation	Single 33kV circuit from Feilding to Kimbolton. The 11kV back-feed capacity does not meet security criteria.	Note 2

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Kimbolton substation	Single transformer substation. Replacement of transformer is scheduled for 2022.	Note 2
Feilding substation	Demand exceeds firm capacity of the two transformers.	Feilding transformers
Sanson substation	Demand exceeds firm capacity of the two transformers.	Sanson transformer
Kairanga substation	Demand exceeds firm capacity of the two transformers.	Kairanga transformers
Kelvin Gr substation	Demand exceeds firm capacity of the two transformers.	Kelvin Gr transformers
Kelvin Gr substation	Kelvin Grove substation demand is expected to exceed 24MVA in future . This will cause reliability and lost load issues..	New Ashhurst Zone substation
Oroua Downs, Rongotea and Bainesse feeders	High growth due to increasing irrigation loads. Heavily loaded feeders have limited backfeed.	Rongotea Zone substation
Turitea Substation	Turitea substation requires class AAA, presently has switched N-1 from Linton and Bunnythorpe.	Turitea Area Subtransmission Supply
Milson Substation	Milson substation demand will exceed its class capacity.	Milson Substation Supply Transformers and Subtransmission Upgrade

Notes:

1. The oil-filled cables between Pascal and Gillespies Line. With better communications from Linton GXP to the city, it is expected the protection issues can be resolved and it will then be possible to operate Kairanga on a closed 33kV ring.

2. Kimbolton's small load and the large distance to the substation prevents a second 33kV circuit. Similarly, a second transformer is unlikely to be economic but options to improve security will be considered when the existing transformer is due for replacement.

11.4.11.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Manawatu area.

PALMERSTON NORTH CBD (FERGUSON SUBSTATION)	
Estimated cost (design and consenting):	$27.4m
Expected project timing:	2016-2023

The Palmerston North CBD is supplied from Pascal and Main St substations with support from Keith St substation. Pascal is supplied from Linton GXP. Keith and Main St are supplied from Bunnythorpe GXP, which has exceeded the firm capacity of the two 220/33kV transformers.

A meshed network of 33kV lines and cables supplies Keith St, and these are approaching their N-1 capacity. From Keith St, two oil-filled 33kV cables supply Main St. These have exceeded their N-1 capacity and recent issues with leaking joints mean these cables are a significant risk in terms of supply security and the environment.

Both Main St and Pascal substations have already exceeded the firm capacity of their transformers. Expansion at these substations is not practical because of space limitations. The security of Pascal is further limited by a section of under-rated cable from the Manawatu River through to the substation.

Options considered are detailed in Appendix 8.

We propose a strategy where in future there will be three highly secure substations serving the CBD, all supplied from Linton GXP. To enable this, two new high capacity 33kV circuits are needed from Linton GXP to the city. A new inner city substation is also required, which we will establish at Ferguson St. Main St substation will be transferred over onto Linton GXP. The under-rated section of 33kV cable into Pascal will also be replaced.

The combination of these investments will resolve all the existing issues, both in terms of security of supply and the environment. Security will be restored to all substations, particularly the three that serve the CBD. Capacity of the new circuits and substations will be optimised to cater for continued growth, balanced by consideration of potential demand side moderations as new technology emerges. The strategy will also defer any major investment at Bunnythorpe GXP.

SANSON-BULLS 33KV	
Estimated cost (concept):	$6.0m
Expected project timing:	2022-2023

Sanson substation is supplied through a single 33kV circuit from Feilding. The 11kV back-feed for Sanson is not adequate to meet the security criteria. The restriction this imposes on planned outages means it has been difficult to maintain the 33kV line, and its condition and performance is a risk.

The Ohakea air base is an important customer supplied from Sanson substation. The base is supplied via a 33kV cable operating at 11kV. The 33kV cable was installed some years ago as part of a plan to eventually link Sanson and Bulls substations at 33kV. In addition to providing the required security of supply to Sanson, this will benefit Bulls security and transfer load off constrained assets at Bunnythorpe GXP and Feilding.

This project covers construction of the remaining 33kV circuits and the substation alterations needed to complete the Sanson-Bulls 33kV link.

The preferred option involves thermally upgrading the Bunnythorpe to Feilding 33kV lines, constructing a new 33/11kV substation at Ohakea, constructing a new 33kV line from Bulls substation to the new Ohakea substation[27] and installing an automatic load transfer facility at Sanson substation.

Further details of the options considered and reasons for adopting this strategy are included in Appendix 8.

11.4.11.5 MINOR GROWTH AND SECURITY PROJECTS

Below are summaries of the minor growth and security projects planned for the Manawatu area.

KAIRANGA TRANSFORMERS	
Estimated cost:	$2.2m
Expected project timing:	2023

The Kairanga substation supplies residential, rural and industrial loads in the southern parts of the Palmerston North area. The substation contains two 15MVA rated transformers. The demand has exceeded the transformer firm capacity. High growth demand is expected on this substation because of residential and agricultural developments.

The proposed solution is to replace the existing transformers with two 24MVA units. This will provide adequate capacity for future demand with appropriate security.

SANSON TRANSFORMERS	
Estimated cost:	$1.9m
Expected project timing:	2023

The Sanson substation supplies Sanson township, Rongotea and Himatangi areas, and the Ohakea air base. The substation contains two 7.5MVA rated transformers.

[27] The section between Ohakea substation and Sanson substation will utilise an existing 33kV underground cable.

The demand has exceeded the firm capacity of the transformers. There is also limited back-feed capability from the 11kV distribution network.

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand with appropriate security.

KELVIN GR TRANSFORMERS	
Estimated cost:	$2.4m
Expected project timing:	2021

The Kelvin Gr substation supplies commercial, industrial and residential loads in Palmerston North and the rural load to the north of Palmerston North city. The substation contains two transformers rated 15MVA. The demand has exceeded the firm capacity of the transformers.

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate capacity for future demand with appropriate security.

FEILDING TRANSFORMERS	
Estimated cost:	$2.6m
Expected project timing:	2021

The Feilding substation supplies the town of Feilding and commercial, industrial, residential and rural loads in the area. The substation contains two transformers nominally rated at 21MVA each. The demand has exceeded the firm capacity of the transformers. Because of limitations in back-feed capability, the security of supply will not be adequate as load grows.

The proposed solution is to replace the existing transformers with two larger units. This plan is likely to be reviewed closer to the expected upgrade date. Our standard large urban transformer capacity is 24MVA, which does not provide much margin for growth over the existing units. However, there may be possibilities to mitigate this by transfer of load or if there is lower growth. If not, we will need to consider alternative strategies, including the possibility of building another zone substation.

11.4.11.6 OTHER DEVELOPMENTS

As noted in the overview section, we have a coordinated programme in place to upgrade small sections of 11kV cable within Palmerston North. This also takes into account renewal needs and substation and feeder back-feed capacities. In some cases, proposed automation of feeder inter-tie switching may warrant feeder upgrades.

Feeder upgrades will be needed in rural areas, both for growth and for ensuring adequate reliability (ie back-feed capability). Most of these involve conductor replacements or voltage regulators. Significant changes in demand, such as for a rapid and concentrated uptake of irrigation, will likely result in a new substation (ie Rongotea project, above).

New urban subdivisions generally require continued investment in upgraded upstream or backbone sections of feeders. There is regular communication with Massey University to ensure appropriate supply and capacity. We are also planning an 11kV link between Turitea substation and the inner CBD substations, although this is subject to physical obstacles such as the river crossing.

The Manawatu area is known for its wind generation. Most of the prime sites appear to have been used and we are not aware of any immediate new developments. The larger scale of wind generation often means these projects connect directly with the grid. Smaller embedded generation is not yet of a nature or scale to have an impact on demand peaks.

We will investigate non-network opportunities, particularly where this might defer major investment (ie cogeneration in central Palmerston North).

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Rongotea Zone Substation	The Rongotea area is experiencing strong growth in irrigation and other rural activities. Supply to the area is required to have higher security level due to supplying industrial loads. The solution is to build a new Rongotea zone substation.
Turitea Area Subtransmission Supply	The substation has shifted N-1 subtransmission switching capability from Bunnythorpe and Linton GXPs. The demand has exceeded the class capacity. There is limited backfeed capability from distribution network. The solution is to install the second subtransmission supply for the substation.
Milson Substation Supply Transformers and Subtransmission Upgrade	The substation contains two transformers and limited 11kV backfeed capability. The demand has exceeded the transformers' capacity. The solution is to replace the existing transformers with two larger units. This will improve the security level at the subs

PROJECT	SOLUTIONS
New Ashhurst Zone Substation	The demand growth is high in areas covered by the Kelvin Grove substation. The risk of exceeding substations N-1 capacity is also high. The solution is to establish a new zone substation, named Ashhurst, to offload the existing Kelvin Grove substation. This will reduce the lengths and demand of the feeders and consequently reduces the risk of feeder outages.

11.4.12 TARARUA

Other than some industrial activity, the Tararua region has low growth and reasonable security because of a subtransmission ring circuit. No major or minor growth and security projects are planned.

11.4.12.1 OVERVIEW

The Tararua area covers the southern part of the Tararua district, which is in the upper Wairarapa region.

The district has rugged terrain, especially towards the remote coastal areas. Subtransmission and distribution lines are generally long and exposed.

The area generally has a dry, warm climate. Strong winds can occur in spring and summer. The winds gather strength as they come down the Tararua Range, and can be very strong especially in the coastal areas.

The area receives heavy rain from the south and east, which can cause flooding.

The Tararua area is connected to the grid at Transpower's Mangamaire GXP. The region uses a 33kV subtransmission voltage.

Mangamaire GXP supplies four zone substations - Mangamutu, Parkville, Alfredton and Pongaroa.

The subtransmission and distribution networks are almost entirely overhead.

Downstream of the zone substations the distribution networks operate at 11kV. These 11kV distribution feeders can be long and sparsely loaded. Locating, isolating and restoring the network after a fault can be challenging and often time-consuming.

11.4.12.2 DEMAND FORECASTS

Demand forecasts for the Tararua zone substations are shown below.

Table 11.24: Tararua zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Alfredton	A2	1.4	0.5	0.5	0.5	0.5
Mangamutu	AAA	12.8	12.8	12.8	12.8	12.9
Parkville	A1	0.0	2.0	2.0	2.0	1.9
Pongaroa	A2	2.9	0.7	0.7	0.7	0.7

The demand at Mangamutu substation incorporates the now confirmed significant increase in capacity for Fonterra Pahiatua. Underlying growth at both Mangamutu and the other substations is much lower and generally not expected to exceed 0.1%.

Other than Mangamutu, the substations service very small loads with quite low criticality in most cases. These loads are unlikely to justify security upgrades, unless a significant change occurs, such as irrigation. Future demand growth in the Tararua Area is expected to be 0.1% per year.

11.4.12.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tararua area are shown below.

Table 11.25: Tararua constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Mangamutu substation	Increased demand at Pahiatua would cause the demand to exceed secure capacity. The existing transformers are scheduled for replacement in 2020.	Note 1
Parkville substation	Single transformer. The 11kV back-feed does not meet security criteria. The transformer is due for renewal.	Note 2
Alfredton substation	Single transformer. The transformer is due for renewal.	Note 3
Pongaroa substation	Single transformer. The 11kV back-feed does not meet security criteria.	Note 3

Notes:

1. Upgrades for the Fonterra plant are accommodated through our customer works programme. Any renewal needs will be optimised at the same time.

2. Two transformers to meet security criteria cannot be economically justified. Transformer capacity will be at the best possible when replaced. Parkville substation enclosure has other operational and physical security issues and we may consider an upgrade to the whole site.

3. Two transformers to meet security criteria cannot be economically justified. Transformer capacity will be at the best possible when replaced. The transformer winding vector group on these units also causes 11kV faults to be seen on the 33kV protection. We will replace all units with standard delta star vector group transformers as soon as possible.

11.4.12.4 GROWTH AND SECURITY PROJECTS

No significant capacity or security upgrades are anticipated, other than to increase the size of the Mangamutu transformers to ensure adequate security, especially for the dairy factory.

The issues affecting the security of supply at other substations are all of low risk. Of more concern is the age and condition of many assets and issues with the substation sites. The protection issues, because of the transformer star-star windings allowing 11kV faults to be seen by 33kV protection, are the biggest concern.

All substations therefore have renewal or performance-driven work scheduled in the next decade. It is proposed to rebuild the Parkville site with appropriate space, physical security and operational flexibility. All transformers will need to be replaced with standard delta-star windings to resolve protection issues.

We will continue to monitor distribution feeder loading and voltages and schedule any upgrades to cater for growth. We will also focus on improving existing reliability, especially through back-feeding, new feeder links and automation.

11.4.13 WAIRARAPA

The Wairarapa region has low growth and adequate security considering the loads. Subtransmission ring circuits supply the major towns of Masterton, Carterton, Greytown, Featherston and Martinborough. No large growth and security projects are planned, but routine expenditure will be needed on distribution circuits.

Minor project spend related to growth and security over the next 10 years is $6.1m.

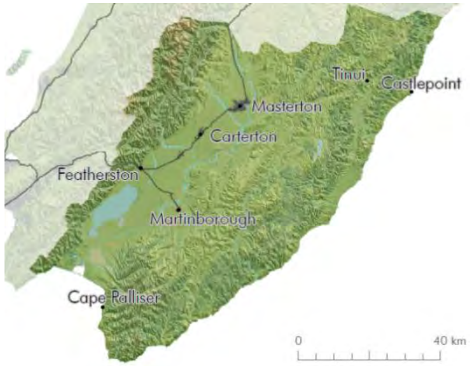
11.4.13.1 OVERVIEW

The Wairarapa area covers the central and southern parts of the Wairarapa district.

Masterton is the major urban centre, with a population of approximately 23,500.

Other significant towns are Greytown, Featherston, Carterton and Martinborough.

The Tararua Range runs along the western boundary of the Wairarapa area.



Adjacent is a low lying area that is generally flat or rolling and in which are located the main urban centres. To the east the terrain is generally hilly through to the coast.

The Wairarapa area has a dry, warm climate. Strong winds off the Tararua Range can occur in spring and summer. Weather can be extreme in the coastal areas. The area also receives heavy rain from the south and east, which can cause flooding.

Forestry, cropping, sheep, beef and dairy farming are the backbone of the economy. The area around Martinborough, in the south, is notable for its vineyards and wine, as are the outskirts of Masterton and Carterton. Deer farming is growing in importance.

Lifestyle sections are also becoming popular in the area, particularly as it is just a commute, albeit long, from Wellington.

Wind generation and irrigation could impact this area significantly, especially in regard to the electricity system.

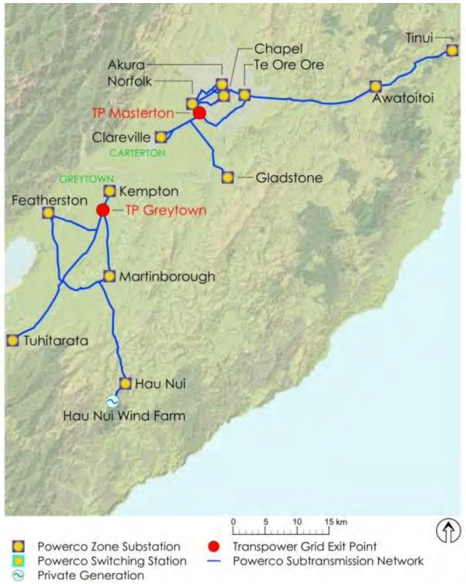
The Wairarapa area is connected to the grid at two Transpower GXPs - Greytown and Masterton. The region uses a 33kV subtransmission voltage.

The Masterton GXP supplies eight zone substations - Norfolk, Akura, Chapel, Te Ore Ore, Awatoitoi, Tinui, Clareville and Gladstone.

The Greytown GXP supplies five zone substations - Kempton, Featherston, Martinborough, Tuhitarata and Hau Nui.

The 33kV network has a meshed or ring architecture in Masterton.

Similarly, a ring connects Martinborough and Featherston with Greytown (Transpower GXP).



Rural substations are generally supplied by single radial lines of quite small capacity. Downstream of the zone substations the distribution networks operate at 11kV.

The subtransmission and distribution networks are almost entirely overhead. Access is reasonable except in the back country and eastern coastal hills.

11.4.13.2 DEMAND FORECASTS

Demand forecasts for the Wairarapa Zone Substations are shown below, with further detail provided in Appendix 7.

Table 11.26: Wairarapa zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2016	2020	2025	2030
Akura	AAA	9.0	13.3	13.5	13.8	14.1
Awatoitoi	A2	3.0	0.7	0.7	0.7	0.7
Chapel	AAA	13.8	15.3	15.6	16.0	16.4
Clareville	AA	10.9	11.5	12.1	12.9	13.7
Featherston	A1	1.5	5.0	5.1	5.3	5.5
Gladstone	A2	1.4	0.9	0.9	0.9	0.9
Hau Nui	A1	0.0	1.0	1.0	1.1	1.1
Kempton	A1	2.1	5.0	5.2	5.5	5.8
Martinborough	A1	1.5	5.0	5.3	5.6	5.9
Norfolk	AA+	7.0	7.1	7.6	8.2	8.8
Te Ore Ore	AA	6.7	7.4	7.5	7.7	7.9
Tinui	A2	1.3	0.5	0.5	0.5	0.5
Tuhitarata	A1	0.2	3.1	3.2	3.3	3.4

Growth in the Wairarapa area is modest. No significant residential demand increases (eg large subdivisions) are anticipated. No new major customers or demand increases from existing commercial, industrial or rural customers are planned. Major wind generation plants have been investigated but are likely to be at a scale where they would connect directly to the grid. The Hau Nui wind farm is considering a small upgrade to its injection capacity.

Irrigation proposals are the most likely to cause significant disruption to our network development plans.

Shaded years indicate that the demand exceeds the capacity we can provide with appropriate security. Of note is that several of the Wairarapa substations already exceed security criteria. Therefore, development plans are focused on improving security and reliability for the existing load base, rather than catering for future new load.

11.4.13.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Wairarapa area are shown below.

Table 11.27: Wairarapa constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Akura, Chapel, Norfolk substations	Masterton GXP-Akura-Chapel-Norfolk 33kV ring. Demand on the ring exceeds N-1 capacity.	Note 1
Akura, Te Ore Ore, Awatoitoi and Tinui substations	Outage on Masterton GXP to Te Ore Ore 33kV circuit can overload alternative circuits.	Note 2
Akura substation	Demand exceeds firm capacity of the two transformers.	Note 2
Clareville substation	Demand exceeds secure capacity of the two transformers.	Note 2
Featherston substation	Single transformer. The 11kV back-feed is insufficient to fully meet security criteria.	Featherston Substation Second Transformer
Martinborough substation	Single transformer. The 11kV back-feed is insufficient to fully meet security criteria.	Martinborough Substation Second Transformer
Te Ore Ore substation	Single transformer. The 11kV back-feed is insufficient to fully meet security criteria.	Note 3
Kempton substation	Single transformer. The 11kV back-feed is insufficient to fully meet security criteria.	Kempton Substation Second Transformer and Subtransmission Supply
Hau Nui substation	Single transformer and single 33kV circuit. The 11kV back-feed is insufficient to meet security criteria.	Note 3
Tuhitarata substation	Single transformer and single 33kV circuit. The 11kV back-feed is insufficient to fully meet security criteria.	Tuhitarata Substation Security Upgrade

Notes:

1. The risk is low and demand only exceeds capacity under peak loading and for rare fault conditions. Alternative supply options and back-feed capability mitigate the risk.

2. Expenditure for this work is allowed for in the renewal forecasts, and capacity will be considered so as to economically provide for expected long-term load growth.

3. N-1 for 33kV circuits or zone transformers for these substations are not economic. Options to improve 11kV back-feed will be considered during routine planning.

11.4.13.4 GROWTH AND SECURITY PROJECTS

No large capacity or security upgrades are planned in the Wairarapa area. While there are several zone substations and subtransmission circuits that do not fully meet the security standards, the risk is relatively low in all cases. This is especially the case for remote rural substations, where the distance rather than capacity was often the main reason for establishing a zone substation. The small loads do not justify the cost of alternative circuits or transformers.

Appropriate capacity upgrades at zone substations will be done during any renewal work.

Where 11kV distribution feeders are being rebuilt, consideration will also be given to potential upgrades to provide more back-feed and substation inter-tie capacity.

We will continue to monitor distribution feeder loading and voltages and schedule any upgrades required by demand growth. We will also focus on improving existing reliability, especially through back-feeding and automation.

As noted before, potential irrigation projects could significantly alter network development plans, but until proposals are certain this is something we can only monitor through communication with our customers.

The Hau Nui wind farm is investigating a re-powering of some of its turbines, which will increase its injection capacity. No network capacity upgrades are planned as they intend to operationally manage any injection limits.

The following projects have been identified as being likely to occur in the later part of the planning period. The following descriptions represent the most probable solutions but the final solution and optimal timing is subject to further analysis and would be confirmed closer to time.

PROJECT	SOLUTIONS
Featherston Substation Second Transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.
Kempton Substation Second Transformer and Subtransmission Supply	The substation is supplied by one single 33kV circuit from Greytown and has limited backfeed capability. As the demand increases, the class capacity is exceeded. The solution is to install a second subtransmission supply and transformer for the substation.
Tuhitarata Substation Security Upgrade	The substation is supplied by one single 33kV circuit from Greytown and has limited backfeed capability. As the demand increases, the class capacity is exceeded. The solution is to increase backfeed through the distribution network. Due to the long lengths and high impedance of the conductors, upgrading to 22kV could be cost effective.
Martinborough Substation Second Transformer	The substation contains a single supply transformer with limited backfeed capability. As the demand increases, the class capacity is exceeded. A second transformer is proposed to improve the security level at the substation.

11.5 GRID EXIT POINTS (GXPS) AND EMBEDDED GENERATORS

11.5.1 GXPS

Our network connects to the transmission grid mainly at 33kV, but also at 110kV, 66kV and 11kV. We have 30 points of supply or grid exit points (GXPs). Most assets at GXPs are owned by Transpower, although we do own some transformers, circuit breakers, protection and control equipment. The GXPs supplying our electricity network are detailed in **Table 11.28**, along with their respective peak load, capacity and security characteristics.

Table 11.28: Grid exit point summary statistics for financial year 2015

GXP NAME	TRANSFORMER (MVA)	N-1 CAP (MVA)	2015 MD (MVA)	N-1 SECURE	2015 MAX EXPORT (MW)
Brunswick (BRK)	50	-	40	No	-
Bunnythorpe (BPE)	83, 83	100	101	No	25
Carrington St (CST)	75, 75	64	60	Yes	-
Greytown (GYT)	20, 20	20	13	Yes	2
Hawera (HWA)	30, 30	35	29	Yes	19
Hinuera (HIN)	30, 50	-	47	No	-
Huirangi (HUI)	60, 60	74	34	Yes	-
Kaitemako (KMO)	75	-	22	No	-
Kinleith 11kV Mill	30, 30, 30	60	77	No	-
Kinleith 11kV Cogen (KIN Gen)	50	-	18	No	31
Kinleith 33kV (KIN33)	20, 30	25	19	Yes	-
Kopu (KPU)	60, 60	59	43	Yes	-
Linton (LTN)	100, 60	100	53	Yes	15
Mangamaire (MGM)	30, 30	30	14	Yes	-
Marton (MTN)	20, 30	20	17	Yes	-
Masterton (MST)	60, 60	60	43	Yes	-
Mataroa (MTR)	30	-	7	No	-
Mt Maunganui (MTM)	75, 75	87	63	Yes	-
New Plymouth (NPL)	30, 30	30	20	Yes	-
Ohakune (OKN)	20	-	2	No	-
Opunake (OPK)	30, 30	30	12	Yes	-
Piako (PAO)	60, 40	40	33	Yes	-
Stratford (SFD)	40, 40	27	35	No	-
Tauranga 11kV (TGA11)	30, 30	30	27	Yes	-
Tauranga 33kV (TGA33)	90, 120	90	77	Yes	9
Te Matai (TMI)	30, 40	39	31	Yes	-
Waihou (WHU)	20, 20, 20	48	43	Yes	-
Waikino (WKO)	30, 30	37	35	Yes	-
Whanganui (WGN)	30, 20	24	43	No	-
Waverley (WVY)	10	-	5	No	-

Three of our smaller GXPs (Mataroa, Ohakune and Waverley) have only a single transformer. N-1 security cannot necessarily be justified for these but contingency plans and spares are coordinated to minimise the impact should the single transformer fail.

Brunswick and Kaitemako are larger GXPs but also have just one transformer and therefore only N security. Brunswick has partial backup from Whanganui GXP, the capacity of which is a focus of our future development plans. Kaitemako is a new GXP and will be equipped with a second transformer when load exceeds the 33kV back-feed capability from Tauranga.

Hinuera is a single circuit GXP. Improving the security has been a significant focus of our growth and security plans for the past decade and is the main driver behind our proposed new GXP at Putaruru.

Bunnythorpe GXP is just in breach of the N-1 transformer capacity. Our major Palmerston North growth and security project will transfer some load on to the Linton GXP and reduce the loading on the Bunnythorpe GXP (within N-1 capacity).

Security at Kinleith GXP is a function of the customer's specific needs. Transpower is planning major replacement work at Kinleith soon, and designs are being considered to improve security to parts of the load and the Cogen plant.

Tauranga 11kV and Waihou are both on the limit of firm capacity also. Pyes Pa will effectively transfer load off Tauranga onto Kaitimako, while Waikino load is managed operationally until transformer replacement is scheduled.

Beyond the GXPs certain localised grid constraints are of significance to our planning:

- Valley Spur 110kV dual circuit spur line, which supplies our Piako, Waihou, Waikino and Kopu GXPs, is approaching its N-1 capacity.
- 110kV circuits between Tarukenga, Lichfield, Kinleith, Putaruru, and Arapuni are a known grid constraint under certain circumstances and impact the security and capacity available at our GXPs.
- Transpower's proposals for the New Plymouth GXP and North Taranaki transmission may require an alternative grid connection for our Moturoa substation.
- The 110kV circuits to Tauranga are already reaching N-1 capacity and rely on Kaimai generation at peak loads.
- Constraints are expected in the next decade on the 110kV circuits to Mt Maunganui. The Papamoa project will offload these circuits but a constraint on the 110kV to Te Matai will then emerge. Te Matai transformers will also need upgrading to maintain firm capacity. Longer term, constraints may reoccur at Mount Maunganui also.

Spur acquisitions

Transpower has a programme to divest spur assets to distributors when these assets could be more economically owned and operated by the distributor.

There are several possible divestments within our network footprint, and the following were being actively considered until recently:

- Hinuera GXP: a single radial 110kV circuit and GXP.
- Valley Spur: a dual circuit 110kV radial line serving 4 GXPs.

Other divestments that were being considered in the longer term:

- Tauranga: 110kV ring serving Mt Maunganui and Tauranga GXPs (subject to the status of the circuits).
- Various 33kV switchboards and 110/33kV transformers.

The Hinuera divestment has been deferred until the Putaruru GXP can be commissioned. The Valley Spur is also being reconsidered in terms of its strategic significance, especially for potential generation connection to the grid. As such, we have no confirmed agreements for any acquisitions in the near future, but both parties remain committed to investigating transfers in the future should these prove efficient for our customers.

11.5.2 EMBEDDED (DISTRIBUTED) GENERATORS

Table 11.29 lists the generators greater than 1MW in size that are connected into the Powerco Networks.

Table 11.29: Distributed Generation greater than 1MW by GXP

GXP	CAPACITY [KW]	VOLTAGE	GENERATION NAME	MOTIVE POWER
Tauranga 33	40,000	33kV	Kaimai Hydro Scheme	Hydro
Kinleith	35,000	11kV	Kinleith Cogen	Cogen
Bunnythorpe	34,000	33kV	Tararua Wind - North	Wind
Linton	34,000	33kV	Tararua Wind - South	Wind
Hawera	30,000	110kV	Patea Hydro	Hydro
Hawera	2,500	11kV	Ballance Kapuni	Cogen
Hawera	1,200	11kV	Origin Hawera	Gas
Huirangi	9,000	33kV	McKee (Mangahewa)	Gas
Huirangi	2,000	11kV	McKee (Mangahewa)	Gas
Huirangi	4,800	33kV	Motukawa Hydro	Hydro
Greytown	5,000	33kV	Hau Nui Wind Farm (33kV)	Wind
Greytown	3,850	11kV	Hau Nui Wind Farm (11kV)	Wind
Carrington St	4,500	11kV	Mangorei Hydro	Hydro
Mt Maunganui	4,000	11kV	Ballance Tauranga	Cogen
New Plymouth	1,875	11kV	Taranaki Base Hospital	Diesel backup
Stratford	2,000	11kV	Cheal - 2 x 1MW units - Stratford injection	Gas
Stratford	1,063	11kV	Cheal - 1 x 1MW - Eltham injection	Gas
Waihou	4,200	11kV	Waitoa Dairy Factory Cogeneration	Cogen

11.6 COMMUNICATIONS INFRASTRUCTURE

11.6.1 OVERVIEW

We currently have two separate communications systems – a distributed Internet Protocol (IP) layer 3 communications system in our Western Region and a time division multiplexed network in our Eastern Region. The two are linked by public networks.

Our Network Insight trials (discussed in Chapter 13) and other new technologies have used public communication infrastructure. This is acceptable for conveying data that is not immediately needed (eg historical information or information required for long-term planning). Lower latency or more secure private communications systems are needed for real time control and fault response.

The current approach has a number of drawbacks that will limit our ability to employ new technologies and use improved data. These include:

- Different base protocols in the Eastern and Western Regions
- A reliance on manual configuration, not centrally managed
- Neither network is easily scalable, nor do they provide the capability or capacity needed by future technologies
- The eastern network cannot accommodate IP devices in zone substations (e.g. remote access security or video)
- Difficulty interacting with third party systems

This will be addressed by developing a multi-protocol layered system throughout both regions.

11.6.2 DRIVERS FOR DEVELOPING OUR COMMUNICATIONS SYSTEMS

The drivers to augment our communications infrastructure relate to our core asset management objectives. This recognises the importance of communication systems in facilitating and supporting the way our network is expected to function. Aspects of asset management supported by our communications infrastructure include:

- **Safety and environment** – the need for reliable, real time communications with field crews and the need for good visibility of network state under fault conditions
- **Future technologies** – supporting expansion of remote control (automation), monitoring and the SCADA system. Appropriate communications infrastructure is a key facilitator of our future network strategies (see Chapter 13)
- **Protection and monitoring** – improvements require expanded data handling capabilities and bandwidth
- **Operational data** – the collation and timely availability via mobile information systems will help improve fault response, vegetation management, field inspections, and condition monitoring

Electricity networks will increasingly require complex multi-layered systems and architectures to support functionalities such as:

- Increasing SCADA coverage of devices
- Implementation of new technologies
- Improved management of assets
- Integration with metering
- Workforce and dispatch management
- Inspection data mobility
- Transactional grids
- Supporting future technologies

We expect that network devices with SCADA capability will become more prevalent as our automation strategy is implemented. Over the medium-term up to 30,000 remote network devices will need detailed monitoring. The number of devices will exceed the capacity of our existing communications system.

Communications reliability will be provided through diverse communications paths. The augmented system will be easily expandable and simpler to deploy. It will be compatible with other communication mediums such as fibre or radio frequency technologies and will therefore be more future proofed.

Cyber security is an important focus of our Operational Excellence objective. Communications supporting asset management functions are inherently exposed to risk through communication nodes and channels that are physically unprotected in the public domain.

The key requirements of the communication systems are to enable our asset management objectives. Existing strategies to achieve this are set out in the table below.

Table 11.30: Asset management requirements and communications capability

ASSET MANAGEMENT REQUIREMENTS	POTENTIAL SOLUTIONS
Trunk, high capacity backbone with full redundancy	Fibre or high capacity microwave
Mobile ICT platform to support maintenance activities	Mix of cellular and WI-FI hotspots
Voice mobile – field crews	VHF DMR Tier 3 radio system

ASSET MANAGEMENT REQUIREMENTS	POTENTIAL SOLUTIONS
Engineering access/ event downloads	Mix of cellular and remote radio connectivity
Zone substation functionality (video, access security, remote engineering management)	Fibre and high capacity point-to-multipoint radio
SCADA – future development	Point to multipoint radio systems, or mesh radio systems
Protection – unit	Point-to-point dedicated microwave, pilot or fibre systems
Distribution remote control and monitoring (automation) - urban	Mesh radio systems
Distribution remote control and monitoring (automation) - rural	Point-to-multipoint radio systems, or mesh radio systems
RAPS	Public cellular or internal network
GXP and other check metering	Fibre or public cellular
Network Insight	Public cellular; mesh radio systems, point-to-multipoint
Distributed generation	Ripple system or future third party or internet
Customer metering or demand functions	Ripple system or future third party or internet

As we discuss in Chapter 13, we see a future where we will need increased visibility and a degree of real time control of a large number of disparate devices This would need a reliable, secure, low latency, moderate bandwidth, high density communications network.

11.6.3 FUTURE ROLLOUT

Our principal development programmes on the communications network are as follows:

- Extend and upgrade core transport system across our Eastern and Western Regions
- Implement field staff voice radio system
- Implement mobile platforms
- Deploy substation video and security
- Provide remote engineering access

Our schedule for delivery of these programmes is spread over the planning period, with priority for core network, voice mobile and data mobility platforms. With the pace of change in network and customer technologies, we recognise our communication solutions need to be future proofed. The timing and scale of investment may need to be reassessed periodically.

Of particular interest are the numerous new network and customer side technologies that may require changed approaches to network management and operation. These include widespread distributed generation, particularly small scale PV, batteries or other energy storage, islanded micro-grids and home energy management systems.

11.7 ROUTINE PROJECTS

11.7.1 OVERVIEW OF ROUTINE CAPEX

Routine Capex incorporates the lower cost, usually repetitive projects that address capacity and security. These mostly occur at the distribution level.

Routine Capex projects have shorter lead times and are often more sensitive to changing growth rates and customer or network activity therefore they are more likely to change in scope at short notice. It is impractical to try to identify individual projects less than one to two years before implementation.

As such, to understand our longer term investment requirements, we need to consider the type of work, the reasons why it needs to be done, and the generic trends in these activities.

Types of projects include those that come from distribution planning analysis (refer to Chapter 7). These projects typically add capacity to existing parts of the feeder network or create additional feeders or back-feed ties. There are also some distribution transformer and LV projects.

Some lower cost zone substation growth and security projects also fall into the routine projects category. These include smaller power transformer upgrades, especially at single transformer substations.

While it is not practical to identify specific projects in the routine class, there are trends and patterns that dominate each planning area. Commentary on these is provided near the end of each area section.

11.7.2 ROUTINE PROJECTS FORECAST CAPEX

Historical expenditure trends on routine growth and security projects have been used to inform appropriate expenditure levels. Traditionally such expenditure was strongly linked to underlying growth. This is still true for some project types, such as capacity upgrades, voltage regulators and new feeders. However, in areas of less growth, upgrades to distribution feeder links are often focused on providing additional back-feed capability. This includes new feeder interconnections (or ties) and larger conductors or cables to allow better voltage or thermal capability under back-feed conditions.

Our automation plan (refer Chapter 12) has required a rise in development investment so that the automated or remote controlled switching schemes do not overload existing circuits or result in unacceptable voltages. This has brought forward a number of feeder tie and back-feed upgrades.

Some emerging technology (discussed further in Chapter 13), especially concentrated PV, have the potential to require voltage support to the network. As part of our future network strategies we are developing tactics to address this. In an extreme scenario it could require a significant increase in distribution transformer replacements or LV circuit upgrades. However, the level of impact will be determined by PV uptake rates.

Other drivers for routine project growth and security expenditure include:

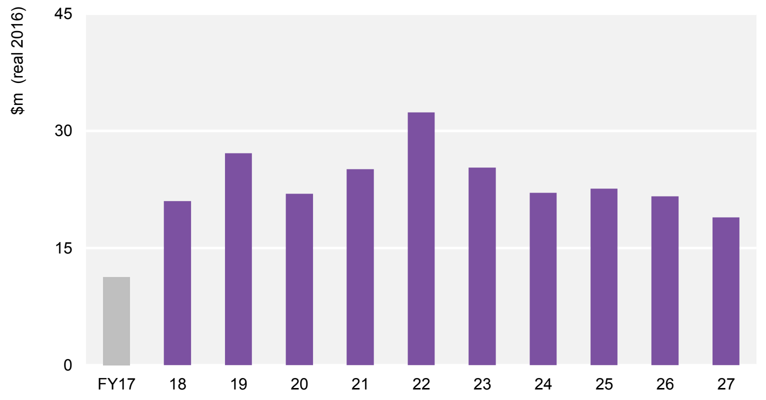
- Areas of intensive irrigation.
- Intensive dairy conversion, or existing dairy areas needing to upgrade plant.

Local reticulation for new subdivisions is mostly funded through customer contributions and our customer connections expenditure. However some upstream feeder development can also be required but cannot be attributed to any specific customer or subdivision. In this case expenditure falls into the routine development category. This type of project mainly occurs in high urban growth areas, such as Tauranga and Mt Maunganui.

11.8 FORECAST GROWTH AND SECURITY CAPEX

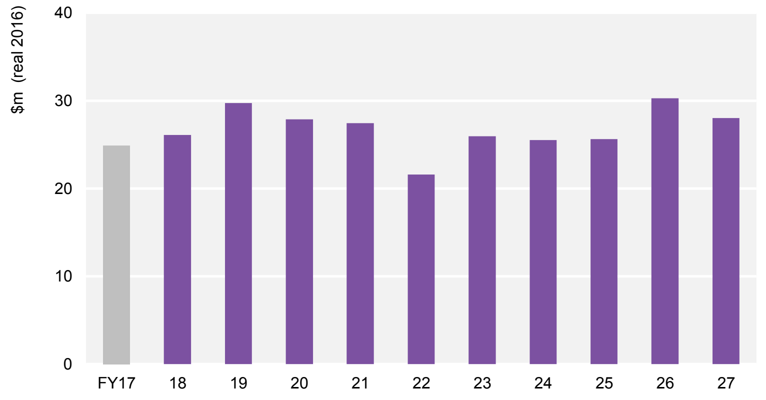
The figure below shows forecast Capex on major projects over the planning period. The small number of relatively large projects creates a somewhat ‘lumpy’ expenditure profile.

Figure 11.4: Forecast Capex on major projects



The figure below shows forecast expenditure for minor growth and security works.

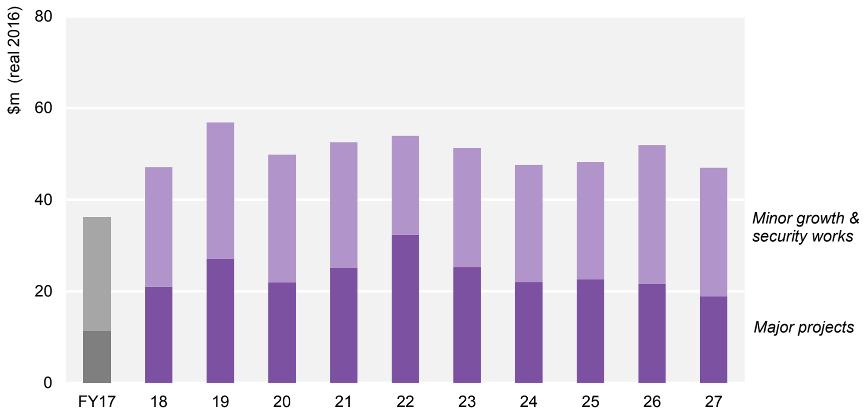
Figure 11.5: Forecast Capex on minor growth and security works



Expenditure on minor growth and security remains reasonably constant over the planning period. Minor projects have some timing flexibility. This allows us to balance the variable spend on major projects per year to maintain a steady, deliverable workload.

The figure below shows forecast Capex on both major projects and minor growth and security works over the planning period.

Figure 11.6: Forecast Capex on major projects and minor growth and security works



With both portfolio forecasts added together, expenditure is expected to somewhat increase over the planning period. As discussed earlier, variability in major projects is balanced by activity in the minor works portfolio to ensure that a deliverable workload is maintained.

12.1 OVERVIEW

Many projects contribute to the long term reliability of our networks. Renewal projects address areas of reliability concern for older assets, while network development projects help enhance reliability for our customers by providing alternative options for supply.

For the purpose of this chapter we consider only those expenditures not covered in other sections, ie expenditures not specifically covered in our network development plans, fleet management plans, or operational and maintenance plans. Currently the only expenditure that falls into this category is on network automation projects.

We use network automation to help manage the reliability performance of our network. In this context 'network automation' refers to the systems and devices that are used to undertake remote switching and reconfiguration of our networks.

Judicious automation of distribution switchgear allows us to:

- Remotely isolate and reconfigure networks
- Automate fault response actions
- Gain better visibility of network operating conditions
- More easily pinpoint fault locations
- Gain SAIDI reductions to allow deferral of renewal expenditure

Automation is an important investment area within our plans as it provides reliability improvements to be achieved reasonably quickly. This helps us stabilise reliability outcomes on our networks while we work to address and stabilise emerging asset health and network security issues.

12.2 AUTOMATION PLAN

The automation plan involves deploying new remote controlled or automated distribution switchgear, protection and monitoring devices, along with the required extensions to our communications network.

We have also developed strategies to lift the overall density of reclosers, sectionalisers and Distribution Automated Switches (DAS) which will impact later in the planning period.

Our rollout plan includes the following device types:

- Three-phase main line reclosers, sectionalisers or DAS, with SCADA control and visibility
- Line Fault Indicators (LFIs) to pinpoint fault locations
- Fuse-savers (on SCADA capable 1ph spur line reclosers)
- Single phase sectionalisers or reclosers, protecting spur lines, with visibility via SCADA where available
- Ground fault neutralisers

Table 12.1 shows the approximate number of automation devices we plan to install over the planning period.

Table 12.1: Number and type of planned new automation devices

DEVICE TYPE	DEVICES
SCADA controlled reclosers and DAS sectionalisers	400
LFI on non-SCADA monitored lines	1,000
Fuse-savers (on SCADA capable 1ph spur line reclosers)	300
Single phase sectionalisers for Spur Lines	350
Ground fault neutralisers	2

We have developed our automation device rollout works plan using a lifecycle costing approach. This approach identifies the benefits associated with additional switching devices, enabling us to set an appropriate density of switching devices of each type.

12.3 ALIGNMENT WITH ASSET MANAGEMENT OBJECTIVES

12.3.1 SAFETY AND ENVIRONMENT

Use of automation must be balanced against safety which is our most important asset management objective. Automation brings substantial benefits in improved reliability but automatic reclosing of circuits that have been subject to a fault can present risks for the public and workers.

Our approach to automation uses a risk-based assessment process to understand and manage the safety implications of automated reclosing schemes, either loop or radial. We must avoid automatically reclosing circuits when there is a possibility of danger to workers or the public.

To address this we have, for the moment, adopted a strategy of centralised operator control (ie remote control), in conjunction with improved fault and network state visibility. Specifically:

- Maintaining control room oversight of automated switching for complex situation which may introduce a risk to the public.
- Prioritising sectionalisation and isolation capability over fully automated loop automation schemes
- Ensuring protection systems remain robust by limiting the number of reclosers on circuits

12.3.2 NETWORKS FOR TODAY AND TOMORROW

Our focus on networks fit for today and tomorrow helps us ensure our assets provide the services our customers require and adequately take into account the benefits that technology can provide.

Network automation provides a number of benefits that strongly complement our goals and objectives to shape our networks for the benefits of customers over time. Specifically:

- Automation helps us manage reliability on heavily loaded or older circuits where the impact on customers may otherwise be unacceptable.
- Automation lifts the level of central oversight and control we have on our network, giving us operational flexibility and real time control.
- Automated switches provide a range of real time measurements which are complimentary and can be used for advanced asset management.

Overall, new switching and control capabilities, especially when combined with communications, data gathering and data processing technologies, greatly improve the ability of utilities to adapt to the technological, consumer-driven change being experienced across the world.

12.3.3 ASSET STEWARDSHIP

This objective requires we manage our large number of diverse assets efficiently, keeping them in good health.

Network automation systems enable us to remotely reconfigure networks without the need for ground crews. This provides faster restoration times, thereby helping us manage SAIDI. They also enable us to pinpoint fault causes and locations accurately, reducing fault crew effort.

All of this reduces costs, improves efficiency and contributes to ensuring we manage our assets in an effective way.

12.3.4 OPERATIONAL EXCELLENCE

Automation provides us with a range of important short term benefits which are of particular value while we move to address emerging issues associated with aging assets and security related exposure. In particular:

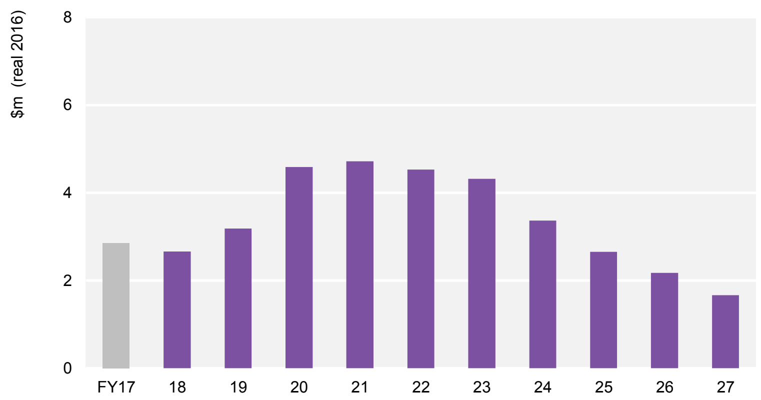
- Shorter outages through faster fault location and reduced time to reconfigure the network
- Reduced number of customers affected by faults
- Reduced costs relating to line patrols, manual switching and manual fault location
- Reduced likelihood of equipment damage due to overloading, under-voltage or slow protection settings

Overall, automation is an important investment area to enable us to manage our networks effectively, in real time.

12.4 EXPENDITURE FORECASTS

Our forecast expenditure is shown in **Figure 12.1**. The cost estimates are based on historical unit rates including costs related to extending the communications network from our backbone network to each remote device.

Figure 12.1: Forecast Capex – Reliability



The expenditure level reflects the automation density in our rollout works plan. During the planning period we will regularly assess the performance benefits of our automation strategies. We may also have to revise the forecast later in the planning period in light of changes to the technological landscape.

13.1 CHAPTER OVERVIEW

This chapter sets out our plans to develop our network in a way that will enable our customers to access new energy options as energy markets evolve and mature. We believe that our network will become an essential platform, linking customers and communities to a range of energy alternatives.

Nevertheless we believe that customers will need to continue to access electricity as they do today. We are therefore committed to ensuring our network is developed so that these services continue to be supported and that we are able to do this in a safe, reliable and cost-effective way.

The chapter includes an overview of the expected changes that will affect our network as the energy environment evolves. It highlights the progress we've made on innovative solutions that support our future network strategy. We then explain how we plan to evolve our network and service offerings over the next 10 to 20 years. Finally, the chapter describes our focus areas for the next five years, including our medium-term initiatives and associated expenditure during the planning period.

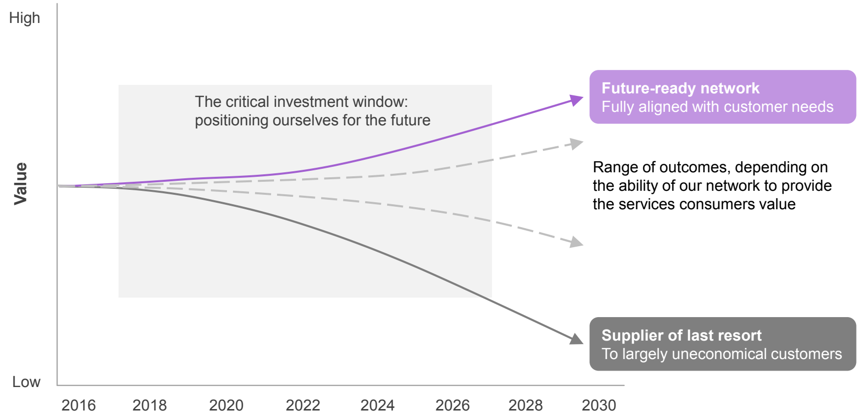
13.2 INTRODUCTION

It is widely recognised that the energy supply environment is undergoing a substantial transformation. The pace of this transformation varies greatly in different parts of the world and for different types of network. There are many different opinions of what the eventual outcomes will be, and how this will influence the shape of the future electricity distribution network. However, there is broad consensus that we are facing fundamental change and that distribution network operators need to respond to this to ensure they can provide the services that customers will require in the future while remaining relevant in the longer term.

We are fully cognisant of the emerging changes in the energy environment and the material impact these could have on our business in the future. More than at any time in recent memory, decisions we make today will have repercussions on the shape and viability of our business in the longer term. We strongly believe distribution networks should continue to be valuable to our customers and our society in the future, but accept that to realise and grow this value will require us to evolve, innovate and above all, respond effectively to our customers' needs.

The figure below illustrates stylistically how our investment and operational decisions of the next few years could influence the value of our business, to our customers and shareholders alike, in the longer term.

Figure 13.1: Investing for the future – a range of possible outcomes



A key driver for the future evolution of our network is the need to enhance the value it offers to our customers and through this to the wider New Zealand society and economy. Most energy commentators agree that energy consumption patterns will change materially as a result of increased uptake of distribution edge technologies, such as various forms of distributed generation, EVs, and energy storage. This will require us to carefully plan how to best accommodate the changing requirements and integrate new technology into our network.

We do not subscribe to the view that suggests distribution assets will become surplus to requirements – instead we see distribution networks providing a vital platform to support flexibility and innovation in our customers' future energy use.

In focusing on the electricity network of the future, it is important not to lose sight of the fact that it will rely on the continued efficient operation of our existing assets. The proposed future applications discussed below will expand our suite of available investment solutions and enhance our customer offerings. They will also offer opportunities for improving efficiency and reliability. However, they will not remove the need for ongoing investment in traditional network maintenance, renewal and growth.

We have been adopting new and innovative solutions into our networks for some time, where these were demonstrated to be cost effective and adding value to our customers. Our future network strategy is a continuation of that successful approach.

13.3 THE CHANGING ENERGY ENVIRONMENT

13.3.1 OVERVIEW

The fundamental way electricity is delivered to consumers has remained largely unchanged for almost a century. While technology has evolved, and with it the reliability and capacity of supply, the flow of electricity is almost exclusively from large generators, through transmission and distribution networks, to end consumers. The large majority of smaller consumers are essentially quality takers – the service they received is determined by their position on a network, with only limited ability to influence this.

This situation is now changing, which is the basis for the major transformation of the energy supply industry. We see this coming about as three major trends converge.

- Customers are increasingly expecting more flexibility and choice in the services they procure. This applies to electricity, along with an expectation of improving supply reliability and resilience. Emerging energy technologies and service offerings are putting this within realistic reach.
- Technology is rapidly evolving on both the customer and network side of the supply network. This allows ever increasing opportunities for rolling out 'intelligent' devices on the network and at customers' premises which in turn support increased measurement, remote communication, computing and control. A better understanding is gained of the real time performance of the network, increasing ability to take effective action based on data available. Ultimately this allows networks to be 'run harder', and for electricity demand to be spread more evenly over the day, without compromising reliability. This will increase utilisation levels and reduce investment needs compared with that of traditional networks.
- Significant improvements in efficiency, along with major reductions in cost, are making it economically and technically viable to bring electricity generation closer to the source of consumption. This includes the ability of consumers to generate their own electricity, in part or fully – which is largely done through renewable generation sources, especially solar PV. Over time, this viability will increase as cost-effective means of energy storage become available, which will help to overcome the inherent variability of renewable generation. These developments will change the manner in which electricity is conveyed across networks, potentially reducing overall demand.
- The trend of cost reduction is also impacting the development of EV fleets, which will almost certainly result in greater electrification of New Zealand's transport fleet and a net increase in electricity loads. This will lead to a net increase in electricity required, which may have to be carefully managed to avoid increased peak demand[28].

[28] Conversely, there is potential for exporting excess energy stored in EVs back into the electricity network or to consume locally. This would be especially valuable during peak demand periods

Our understanding of the future impact of these trends on our network and how we intend to respond is set out in the section below.

13.3.2 CHANGING CUSTOMER TRENDS

Material changes in consumer energy use are emerging overseas with many jurisdictions reporting a material decline in average electricity taken from the grid. Importantly however, this decline in consumption is not necessarily proportionally reflected in peak electricity demand. As electricity networks are generally designed to meet peak demand, while cost-recovery tends to be based on energy volumes used, this trend is causing major concern. The issue is far from settled and internationally debates are raging about aspects such as net-metering, the value of solar PV or energy storage, the introduction of demand, service-based, or time-of-use tariffs. The debate also extends to the manner in which distribution utilities which, as natural monopolies, have traditionally been regulated on price and quality within narrow well-defined boundaries, should in future be regulated and recover their costs.

While these trends are still less pronounced in New Zealand, anecdotally there has been a flattening of average electricity consumption per ICP in recent years (although this has not been as evident on our network). Similar to the overseas experience, the impact on peak demand appears to be less than on average consumption.

Internationally, changing energy consumption is the result of a number of factors. Some of these are contributing to reduced consumption, while others lead to increased use.

Factors leading to decreasing average electricity consumption include:

- **Local generation:** The biggest impact on customer energy use patterns arises from the increasing use of local generation, mainly solar photovoltaic units. This is discussed in more detail in the next section.
- **Energy efficiency:** Modern household appliances, including lighting, are becoming more energy efficient. A consumer with these devices can enjoy the same (or improved) functionality as in the past, while consuming less energy.
- **Energy awareness:** Consumers are increasingly aware of their energy consumption and many are taking active steps to reduce it.
- **Increased use of smart devices:** Electricity can be consumed more efficiently through the judicious use of appliances. This is becoming increasingly feasible using smart devices that control the use of appliances, such as lighting, water or space heaters to best match residential patterns.

Factors leading to increasing average electricity consumption include:

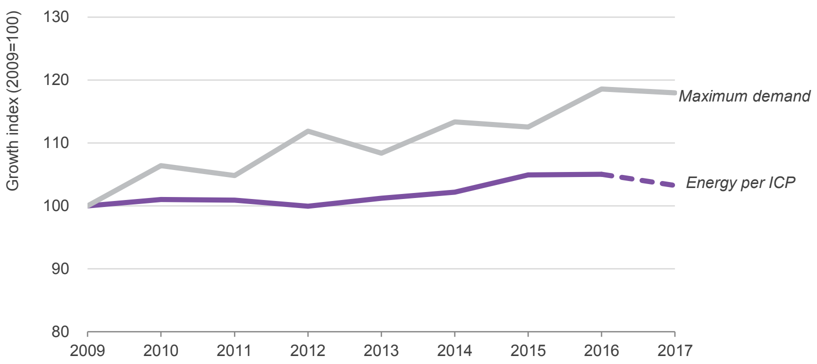
- **Electric vehicles:** As EVs become mainstream, more electricity will be used.

- **Household energy substitution:** In some jurisdictions there are programmes to substitute electricity for other forms of heating.[29]

In New Zealand, and in particular on our network, the impact on electricity consumption from most of the trends described above is still minimal. Some distributors report a flattening of demand, driven by lower individual household demand. However, we continue to see growth, largely driven by new housing developments and localised industrial growth.

Our average energy consumption and demand trends in recent years are indicated in **Figure 13.2**. While showing year-on-year growth in both aspects, it does suggest that demand growth is outstripping consumption growth[30].

Figure 13.2: Average electricity consumption and demand on our network



Note: The figures are based on electricity drawn from GXPs and do not include the impact of distributed generation. 2017 consumption is a projection of expected consumption.

In the absence of strong drivers for change, such as government-mandated carbon emission targets with associated subsidies or feed-in tariffs for local generation, we do not foresee material changes in electricity consumption on our network in the near future. Our own analysis suggests flat demand per household, localised increases in demand where there is housing and industrial growth, and modest uptake of 'edge technologies' over the next five years. This is reflected in our planning assumptions.

Importantly however, we believe it is likely that in the medium to longer term, changing customer preferences, the increased availability of new technology, reduced costs and improving efficiency of renewable generation and energy storage will have a material impact on local electricity consumption and consumption patterns. In the life cycle of an electricity network, that change is very near and it is essential we prepare for this eventuality to ensure our networks can accommodate related changes.

We will therefore continue to monitor emerging international and local trends, to ensure that we remain abreast of these and the potential implications for our network. It will also allow us to adopt promising technologies or solutions that could improve our network efficiency and reliability, or reduce costs. Above all, this will help ensure that we remain in touch with our customers and deliver the flexibility and services that they value.

13.3.3 DISTRIBUTION EDGE TECHNOLOGIES AND TRENDS

The term 'distribution edge technologies' is used as most of the changes emerging in electricity use are at the point where consumers connect to the electricity grid – at the edge of the distribution network. The dominant edge technologies and their presence on our network are discussed in this section.

13.3.3.1 SOLAR PHOTOVOLTAIC GENERATION

The uptake of residential solar photovoltaic (PV) generation is growing rapidly across the world. However, the uptake rates vary greatly between countries and have been particularly pronounced in Germany, parts of Australia, the UK, Denmark and some US states (such as California). This has broadly been in direct response to government mandates to achieve low carbon emission targets, encouraged by way of subsidies, tax incentives or feed-in tariffs (buy-back of excess power generated) to consumers. Regardless of the initial driver, the scale of uptake has supported large-scale manufacture and resulted in reduced costs. We are currently seeing rooftop solar becoming available at prices which can be economic without subsidy, and the industry is now generally regarded as 'self-supporting'.

In parallel with small scale (mainly residential) PV generation, there is significant annual growth in industrial or utility scale PV installations. While much of this is also the result of government mandated targets or incentive schemes, in many instances the cost of generating electricity from large scale PV installations is at parity (or sometimes less) than that of conventionally produced electricity.

Internationally, it is reported that 1.6% of electricity consumed in the OECD in 2015 was produced by PV installations[31] This represents an 18.9% increase from the previous year.

By contrast, the uptake of PV in New Zealand, while growing substantially on an annual basis, is still at a much lower level. In 2016, it was reported that 0.6% of

[29] An example is the UK, where over the last number of years, there has been a significant increase in the use of electric heat pumps for central heating, at the expense of gas-fired heating.

[30] Annual compound growth in the average consumption per ICP (all categories) since FY11 has been 1.2%, while the coincident network peak demand over the same period has grown by 1.9% per year.

[31] International Energy Agency, "Key Renewables Trends. Excerpt from : Renewables information", 2016 Edition

ICPs in New Zealand had PV installations in place[32], providing 0.1% of electricity used in the country[33].

PV uptake on our network is shown in **Figure 13.3** and **Figure 13.4**[34]. At the end of March 2017, the total PV connection proportion on our network was less than 1% (1,960 ICPs), representing a 49% increase since March 2016.

Figure 13.3 : PV uptake on our network (percentage of ICPs)

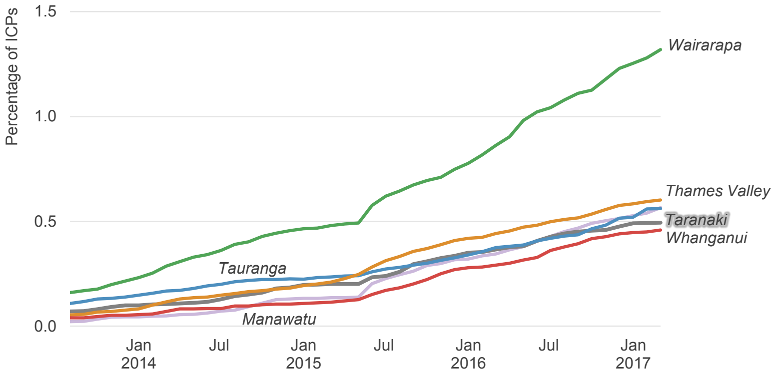
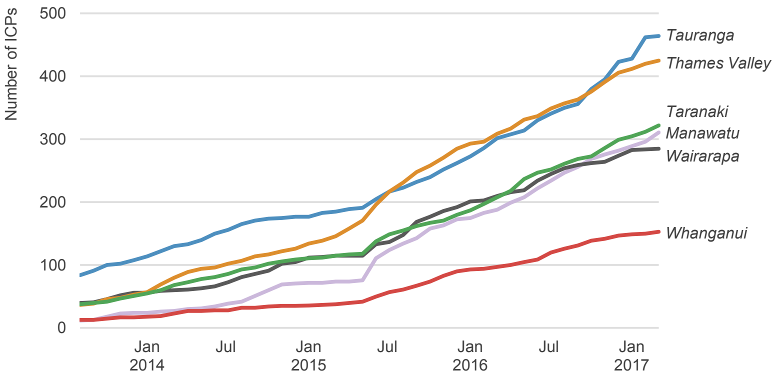


Figure 13.4 : PV uptake on our network (number of ICPs)



Although the current uptake rate for PV on our network is still very low, it is growing steadily. Over the last 15 months, there have been on average 52 new solar PV connections per month. International literature suggests that when PV penetration reaches around 10% on a network, issues associated with the variability of its output could become material, requiring some form of network investment[35]. At current growth rates, this still appears to be some distance off on our network, although localised clusters of high PV penetration rates would have to be closely monitored.

In August 2016, the Ministry of Business, Innovation and Employment (MBIE) provided an updated Electricity Demand and Supply Generation Scenarios (EDGS) model, which included forecasts for the anticipated growth of solar PV generation in New Zealand under various scenarios. The 'Disruptive' scenario suggests that PV generation could approach 10% of (current) installed NZ generation capacity by around 2035.

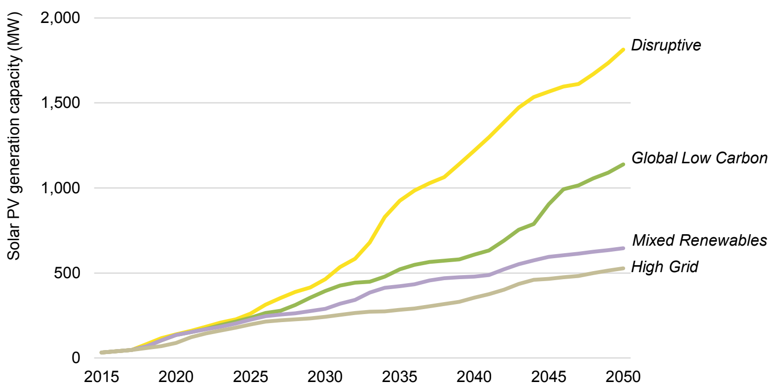
[32] Electricity Authority, EMI (Market Statistics and Trends), "Installed Distributed Generation Trends", January 2017

[33] Ministry of Business, Innovation and Employment, "Energy Statistics : Electricity", January 2017

[34] Supra note 32.

[35] This relates to issues such as excessive voltage rise at periods of low load, and voltage fluctuations with potential to create network instability. The impact could be reduced if modern inverters allowing volt/VAR correction, or energy storage devices are in wide use.

Figure 13.5 : Forecast growth of PV installations in New Zealand36



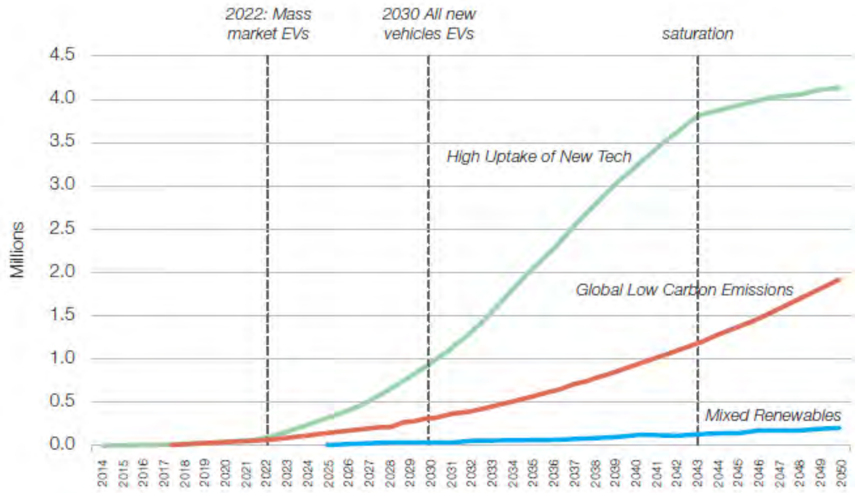
13.3.3.2 ELECTRIC VEHICLES

The use of EVs (full electric or plug-in hybrid) is still in its infancy in New Zealand, with a total of 905 vehicles registered at the end of 2015[37]. However, as with other emerging technologies, the uptake rate is accelerating and it is likely that these vehicles will be a regular feature on our roads in the foreseeable future. There is also wide recognition of the fact that New Zealand, with its high proportion of renewable electricity generation, is well placed to achieve major carbon emissions reductions from switching its vehicle fleet from conventional fuel to electricity[38], which may provide further impetus to the uptake of EVs.

In its 2015 study, MBIE also provided forecasts for the uptake of EVs in New Zealand. In its response to the consultation, the New Zealand Smart Grid Forum suggested that a more aggressive technology uptake scenario is also feasible, which MBIE subsequently agreed with and included in their final set of electricity consumption forecasts. MBIE's forecasts along with the Smart Grid Forum 'high uptake of new technology' scenario for EV are indicated in the figure below.

Overall we do not foresee a material impact on our network from the uptake of EVs over this AMP planning period, but it is likely to change in the longer term. Further impetus will be provided from plans currently underway to deploy public EV charging network(s) nationwide over the next three to five years. In the interim we may see clusters of high EV uptake where some network reinforcement will be required. This situation will be closely monitored.

Figure 13.6: Forecast growth of electric vehicle uptake in New Zealand[39]



13.3.3.3 ENERGY STORAGE

Energy storage has been one of the major topics of discussion in the industry during 2015, with a rapidly escalating range of market offerings at both the domestic and utility scale. While the main focus is on battery products, other storage mechanisms such as compressed air storage, pumped water storage and various forms of heat storage are also receiving attention, but generally for large scale applications only.

Worldwide, the installation of battery storage capacity is increasing at a significant rate – mainly in utility scale applications (typically in the range of 0.5 to 10MWh, though with some larger units). These are mainly installed by electricity utilities for peak demand management, network stability, or to participate in ancillary service markets. Meeting government mandated targets for renewables and energy storage also plays a major role.

Residential scale applications are increasing rapidly in number, but the overall storage capacity associated with these is still relatively small. Other than the installation cost, uptake rates for domestic storage systems are also very sensitive to factors such as (the absence of) feed-in tariffs, subsidies, the cost of electricity, and the reliability of supply.

36 Source : MBIE, "Electricity Demand and Supply Generation Scenarios 2016", http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016

37 Drive Electric, 29 December 2015

38 For example, Electric Vehicles in New Zealand: From Passenger to Driver, published by Dr Allan Miller and Scott Lemon, EPECentre, University of Canterbury

39 New Zealand Smart Grid Forum: Transform Modelling Paper, May 2015

In New Zealand the uptake of battery storage and other new forms of energy storage is still in its infancy and is mainly limited to trials at present. This situation is expected to change over the planning period although we still don't foresee a major proportion of energy supply assisted from storage devices.

Although the cost of battery storage systems has reduced substantially in recent years and is anticipated to decline further in the foreseeable future, for the vast majority of individual consumers it is still significantly more expensive than conventional grid-supplied electricity (by comparable capacity). In some instances, mainly in remote rural areas, the installation of combined generation and battery storage units is economically feasible and uptake rates in these cases may accelerate. It is also noted that the combination of effective storage and local, mainly PV, generation offer customers a significant degree of flexibility in how they procure and use electricity, which in some cases may override decisions based on economic factors alone. Overall, we believe that battery storage will not lead to meaningful levels of grid defection or even have a substantial impact on the manner in which the electricity network is utilised in this planning period.

In the longer term, our view is that energy storage systems, both at utility and residential scale, will have a valuable role in the provision and use of electricity. They offer significant potential for increased reliability and resilience of supply, potential for deferring network reinforcements and lifting network utilisation, improving network stability and maximising the value from distributed generation sources. It is therefore an area on which we intend to increase our focus, increasingly incorporating storage solutions where these provide economic or reliability benefits to our customers.

13.3.3.4 DEMAND MANAGEMENT

For years New Zealand has been a world leader in the application of demand management systems, particularly in its use of water heaters as controllable load. Considerable debate is underway on whether these load control systems should be maintained, expanded, or replaced with newer technology. Hot water control systems continue to play an important part in managing peak demand on our network and avoiding transmission peak charging to our consumers.

With improving communications systems and more intelligent home devices, new opportunities are opening up for demand management on the consumer side of the electricity meter. While it is not our intent to become involved in consumer products (such as home area networks), we will continue to pursue demand management solutions where these offer economic alternatives to network reinforcement. In particular, we see potential through the implementation of pricing arrangements or through commercial load-shedding agreements to work with consumers to reduce peak demand and/or improve network utilisation.

With the advent of large-scale energy storage on our network in future, opportunities will also arise for demand management on the network side. This could be used for peak lopping, in areas where network capacity is constrained.

13.3.4 IMPACT OF THE REGULATORY ENVIRONMENT

While the changing energy environment is not driven by changes in the regulatory landscape, it is recognised that regulation plays a major role in influencing how we invest in our network. The manner in which our regulatory regime is adapted to reflect the future network environment could have a large impact on the adoption of future technology and solutions.

We do not see the current regulatory regime as a major roadblock to investing effectively in the network of the future, although it has not been thoroughly tested under multiple new technology investment scenarios. We are participating in the wider dialogue around encouraging future network and non-network technologies, as part of the Input Methodologies review. We support a regulatory environment that encourages distribution utilities to seek out cost-effective new solutions that provide real network benefits, for the ultimate benefit of all customers (without unfairly benefitting some, at the expense of others).

Around the world, some interesting regulatory debates are being had about the role of distribution utilities in the future and where the boundaries of regulated service should be drawn[40]. There is also major debate about the cost of connecting distributed energy sources to networks and how these should be priced to balance the interests of utilities and generating consumers[41]. The view that our regulator takes on these matters will be very important to us and we intend to follow and participate fully in the debate.

13.4 OUR CURRENT INNOVATION PROGRAMME

This chapter discusses our plans for our network of the future. However, it is worth reflecting that we have been pursuing intelligent and innovative network solutions for a long time. In this section, we describe some of the new applications that we have been developing in the past two years.

13.4.1 BASEPOWER

We have continued to develop BasePower as a more cost effective and better power quality solution for remote rural consumers needing renewal of existing (pre-1992) overhead lines. BasePower is a fully autonomous, self-healing off-grid power solution for homes, lodges, hill country farms and communications sites. More generally they are referred to as remote area power supplies, or RAPS. A

[40] A leading example of this is in New York. As part of the "Reforming the Energy Vision" (or REV) programme, the regulator is requiring distribution utilities to evolve towards fulfilling a system operator function. To avoid potentially unfair competition against suppliers who do not have the 'protection' of a regulated asset base though which costs can be socialised, it has drawn strict boundaries around the (regulated) services distributors are allowed to provide. It is enforcing independent, arms-length arrangements for services that utilities may want to provide in the competitive market.

[41] For example, there are several examples across the US of regulators and courts finding in favour or against utilities wishing to impose a charge for connecting solar PV to networks, or to disallow net metering arrangements (whereby consumers essentially only pay for the energy they use after deducting their own generation), yet still retain the full benefit of the grid during non-generation periods. A recent example is the decision by a court in Hawaii to uphold the changes made by the regulator to end the net energy metering policy (reported in Utility Dive on 4 January 2016).

BasePower unit operates as a mini-AC grid managing the sources of generation, storage and loads across the connected loads. It is designed to typically use renewable PV generation and energy storage to meet consumer needs, only supplemented by a diesel generator when necessary.

The piloting of advanced lithium-based battery chemistry together with improved self-healing capabilities was completed in FY15 allowing greater use of renewables (and fuel savings) and support for larger sites.

13.4.2 NETWORK INSIGHT

The Network Insight programme involves the installation of monitoring devices on the LV side of key distribution transformers. Transformers selected for installations are determined by the strategic objectives of the programme, which include:

- Better overall operational and planning visibility of LV network and distribution transformer load flows and voltages
- Improved understanding of CBD transformer loading and LV interconnection loading for parallels
- Improved fault location, through possible 'last gasp' communications on failure
- Improved modelling and understanding of SSDG, especially PV clustering effects on LV power quality
- Improved power quality visibility and modelling capability to assist in determining compliance and performance

13.5 OUR FUTURE NETWORK STRATEGY

13.5.1 OVERVIEW

As noted before, the energy environment, with electricity supply at the forefront, is undergoing a major transformation. Over the next 10 to 20 years, the way electricity is generated and used will change fundamentally, with major implications for the way in which electricity distribution networks are built and operated. The investment and operational decisions we make over the next 10 years will be fundamental to the future architecture and functionality of our network and the value that it will offer to consumers in the longer term.

Making investment decisions in a rapidly changing environment, with very uncertain outcomes, is by its very nature challenging, but is not unlike the situation faced by many other businesses.

While we have been evolving with technology developments to date, this has been somewhat ad hoc – driven by direct needs. One of our core goals for the coming year is to develop and publish a formal network evolution strategy. The strategy will also contain a detailed roadmap of how we intend to transform ourselves to ensure our readiness for the future. Given that our operating environment is anticipated to continue to change, this will only be the first step – the roadmap will have to continuously evolve.

As noted before, the uptake of edge technologies is still at a very early stage. We do not currently have subsidies or other forms of government mandated incentives in place that would artificially accelerate the uptake of these technologies. It is therefore expected that this uptake will take a more natural evolutionary path – influenced by economics and customer sentiment.

As a result, we do not foresee that our network will be placed under immediate and unresolvable strain or that we are likely to face materially changed demand patterns as a result of new technologies over the planning period. This view was also borne out during the recent implementation of the 'Transform' model for all electricity distributors in New Zealand[42] – where the modelling results indicated that we are unlikely to face material disruption for at least the next eight years.

Instead, we see that New Zealand utilities have a unique opportunity to prepare for the future by using this window of opportunity before disruptive technologies and customer trends have a substantial impact on networks. There are multiple overseas examples to study that can provide good insight on emerging trends and how to effectively deal (or not) with this. New technology and non-network solutions are widely tested around the world, and again we can learn much from others.

We also have time to test new solutions and prove concepts on our own network in a relatively benign environment. This will help us to be ready with these when the real need emerges in future and not have to scramble to find solutions. It will provide us with early benefits from solutions offering efficient network improvements or cost reductions and could help us defer large investments where we have to consider much longer planning cycles than the next 10 years. The benefit of such testing and proofs of concept can be further enhanced by cooperating with other New Zealand utilities facing the same uncertainty as us, as well as with suppliers and academia.

Many of the trends and features described below may still be some way off into the future, but we believe that the optimal strategy is to get ready for the changes while we can do so in a controlled manner. We therefore intend to use the next five years to ready ourselves for the anticipated future and to evolve in a well-managed fashion to what we see as the role of the distribution utility of the future.

In the section below, the essence of our future network strategy is discussed. This will form the basis for the fully-fledged strategy to be released by the end of FY18.

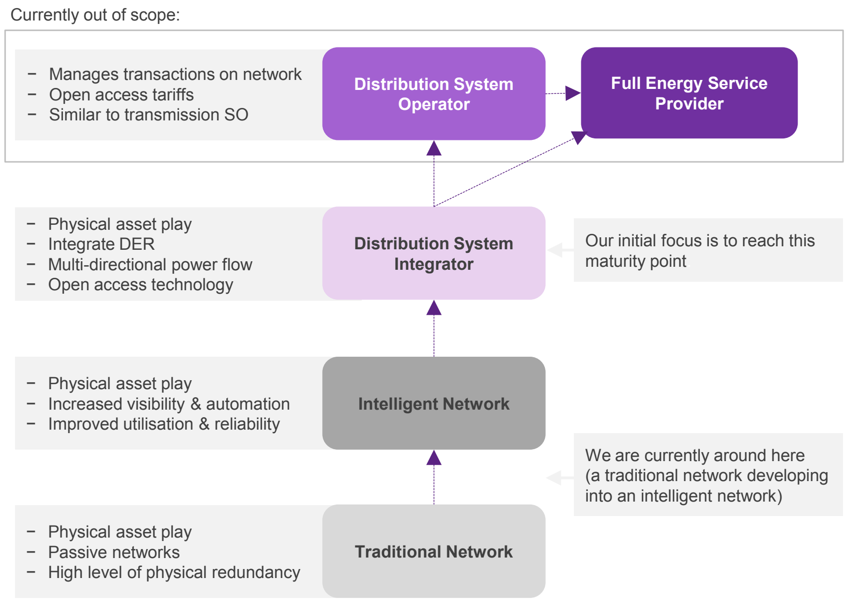
13.5.2 EVOLUTION OF OUR DISTRIBUTION NETWORK

The future nature of electricity distribution networks is being widely debated around the world. While there is no clear conclusion at this stage, a framework that neatly

[42] This model was adopted from a similar model developed for UK utilities. It was implemented during the course of 2015 for the New Zealand networks via of the Electricity Networks Association, with support from the Smart Grid Forum.

sets out how we see networks evolving in the short to medium term future is illustrated in **Figure 13.7**.[43]

Figure 13.7: The evolution of the electricity distribution network[44]



According to this framework there are distinct stages though which networks can evolve – with each building on the one before. The key features of each stage are as follows.

Traditional network – is the distribution network that we are used to.

- It relies on physical assets to convey electricity from bulk electricity supply points[45] to end consumers.
- Other than providing the electricity conveyance service, distribution utilities traditionally do not participate in energy markets and are compensated only for the assets they provide and operate.
- Although elements of control and automatic disconnection (through protection systems) are in place, traditional networks and their components are largely passive in nature. Network reconfiguration requires human intervention.
- A substantial degree of redundancy is normally built into traditional networks. This is to ensure that peak demand can be met at all times and also to provide acceptable levels of reliability, ensuring continuation of supply in case a critical asset should fail. Even if all communications to control centres are lost, these networks will largely keep operating as normal for an extended period.
- Assets are generally sized for the peak demand they are anticipated to experience, which is predetermined at design stage. Actual measurement of peak power flows in assets is limited.

Intelligent network – is the often touted 'smart network', which is based on the traditional network with much extended capabilities for monitoring, measurement, control and automation – and the associated communications network and information systems to support this. There is also a shift from centralised to de-centralised control, relying more on the local 'intelligence' of modern devices.

- It relies on physical assets to convey electricity from bulk electricity supply points to the end consumers.
- Distribution utilities still do not participate in energy markets (other than providing the electricity conveyance service). They are compensated for the assets they provide and operate as well as, in many instances, for the reliability of service and for energy efficiency improvements[46].
- Intelligent devices are widespread throughout the network, with associated communications systems. These allow broad visibility of power flows, asset loading, and asset and network performance. They also provide control of devices, which in turn allows much greater network automation. Networks can be reconfigured in real time to respond to demand patterns, or operational events.
- Because of the improved visibility of actual asset and network loading and performance, and increased possibilities for automation, it is possible to safely increase the utilisation of networks to much higher levels than with purely passive networks. Automation also provides opportunities for easy network reconfiguration after faults, or self-healing networks, that can provide substantial reliability improvements.
- While assets are still sized in accordance with the expected peak demand they will carry, the improved utilisation factors and network flexibility allows a significant reduction in the degree of asset redundancy required (to achieve the same or improved network outcomes).

Distribution system integrator – this next stage expands on the capabilities of the intelligent network to allow for the widespread use of local generation sources connected to the network at multiple points, with associated two-way power flows. It also ensures open access arrangements for customers to allow them to transact

43 In practice no framework can be 100% 'pure' and that exceptions to, and overlaps between these definitions will occur.

44 Figure based on the Edison Institute, Possible Utility Pathways for the Future.

45 These are generally points of connection to the transmission grid, but can be direct connections to generators.

46 This is to ensure that incentives exist to find optimally efficient solutions, rather than stick to traditional network investment solutions.

over the network and to connect any device they wish within acceptable safety and reliability limits.

- It relies on physical assets to convey electricity from bulk electricity supply points to the end consumers, as well as from consumer to consumer, or consumer to bulk supply point.
- It provides network connections for multiple sources of distributed generation devices (and other customer side devices, if these are required to interact with the network). However, the distribution utility does not become involved in the transactions between customers and other parties or in the balance between supply and demand.
- It provides the necessary functionality to maintain network stability, power quality and effective protection under the widely expanded range of operating scenarios associated with the anticipated future arrangements. This may include use of large scale energy storage on the network.
- Revenue is earned through providing electricity conveyance (as in the past), but also from the other network services provided to customers – reflecting for example the cost to connect distributed generation, maintain network stability, and provide flexible open access functionality. Distributors are also likely to transact with customers for value that they (customers) can add to the operation of the network – for example for demand management capability, and electricity buy-back.
- Building on the intelligent network already in place, network investments and asset sizing will reflect the impact of the evolving electricity demand patterns. This will include consideration of the benefits made possible through transacting with customers for generation or other support services.
- To facilitate all of the above, customer pricing will have to evolve to reflect a far larger degree of individualisation than in the past. This will recognise the varying services that customers may require, the devices they wish to connect and the impact of these on the network, or the network benefits they can offer.

Distribution system operator – this is the next step up from a DSI, and represents the point at which distributors become involved in the energy transactions occurring over its network. This would include the balancing of energy supply and demand on the network, similar to the system operator function that exists for transmission grids.

- The physical attributes and functionality of the network will be similar to those required for a DSI.
- In addition, distributors will build the capability to manage multiple energy transactions on its network, to form a real time forward view of energy required and energy available on its network, and the ability to transact to ensure an effective balance between energy in and out-flows.
- Managing the stability and power quality on distribution networks will become much more important than in the past.

Full energy service provider – this could be a final step in the evolution of distribution utilities for the foreseeable future. In addition to the functions described above, it would include involvement in large scale electricity generation (eg through utility scale solar generation plants or gas-driven fuel cells), or procuring large blocks of energy for distribution on the network.

At present it is not clear whether regulatory arrangements would allow for distribution utilities to evolve to this stage.

13.5.3 OUR CURRENT AND DESIRED STAGE OF EVOLUTION

At the moment, our network finds itself somewhere between the traditional and intelligent network stages. The main features of the traditional network have been in place for some time. We also have many of the initial features of an intelligent network in place. This includes:

- Modern SCADA systems that provide reasonable visibility and remote control of our subtransmission and distribution networks
- Modern power transformer and switchgear monitoring and control
- A modern OMS
- Extensive automation devices spread across the network

More recently we commenced the rollout of devices to enhance visibility on our LV network and are developing remote area power supply applications, to enhance reliability of supply in remote rural areas.

Our goal over the planning period is as follows:

> Our goal over the planning period is to evolve to a Distribution System Integrator. This will include the building and operation of a fully functional intelligent network.

We believe that it is in this capacity that our network will provide the most value to our customers over a five to 20-year horizon. In future we may choose to evolve deeper into the energy service provider space, but that is not a current focus.

In achieving this goal, we see the range of fundamental distribution services that we currently provide expanding as set out in **Table 13.1**.

Table 13.1: The expanding range of services for the future network

FUNCTIONAL AREAS	POTENTIAL NETWORK SERVICES
Additional Services	Demand response
	Facilitating open access arrangements
	Energy storage
	Broader grid acts as a 'battery' for DG customers
Balance Services	Network stability
	Voltage/VAR support
	Frequency regulation
Power Quality	Voltage levels
	Flicker and harmonics
Protection	Fault detection and isolation
Fundamental Services	Accommodating diversity of connection choices
	Accommodating a diversity of customer load needs
	Proactive replacement and maintenance of equipment
	Managing for load growth
	Reliability services
	24/7 electrical energy

Shading indicates the current status: In place Will expand Future focus

13.5.4 ASSET RENEWALS

Discussions on future electricity networks tend to centre on network expansions and new technology and applications. However, it is worth reflecting that for most long established distribution networks, the largest single expenditure category is asset renewals – which tends to focus heavily on modern equivalent, but like-for-like (and therefore traditional) asset replacement.

This is not surprising, as many networks have an ageing and often deteriorating asset base, with substantial volumes of assets at or near replacement stage. As we have an obligation to maintain supply to consumers, the most obvious and often most effective solution is to replace assets. We are no exception to this rule and, as discussed in Chapters 15-21, we are planning significant asset renewal programmes.

While we fully expect the majority of renewals to be like-for-like replacements using modern equivalent assets as appropriate, we will be investigating and applying new solutions that can improve the efficiency of our renewal programmes. These will include techniques to defer asset renewal where it can be done without compromising safety and reliability; incorporating new technology where this can be practically integrated with existing assets; and solutions that allow assets to be de-loaded, thereby extending their lives.

In terms of network development, where practical and cost effective, we will build new assets in accordance with the long-term future network strategy.

13.5.5 FUTURE NETWORK ARCHITECTURE

13.5.5.1 OVERVIEW

When considering the distribution network architecture of the future, it is important to reflect that we operate at least three distinct types of network, with differing consumer groupings and configurations. It is therefore not possible to ascribe a single or even dominant architecture to our network. The three distinct types of network are:

- **Urban networks:** These networks, covering the towns and cities in our network area, represent the smallest geographic footprint but serve the majority of our customers. They have a high connection and consumption density, with the resulting economics allowing for reasonable levels of supply redundancy or back-feeding and network undergrounding. Demand varies across urban networks, and includes some substantial commercial and industrial loads, many of which are very sensitive to supply interruptions or power quality issues.
- **High demand rural:** These networks, while built in rural areas, serve large commercial enterprises with substantial electricity demand where reliability of supply is very important. They include areas with substantial horticulture activities (such as kiwifruit or vegetable farms) and major dairy producing areas. In general, these parts of our network are served by long overhead lines, which are intrinsically more subject to supply interruptions than shorter, often undergrounded, urban feeders. It is also less economical to provide supply redundancy.
- **Rural and remote rural:** These networks cover the largest geographical part of our network, serving relatively sparsely populated, low load density areas, although some high point-loads can occur. They are served by long overhead lines, very often with single supply feeders only (especially in remote rural areas) and little economic possibility of network redundancy. Given their length and the terrain they pass through, these networks are especially vulnerable to external interference, leading to higher risk of outages.

These distinguishing characteristics will persist into the future, and will therefore have a major bearing on the future architecture of our network. However, there are some common fundamentals that will apply to our whole network including the uncertainty of how consumers will use the network in future. We are therefore keeping network options open as long as reasonably possible, before committing to major new investment. These common fundamentals are set out below.

- **Flexibility:** As we do not fully understand the future needs of customers, it will be valuable to be able to reconfigure, expand or contract installations with relative ease. This requires the maximum practical degree of flexibility be incorporated in the future network architecture.
- **Deferral:** In periods of major uncertainty, deferring investment decisions is especially valuable, as long as this can be achieved without compromising safety or service quality. It allows more time to see how the future pans out before having to commit, which reduces the risk of over-investment or committing to the wrong solution. Our network of the future will therefore reflect this principle – favouring solutions and configurations that will allow deferral of major investments.
- **Smaller incremental investments:** Associated with greater flexibility and deferral of major investments, adopting an approach of smaller incremental investment where appropriate is most beneficial[47]. Network layouts would need to reflect this as well.
- **Open standards:** Locking in proprietary equipment solutions may be attractive in many respects, but does not encourage longer term flexibility. It is therefore important to ensure that the equipment we use adhere to commonly accepted industry standards, including data and communications protocols. This will allow applications from different manufacturers to be used in parallel, as well as provide more certainty that future equipment will be easily deployable on our network.
- **Communications:** Effective high-speed data communication will be a common requirement for all future network applications. Planning for this will therefore be an integral part of our future network architecture.
- **Data collection and analysis:** Underlying almost all future network enhancements, as well as improving existing operations, will be increased access to network information. It is the effective processing of network information that will allow automated control systems to function and to indicate to network operators when intervention is required. Likewise, it is the effective analysis of information gathered from the network that will support improved planning and optimised asset renewal decisions. Increased data collection will also support modern IT applications such as outage management, advanced distribution management, and advanced asset management systems.
- **Standardisation:** While it will be important to continually investigate new network solutions, it is equally important to guard against excessive proliferation of asset types and devices on the network. There are significant operational, maintenance and spare-holding benefits from effective standardisation – especially for those assets most commonly used across the network.
- **More dynamic pricing structures:** Effective tariffs should be a key part of the network of the future. The current major cost driver for electricity distribution is power consumed at peak demand times[48], but in future we expect additional costs to be added by customer devices connected to the network, where these require power quality control or managing substantial two-way power flows. Tariffs that more closely reflect consumers' actual contribution to overall distribution costs are not only more economically efficient, but are intrinsically fairer than existing, energy volume-based schemes. They can also form a stronger basis for incentive arrangements that reward customers for demand smoothing or delivering energy to the network at peak demand times.

13.5.5.2 URBAN NETWORKS – FUTURE FEATURES

Urban networks connect large numbers of customers and relatively high loads, many of which are very sensitive to power interruptions. We expect to see increased use of distributed generation sources on these networks, with associated two-way power flows, and a reduction in demand at times of the day (although not necessarily at peak demand times). Conversely, we also see potential for significant uptake of EVs, which can cause parts of the network to overload at times, if not managed.

A basic driver for building future urban networks will therefore be to enhance network reliability, maintain power quality and maximise network utilisation without incurring major reinforcement costs.

In addition to the common features described above, our urban networks of the future are therefore likely to be characterised by the following:

- Substantial degree of interconnected (meshed) networks, at all voltage levels. This will enhance network flexibility and allow applications such as automatic fault isolation and restoration (minimising affected areas), rerouting of power flows during peak times, improved network utilisation and more flexibility for outage planning.
- Ubiquitous use of intelligent devices around the network, for much increased levels of measurement, data collection and device control (centrally and remotely). This will in turn allow near real time state estimation (detailed understanding of power flow around the network); automatic network

[47] We do however recognise that given the nature of some of the assets we install, investing in smaller incremental steps will not always be practical or economically sound – even in the face of future uncertainty. For example, when installing an underground cable or a power transformer, the incremental cost of larger equipment normally represents only a small fraction of the overall installation. In such instances, it may still be more appropriate to install equipment with higher capacity than initially needed – especially if this allows standardisation of network sizes and equipment types.

[48] Networks have to be built with sufficient capacity to meet peak demands.

reconfiguration; improved network planning (growth and renewal) based on more in-depth understanding of network use and asset performance; higher asset loading through real time ratings; and sophisticated pricing schemes that better reflect the real time use of the network.

- Ubiquitous communications coverage, on all parts of the network. This could include fibre optic networks between major network nodes, meshed radio networks in larger centres, satellite networks in smaller towns, and power line carrier systems at LV levels (where feasible).
- Wide use of devices to enhance power quality control, to avoid issues that may arise from the widespread application of renewable distributed generation. This may be to prevent over-voltage conditions during periods of low demand, voltage variability caused by intermittent generation, harmonic distortion caused by power electronic devices connected to the network, etc.
- Large scale energy storage devices could in some instances prove an economically efficient alternative on urban networks in order to defer expensive network reinforcements.

13.5.5.3 HIGH DEMAND RURAL NETWORKS – FUTURE FEATURES

High demand rural networks serve a relatively low number of consumers spread over large areas, but many of these represent operations with high commercial value and large electrical loads and are very sensitive to loss of supply or power quality issues.

It is broadly not economically efficient to provide the same quality of supply to these networks as that of urban networks. The high demand rural networks of the future will be developed to strike a sound economic balance between supply reliability and resilience and economic viability. In addition to the common features described above they are likely to be characterised by the following:

- Increased interconnection of subtransmission and distribution networks, where this can be economically achieved. This will allow more network flexibility and enhance our ability for fault isolation and automatic supply restoration – albeit to a lesser degree than in urban areas.
- Expanded use of intelligent devices around the network to improve our visibility of loading and power flows and increase the degree of automation and remote switching capacity. This will also enhance network planning and support the use of more sophisticated pricing schemes.
- Wide rollout of intelligent fault detection schemes – allowing us to pinpoint where outages occur and thereby provide a faster fault response. This will also work in with network automation schemes to isolate affected areas where possible, minimising the extent of outages.
- Judicious use of distributed generation and associated energy storage. Given the size of electrical loads involved, distributed generation and energy storage will have to be of relatively large scale before they will contribute substantial benefits. This will require careful trade-offs against the cost of network enhancements, and are likely to be used in conjunction with rather than instead of conventional network supplies.
- Relatively high proportion of communications coverage of the network, to allow connection to the relatively high number of intelligent devices anticipated. This would mainly rely on point-to-point radio communications, backed up with power line carrier systems on distribution or subtransmission networks. In some cases, 3G cellular coverage may also be used.
- Power quality control is an issue here as well, arising from voltage regulation problems associated with large fluctuating loads, and potential issues through harmonics introduced by power electronic control devices. Widespread use of power quality monitoring devices is therefore foreseen on these networks in the future, along with automated schemes for voltage compensation, power factor correction and, where needed, harmonic filtering.

13.5.5.4 RURAL AND REMOTE RURAL NETWORKS – FUTURE FEATURES

The rural and remote rural networks generally cover areas where it is uneconomical to provide high levels of supply quality or in some more remote areas, to provide electricity supplies at all. Energy density on these networks is low and feeders are long and susceptible to external interference. However, it is fully recognised that access to electricity at reasonable cost and at reasonable quality is still very important to customers in these areas.

The rural and remote rural networks of the future will therefore also be developed to strike an acceptable balance between supply capacity, reliability and resilience, and economic viability. In addition to the common features described above they are likely to be characterised by the following:

- Where practical opportunities exist, install interconnection on distribution networks but this is expected to be relatively rare. Interconnection will provide some options for automatic fault isolation and supply restoration.
- Intelligent devices at key points on the network to provide a reasonable level of insight into network loading and performance, and some remote controllable devices.
- Increased installation of intelligent fault detection schemes, allowing us to pinpoint where outages occur and thereby provide a faster fault response.
- Given the relatively small size of loads and the remote location of many of these, it is likely to be more economic in some instances to install remote power generation units, with associated energy storage, rather than upgrade network supplies.
- Communications to critical points on the network, where intelligent devices are installed. This will rely on point-to-point radio communications and 3G cellular systems. Where feasible, power line carrier technologies may also be considered on higher voltage lines.

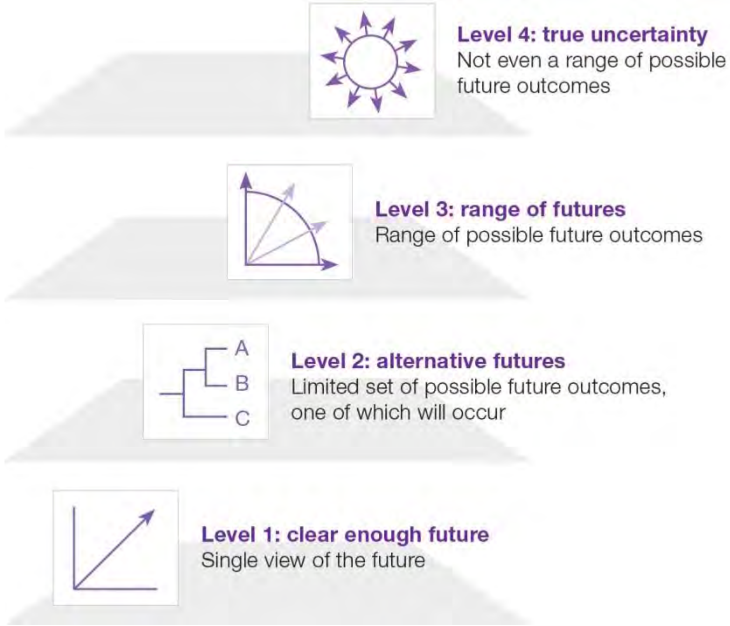
13.5.6 DEALING WITH UNCERTAINTY

13.5.6.1 OVERVIEW

The transforming nature of the energy industry gives rise to a classic problem of developing strategy under uncertainty. It has long been recognised that developing a strategy in such an environment requires a shift away from traditional strategic planning methods. An attractive model for dealing with uncertainty was described by McKinsey & Company[49], defining four levels of uncertainty as set out in **Figure 13.8**, and suggesting an approach to planning under each of these. We will largely adopt this suggested approach. In terms of the framework, we consider the electricity distribution industry to be facing a Level 3 challenge – a range of possible future outcomes.

In such an environment, the appropriate response would be to develop a limited set of scenarios that would cover the range of probable future outcomes (not all outcomes) and to conduct further analysis on these. Strategies are tested against each of these scenarios, which would provide an indication of how they would fare. In doing this, it should be possible to identify the strengths, weaknesses and degree of risk inherent to each strategy. This in turn would guide decision-making towards what would be required to maximise our options for the future, and to identify 'no-regret' actions or investments.

Figure 13.8: Four levels of strategic uncertainty[50]



13.5.6.2 FUTURE SCENARIOS

In-line with the methodology described above, we intend to develop four potential future energy scenarios against which we will test our various future network strategies. For this, we will consider the trends already discussed in Section 13.3.3, adapting these for our network. We will use scenarios that range from a moderate take up of distribution edge technologies to a complete disruption of the electricity industry.

For each of the scenarios we will consider what the impact on the network would be and develop the optimal network architecture and investment plan (taking into account the different types of network we operate). Based on this, we will determine the common elements between the scenarios, and identify the 'least regrets' development path. This will help select the optimal architecture.

We will pay particular attention to potential trigger points for major disruption, and how they could influence the future use and operation of our network.

[49] McKinsey & Company, Strategy under Uncertainty, McKinsey Quarterly, June 2000

[50] Ibid

13.5.6.3 CAPABILITY DEVELOPMENT

A primary response for companies facing a range of uncertain outcomes is to invest in keeping its options open. While obvious asset, business development or operational investments to achieve this may not exist, investing in expanding and developing internal capability for dealing with the changing future is generally considered a sound, no-regret investment. In a distribution network environment this will include attention to the following:

- Expanding our research and information gathering programme
- Increasing our collaboration with external parties, including academia, suppliers and other distributors
- Sharpening our forecasting and scenario analysis capability
- Enhancing our understanding of customer needs and trends
- Expanding our range of technology trials and proofs-of-concept
- Developing our in-house skills and capability to manage research and technology trials
- Developing our capability to introduce promising new solutions into business-as-usual planning and operational practices, including the capability to maintain new technology
- In general, enhancing our ability to respond to changing circumstances

As discussed in Chapter 10, we plan to develop our capability in these areas over the planning period.

13.5.6.4 TECHNOLOGY TRIALS AND PROOFS OF CONCEPT

Another important element of keeping our options open for the future is to keep abreast of emerging technology, concepts and solutions – not only in theory, but also in their practical application. We have been conducting trials and proving new technology on our networks for a considerable time. These activities will need to escalate in the near future.

We therefore intend to embark on an increased number of proofs of concept and technology trials over the planning period.

The purpose of this work is twofold.

- Firstly, we intend to develop sufficient understanding of new technologies and their practical application on our network, to ensure that we are ready to introduce these when customers' needs dictate, and it becomes practical and economic to do so. This also requires the development of enabling technologies and processes that will allow the new solutions to be efficiently integrated on the network.
- Secondly, we are actively looking for new solutions (network or non-network) that would enhance what we currently do. If we therefore identify new solutions that could improve asset utilisation, reduce costs, enhance safety or reliability, or simplify operations, these will be introduced into our business as part of our suite of network solutions.

13.6 FOCUS AREAS FOR THE NEXT FIVE YEARS

13.6.1 OVERVIEW

As discussed above, it is our intention to greatly develop our future readiness in the next five years, making the best use of the window of opportunity we have. We also discussed our closely aligned intention to evolve our electricity network to a DSI over the next five to 10 years.

Significant work needs to be done to achieve this and we accept that we don't yet have a fully evolved view of what this will entail. However, based on our current best view of the requirements to become an intelligent network and then to evolve into a DSI, we have identified a number of activities and projects that we wish to undertake in the next five years. These are shown in **Table 13.2**. These are a combination of strategic activities, network technology trials and proofs of concept, enabling technology, and system developments (required for new network solutions to be effectively applied).

We accept that the outcome of our detailed strategic planning approach (as will be captured in our future networks roadmap) will have a major influence on the direction of our proposed work. We also note that this is a five-year list, even though the AMP planning period spans 10 years. This is deliberate in light of the anticipated uncertain, rapidly changing energy environment and associated technology change.

It is also not feasible to plan technology trials too far ahead, as they will undoubtedly be influenced by the successes and failures of earlier trials and new directions of research identified along the way. The list in the figure below will therefore be regularly updated.

More details of the proposed activities and projects are provided in the sections below. In addition, we also discuss some of the capacity building activities that we plan to undertake.

Table 13.2: Future focus projects and programmes for the next five years

TIMING	INTELLIGENT NETWORK	DISTRIBUTION SYSTEM INTEGRATOR *Intelligent network applications as well as:*
Next five years	Communication Strategy	Cost-of-service tariffs
	Information Systems Strategy	Gas-fired generators/fuel cells
	Future network roadmap	Smart city programmes
	Security of supply standards	Comprehensive customer engagement
	Automatic fault detection and location	Protection for two-way power flow
	Real time asset ratings	Integrating community energy schemes
	Distributed control and automation	Bulk and small scale battery storage
	Expand RAPS solutions	Voltage support
	Self-healing networks	DG and storage network integration
	Enterprise Resource Planning	Commercial demand side management
	Communications networks	State estimation
	Low voltage monitoring and metering	
	Enhanced OMS	
	Asset data analytics	
	R&D solution agility	
	Smart meter data analysis	
Future focus	DMS	Data and control sharing with Transpower
	Auto-generated LV connectivity models	Instantaneous reserve market (batteries)
		Frequency keeping support

Future network strategies *Network application proof of concept* *Enabling / parallel technologies and systems*

13.6.2 FUTURE NETWORK STRATEGY

As already discussed, we intend to use FY18 to develop a detailed network evolution strategy, with an associated 10-year roadmap. This plan will capture the outcomes of the strategic approach and scenario analysis discussed before.

It will also contain details of:

- The network architecture we intend to adopt for the different parts of our network
- The technology trials and proof-of-concept projects we intend to undertake, along with the initial scope, intended outcomes[51], and timing for these
- Our planned customer engagement programmes to inform and support the networks of the future
- Our strategy to encourage innovation within our teams
- Our strategy to collaborate with external parties
- Our plan to develop the required capabilities to implement the future network strategy
- Plans to develop promising new solutions into practical applications that can be adopted as business-as-usual
- Details of how the strategy itself will be kept 'live'

This plan will be one of our key business documents and its development and implementation will involve parties from right across the business.

13.6.3 COMMUNICATIONS NETWORK STRATEGY

Communications infrastructure is a key enabler for the network of the future. It is therefore imperative that we develop our communications network strategy alongside the future network strategy. These two documents will be fully integrated.

Our current communications network strategy is set out in Chapter 11 of the AMP. We will further develop this in FY18 alongside our network evolution strategy. The updated document will cover:

- The forms of communications technology we intend to adopt across the various parts of our network
- Technology trials and proofs of concepts we intend to carry out on communications solutions
- The communications protocols and standards we intend to adopt
- Our strategy to collaborate with external parties
- Our plan to develop the required communications network capabilities to support the future network strategy
- Plans to develop promising new solutions into practical applications that can be adopted as business-as-usual
- Details of how the strategy itself will be kept 'live'

[51] It should be noted that with work requiring trials and proofs of concept (and innovation in general), the success of projects are not guaranteed. It is therefore important that we establish in advance what we want to learn and achieve from a project – and if it demonstrates that an application is not worthwhile pursuing further, that is also a valid and valuable outcome.

The communications network strategy will be the responsibility of our Network Support group, but will be developed in close consultation with the network teams responsible for the future network strategy.

13.6.4 SECURITY OF SUPPLY STANDARDS

Our existing security of supply standards are described in Chapter 7. These deterministic standards essentially prescribe the degree of redundancy we build into the various parts of our electricity network, based on the load served and number of customers involved. This in turn largely dictates the reliability of the network.

In future, we foresee that deterministic security standards will no longer be appropriate. Not only are these standards incapable of reflecting the contribution to overall network reliability of multiple (and intermittent) sources of generation and energy storage, but they are also not effective at ascribing value to reliability.

We therefore intend to completely revise our security standards over the course of FY18, in line with anticipated customer behaviour patterns and the features of the network of the future. The new standards will be probabilistic in nature and will reflect the impact of distributed generation and energy storage. They will also incorporate concepts associated with the value of load, or the economic cost of outages.

13.6.5 NEW NETWORK TECHNOLOGIES AND APPLICATIONS

We intend to investigate several promising new technologies and applications over the next five years. These are all ideas that have been implemented, or are being investigated elsewhere in the world, so it is not our intention to conduct true research and development work – rather to investigate, exchange information, conduct trials and prove concepts on our network.

The various technologies and applications that we intend to investigate are listed below, loosely ordered as we intend to approach them. Further information on these initiatives is provided in Appendix 13.

- LV monitoring and metering
- Expand RAPS applications
- Automatic fault detection and locations
- Battery storage
- Real time asset ratings
- State estimation and network automation
- Self-healing networks
- Voltage support applications
- Distributed control and automation
- Integrating community energy schemes
- EV charging control systems
- Data and control sharing with Transpower
- Frequency keeping support
- Smart meter data analysis
- Gas-fuelled generators/fuel cells
- Enhanced asset and network data analytics
- Communications networks
- Enhanced information system solutions
- Smart city programmes
- Cost of service tariffs

13.6.6 CAPABILITY BUILDING

13.6.6.1 OVERVIEW

We are well structured to deliver the traditional outcomes required by owning and operating our electricity network. However, in readying ourselves for the network of the future, we recognise that we will have to materially expand our capacity and capability to respond to the changing environment we face.

We not only need the capacity to undertake the range of future network activities discussed above, but also need to generally expand our capability to respond to the changing environment. One of the primary no-regret investments identified for implementing strategy under uncertainty is developing appropriate internal capability to deal with it. These aspects are also discussed in Chapter 10.

13.6.6.2 EXPANDING OUR CAPACITY

Our existing teams of engineers, operators and field staff are resourced to manage the existing network in the traditional way. This will remain an essential function, as our customers will continue to require safe and reliable electricity from our network, and none of the developments discussed above are anticipated to materially change this during the planning period. To successfully undertake the additional activities we will have to increase the size of our teams or employ external support to allow the necessary resources for our future readiness work.

This future readiness work is key to ensuring we provide future value to our customers. It also provides a platform for future cost efficiencies and improvements resulting from new network solutions and applications. It is therefore fully expected that the initial investment in additional resources will be offset by savings and efficiency improvements in the future.

13.6.6.3 EXPANDING OUR CAPABILITY

Expanding our capacity to carry out the work associated with future readiness is essential. However, we will not be successful at this if we merely expand our resources by adding more of the same skill sets we currently have. There are several areas of future work that requires us to broaden our focus, and we also need to enhance our ability to deal with (relatively) rapid change.

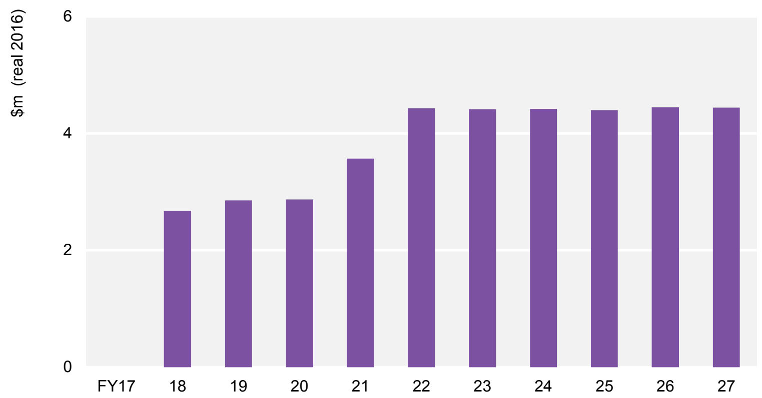
Areas in which we intend to develop or expand existing capability in the next two years include the following:

- **Solution agility:** Our traditional network applications are largely based on well-proven, out of the box solutions requiring little by way of research or substantial product development. As many of the new network solutions are still in an early, even conceptual stage, these cannot be procured in the traditional manner. We therefore need to enhance our ability to not only identify more innovative solutions, but to develop this through to a proof-of-concept stage. This includes developing the skills to develop business and use case studies for projects with uncertain outcomes.
- **Information management:** While we have been managing information for a long time, the information needs of future networks will exponentially increase. We therefore need to enhance our ability to deal with all facets of 'big data', including data collection and management, pattern recognition, information extraction and analysis. This will also support our drive to improve the management of our existing assets.
- **Increased collaboration with external parties:** These include academia, suppliers, innovative start-ups, and other distributors. We have traditionally been very effective at working with external parties and are recognised in the industry as one of the most collaborative utilities in New Zealand. However, the need for collaboration and shared research and development programmes is expected to increase significantly in future and we need to ensure that we have the structures and resources in place, including commercial arrangements, to effectively participate in this.
- **Forecasting and scenario analysis capability:** Much of our future strategy work will require intricate planning under various future scenarios. While we have always had to plan for the future, the changes in the environment were largely one-dimensional and predictable. The future we now face is much more complex and less predictable.
- **Greatly enhanced customer engagement:** We have a long history of engaging with our customers around their power supply preferences and appetite for price/quality trade-offs. However, as discussed in Section 13.3.2, customers' expectations of the electricity service they receive is expanding and at the same time many of the solutions foreseen for the distribution network of the future will rely on close interaction with customers. This is also discussed in Chapter 4.
- **Managing technology trials and proofs of concept:** While we have much experience in managing large conventional infrastructure projects to completion, this is not the case for managing trials of new products with uncertain outcomes.
- **Integrating new solutions into business-as-usual:** Evidence shows that many promising new solutions fail because of the inability to successfully make these part of business-as-usual. Companies also struggle with the operation and maintenance of new technology solutions. The successful introduction of new solutions after the proof-of-concept stage is therefore an area we will need to develop. It will also require the involvement of our service providers.

13.7 FORECAST EXPENDITURE

The forecast Capex on network evolution activities is set out in in the figure below[52].

Figure 13.9: Forecast Capex – network evolution



Historically, our investments in this area have been categorised as part of our general network enhancements expenditure. For this planning period we have separated the expenditure out in recognition of its growing importance. Expenditure is forecast to increase as we expand our proof-of-concept trials.

52 In overall expenditure forecasts in Chapter 26 capex associated with Network Evolution is categorised as 'Other Network Capex'.

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Fleet management

This section explains our approach to managing our network and non-network assets.

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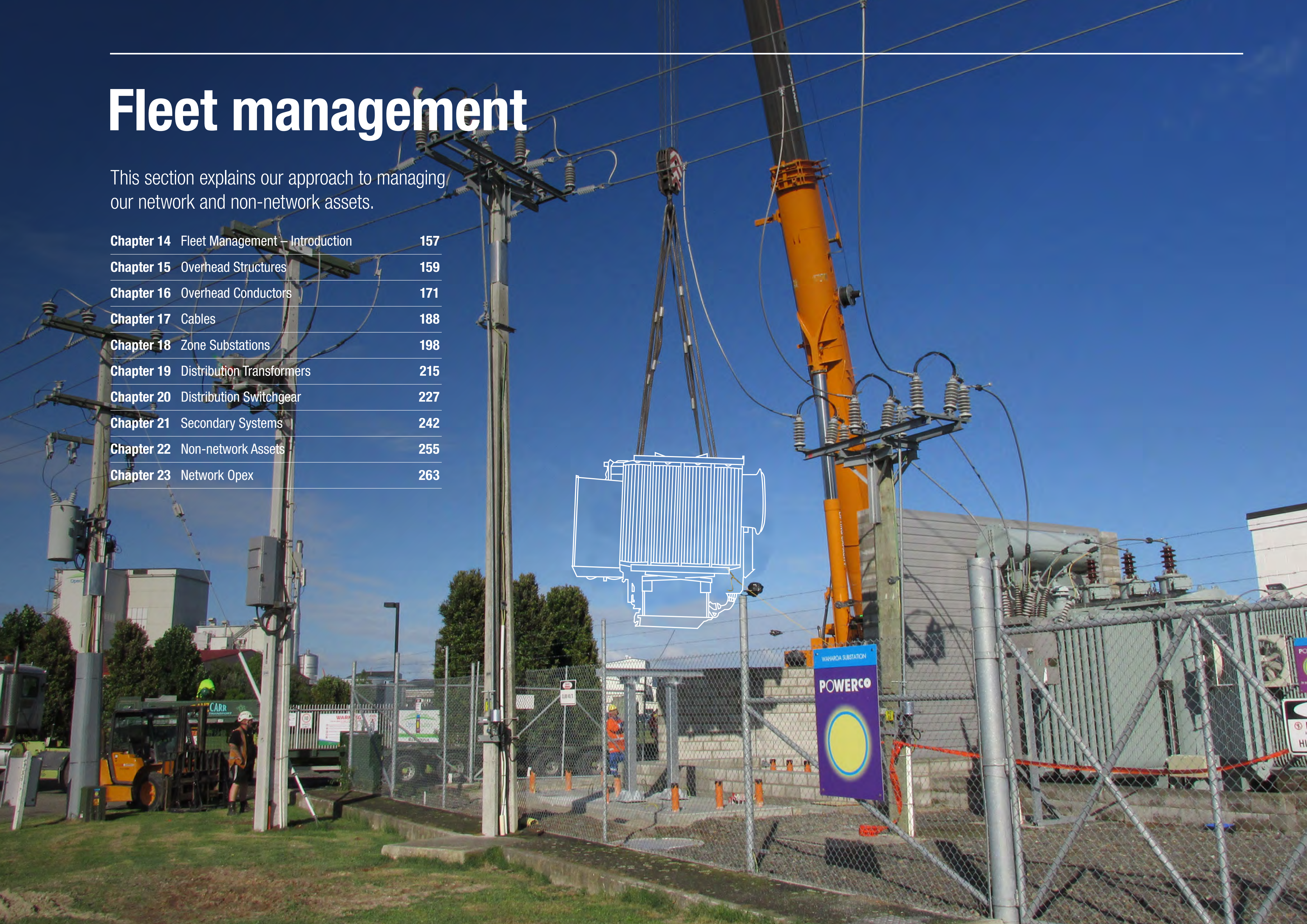


14.1 THE ROLE OF FLEET MANAGEMENT

Fleet management is an integral and critical part of our Asset Management system. It enables us to translate our Asset Management objectives and targets into specific renewal investment programmes, for each of the asset fleets we manage. This helps ensure the investments and decisions we make regarding our assets appropriately support our asset management objectives and targets.

Fleet management also helps ensure disciplined top-down oversight to ensure each fleet is managed appropriately over the life of the associated assets. Our goal is to manage performance within acceptable bounds and ensure the total cost of ownership is appropriate. This gives us confidence assets are safe and in a suitable condition to remain in service.

14.2 STRUCTURE OF THIS SECTION

We discuss in detail the approach we use for renewal expenditure governance and planning in Chapter 6 and 7 of this AMP those chapters discuss the asset management frameworks we use to guide the investments we make, including our fleet management decisions.

This section of the AMP summarises the content of our fleet management plans. The chapters within the section are intended to provide a general overview of the trends, issues and considerations which have shaped our fleet management approach. They show how this translates into our forecast renewal investments for the planning period.

We have grouped our network assets into seven portfolios[53] and have prepared a chapter on each. The portfolios and associated chapters are listed below.

Table 14.1 Portfolio and asset fleet mapping

PORTFOLIO	ASSET FLEET	CHAPTER
Overhead structures	Poles Crossarms	15
Overhead conductors	Subtransmission overhead conductors Distribution overhead conductors Low voltage overhead conductors	16
Cables	Subtransmission cables Distribution cables Low voltage cables	17
Zone substations	Power transformers Indoor switchgear Outdoor switchgear Buildings Load control injection Other zone substation assets	18
Distribution transformers	Pole mounted distribution transformers Ground mounted distribution transformers Other distribution transformers	19
Distribution switchgear	Ground mounted switchgear Pole mounted fuses Pole mounted switches Circuit breakers, reclosers and sectionalisers	20
Secondary systems	SCADA and communications Protection DC supplies Metering	21

[53] These portfolios differ in some respects from the asset categories specified by Information Disclosure. They better reflect the way we manage these assets and plan our investments.

For each portfolio, we set out the key information which has an impact on our investment decisions. The level of coverage in this AMP is less than we have in the detailed fleet management plans we use for internal purposes, in this document we opt for brevity and limit our discussion to a high level overview. The key points covered are:

- High level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition and risks
- Preventive maintenance and inspection tasks
- Renewal strategies
- Renewal forecasting approaches

In the later part of the section we consider other investment portfolios:

- In Chapter 22 we consider non-network assets including Information Communications Technology (ICT), buildings, office fittings and vehicles.
- In Chapter 23 we describe our maintenance and vegetation strategies and associated expenditure forecasts.

14.3 SCOPE OF EACH FLEET MANAGEMENT PLAN

The investments covered by our fleet management plans comprise both asset renewal (replacement of assets with like-for-like or new modern equivalents) and refurbishment (investments that extend the useful life or increase the service potential of an existing asset). They exclude 'network development capex' which increases the size, capability or functionality of our network, which is covered in Chapters11 to 13 of this AMP.

Renewal and refurbishment are carried out, for the most part, to manage asset deterioration and ensure our assets remain in a serviceable and safe condition. As an asset deteriorates it will eventually reach a state where ongoing maintenance becomes ineffective or excessively costly. Other reasons for renewal or refurbishment include managing safety risk or network performance, meeting regulatory and legislative requirements and obsolescence.

During the planning period set out in this AMP, we are committed to increasing renewals related investments across a number of our key asset fleets (most significantly overhead conductor, poles, and crossarms) in response to the key issues outlined in **Table 14.2.** Renewals expenditure forecasts are contained in each portfolio chapter, and summarised in Chapter 26.

Table 14.2 Emerging issues relating to our asset fleets

AREA	DESCRIPTION
Safety of staff, contractors and the public	Where asset condition and health is degraded, the likelihood of failure increases. This increases safety risk for the public and anyone working on the assets, especially in the case of overhead transmission lines. We prioritise replacement of assets that present elevated safety risks.
Asset health	We use 'asset health' to reflect the expected remaining life of an asset based on a variety of factors including its condition, age and known type issues. Maintaining appropriate levels of asset health is a key driver for our renewals investment. Assets in poor health pose an increased risk of failure, leading to additional reliability and safety risks.
Reliability	Our renewal investments target assets that have the potential to degrade, or have already degraded, service reliability due to faults or forced outages. Some of our customers experience interruption levels exceeding our targets. We prioritise our renewal investment in these areas to improve our service.
Obsolescence	Asset renewal can become necessary when existing assets become incompatible with our modern systems and standards, lack necessary functionality or are longer supported by the manufacturer. We also consider the level of diversity in our fleet as removing 'orphan' models streamlines our approach to maintenance, helping to manage costs. Renewing obsolete assets supports our future readiness objectives and will enable us to deliver our forecast efficiencies.

15.1 CHAPTER OVERVIEW

This chapter describes our overhead structures portfolio and summarises our associated fleet management plan. The portfolio includes two asset fleets:

- Poles
- Crossarms

This chapter provides an overview of these asset fleets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to increase our investment in overhead structures renewals from $23m in 2018 to a peak of $38m in 2022. This portfolio accounts for 40% of renewals Capex over the period. The increase is gradual to ensure deliverability.

Increased investment is needed to support our safety and reliability objectives. Failure of overhead structures can have a significant impact on our safety and reliability performance. This increase in renewals Capex is driven by the need to:

– Reduce the number of pole defects to steady state levels
– Continue to replace poor condition poles and crossarms
– Address type issues in our crossarm fleet
– Ensure overhead structures are sized appropriately when associated conductor is replaced

Below we set out the asset management objectives that guide our approach to managing our pole and crossarm fleets.

15.1 OVERHEAD STRUCTURES OBJECTIVES

Poles and crossarms are core components of our network. Combined with overhead conductors they make up our extensive overhead network (78% of total circuit length), connecting our customers to the transmission system at grid exit points and enabling the flow of electricity on circuits of varying voltages.

The performance of these assets is essential for maintaining a safe and reliable network. As the majority of our overhead network is accessible to the public, managing our overhead structure assets is also critical in ensuring public safety, especially in urban areas.

To guide our day-to-day asset management activities, we have defined a set of portfolio objectives for our overhead structures assets. These are listed in the table below. The objectives are linked to our asset management objectives as set out in Chapter 5.

Table 15.1: Overhead structures portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No condition driven pole failures resulting in injury. No crossarm failures resulting in injury. Dispose of softwood poles responsibly. Ensure hardwood crossarms are sourced from sustainable forests.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Pole and crossarm renewal is targeted at poor performing network areas to improve feeder reliability and manage overall SAIDI and SAIFI. Consider the use of alternative technology to improve reliability or reduce service cost (eg remote area power systems).
Asset Stewardship	Expand use of criticality and asset health to inform renewals. Reduce the number of pole and crossarm defects to sustainable levels.
Operational Excellence	Improve and refine our condition assessment techniques and processes for poles and crossarms.

15.2 POLES FLEET MANAGEMENT

15.2.1 FLEET OVERVIEW

Our network comprises concrete poles (85%), wooden poles (15%) and a small number of steel poles. We have approximately 265,000 poles on our network.

There is a wide range of poles in terms of height, strength, age, condition, and the types of failure modes.

Concrete poles
There are two types of concrete poles - pre-stressed and reinforced. Pre-stressed constitutes the majority of poles on our network (55%).

Pre-stressed poles are generally considered a robust, mature asset type and are expected to perform their function reliably over a long period.[54] Pre-stressed poles have been used for more than 50 years and are manufactured with high tensioned steel tendons (cables or rods). Most new poles installed are pre-stressed and are

[54] Note: an issue has been identified with a certain type of pre-stressed concrete pole which is discussed in the condition, performance and risks section.

designed and manufactured to meet stringent structural standards. Pre-stressed poles have a design life of 80 years.

Reinforced concrete poles contain reinforcing steel bars (usually four to six) covered by concrete. These poles were regularly used from the 1960s to 1980s but less so during the past 35 years. These concrete poles have been produced by many manufacturers for different areas of our network, which has resulted in differences in design, manufacture and material quality.

Figure 15.1: A modern pre-stressed concrete pole and a rural softwood pole

Wooden poles

Wooden poles can be categorised into three types based on the wood used – hardwood, larch, and softwood.

Many hardwood varieties are used on our networks, most of which were installed before 1985. The exact species is unknown in some cases and performance varies within and across species. We have found that certain species decay faster than others, some have a tendency to split, some have head rot, some have below ground rot, and others 'peel' concentrically.

The category of larch poles incorporates species with strength and durability falling between softwood and hardwood, with performance that varies widely. The use of larch poles was phased out from 1990.

Softwood poles are generally pine that has been treated with copper chrome arsenic (CCA). On rare occasions, softwood poles can deteriorate rapidly and unpredictably. While these poles are lighter and lower cost than others, the decreased reliability meant we used fewer from the mid-1990s and they are now no longer installed on our network.

The use of wooden poles in the construction of new networks is being phased out. Our analysis of testing methods has highlighted that there is no single fool proof technique for assessing the condition of wooden poles, especially softwood, some of which have failed for reasons that are difficult to identify. The wide natural variances in timber strength mean that wooden poles perform inconsistently. Life extension techniques, such as pole staking, are also not considered a viable approach. We continue to evaluate better condition assessment techniques for wooden poles to better understand the reliability of those remaining on our network.

Steel poles

We have a small number of steel poles in service. There are two main types in use - legacy 'rail iron' poles, which were installed during the 1970s, and modern tubular poles. Both have more consistent performance compared with wooden poles.

Tubular steel poles are more expensive than concrete poles. These are useful for remote or rugged sites as they are light and can be flown in as sections for on-site assembly. However, it can be difficult to assess corrosion on the inside of the pole and below ground. Our policy is to use steel poles only in special circumstances. This will be reassessed when they become price competitive with pre-stressed concrete poles over their life cycle.

15.2.2 POPULATION AND AGE STATISTICS

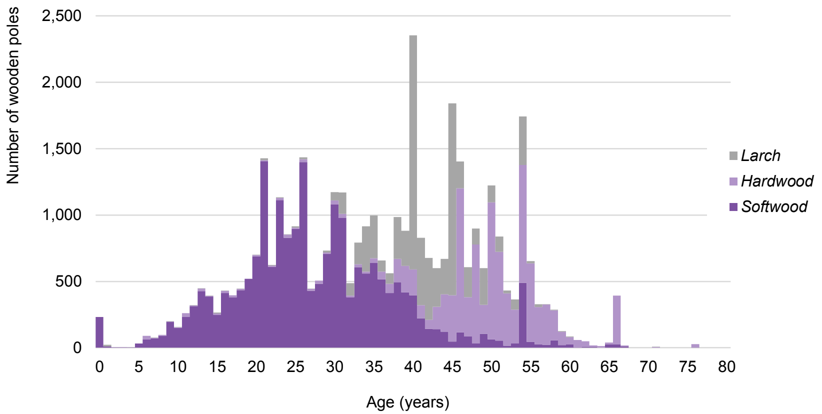
The table below summarises our population of poles by type. High performing pre-stressed concrete poles make up more than half of the pole population. Wooden poles make up only 15% of our pole fleet, but their large number means their replacement will still require a large investment.

Table 15.2: Pole population by type at 31 March 2016

POLE GROUP	POLE TYPE	NUMBER OF POLES	% OF FLEET
Concrete	Pre-stressed	145,532	55
	Reinforced	79,280	30
Wood	Hardwood	9,827	4
	Larch	8,330	3
	Softwood	21,184	8
Steel	Steel	1,066	0.4
Total		265,219	

The figure below depicts our wooden pole age profile. It shows that many hardwood and larch poles have exceeded or soon will exceed their expected lives. Our survivorship analysis estimates expected average lives of between 30 and 40 years, depending on type.

Figure 15.2: Wooden pole age profile

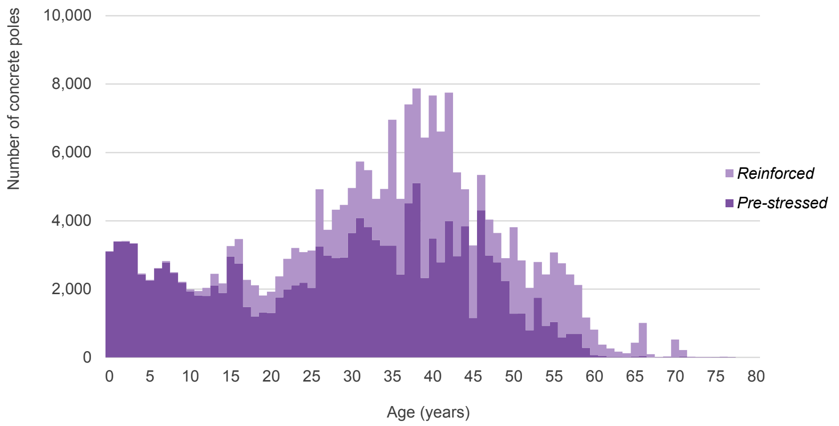


This is consistent with the high proportion of pole defects on our network involving these pole types. Softwood poles have an average age of 27 years and many have or soon will exceed their expected life.[55]

The majority of poles installed in recent years have been pre-stressed concrete. Concrete poles have longer expected lives than wooden poles.

The figure below shows our concrete pole age profile. The reinforced concrete pole fleet has a higher average age than the pre-stressed pole fleet.

Figure 15.3: Concrete pole age profile



We expect that few concrete pole replacements will be needed for condition reasons in the medium-term. The average age of our concrete poles is 32 years and no poles exceed their 80-year expected life, which is based on our survivorship analysis.[56]

15.2.3 CONDITION, PERFORMANCE AND RISKS

In-service pole failure can be a serious safety issue, in the worst case dropping live conductor on the ground and potentially putting the public in danger. It is also a reliability issue as pole failure typically results in the loss of supply. We always aim to replace poles before they fail so as to minimise safety and reliability risks.

Meeting our portfolio objectives

Safety and Environment: Poles are replaced using condition information before failure, thereby minimising safety risks.

It is important to rectify pole defects promptly. While most pole failures are caused by vehicle accidents and adverse weather, pole failures with existing condition defects can be triggered under stress (eg through high winds).

55 Note that actual pole replacement is based on condition assessment and field inspection results.

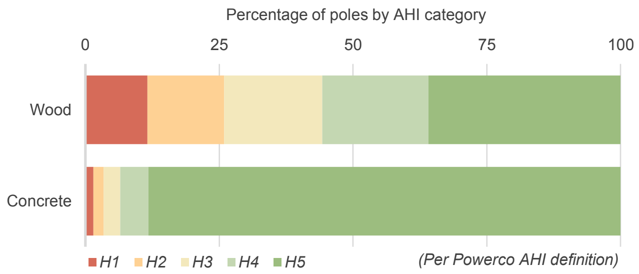
56 Note that the industry standard life is 60 years.

Pole asset health

As outlined in Chapter 7, we have developed asset health indices (AHI) that reflect the remaining life of an asset. In essence, our AHI models categorise their health based on a set of rules. For poles we define end-of-life as when the asset can no longer be relied upon to carry its mechanical load and the pole should be replaced. The AHI is based on our survivorship analysis and our current defect pool.

The figure below shows current overall AHI for our population of concrete and wooden poles.

Figure 15.4: Wooden and concrete pole asset health as at 2016



The health of our wooden poles is a concern as approximately half our wooden pole fleet will require renewal over the next 10 years (H1-H3). About 12% have already been identified for replacement within one year (H1).

In contrast, the concrete pole fleet is in good overall health. Only 7% of this fleet is expected to be replaced in the next 10 years (H1-H3).

Pole defects

We carry out regular inspections of our poles to verify their condition and to identify any defects that require repair or replacement.

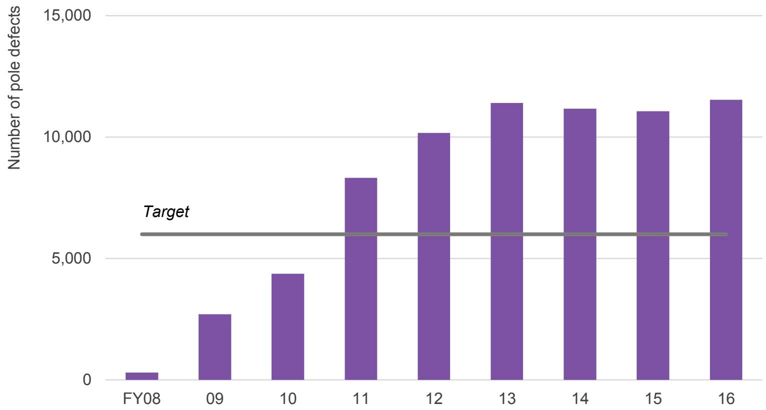
The main pole failure modes differ by pole type. Some common examples are set out in the table below. Our defect process aims to identify these issues well in advance of pole failure to allow planned and coordinated replacement.

Table 15.3: Pole failure modes by type

POLE TYPE	FAILURE MODES
Pre-stressed concrete	Cracking in concrete allows moisture ingress, causing the internal steel pre-stress tendons to rust and lose strength. If not addressed, this loss of strength can allow a strong force, such as storm winds, to catastrophically snap the pole.
Reinforced concrete	Spalling is the loss of concrete via flaking or fragmenting. If the concrete falls away, significant strength remains in the internal reinforcing bar structure. Rusting will occur once the interior becomes exposed but there would need to be a large amount of spalling before replacement is warranted.
Steel	Corrosion of steel poles typically occurs over time. This is relatively easy to assess through inspection, although internal corrosion of tubular steel poles and underground corrosion is more difficult to assess.
Hardwood	Decay in hardwood poles occurs below or above ground at the pole head because of moisture. Both areas are difficult to assess and susceptibility to decay varies between hardwood species. Cracks may appear as the pole ages in certain environments.
Softwood and larch	Decay in softwood and larch poles typically occurs from the inside out, making it more difficult to identify defects than for other pole types. This means they can appear sound but actually be in poor condition.

The figure below outlines the increase in pole defects over time against the sustainable defect pool level.

Figure 15.5: Defected poles



Our current inspection and defect process has been in place since 2008. Since then, we have inspected our entire pole population and identified significant numbers of defected poles requiring replacement. Although we have been carrying out pole renewals over this time, the defect pool[57] (approximately 11,000 poles requiring replacement) is larger than our long-term sustainable level, and an increase in renewals is required to reduce this risk. Our inspection programme is ongoing and we expect to find further defects as our pole fleet ages and its condition degrades.

The target level is based on a three-year replacement stock, which allows time for replacement coordination to ensure efficient delivery. Note that the defect pool contains no urgent 'red' defects – these poles are replaced as a priority because of associated safety risks.

Wooden pole testing

To inform our condition-based forecasts we have trialled a variety of techniques to improve the accuracy of our predictive models. We have adopted the Vonaq acoustic resonance tool for wooden pole testing. Acoustic resonance tools use the relationship between wood structure elastic parameters and resonance frequency behaviour.

Our trials involved poles already earmarked for replacement being tested with several lightweight portable testing devices and then break tested to confirm failure load. The acoustic resonance tests, and specifically the Vonaq tool, showed the highest correlation with the break testing results (the only way to confirm the actual strength/condition of the pole) as well as being the easiest tool to use across the network. The acoustic resonance test outperformed visual inspection results.

We also found that no test proved effective in detecting all 'poor' poles. Any new tests will be used alongside existing techniques.

Overall, the results indicate that while current inspection techniques are prudent, better information will allow us to improve the timing of our pole renewals, extending the lives of some while also identifying defects not found through current techniques. We will continue our trials and refine our testing approaches.

Meeting our portfolio objectives

Operational Excellence: We have trialled and are implementing improved pole condition assessment techniques to improve defect accuracy and asset renewal timing.

Type issues

In addition to condition related defects, we also have several pole type issues[58] within the fleet. We identified one type of pre-stressed concrete pole (known as '105 series') to have very poor strength under certain 'down-line' stresses, despite being visually assessed as in good condition. We no longer install these poles and ensure overhead line designs for upgrades take into account their lower strength.

As noted above, reinforced concrete poles were made by a variety of manufacturers using local materials (eg gravels, sands) with varying degrees of quality control. As a result, we are not able to verify the design strength for some of these poles. We are confident they safely carry their working load (as they have been in service many decades) and we ensure that no additional load is added to these poles because of the uncertainties in overall strength.

15.2.4 DESIGN AND CONSTRUCT

Most new poles installed on our network are pre-stressed concrete. In special circumstances we use lighter-weight steel poles, for example where a pole needs to be installed using a helicopter.

57 The defect pool includes both serious defects requiring asset replacement (such as rotting poles) and minor defects requiring only minor repairs or remedial work (such as lack of pole signage). This chapter addresses defects requiring full asset replacement.

58 A type issue is a problem affecting the reliability or safety of a particular subset of assets, often related to a particular design or manufacturing issue. These are sometimes also referred to as 'batch' issues.

When performing larger overhead line works we use our internal design and construction standards, which draw heavily on external rules and standards such as AS/NZS 7000 – Overhead Line Design. Safety is central to our standards.

15.2.5 OPERATE AND MAINTAIN

Poles are inspected and their condition assessed as part of overall overhead network inspections. There is little physical maintenance work undertaken on poles. Poles are durable, static, and do not require mechanical or electrical maintenance work.

Our preventive pole inspections are summarised in the table below. The detailed regime for each type of pole is set out in our maintenance standards.

Table 15.4: Pole preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	1 yearly
Visual inspection of all subtransmission poles as part of overhead network inspections. Alternates between a rapid inspection (ie no digging at ground line required) and a more detailed condition assessment.	2 ½ yearly
Visual inspection of distribution and LV poles as part of overhead network inspections, completing a detailed condition assessment.	5 yearly
Structural assessment of urban wooden angle poles and wooden termination poles.	10 yearly

The pole inspection frequency reflects a combination of historically legislated periods and our experience with identifying defects in pole types and locations.

The nature of wooden poles makes routine maintenance work and inspections difficult. For example, deterioration is typically internal and/or below ground. Testing techniques, such as drilling, can weaken poles and allow in water, which accelerates deterioration. Modern inspection techniques can identify most poles in poor condition but may not accurately detect all failure modes.

All poles need regular inspection because they may be damaged or compromised by a third party and without inspections we may not find out. As an example, a pole may be undermined as a result of roading activity or a third party may add an unapproved attachment that places additional load on the pole. Poles may also lean because of poor ground conditions or flooding.

One of the most common causes of pole failure is third party vehicle damage. At times we need to temporarily prop a damaged pole either by using a vehicle-mounted crane or by temporary bracing using another pole. A temporary prop or bracing is used to enable the line to remain energised while preparation is made to replace the damaged pole, thereby minimising the effect of any outage.

A key component of our routine inspections is identifying defects. Where a defect that presents a hazard is detected, the defect is assessed for failure likelihood and prioritised.

Red defects are immediately reported to the NOC. Amber and green defects are reported to the Service Delivery team (amber) or the Planning team (green) to address. Corrective maintenance or asset replacement is scheduled based on the severity of the defect.

15.2.6 RENEW OR DISPOSE

Renewal of poles is primarily determined by asset condition, typically through our defects process. Defects are identified through our routine network inspections and poles are either replaced reactively (for red defects) or enter our planning processes for replacement through work packages.

Prioritisation uses our in-house Defect Risk Assessment Tool (DRAT) to systematically analyse defects and the risks presented by them, enabling prioritisation on the basis of criticality and condition. As part of this planning we also identify poles with strength related issues (such as ‘105 series’ poles) where not already defected, and prioritise these for replacement.

SUMMARY OF POLES RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

As discussed earlier, our inventory of pole defects exceeds our long-term sustainable level and we need to increase our number of pole replacements to correct this. We aim to have our pole defect pool at a sustainable level by FY25.

Meeting our portfolio objectives

Asset Stewardship: Forecasted pole renewals expenditure will reduce the defect pool to sustainable levels by FY25.

A number of poles also get replaced through our reconductoring programmes.[59] Replacement of overhead conductor (whether for renewal or growth reasons) often uses a heavier conductor than what was previously installed, thereby increasing the mechanical load on each pole. Although the pole may still be in reasonable

59 See Chapter 16 on Overhead Conductors.

condition, if the additional load exceeds the residual strength of the pole then it must be replaced.

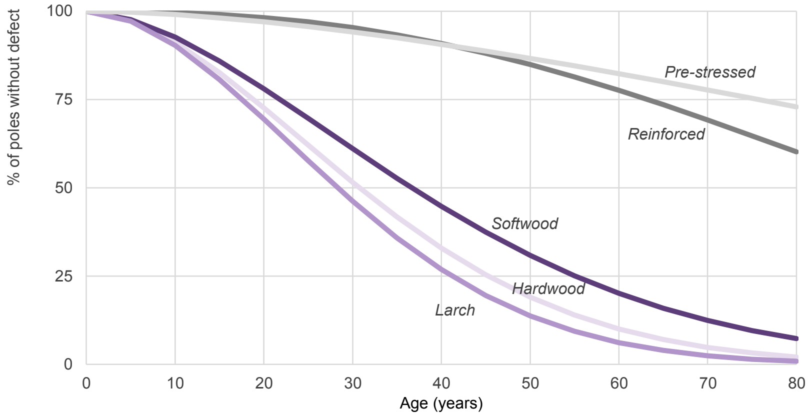
We have previously considered and trialled pole-life extension techniques, but generally found these not to be cost effective (refer to Pole Life Extension discussion later in this section). An example of these techniques is 'pole bandages' that contain preservatives and fungicides around wood poles at ground level to prevent rot.

Renewals forecasting

Our pole replacement quantity forecasting incorporates historical survivorship analysis. We have developed survivor curves for each of our pole types and use these to forecast defects and renewal quantities.

A forecasting approach that incorporates defect history is more robust than a purely age based approach, due to the use of historical quantitative data. The figure below shows our typical pole survivor curves. Each curve indicates the percentage of population remaining at a given age.

Figure 15.6: Pole survivor curves



The survivor curves show that poles require replacement over a wide range of ages. In addition to type, this is influenced by factors such as location and manufacturing.

Our wooden poles tend to require replacement at a similar age to the industry expected life (although with a very wide distribution). Our concrete poles generally do not require replacement until well after their industry expected life.

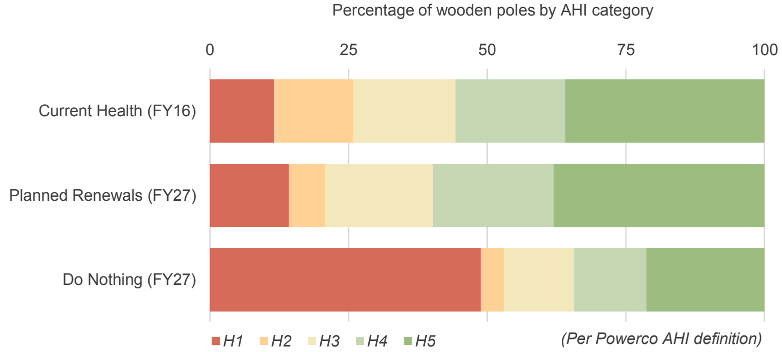
Volumes of pole renewals are forecast to increase over the next three to five years, primarily to reduce the size of the defect backlog. Longer term levels of defect based renewal are expected to stabilise at around today's volume.

End-of-life pole replacements over the planning period will primarily target wooden poles. As discussed earlier in the condition, performance and risks section, the health of our wooden pole fleet is poor.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our investment will lead to an improvement in overall health.

An equivalent chart for concrete poles has not been provided as the level of renewals is small in comparison to the overall fleet, leading to a relatively small change in health categories.

Figure 15.7: Projected wooden pole asset health as at 2027



A significant number of wooden poles will still need to be replaced after 2026, as indicated by the H1-H3 portion in Planned Renewals (FY26). These will be mainly softwood poles due to their relatively short expected lives.

Pole disposal

Poles are disposed of when they are no longer needed because of asset relocation (eg undergrounding), asset replacement, or following failure. When a pole fails we carry out diagnostic inspection and testing to assess the root cause of failure. As trends emerge from the failure analysis we incorporate them into our pole fleet asset management approach.

Requirements for recovery and disposal include safe work and site management processes and appropriate environmental treatment of scrap material. In particular, CCA treated softwood poles need to be disposed of appropriately.

Meeting our portfolio objectives

Safety and Environment: Softwood poles are disposed of appropriately to avoid potential environmental impacts.

Pole life extension

Historically we have trialled and utilised a number of pole life extension techniques, where we have assessed that these reduce the whole-of-life cost of a pole or manage network risk associated with end-of-life assets. These have included painting, washing insulators to remove contaminant build-up, applying chemicals as in the case of pole bandaging (wrapping gel bandages containing fungicides and preservative around the ground line of the pole), and epoxy repairs to prevent corrosion on exposed reinforcing rods. We have also used pole stapling as a temporary solution to strengthen the base of decaying wooden poles until they can be replaced.

Few of these measures remain in use due to lack of efficacy or cost effectiveness, because of difficulty in applying the technique live-line, and due to concerns about risks associated with handling chemicals and maintaining staked poles. We plan to revisit several of the measures that were found to be effective (or potentially effective) but faced other hurdles. In particular, we plan to review application of gel to pole tops that do not have metal caps, and insulator washing. We may use epoxy repairs in situations where damage is superficial, but not more widely due to safety concerns.

Coordination with Network Development projects

Pole replacements can be triggered by a need to upgrade or thermally uprate the conductor they are supporting, as part of the Develop or Acquire life cycle stage. These upgrades put higher mechanical loads on the poles, often forcing an accompanying replacement to ensure the new conductor is safely supported.

Modern pre-stressed concrete poles often have enough design strength ‘headroom’ to support these upgrades. Older wooden poles or reinforced concrete poles, where their design strength is unable to be verified (see discussion above), will likely require replacement.

As part of these upgrade projects we also identify poles in poor condition and coordinate their replacement alongside the conductor to ensure efficient delivery and to minimise customer disruption. The detailed requirements for each individual upgrade project are confirmed by a full design study.

Meeting our portfolio objectives

Customers and Community: Replacement works are coordinated across portfolios to minimise customer interruptions and ensure efficient delivery.

15.3 CROSSARMS FLEET MANAGEMENT

15.3.1 FLEET OVERVIEW

A crossarm assembly is part of the overall pole structure. Their role is to support and space the insulators that connect to the overhead conductor. A crossarm assembly is made of one or more crossarms and a range of ancillary components such as insulators, armour rods, binders and jumpers, and arm straps.

From this point, we simply use crossarm to refer to a crossarm assembly.

A pole may have more than one crossarm, such as when an 11kV and 400V circuit are constructed on the same overhead line. There are significant safety and performance risks associated with crossarm failure.

Figure 15.8: Different crossarm configurations

Our crossarms are typically made from hardwood. Hardwood crossarms have insulating characteristics that limit fault currents. They can be easily drilled, allowing for simple installation of insulators, HV and LV fuse holders, and arm braces.

The crossarm fleet also includes a small number of steel crossarms. Like steel poles, deterioration is relatively predictable and their condition can be more easily and reliably assessed (even from the ground) than wooden crossarms.

Crossarm components

Crossarm components such as insulators, binders, jumpers and armour rods are needed so the crossarm can carry conductor. Components may be replaced through the defect process as needed (this is treated as maintenance Opex). It is generally cost effective to replace the entire assembly when a crossarm fails or has a defect.

The purpose of insulators is to support the conductor while providing electrical separation (through creepage distance) of the live conductor from the crossarm and pole structure. There are many types of insulators. Those on our network are generally pin, shackle or suspension/strain types made from high grade glazed porcelain, glass or polymer.

Binding wire binds the conductor to the insulator. It is made of soft-drawn wire of the same material as the conductor. Armour rods wrap around the conductor, protecting the conductor from chafing on the insulators as well as providing some Aeolian dampening for conductor vibrations.

15.3.2 POPULATION AND AGE STATISTICS

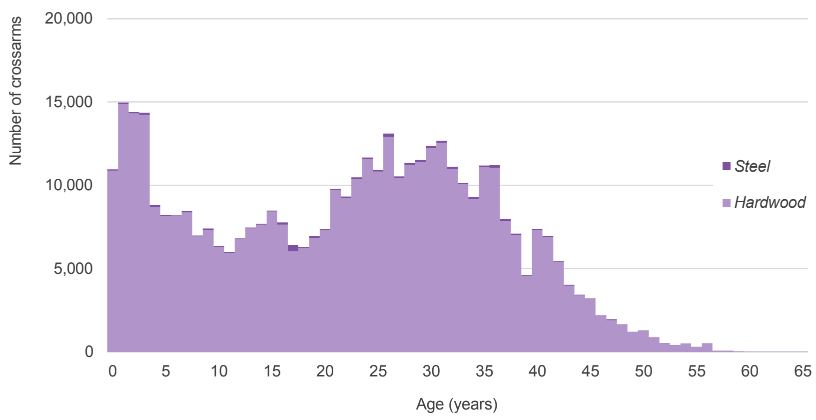
We have approximately 419,000 crossarms in service, comprising a number of sizes and configurations.

Table 15.5: Crossarm population by type and voltage at 31 March 2016

CROSSARM TYPE	VOLTAGE	COUNT	% OF TOTAL
Hardwood	Subtransmission	15, 890	3.8
	Distribution	227,418	54.3
	Low voltage	170,990	40.8
Steel	Subtransmission	1,265	0.3
	Distribution	2,044	0.5
	Low voltage	1,146	0.3
Total		418,753	

The figure below shows our crossarm age profile. Crossarm condition typically deteriorates after 30 years in service. Our analysis reveals that after 35-40 years the likelihood of defects increases rapidly. Many of our crossarms are older than 40 years, indicating the need for significant renewal investment in the short-term.

Figure 15.9: Crossarm age profile



We have compiled the crossarm age profile using different data sources. Data on new crossarms installed since 2000 are taken from GIS. GIS also captures information on some older crossarms captured during regular inspections. For older assets we have derived crossarm ages based on other asset information. For example, it is common to replace a crossarm at the same time as a pole; therefore pole age can be used as a proxy for crossarm age.

15.3.3 CONDITION, PERFORMANCE AND RISKS

In-service failure of a crossarm can lead to dropped conductors or spans lowered to unsafe clearances. This would present a significant safety risk to the public.

Hardwood crossarms typically fail as a result of age-related cracking and loss of strength as the wood dries out, or because of rotting on the upper side as a result of moisture ingress. Wooden crossarms also fail because of burning caused by electrical tracking as a result of insulator degradation. Failure modes tend to be strongly influenced by environmental conditions.

Crossarm components also fail. Insulators on hardwood crossarms may loosen because of shrinkage or significant levels of rot. Line guards (short spans) and armour rods (long spans) are designed to wear to prevent conductor fatigue. Binders fatigue over time and are replaced as part of maintenance.

We have identified a subtransmission insulator type issue. Some insulators of two-piece porcelain construction have an increased failure risk. For example, we recently had a near miss where the top of an insulator sheared off during live line maintenance. Because of the potential safety consequences of these failures, we are proactively replacing crossarms that have these insulators.[60]

Meeting our portfolio objectives

Safety and Environment: Crossarms are replaced proactively using condition and type information, thereby minimising safety risks.

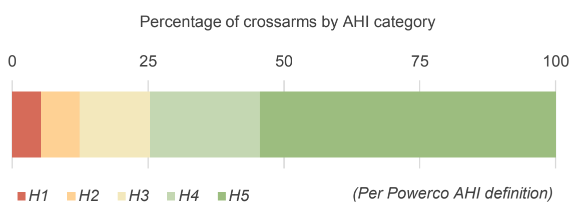
Insulators can crack or completely fail through shock loading, typically caused by adverse weather or tree strikes. Failures can also occur through flashovers, which are more prevalent in areas with high air pollution. These issues are fixed as needed (reactively).

Crossarms asset health

As outlined in Chapter 12, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end-of-life and categorise their health based on a set of rules. For crossarms, we define end-of-life as when the asset can no longer be relied upon to carry its working load, and the crossarm should be replaced. The AHI is based on our survivorship analysis, our current defect pool and reflects the type issue affecting subtransmission insulators.

The figure below shows current overall AHI for our crossarm population.

Figure 15.10: Crossarm asset health as at 2016



Approximately 5% of crossarms require renewal in the short term (H1). This is primarily due to the crossarm defect pool and our replacement programme of subtransmission crossarms with two-piece insulators.

There are also many crossarms that will require renewal during the next 10 years (H2 and H3). This reflects the large number of older crossarms in our fleet, as shown in the age profile earlier.

60 It is cost effective to replace the whole crossarm assembly not just the insulators. These crossarms usually are in poor condition and would need to be replaced in the medium-term anyway.

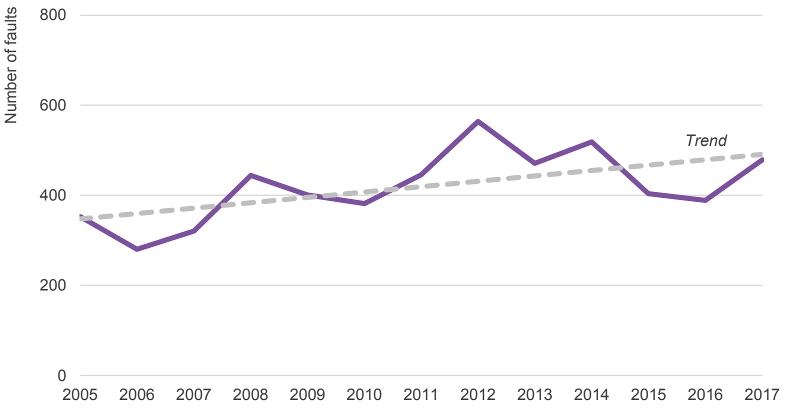
Crossarm defects

As with poles, we carry out regular inspections of our crossarms to assess their condition and to identify defects. Like poles, defect levels have been rising and we need to increase our levels of crossarm renewals. Defect analysis shows that crossarms older than 35 years are much more likely to have defects. This means that their risk of failure increases.

We are currently focused on improving the condition assessment regime for crossarms. We are considering changes to the inspection methods, measures to address data gaps, and the use of additional training for field staff.

The increasing number of crossarm and hardware related faults on our network (shown below) supports the needs case for increasing crossarm renewals. The fault trend suggests that the health of our crossarm fleet is worsening.

Figure 15.11: Crossarm fault history[61]



15.3.4 DESIGN AND CONSTRUCT

While the crossarms on our network are typically made of hardwood, we are exploring the use of steel or fibreglass/polymer in the longer term. Their initial cost is higher but they are likely to have lower costs through other parts of the life cycle because they last longer, are easier to inspect and their condition can be assessed with greater confidence. They are also likely to be more reliable.

Steel crossarms may increase public safety risks due to earth potential rise around poles during high impedance faults. To manage these risks in urban environments may require pole earthing improvements.

61 Fault history excludes events related to vegetation, human elements, lightning and planned shutdowns.

We are considering different types of hardwood to those currently in use as we expect they will become harder to source and more expensive. We are also monitoring developments in polymer insulators for distribution and LV networks.

15.3.5 OPERATE AND MAINTAIN

We undertake various types of inspections on crossarms, as set out in the table below. Crossarms are inspected as part of overall overhead network inspections. The detailed regime for each type of asset is set out in our maintenance standards.

Table 15.6: Crossarm preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	1 yearly
Visual inspection of subtransmission crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	2 ½ yearly
Visual inspection of distribution and LV crossarms as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

Crossarm faults generally occur because of age-related deterioration. Fault repairs involve replacement of individual components or complete crossarm assemblies (considered replacement Capex). Preventive inspections identify components that have deteriorated, enabling us to do remedial work before a fault occurs. Typical corrective jobs include:

- Replace broken, rotten, or cracked arms. Replace arms where insulator pin has flogged the mounting hole because of wind movement.
- Replace broken or damaged arm braces and bolts.
- Replace individual cracked or failed insulators.

Crossarm components are held in stock at service provider depots and field trucks. The individual items are relatively light and can be readily hauled or carried into place to expedite fault repairs.

Wooden crossarms are relatively easy to cut and drill (for insulator pins and mounting holes) from stock timber lengths. Pre-drilled arms, insulators and other components are held in stock at strategic locations.

15.3.6 RENEW OR DISPOSE

Historically we have taken a mainly reactive approach to crossarm renewal, as determined by the defects process. Some additional replacements were undertaken in critical areas of our networks and others have been replaced during pole replacements.

Over the planning period we intend to increase the volume of proactive replacement because of failure-related safety risks, worsening crossarm asset health, and because planned work is more cost effective than reactive work.

SUMMARY OF CROSSARMS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based, type
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

We will use our Defect Risk Assessment Tool alongside other condition and type information to prioritise renewal work programmes. In the short to medium term our works will focus on replacing crossarms already marked as defective and subtransmission crossarms with insulator type issues. We will deliver these renewals as large programmes where possible to ensure cost effectiveness.

Renewals forecasting

Our crossarm replacement quantity forecast incorporates historical survivorship analysis. We have developed a survivor curve for our hardwood crossarms and use this to forecast required renewal quantities.

The analysis reveals that crossarms require replacement over a range of ages. This is likely due to varying environmental conditions on our network and the inherent variability in the quality of hardwood crossarms.

The volume of renewal needs to significantly increase over the next five years to longer term sustainable levels (as indicated by the survivorship analysis). This increased renewal is expected to halt the rise in crossarm related faults.

Meeting our portfolio objectives

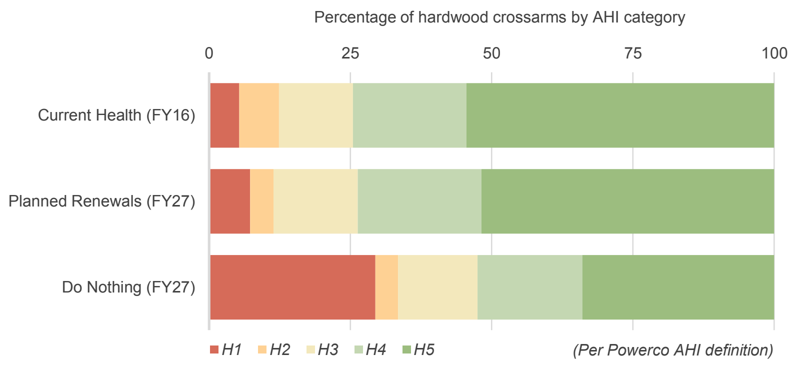
Networks for Today and Tomorrow: Crossarm replacements are forecast to increase, improving the reliability of poor performing feeders and managing network SAIDI and SAIFI.

The volume of crossarms renewals will gradually rise to reduce the crossarm defect pool and complete the replacement programme of type issue subtransmission crossarms.

Longer term, levels of condition based renewals will be higher than current levels. Renewals will transition to maintaining fleet health rather than improving it.

The figure below compares projected asset health in 2027 (following planned renewals) with a ‘do nothing’ scenario. Our investment will lead to an improvement in overall health.

Figure 15.12: Projected crossarm asset health in 2027



A significant number of crossarms will still require replacement after 2027, as indicated by the H1-H3 portion in Planned Renewals (FY26).

Coordination with Network Development projects

Like poles, crossarms are often replaced as part of overhead line reconstruction projects, such as conductor upgrades as part of network development works. As a crossarm's expected life is short compared with a pole or conductor, their replacement for end-of-life reasons can often be coordinated with these works.

15.4 OVERHEAD STRUCTURES RENEWALS FORECAST

Renewal Capex in our overhead structures portfolio includes planned investments in our pole and crossarm fleets. Over the planning period we plan to replace 48,000 poles and 108,000 crossarms. This will require an investment of approximately $330m.

Levels of identified defects have been steadily rising over the past five years, partly as a result of increasing age of the assets and partly due to having established a more robust defects process.

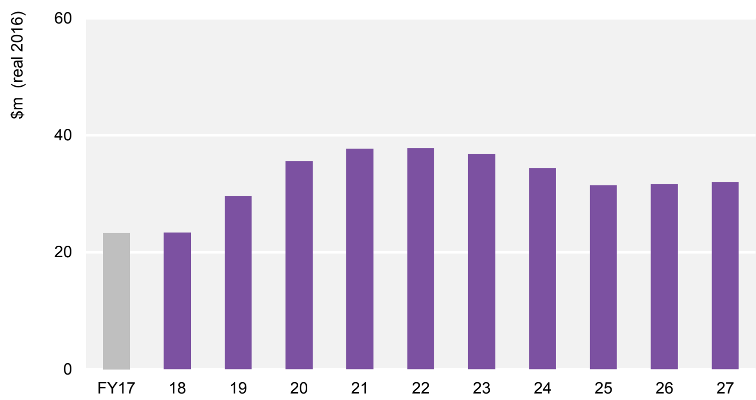
A key driver for pole and crossarm replacement is managing safety risk as pole or crossarm failure can cause conductor drop, and reduce electrical clearance distances. Unsafe poles and crossarms also present significant safety risks to our field workforce.

Pole and crossarm renewal forecasts are derived from bottom up models. These forecasts are generally volumetric estimates (explained in Chapter 24). The work volumes are relatively high, with the forecasts based on survivor curve analysis. We use averaged unit rates based on analysis of equivalent historical costs.

Expenditure in this portfolio includes renewals of poles and crossarms to support our reconductoring programmes. More information on our reconductoring programmes is contained in Chapter 16.

The chart below shows our forecast Capex on overhead structures during the planning period.

Figure 15.13: Overhead structures renewal forecast expenditure



We plan to gradually increase the level of investment over the first five years of the period to allow the mobilisation of additional resources. This forecast reflects the level of investment needed to manage defects within the fleets and includes expenditure on crossarms that have known safety issues. Renewal expenditure will return to a stable level by 2025.

Further details on expenditure forecasts are contained in Chapter 26.

16.1 CHAPTER OVERVIEW

This chapter describes our overhead conductors portfolio and summarises our associated fleet management plan. This portfolio includes three asset fleets:

- Subtransmission overhead conductors
- Distribution overhead conductors
- LV overhead conductors

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to increase our investment in overhead conductor renewals from $4m in 2018 to $17m in 2027. This portfolio accounts for 15% of renewals Capex over the planning period. The increase will be gradual to ensure deliverability.

Increased investment is needed to support our safety and reliability objectives. Failures of overhead conductor can have a significant impact on our safety and reliability performance. This increase in renewals Capex is mainly driven by the need to replace poor condition conductors due to their type, age and accelerated degradation due to coastal environments. We are also commencing a programme of proactive LV overhead service fuse assembly replacements to improve customer service and manage public safety risks.

Certain types of distribution conductor on our network perform more poorly than others. Our average distribution conductor failure rate is 1.4 faults per 100 km per annum.[62] However, we have four types of conductor with failure rates between 2.7 and 4.0 per km per annum. These types of conductor make up 14% of our distribution overhead fleet (or 2,131km). During the planning period we will prioritise the replacement of these types of conductors.

Below we set out the asset management objectives that guide our approach to managing our overhead conductor fleets.

16.2 OVERHEAD CONDUCTORS OBJECTIVES

Overhead conductor is a core component of our network and connects our customers to the transmission system via grid exit points. It enables the flow of electricity on circuits of varying voltage levels. Our network is long, predominantly rural, and most circuits (78%) are overhead.

Our three overhead conductor fleets are defined according to the operating voltage of the conductor. The same conductor type (material) is often used across voltages, albeit of different sub-types and sizes. However, the risks and criticality differ by operating voltage. This means they require different life cycle strategies.

To guide our asset management activities, we have defined a set of portfolio objectives for our overhead conductor assets. These are listed in the table below. The objectives are linked to our asset management objectives as set out in Chapter 5.

Table 16.1: Overhead conductor portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No injuries to the public or our service providers as a result of conductor failure. No property damage, including fire damage, as a result of conductor failure.
Customers and Community	Minimise planned interruptions to customers by coordinating conductor replacement with other works. Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Distribution conductor renewal is targeted at poor performing network areas to improve feeder reliability and manage overall SAIDI and SAIFI. Consider the use of alternative options and technology to improve customer experience and/or minimise network costs, such as remote area power systems.
Asset Stewardship	Reduce the failure rate of distribution overhead conductors to target levels (as indicated by failure rate modelling) by 2030. Maintain the failure rate of subtransmission and LV overhead conductors at or below today's levels. Increase the use of conductor sampling and diagnostic testing to inform and verify renewals expenditure.
Operational Excellence	Develop condition-based AHI for all subtransmission overhead conductors. Develop risk-based techniques for prioritising the renewal of distribution overhead conductors. Improve our information of the LV overhead network, including conductor types, ages and failure information.

[62] This failure rate refers to asset related conductor faults and not total overhead line fault performance.

16.3 SUBTRANSMISSION OVERHEAD CONDUCTORS FLEET MANAGEMENT

16.3.1 FLEET OVERVIEW

Subtransmission overhead conductors are classified as the conductors used in circuits operating at 33kV and above, connecting zone substations to grid exit points (GXPs), and interconnecting zone substations.

Figure 16.1: 66kV subtransmission overhead line in the Coromandel

Conductors used at subtransmission voltages are made of aluminium and copper, in various compositions. Annealed copper was the predominant type used on our networks until about 60 years ago, being highly conductive with good strength and weight characteristics.

During the 1950s we started to use all-aluminium conductor (AAC) and aluminium conductor steel reinforced (ACSR) conductors in place of copper. AAC is a high purity conductor but its poor strength-to-weight ratio (compared to other conductor types) means that today it is typically only used in urban areas where shorter spans and high conductivity are required.

ACSR has become the most widely used type of conductor on our network. An ACSR conductor comprises an inner core of solid or stranded steel and one or more outer layers of aluminium strands. This construction gives it a high strength-to-weight ratio making it ideal for long spans, so it is widely used in rural areas of our network.

The steel core that gives the ACSR conductor its strength also makes it more vulnerable to corrosion in coastal areas. Corrosion is reduced by galvanising and grease coating of the core but this increases the weight of the conductor.

In the last five years all-aluminium alloy conductors (AAAC) have been preferred to AAC conductors. AAAC has recently also become the most used conductor type in new installations, taking over from ACSR. AAAC is stronger than AAC and significantly lighter than ACSR. AAAC also has good conducting properties.

16.3.2 POPULATION AND AGE STATISTICS

There are four types of subtransmission conductors making up approximately 7% of our total conductor length. The table below shows that only small volumes of copper conductor remain in service.

Table 16.2: Subtransmission conductor population by type at 31 March 2016

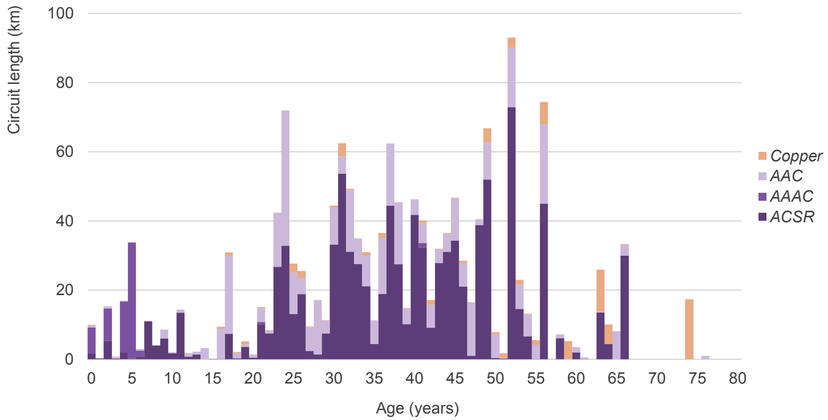
CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	70	5
AAC	415	28
ACSR	937	63
Copper	77	5
Total	1,499	

Our conductor population is ageing. The majority of the conductors were installed in the 1960s, 1970s and 1980s. The average age of the subtransmission overhead conductor fleet is 38. Most remaining copper conductors are 60 years and older.

Significant conductor renewals will be needed over the planning period and beyond based on an expected life of approximately 60 years.[63] The figure below shows our subtransmission conductor age profile.

[63] Note that actual replacement is a condition-based decision.

Figure 16.2: Subtransmission conductor age profile



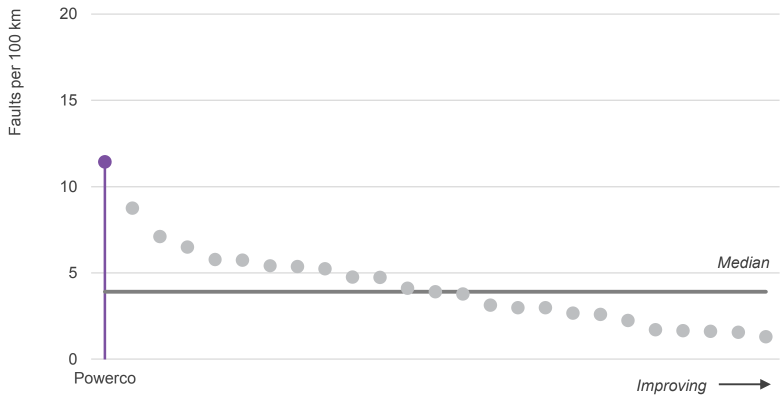
16.3.3 CONDITION, PERFORMANCE AND RISKS

Subtransmission conductor failure rates are lower compared to those of our distribution and LV conductor. Subtransmission conductor makes up 9% of HV conductor length but is only responsible for 2% of total HV conductor failures.

Failure rates are lower because subtransmission conductors tend to be heavier and more robust than distribution and LV conductors. Subtransmission conductors are inspected more frequently due to the higher importance in maintaining reliable supply and a higher ground clearance.

The figure below shows our subtransmission overhead line fault rate compared to that of other EDBs. It shows that we are the worst of the comparison group (averaged over the past four years), with fault rates needing to drop by more than 50% to reach the median of the group.

Figure 16.3: Subtransmission overhead line benchmarking (2013-2016 average)



The table below summarises the common failure modes for all overhead conductors, including distribution and LV.

Table 16.3: Conductor failure modes

FAILURE MODE	DESCRIPTION
Annealing	Annealing is the reduction in minimum tensile strength through heating and slow cooling effects. The effects of heating are cumulative and arise through operation of the line at loads above its rating and design operating temperature. As effects are cumulative, older conductors will generally have relatively lower tensile strength. Copper and AAC/AAAC conductors are more susceptible to annealing; the steel core of ACSR results in lower annealing rates. Smaller distribution conductors are also more susceptible to annealing.
Corrosion	Corrosion, especially from salt spray in coastal areas, is one of the main causes of failure on our networks. Copper has good corrosion resistance but mixed results have been seen with aluminium (including variation within conductors of the same type and size). While ACSR conductors (the steel core) are prone to salt corrosion, this has been managed with galvanising and greasing and as a result it generally performs well.

FAILURE MODE	DESCRIPTION
Fretting or chaffing	Fretting and chaffing is caused by conductor swing causing movement and wear at the contact between two solid surfaces, typically at or near the points of connection to crossarms via the tops of insulators. Binders connect the conductor to the insulators and chaffing can occur between the conductor and binder or between strands of a conductor. Armour rods or line guards (sacrificial metal) are typically used on aluminium conductors at the point of binding to an insulator to avoid this. This issue occurs more on homogenous conductors such as AAC, AAAC or copper. We believe this has a reasonable level of impact on conductor failures on our network.
Fatigue	Conductor fatigue is caused by the flexing of conductors near the insulators. Fatigue is more prominent in long spans (greater than 150 metres) and where lines cross a gully or are on exposed ridges. Continuous 'working' of the conductors causes brittleness over time, resulting in failures. Limiting the amount of conductor oscillation in wind prone areas is desirable with vibration dampers fitted on some lines to mitigate the damage. Copper, AAC and AAAC conductor are more susceptible to fatigue than ACSR.
Foreign object strikes	Foreign object strikes (birds, vegetation etc.) can break a conductor or weaken it to a point where it fails in high winds. Foreign objects need only damage a single strand of a light conductor to cause a loss of tensile strength of around 15%. Strikes can also cause conductor clashing which usually results in the loss of a conductor cross section. ACSR conductors are less susceptible to this issue due to the strength of the steel core. Large object strikes (such as from a tree) can also cause complete mechanical failure of the line.

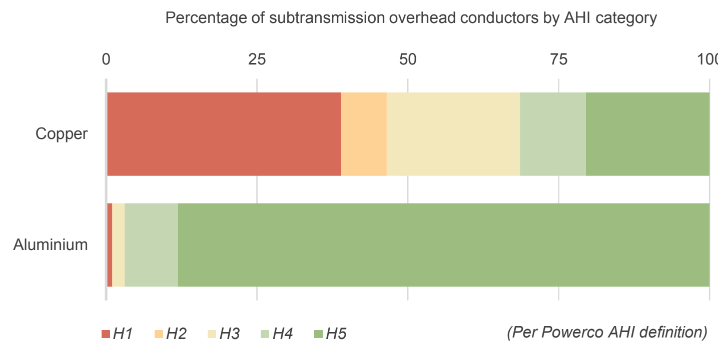
The poorest condition conductors in this fleet are our cooper subtransmission conductor and certain ACSR conductor. Our copper subtransmission conductor is ageing and makes up the majority of our expected renewals during the planning period. We have recently noticed some accelerated corrosion of ACSR conductors. We suspect that improper greasing during manufacture is causing this. When identified this conductor is prioritised for replacement.

Subtransmission overhead conductor asset health

As outlined in Chapter 12, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise their health based on a set of rules. For subtransmission conductors we define end-of-life as when the assets can no longer be relied upon to safely carry their mechanical load and should be replaced.

The figure below shows current AHI for our copper and aluminium subtransmission conductor populations. The AHI for this fleet is based on conductor condition degradation, proximity to the coast, and conductor expected life versus age.

Figure 16.4: Subtransmission overhead conductors asset health as at 2016



The health of our aluminium conductors is very good. Most of the subtransmission conductor fleet is made of aluminium. Of aluminium conductors, only 5% will require renewal over the next 10 years (H1-3).

However, the health of our copper conductor is a concern. Although only 5% of subtransmission conductor is made of copper, 46% of it will require renewal over the next three years, and most of it within 10 years. This conductor will make up the majority of our subtransmission conductor replacement over the planning period.

Conductor sampling

We have recently begun a programme of conductor sampling and diagnostic testing with the objective of improving our understanding conductor end-of-life, and how it is influenced by type, age, inland versus coastal environment, attachment points versus mid-span, and other factors

Samples will be taken from conductors of various ages, types, locations and from different points on the span. A variety of tests will be used which will enable us to build up a profile of each ageing characteristic (external damage, annealing, corrosion, fatigue) by conductor material, location, age and point of span.

This new information will enable us to build up a more accurate picture of how conductor condition degrades. This will be used to improve asset health modelling and more effectively manage public safety and reliability risk while minimising cost through efficient replacement programmes.

16.3.4 DESIGN AND CONSTRUCT

Any subtransmission conductor renewal project includes a project design from first principles, based on AS/NZS 7000 and associated national standards. The design considers land reinstatement and worksite housekeeping issues to minimise impacts on landowners and the wider public (eg when working alongside a roadway). The design phase also considers future underbuilt 11kV circuits.

Meeting our portfolio objectives

Customers and Community: Landowner impacts from overhead conductor renewal are anticipated and minimised during project design.

Choosing a conductor wire size and material involves considering electrical, mechanical, environmental and economic factors. AAAC conductors are our preferred type due to their light weight and good conducting properties. Where loadings are severe, such as long spans, ACSR conductors may be better.

16.3.5 OPERATE AND MAINTAIN

Maintenance and inspection regimes applied to overhead conductors generally involve visual inspections and condition assessments. The table below summarises the preventive maintenance and inspection tasks. The detailed regime for each type of subtransmission overhead conductor is set out in our maintenance standard.

Table 16.4: Subtransmission overhead conductors preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	1 yearly
Visual inspection of subtransmission overhead conductors, as part of overhead network inspections. Alternates between a rapid inspection (drive by type inspection to identify defects) and a more detailed condition assessment.	2 ½ yearly

Conductors do not typically require routine servicing. However, they corrode (particularly in coastal locations) and work-harden, becoming brittle due to wind-induced vibration and movement, and thermal cycling. This degradation requires corrective maintenance. Intrusive inspections are performed only when necessary, such as to support a renewal decision.

Typical corrective maintenance tasks include:

- Replacement of twisted sleeve mid-span joints on HV conductor which was widely used in the 1950s, 1960s and 1970s. Over time these joints develop higher resistance due to internal corrosion, resulting in unacceptable voltage drop and radio frequency interference.
- Replacement of armour rods or line guards and replacement of binders. These items deteriorate due to vibration and movement caused by wind or thermal cycling.
- Replacement of corroded dead end and jumper U-bolt clamps. These clamps were used before compression joints were available. They are made of galvanised steel, and therefore react with aluminium conductors and corrode.

There is a range of more sophisticated condition subtransmission conductor assessment tools available. These include detecting cross-sectional area changes as an indicator of corrosion of the steel core of ACSR conductor, thermography to identify poor connections and failing joints, and acoustic testing for identification of corona.[64]

We are evaluating the use of these tools in our maintenance regimes across our conductor fleets. The evaluation includes comparing the additional costs to the likely benefits of more optimised replacement programmes and reduced failures.

16.3.6 RENEW OR DISPOSE

We use a condition-based renewal strategy for subtransmission overhead conductors, where degradation is related to their age and location (eg. near the coast or otherwise). We use visual inspections to assess conductors for failure modes such as corrosion, fretting, and foreign objects. The number of joints in a span provides an indicator of past failures. For other failure modes, we rely on condition indicators such as failure history, age and location.

As we increase our renewals work on end-of-life conductors, we will progressively adopt new tools and techniques to assess condition, such as conductor sampling. For now, we generally use these tools and techniques only following an in-service failure or where the condition of the asset is suspected to be poor.

Meeting our portfolio objectives

Asset Stewardship: We will increase the use of diagnostic condition assessment tools to inform and verify renewal investments.

Once identified for renewal using the factors discussed above, replacement is prioritised. This is based on an assessment of risk, taking into consideration factors such as network security of supply level, the economic impact of conductor failure and safety risk.

SUMMARY OF SUBTRANSMISSION OVERHEAD CONDUCTORS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Condition and age
Cost estimation	Desktop project estimates

64 Corona is an electrical discharge bought on by the ionization of air surrounding a charged conductor.

Renewals forecasting

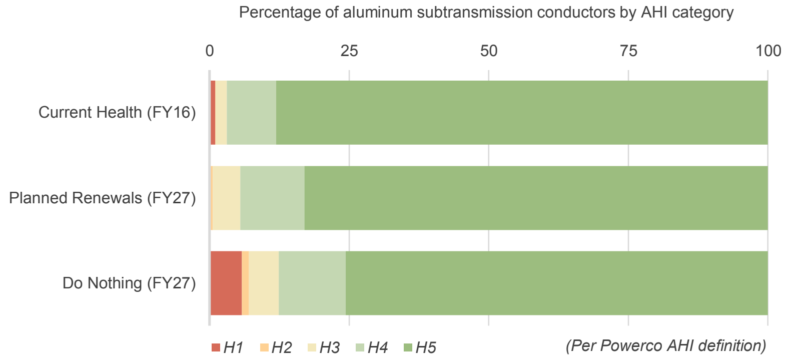
Our condition data provides us with a good understanding of the circuits that require replacement over the next three to five years. We expect to focus our renewals work on our remaining aged copper circuits and ACSR circuits with known greasing issues. Forecast renewal quantities beyond this timeframe are mainly age based, as generally our poorer condition circuits are also aged.[65]

We expect subtransmission overhead conductor replacements to remain fairly constant over the next 10 years and then to start increasing beyond the current planning period. A substantial number of aluminium circuits from the mid-1950s onwards will need to be replaced.

By 2027 we expect to have replaced the majority of our remaining copper subtransmission circuits, most likely with aluminium conductors (AAAC). This means that the asset health of copper conductors will no longer be a concern. We therefore do not provide an AHI projection for copper conductors.

The figure below compares aluminium conductor projected asset health in 2026 (following planned renewals) with a do-nothing scenario.

Figure 16.5: Projected aluminium subtransmission conductor asset health as at 2027



The small amount of planned conductor renewal will maintain aluminium conductors in overall good health, indicated by the H1 portion in Planned Renewals (FY27). Beyond 2026 there will be a growing need for aluminium conductor renewal (H2 and H3).

Coordination with Network Development projects

Subtransmission conductor works are also driven by load growth. An increase in conductor size is often needed to continue to meet demand. Our options analysis considers the costs and benefits of accommodating future demand by increasing conductor size alongside other options (thermal re-tensioning, additional circuits or non-network solutions). Conductor condition is also considered in this analysis.

If the conductor requires replacement in the medium-term, the preferred solution may involve replacing the conductor with a larger size.[66] This means growth and renewal needs are integrated.

Conductor renewal always considers future load growth when selecting a new conductor size. This ensures that, as far as practicable, renewed conductors will not need to be also replaced later due to load growth.

16.4 DISTRIBUTION OVERHEAD CONDUCTORS FLEET MANAGEMENT

16.4.1 FLEET OVERVIEW

Our distribution network overhead conductors operate at voltages of 6.6kV through to 22kV. This fleet of conductors connects zone substations to distribution transformers and makes up the largest proportion of the overhead conductor portfolio.

Figure 16.6: Distribution overhead line with LV underbuilt

65 We intend to further develop and refine our asset degradation and asset health models.

66 Work and expenditure in this chapter only relates to renewals.

In general, we use the same conductor types at the distribution level as for subtransmission. We also have a small population of steel wire[67] conductors.

The backbone of the main distribution network is formed of medium and heavy conductors.[68] These backbone assets are generally replaced when required to meet load growth, increase capacity or solve voltage issues at the ends of the feeders, rather than due to end-of-life. There are significantly fewer failures on these conductors than the small diameter, lightweight types that are typically used on spur circuits.

16.4.2 POPULATION AND AGE STATISTICS

Approximately 69% of our total conductor length is at distribution voltages. The table below shows the five types of distribution conductors used on our network. As with subtransmission, the main types are ACSR and AAC, though a higher proportion of copper conductors remain in this fleet.

Table 16.5: Distribution conductor population by type at 31 March 2016

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	719	5
AAC	2,457	17
ACSR	8,515	57
Copper	2,610	18
Steel wire	533	4
Total	14,834	

The average age of the distribution overhead conductor fleet is 38 years. A lot of construction occurred in the 1960s and 1970s, primarily using ACSR and AAC conductor. 11kV distribution circuits make up the majority of the distribution network. Many different conductor types and sizes were used to suit particular applications.

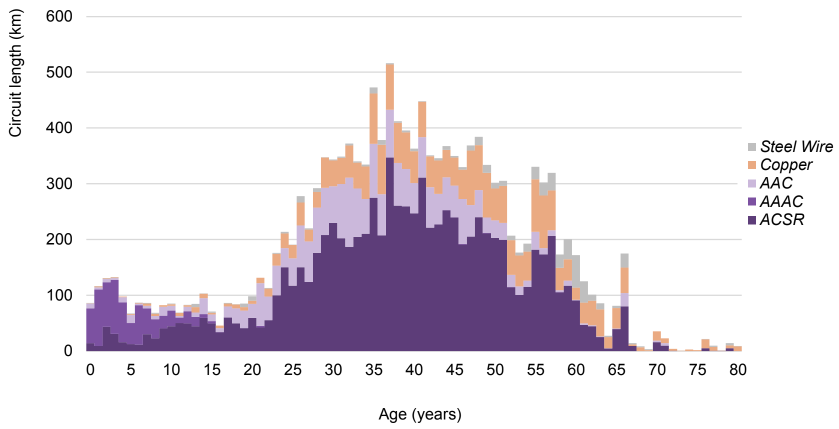
Since 2005 we have typically replaced between 50 and 100km of distribution conductor per annum. The majority of this work was driven by growth upgrades to backbone circuits.

67 Steel wire conductors (predominantly number 8 wire) are galvanised steel. They are typically installed in remote rural areas where only a low current capacity is required. They were predominantly installed during the 1950s and 1960s as a cost effective alternative to ACSR and copper conductors.

68 Medium and heavy conductors are defined as those of >50mm^2 and >150mm^2 equivalent aluminium cross sectional area respectively.

The figure below shows our distribution conductor age profile. A significant number of distribution conductors are approaching or have already exceeded their expected life of approximately 60 years (noting that actual replacement is a condition and risk-based decision).

Figure 16.7: Distribution conductor age profile



16.4.3 CONDITION, PERFORMANCE AND RISKS

Overhead conductors, by their nature, create risks to public and personnel, including:

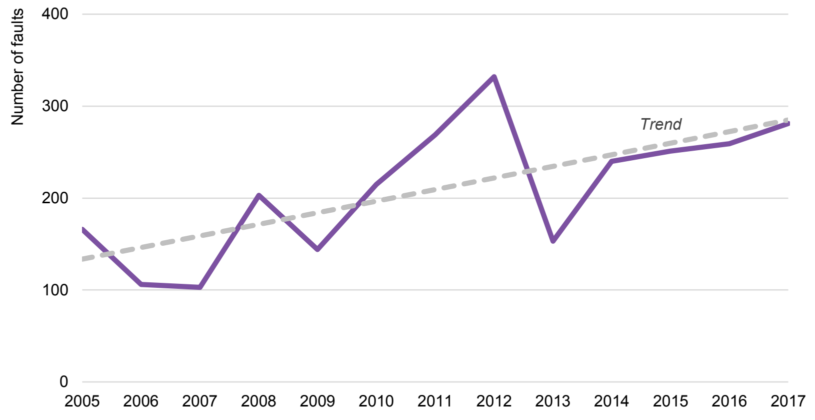
- Lines falling leading to an electrocution risk for people, property or livestock, either directly or indirectly (by livening houses, fences or other structures)
- Lines falling and causing fires affecting buildings, forests and crops
- Risks related to working at height and working near live conductors
- Low hanging conductors that pose a contact risk to people, property or livestock
- Risks to householders undertaking tree trimming who could accidentally touch a live line

These risks apply to varying degrees across all three conductor fleets. Protection systems are employed with switchgear at zone substations to protect conductors and isolate supply when faults occur. Other fault discrimination is employed along distribution feeders by way of circuit breakers, reclosers, sectionalisers and fusing.

We have traditionally managed risks associated with overhead lines to ‘As Low as Reasonably Practical’ (ALARP) levels. There is an increasing concern that distribution conductor failure rates, and therefore public safety risk, are increasing.

The figure below shows historical distribution conductor related faults on our network.

Figure 16.8: Conductor related faults on distribution overhead lines



Meeting our portfolio objectives

Safety and Environment: Conductor renewal strongly considers public safety and property damage risks caused by potential conductor failures when prioritising replacement works.

Our distribution conductor fault analysis has identified conductor type, age and location as the main drivers of degrading condition and failure. We expect the interaction of several factors to result in faster degradation/poorer performance than a single factor.

Our renewal focus for this fleet uses a combination of these three factors to prioritise replacement of distribution conductors in order to reduce overall failure rates.

Smaller distribution conductors (<50mm^2) tend to be less resilient than larger, heavier types. They have poor strength-to-weight ratios and disproportionally high failure rates, regardless of location. Smaller distribution conductors also vary significantly in their performance. Those with an ultimate tensile strength below 10kN tend to have much higher failure rates.

In general, small diameter ACSR conductors perform well but performance of the smaller light homogenous copper, and AAC conductors is consistently poor, regardless of age.

The table below lists the four worst performing conductor types, the length installed on our network and their respective failure rates.

Table 16.6: Poor performing distribution conductor types

CONDUCTOR	KM OF LINE	FAILURE RATE[69]	DESCRIPTION
AAC Namu	768	3.2	Concentrated in Tauranga and Te Puke areas, where it was historically used as the main distribution conductor. Spatial mapping reveals no consistent pattern to failures, which are evenly spread throughout the networks. Fretting and chaffing has been excluded as a major failure mode as line guards / armour rods are installed on most of the lines with Namu conductor."
AAC Poko	156	4.0	Used almost exclusively in Egmont area. Many of the failures thought to be due to poor construction practices such as lack of armour rods or line guards, which have allowed damage to occur on the conductor, weakening it over time.
Copper 16mm^2	510	3.3	These types of conductor were used widely. The large quantities of smaller copper conductors in the Egmont and Taranaki regions are likely a key contributor to the rise in conductor faults in those areas as the wire progressively ages.
Copper 7/0.064	697	2.7	

To reduce the number of distribution conductor faults to our target these conductors will need to be replaced. We target average failure rates[70] of 1.3-1.5 failures per 100km, depending on whether the circuits are in urban or rural areas. Failure rates of our four worst performing conductors vary from 2.7-4.0 failures per 100km.[71] The conductor types in the table above perform very poorly compared to our targets.

Our fault analysis also revealed a correlation between age and poor performance. Conductors older than 60 years of age showed higher average failure rates than younger conductors.[72] This finding is consistent with our knowledge of failure modes. Other than foreign object strikes, all failure modes worsen as the conductor ages.

69 The failures rates in the table relate to those attributed directly to conductor failures, not overall overhead line failure rates. Failure rates are measured as failures per 100km per year.

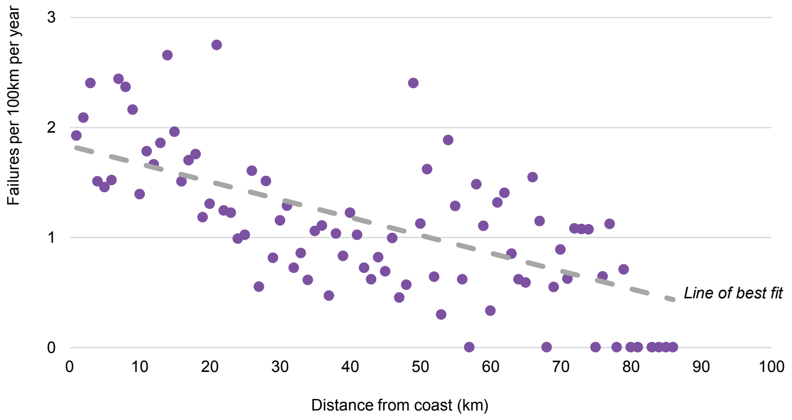
70 The target average failure rates are informed by the historic performance of our well performing conductor assets. A range is given, as we target a higher level of reliability for our urban circuits compared to rural, due to their relative criticality.

71 Conductors on our network average approximately 1.4 failures per 100km.

72 Only small amounts of conductor are currently over 60 years and hence our current sample for analysis is small.

Coastal proximity also has a major impact on conductor life and performance. The figure below shows that the likelihood of failure increases the closer an asset is to the coast.

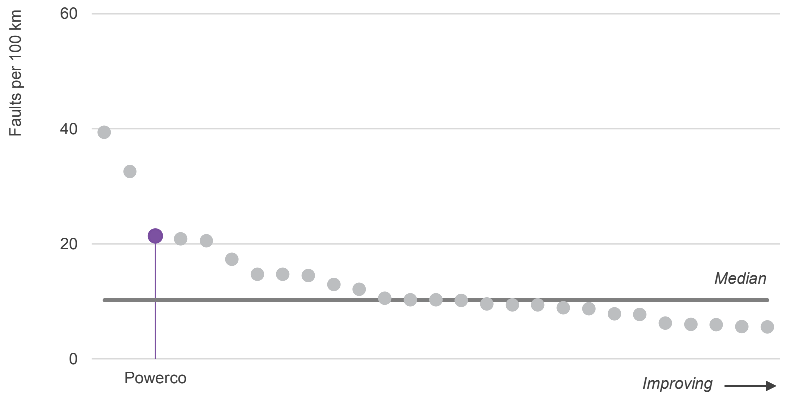
Figure 16.9: Distribution conductor failures compared to coastal proximity



We found this relationship to be particularly strong within 20km of the coast in the Western Region. With other factors constant, we expect conductors to have a shorter life near the coast, particularly for lightweight conductors and those using steel (ACSR and No.8 steel wire).

We can also compare the performance of our network to that of our peers. The figure below shows distribution overhead line fault rates (including poles and crossarms etc.) compared to those of other EDBs over the past four years. We would need to reduce faults by more than 50% to achieve median performance.

Figure 16.10: Distribution overhead line benchmarking (2013-2016 average)

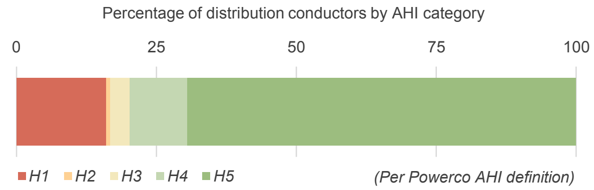


Distribution overhead conductors asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end-of-life and categorise their health based on a set of rules. For distribution conductor, we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical load, and the conductor should be replaced.

The figure below shows current overall AHI for our distribution conductor population. The AHI is based on historical analysis of failure data, known poor performing types and expected condition degradation.

Figure 16.11: Distribution overhead conductors asset health as at 2016



The health of the fleet indicates the need to replace significant amounts of conductor (16% of the fleet, H1) in the short term, to improve the health to a more sustainable level, and therefore improve our reliability performance.

16.4.4 DESIGN AND CONSTRUCT

The renewal of smaller diameter distribution conductors with larger and more robust types may cause strength issues with existing poles. More comprehensive pole replacement increases the cost of reconductoring.

Where a strength issue arises we consider various options. This may include more robust small diameter conductor types (eg ACSR conductor) that require fewer pole replacements, and conductor types that can be used over longer spans requiring fewer poles. Our design and construction standards set out the alternative designs that need to be considered as part of the options analysis.

As with subtransmission, AAAC conductors are our preferred distribution conductor type due to their lighter weight and good conductivity. Approved sizes include fluorine, iodine and krypton.[73]

We also strongly consider the needs and requirements of landowners as part of the detailed planning and design process. We aim to minimise the time spent on landowners' property and ensure no damage is left. We also consider realigning overhead lines where practicable and cost effective, when it benefits the landowner.

With an expected large increase in reconductoring volumes, we are investigating improved methods for maintaining supply (or limiting supply interruption) while this work is done. We currently use generators when a large number of customers are affected. Other methods could include the use of temporary bypass cables to maintain supply.

16.4.5 OPERATE AND MAINTAIN

Distribution conductors are inspected less frequently than subtransmission conductors, due to their lower impact during loss of supply. Our inspection regime for distribution overhead conductors is summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 16.7: Distribution overhead conductor preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of distribution overhead conductor, as part of overhead network inspections, completing a detailed condition assessment	5 yearly

Corrective maintenance tasks carried out on distribution conductors are similar to that of subtransmission. Most conductor failure occurs during storms and particularly in high winds. Failure is generally caused by external contact or interference such as trees or wind borne debris (roofing iron etc.) or where a conductor is weakened due to loss of strands (clashing/bird strike).

Conductor repairs often require unbinding of several spans to enable re-tensioning at a strain pole following mid-span jointing. This results in long repair/outage times. Access to poles and mid-span sections can often be difficult which compounds repair/outage times.

Care is needed when re-terminating a conductor following a fault. Field staff need to identify the correct preformed dead end to be used with a particular conductor. In particular, some sizes of ACSR and AAAC dead ends are similar. Incorrect selection can result in subsequent failure under tension.

While we have standardised conductor types, a wide range of conductor is used on our network. Sufficient spare conductor and associated fittings are available at strategic locations in order to expedite fault repairs.

16.4.6 RENEW OR DISPOSE

Although we have been increasing our levels of conductor replacement over the past three to five years, we are still experiencing an increase in failure rates. This indicates a worsening of overall asset health. Our modelling and analysis indicates that without further replacement rate increases, failure rates will continue to rise.

Visual inspections can identify some defect types – some corrosion, fretting, fatigue and foreign object damage. For other failure modes we have to rely more on other factors to predict risk of failure. For this fleet, the three key indicators are:

- Age – failures increase from the age of 60 years
- Type – certain small cross section problematic homogenous conductor types (AAC Namu and Poko, and 16mm^2 and 7/0.064 copper) have much higher failure rates than other distribution conductor types
- Coastal proximity – conductors near the coast exhibit more failures than other comparable conductors

SUMMARY OF DISTRIBUTION OVERHEAD CONDUCTOR RENEWALS APPROACH	
Renewal trigger	Condition-based considering failure risk
Forecasting approach	Failure rate reduction
Cost estimation	Volumetric average historic rate

We are targeting replacement of distribution conductors that meet these indicators. Safety is our key concern around distribution conductor failure. We prioritise the renewal of conductors in more densely populated areas, typically urban areas. Worst performing feeders will also be targeted for conductor renewal.

73 These are conductor code names used by manufacturers and the electricity industry.

Meeting our portfolio objectives

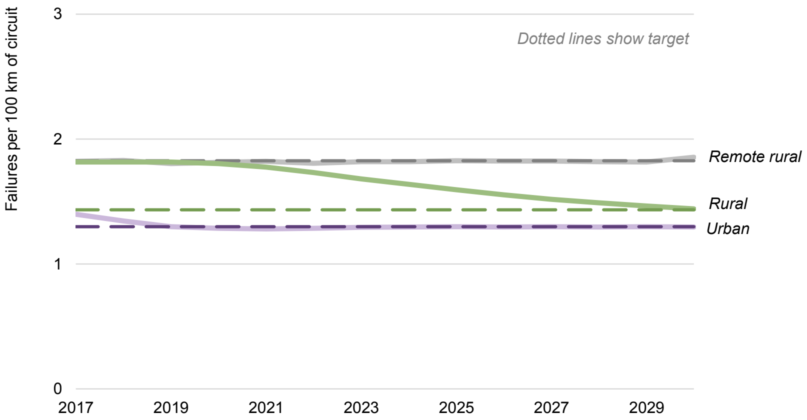
Networks for Today and Tomorrow: Distribution overhead conductor replacements will be targeted in areas of worst performance, improving the reliability of poor performing feeders and managing network SAIDI and SAIFI.

Renewals forecasting

We have modelled expected failure rates for all our distribution conductor spans to help forecast longer term renewal needs and prioritise replacement. Our overall failure rates are higher than good practice levels.[74] We have set ourselves the target of reducing failure rates to good practice levels by 2019 for urban conductors and 2030 for rural conductors, and maintaining remote rural conductor failure rates at today's levels.

The figure below outlines our modelled improvement in failure rates over time. The figure illustrates that we are prioritising the improvement of urban failure rates first, while ensuring rural rates do not degrade.

Figure 16.12: Distribution conductor expected failure rates



We forecast the amount of conductor renewal required to meet these targets using our modelled failure rates, assuming we replace the worst performing conductor first. This indicates the need for a large step-change in renewal quantities over the next 10 to 15 years. Replacement quantities needed are expected to reduce once we reach our failure rate targets. Some ongoing replacements will still be necessary to maintain overall performance at target levels.

The table below outlines the distribution conductor types modelled as requiring replacement to the end of the planning period. As shown, almost two thirds of the forecast is prioritised on replacing the four type issue conductors. Replacing these conductors will lead to a reduction in safety risks association with this asset fleet.

Table 16.8: Distribution conductor forecast by conductor type

CONDUCTOR TYPE	FORECAST REPLACEMENT LENGTH FY18-FY27 (KM)	% OF TOTAL
Type issue conductor	**1,784**	**64%**
of which: **AAC Namu**	779	28%
AAC Poko	149	5%
Copper 16mm^2	492	18%
Copper 7/0.064	364	13%
Non-type issue conductor	**989**	**36%**

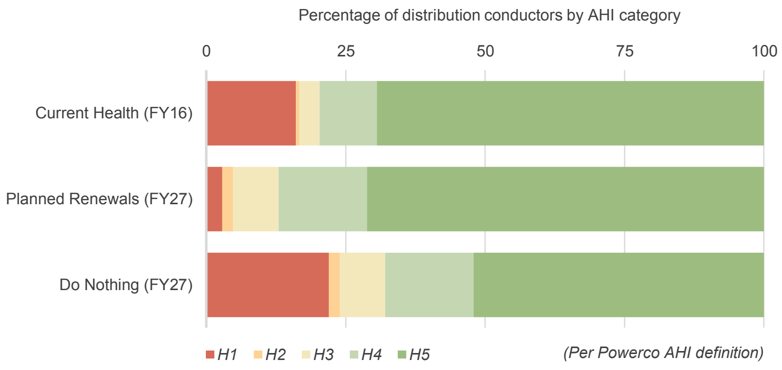
Meeting our portfolio objectives

Asset Stewardship: Forecasted distribution overhead conductor renewal is expected to reduce failure rates to target levels (as indicated by failure rate modelling) by 2030.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our investment will lead to an improvement in overall health by 2027 (as shown by the reduced H1 portion) though not to long-term sustainable levels (in line with our 2030 target).

74 As discussed in the Network Targets chapter, our overall distribution overhead line fault target is 16 faults per 100km. Faults have been increasing over time and we exceeded our target in 2015 and the. However, overall overhead line performance is influenced by many factors, including storms, third party interference and vegetation growing near lines. We therefore also analysed faults related to the conductor asset only. This analysis uncovered the same increasing trend (see earlier section) with a number of conductor types performing poorly compared to the rest of the population, driving our overall poor performance. Our good practice failure rate targets are informed by the historical performance of our well performing conductor assets.

Figure 16.13: Projected distribution conductor asset health in 2027



Significant conductor will still need to be replaced after 2027 as indicated by the H1-H3 portion in Planned Renewals (FY27). However, it will not be at the same level as this planning period.

Coordination with Network Development projects

Distribution conductor upgrades and installations can be triggered by load growth, such as from residential infill or greenfield development. This often requires either feeder backbone upgrades to a larger conductor (thereby increasing capacity) or new feeders.

When planning the renewal of larger distribution lines we forecast load growth and then appropriately size the conductor for the intended 60 years of asset life. This reduces the likelihood of needing to upgrade the asset before it reaches its intended life. Voltage and back-feeding ability are also taken into account where relevant. Some smaller conductor types do not provide scope for back-feeding at an appreciable level of maximum demand.

When renewing remote rural feeders we consider the use of RAPS. This is done instead of traditional conductor replacement where the economic benefits are positive. More information on RAPS is included below.

Remote area power supplies (RAPS)

RAPS provide an option as a modern replacement asset for end-of-line, remote rural distribution feeders. In some situations there may be just one small customer connected to the end of a long distribution feeder that requires end-of-life replacement. Installing a RAPS unit to supply this customer can be more cost effective than renewing the overhead line. When the end of a remote rural line requires replacement, we undertake an economic evaluation of installing a RAPS compared to overhead line renewal.

A RAPS unit typically includes solar panels, battery storage and a diesel generator. Other types of generation such as micro hydro or wind can also be used. They allow the connected customer to go off-grid with only the generator's diesel tank needing to be kept filled.

RAPS are matched to load requirements with different sizes of solar arrays, battery storage and diesel generators available. Typically it is more cost effective to install energy efficient appliances (such as LED lighting) as part of the installation, rather than upsize the RAPS.

We have currently installed eight RAPS on our network and are trialling new versions that use lithium ion batteries for storage. This increases storage levels while reducing costs.

A RAPS Unit with a 1.1 kW photovoltaic array is shown below.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We are installing RAPS where appropriate as an alternative technology on our network to minimise the cost of asset renewal.

16.5 LOW VOLTAGE OVERHEAD CONDUCTORS FLEET MANAGEMENT

16.5.1 FLEET OVERVIEW

LV conductors operate at 230/400V. Almost half of LV conductors are located within urban areas and a high proportion of network incidents relate to LV conductors.

The types of conductors used in the LV parts of our networks, as in the higher voltage parts, are steel wire, AAC, AAAC, ACSR, and copper. LV conductors can either be constructed with their own poles or underbuilt, whereby the LV line is built under a HV circuit.

Modern LV conductors are covered in a poly vinyl chloride (PVC) outer sheath, which provides protection from corrosion and some insulation.[75] This helps to mitigate safety risks and reduces vegetation related faults. The LV conductor fleet also includes overhead LV service fuse assemblies. These are the fuses located at the customer connection to protect customer premises and our network from faults.

Figure 16.14: LV overhead circuit

16.5.2 POPULATION AND AGE STATISTICS

We have approximately 5,200km of LV overhead conductors, of a variety of types, making up 24% of total conductor length. We also have approximately 230,000 overhead LV service fuse assemblies.

The table below summarises our LV conductor population by type. The majority of our LV conductors are made of copper (52%). The AAC conductor is more prevalent in the LV fleet. Its relative lack of strength is less of an issue than for HV conductor as LV spans are typically much shorter than that of distribution, especially in urban areas.

Table 16.9: LV conductor population by type at 31 March 2016

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	7	0.1
AAC	516	10
ACSR	549	11
Unknown aluminium	853	17
Copper	2,705	53
Steel wire	5	0.1
Cable[76]	299	6
Unknown	201	4
Total	5,135	

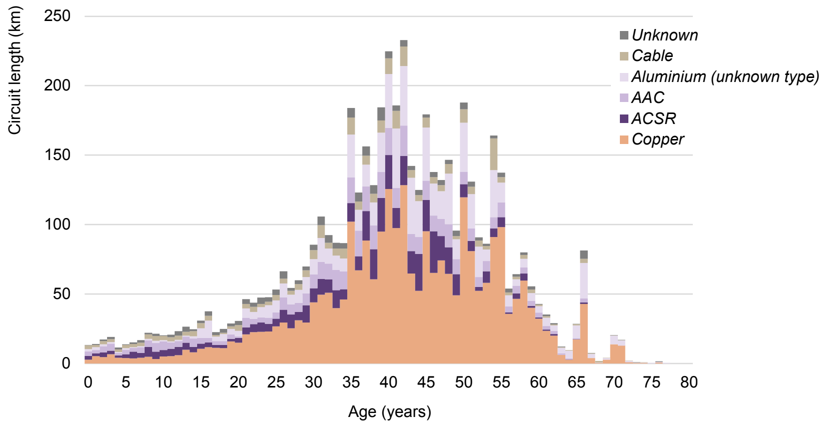
Our asset data is less complete for the LV fleet. We are aiming to increase the accuracy of that information through inspections. Some of the conductors recorded in our information systems are of unknown type or the material is known but not the specific alloy or construction. About 21% of our LV conductors are of unknown type.

The figure below shows our LV conductor age profile. The ageing population indicates that levels of renewal will need to increase.

75 The covering is not considered electrical insulation, but does provide some mitigation of safety risk from accidental contact or a fallen conductor.

76 Cable type LV conductor consists of electrically insulated cable conductor, strung between poles, typically to support service connections (such as road crossings). The majority of this type is neutral screened cable.

Figure 16.15: LV Conductor Age Profile



As with the other fleets, significant investment was carried out in the period from 1960 to the mid-1980s. Only a very small quantity of new LV overhead network was built in the last two decades. Most of the new LV build on our network has been underground with almost no LV overhead renewal.

Due to limitations on LV conductor data we have estimated the age of about half our LV conductors using age data from associated poles.

16.5.3 CONDITION, PERFORMANCE AND RISKS

As discussed previously, failure of an overhead conductor creates large safety risks for the public. This is of particular concern with nearly half of our LV fleet situated in more densely populated urban areas. Mitigating this risk is key to our LV conductor fleet management.

LV circuits cannot be adequately protected against earth faults using overcurrent devices. Protection is unlikely to operate for high impedance faults, or may operate but with a long time delay.

The public safety risk of electrocution due to downed LV conductors can be partially mitigated by covered conductor. Our modern standard requires the use of covered conductor but there are rural and suburban overhead LV circuits that still use legacy bare conductor.

Through our overhead line inspections we identify high risk LV circuits that have bare conductors, assess the public safety risk due to conductor or binding failure, and prioritise its replacement with covered conductors. These measures cannot completely mitigate the risks but help to bring it down to an ALARP level.

Historically we have not captured detailed LV fault data for failure analysis. In 2014 we commissioned our new OMS which captures detailed failure information on our LV network. Over time we will be able to analyse these failures and identify where replacement of conductor should be prioritised.

Meeting our portfolio objectives

Operational Excellence: We are improving our information of the LV overhead network to allow for more informed asset management decision-making.

We believe that conductor type issues are unlikely to be as prevalent for LV conductors as with distribution voltage conductors. Although the same types are used, span lengths are shorter, which means the conductor is supported more and typically under less tension than at higher voltage levels.

Ageing will continue to cause condition degradation, with coastal proximity causing faster degradation. Similar to distribution conductors we expect LV conductor failure rates to increase from approximately 60 years of age.

LV overhead fuse assemblies

Historically we have replaced LV fuse assemblies on a reactive basis, when the device fails. However this causes inconvenience to customers and is not cost effective. There are also public safety risks with running these assets to failure.

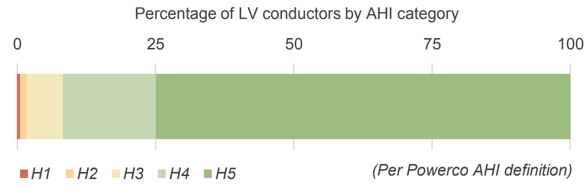
We plan to target replacement based on condition sampling and asset age (using pole age as a proxy). Areas to be targeted for replacement will be identified by analysing fault data and asset age followed by condition sampling of the devices in the planned target areas.

LV overhead conductors asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise their health based on a set of rules. For LV conductor we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical load and the conductor should be replaced.

The figure below shows current overall AHI for our LV conductor population. The overall AHI for this fleet is based on our understanding of LV conductor expected life and age.

Figure 16.16: LV overhead conductors asset health as at 2016



The health of our LV conductor fleet is good with approximately three quarters of the fleet unlikely to require replacement over the next 20 years (H5). However, 8% of the fleet will likely require replacement in the next decade (H1-3), which represents a large increase in renewal volumes. The upcoming renewal need is driving our change from historical reactive replacement of LV conductor to more proactive condition-based replacement.

16.5.4 DESIGN AND CONSTRUCT

Although not a new technology, we are investigating the use of Aerial Bundled Conductor (ABC) for use on our LV network. ABC has been used around the world for many years but has not seen widespread use in New Zealand. ABC includes all three phases and the neutral wire in a single bundle, with the conductors fully insulated.

The conductor is safer because it is fully insulated. This means that conductor clashing due to tree contact is no longer an issue and it will not arc if in contact with a tree. Installation is also simpler, as insulators[77] and crossarms are typically not required. There is an additional cost for ABC and the visual impact differs from traditional four wire systems.

We intend to trial ABC conductors on our LV network once research into New Zealand and international experience is complete. These trials will allow us to better understand the relative performance and cost of the product, and customers' visual preferences.

16.5.5 OPERATE AND MAINTAIN

LV network inspections are undertaken at the same frequency as our distribution network. LV inspections pay particular attention to identifying public safety hazards so they can be addressed.

Table 16.10: LV overhead conductor preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of LV overhead conductors, as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

16.5.6 RENEW OR DISPOSE

Limited data on the condition of the LV conductor fleet has meant that its replacement has generally been reactive. Data limitations mean that the key causes of poor condition are difficult to identify. This means that until now a more proactive approach has not been possible.

[77] Insulated clamp brackets are still required.

However, the LV overhead conductor fleet is ageing and an increased focus on safety has meant we are no longer satisfied with a largely reactive approach. Similarly, we are no longer satisfied with a reactive approach to replacement of LV fuse assemblies due to the higher per unit cost and disruption to customers.

SUMMARY OF LV OVERHEAD CONDUCTOR RENEWALS APPROACH	
Renewal trigger	Condition-based considering failure risk
Forecasting approach	Age
Cost estimation	Volumetric average historic rate

We believe conductor type issues are unlikely to be as prevalent for LV conductors as with distribution voltage. However, coastal proximity and ageing influence failure rates.

We intend to plan for replacement of aged LV conductors, with priority based on condition and safety risk where relevant information is available. For example, we will prioritise the replacement of uncovered conductors in urban areas.

More detailed fault information from OMS will enable us to better target replacement of conductors with poor reliability. This includes particular types or those in challenging environmental conditions.

Similarly, for LV fuse assemblies, replacement planning will take into consideration fault data for an area, age of the assembly, and condition sampling.

Renewals forecasting

To forecast future renewal needs, we use age as a proxy for condition. Rather than using a simple 'birthday' type age model, we use a statistical distribution modelling approach. This approach reflects more closely actual replacement decisions. It reflects that the need for conductor renewal can be expected to arise at different ages depending on the particular condition, environment and criticality of the conductor. The modelling assumes an expected 70-year life for an LV conductor. This is more conservative than the indicative 60-year life of a distribution conductor.

Although conservative, our model forecasts the need for a large step in LV conductor renewal. We plan to slowly increase renewals from FY19, up to a steady state level in FY23. During that time we will undertake fault analysis using the improved fault information from our OMS. This will enable us to refine our understanding of the step change required before committing to a large renewal programme.

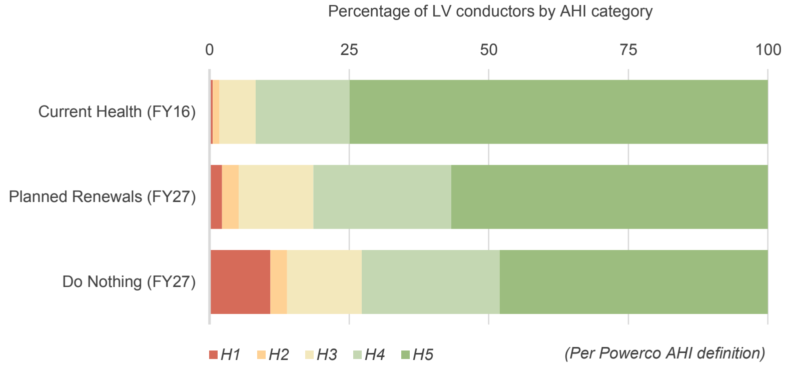
Longer term, we expect renewal levels to continue to increase as the large amount of conductor installed during the 1960s and 1970s will likely require replacement.

In the case of LV fuse assemblies, we forecast renewals based on a steady state replacement programme of 5,100 units per year, using an expected life of 45 years.

The focus on areas with older fuse assemblies and higher fault rates will result in improved asset health. With improved condition data we will be able to refine this forecasting approach.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our investment will appropriately manage health over the next 10 years and support the step change in replacement needed longer term.

Figure 16.17: Projected LV conductor asset health in 2027



The amount of conductor that needs to be replaced will grow by 2027, as indicated by the H1-H3 portion in Planned Renewals (FY27). This indicates that long-term replacement volumes will need to increase further.

Coordination with Network Development projects

We aim to move from a largely reactive approach to an approach where LV network development upgrades can be scheduled before issues arise. Our Network Insight programme (discussed in Chapter 13) aims to improve the level of planning visibility of our LV network. Improved knowledge of transformer load flows and voltages will enable us to better understand power quality and voltage issues. It will also enable us to plan for an increase in distributed generation.

Very little new LV overhead conductor is constructed at present as new residential development tends to use underground cable networks. We sometimes also underground LV circuits when requested by a customer (this is discussed in more detail in Chapter 25 Asset Relocations).

16.6 OVERHEAD CONDUCTORS RENEWALS FORECAST

Renewal Capex in our overhead conductors portfolio includes planned investments in our subtransmission, distribution and LV conductor fleets. Over the planning period we intend to replace approximately 160 km of subtransmission conductors, 2,800 km of distribution conductors, and 440 km of LV conductors. We will also replace 5,100 LV fuse assemblies each year. This will require an investment of approximately $124m over the planning period.

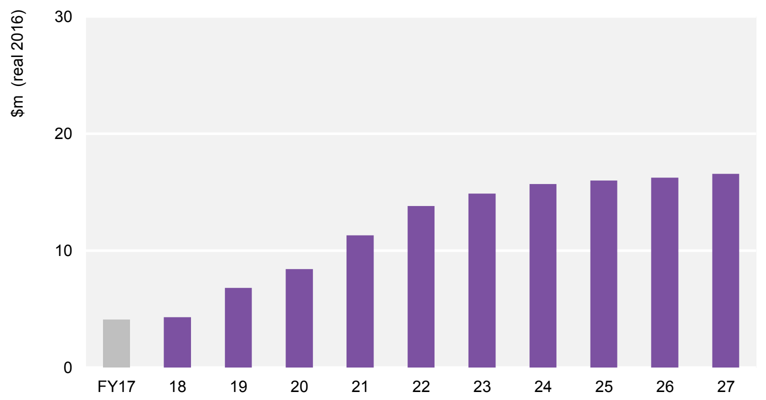
The key driver for overhead conductor renewal is management of safety risk by addressing declining asset health. Failure of an overhead conductor presents a significant public hazard, as well as having reliability implications.

Subtransmission, distribution and LV conductor renewals are derived from bottom up models. Subtransmission reconductoring projects can be scoped at a high level a number of years before implementation. This means we can carry out desktop cost estimates for each project which take into account factors such as terrain difficulties, span lengths, and pole and crossarm renewals.

Distribution and LV renewals forecasts are generally volumetric estimates (explained in Chapter 26). The work volumes are high, with the forecasts based on failure rate analysis and age information respectively. We use averaged unit rates based on analysis of equivalent historical costs.

The chart below shows our forecast Capex on overhead conductors during the planning period. [78]

Figure 16.18: Overhead conductors renewal forecast expenditure



78 Overhead conductor forecasts represent the cost to replace the conductor only, with associated pole and crossarm costs captured in the overhead structures portfolio. Projects are planned, scoped and delivered as overhead line projects.

We plan to gradually increase the level of investment over the next 10 years to allow additional resources to be mobilised. This forecast reflects the increased level of investment needed to renew distribution and LV conductors.

Longer term levels of renewals are expected to remain at these increased levels beyond the 10-year planning horizon, as more conductors constructed during the 1950s to 1970s require replacement.

Over the next five years we will continue to refine our condition assessment techniques to ensure renewals timing is properly optimised. Lessons learned early in the period may allow us to moderate long-term expenditure projections.

Further details on expenditure forecasts are included in Chapter 26.

17.1 CHAPTER OVERVIEW

This chapter describes our cables portfolio and summarises our associated fleet management plan. The portfolio includes three fleets:

- Subtransmission cables
- Distribution cables
- LV cables

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to invest $61m renewing our cables fleets. This accounts for 7% of renewals Capex over the period. The forecast is generally in line with historical levels.

Our cables programmes focus on addressing safety and environmental concerns, and maintaining reliability. Renewals projects are mainly driven by type issues and poor condition. Three type issues affect our cable fleets:

- 11kV paper insulated lead covered cables (PILC) with brittle lead sheaths
- First generation cross-linked polyethylene cable (XLPE)
- A small number of 33kV subtransmission termination joints

Poor condition assets are identified using our condition assessment and diagnostic testing regimes, taking into consideration known type issues.

Our forecast includes expenditure in FY17-18 and FY20 to replace oil-filled subtransmission circuits in the Palmerston North CBD. These cables are leaking oil which has environmental impacts. Renewal is the most cost-effective approach given the high costs of maintenance, high criticality of the assets, and difficulty securing spares and workforce to undertake this specialist work.

We have also identified approximately 5,200 LV boxes with safety-related risks. We have been working to remove these types of LV box from our network and plan to increase the rate of renewal during the planning period.

Below we set out the asset management objectives that guide our approach to managing our three cable fleets.

17.2 CABLES OBJECTIVES

Underground cable makes up approximately 20% of our total circuit length. Cable conductors come in various sizes and are usually made of copper or aluminium.

Aluminium is used in most applications because it is less expensive than copper. However, copper conductors offer better current rating than aluminium for a given size. Copper use is limited to short runs where high capacity is required such as connecting power transformers to switchboards at zone substations.

Several types of cable insulation are used across the subtransmission, distribution and LV fleets. These consist primarily of cross-linked polyethylene (XLPE) cable, PILC, pressurised oil-filled cables and PVC insulated cables. Cables have one, three or four cores.

To guide our management of cable assets, we have defined a set of objectives listed below. The objectives are linked to our overall asset management objectives from Chapter 5.

Table 17.1: Cables portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No public safety incidents from contact with our cable network. Minimise oil leaks from pressurised oil-filled cables.
Customers and Community	Minimise traffic interruptions when managing cable assets in road reserves.
Networks for Today and Tomorrow	Investigate the use of real time cable ratings using distributed temperature sensing.
Asset Stewardship	Maintain the failure rate of cable assets at or below target levels.
Operational Excellence	Improve our knowledge of the LV cable fleet.

17.3 SUBTRANSMISSION CABLES FLEET MANAGEMENT

17.3.1 FLEET OVERVIEW

The subtransmission cable fleet predominantly operates at 33kV, though we have a small amount of 66kV cable. The assets include cables, joints and pole terminations. The three types of cable used are XLPE, PILC and pressurised oil-filled cable.

17.3.2 POPULATION AND AGE STATISTICS

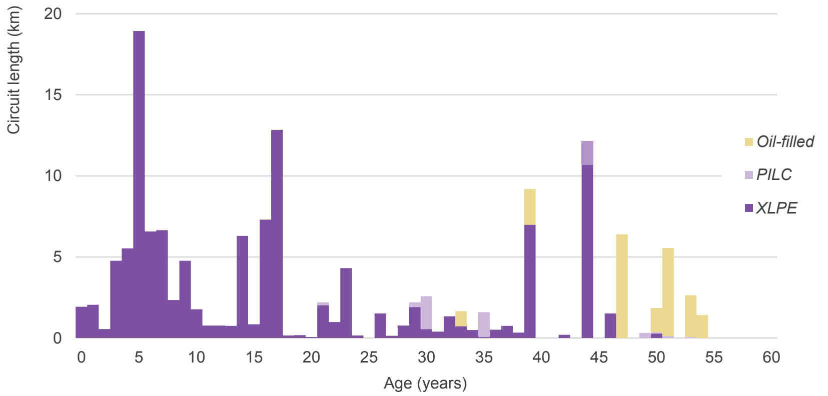
The majority of our approximately 150km of subtransmission cable is XLPE cable. XLPE has been the preferred cable insulation technology for over 30 years. The table below summarises our subtransmission cable population.

Table 17.2: Subtransmission cable population by type at 31 March 2016

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	122	82
PILC	6	4
Oil-filled	20	14
Total	149	

The subtransmission cable fleet is relatively young, with an average age of 22 years. The figure below depicts our subtransmission cable age profile.

Figure 17.1: Subtransmission Cable Age Profile



The age profile shows that oil-filled cable has not been installed for many years as XLPE has emerged as the preferred type. XLPE cable requires less maintenance and is more environmentally acceptable. Although oil-filled cable has an expected life of 70 years, we are concerned with the reliability of particular circuits due to design issues with the cable joints. This is discussed further below.

17.3.3 CONDITION, PERFORMANCE AND RISKS

The four major 33kV oil-filled cable circuits located in the Palmerston North CBD are in poor condition. They require significant oil top ups and exceed expected leakage. The leaks typically originate from the cable joints due to thermal cycling. The cable joints have a recognised design flaw of inadequate conductor clamping strength, affecting the cable's ability to sustain thermal cycling. We have historically applied reduced cable ratings to these circuits to limit thermal cycling but oil leaks are continuing.

We plan to retire the affected cable circuits. Failures have recently occurred, forcing us to take some circuits out of service and install a temporary overhead line. The pressurised oil systems are complex and expensive to maintain. The replacement of individual cable joints on these oil-filled cables is expensive and difficult. Appropriate spares are not readily available and there are not many workers experienced in replacing joints. There are also access issues in urban areas.

Meeting our portfolio objectives

Safety and Environment: subtransmission cable circuits with a history of oil leaks are being retired to minimise environmental impacts.

The table below summarises the actions being taken with the affected pressurised oil cable circuits.

Table 17.3: Palmerston North subtransmission cable circuits

CABLE CIRCUIT	CIRCUIT LENGTH	ACTION
Keith St to Main St (two circuits)	2.7km (x2)	Install one additional XLPE circuit (3.0km) in FY17 and attempt repair of leaks on oil-filled cables. Parallel oil-filled cables to form second circuit. Oil-filled cables become redundant in FY20 due to Palmerston North reinforcement (new Ferguson St substation)
Kairanga to Pascal (underground from Pascal to Gillespie Line)	2.9km	Currently running at half capacity due to failed cable. Being replaced in FY17-18.
Pascal to Main St	1.8km	Cable already removed from service and being replaced in FY18.

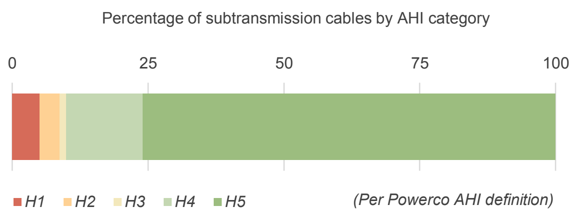
An issue has been identified with a certain type of 33kV indoor heat shrink terminations, where poor installation causes premature failure. An inspection and testing programme identifies affected terminations which are replaced if necessary.

Subtransmission cables asset health

As outlined in Chapter 7, we have developed a set of AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For subtransmission cables, we define end-of-life as when the asset can no longer be relied upon to operate reliably and without environmental harm, and the cable should be replaced. The AHI is based on cable circuit reliability, environmental impacts and asset age.

The figure below shows current overall AHI for our subtransmission cable fleet.

Figure 17.2: Subtransmission cables asset health as at 2016



The health of the subtransmission cable fleet reflects the poor condition of oil-filled circuits in the Palmerston North CBD. Around 9% of the cables will require renewal in the next 10 years (H1-H3). The rest of the fleet is in good health and no further replacement is expected in the next 10 years.

17.3.4 DESIGN AND CONSTRUCT

All new subtransmission cable circuits utilise XLPE insulated cable with stranded aluminium conductors in two standard sizes – single core $300mm^2$ and $630mm^2$. Standardisation assists ongoing fleet management by reducing spares, simplifying the maintenance and repair process and reducing costs.

We are reviewing our management of cable ratings and intend to issue a new standard. This will assign consistent, systematic standard ratings for planning analysis. The standard will also set a framework for real time rating schemes using distributed fibre temperature sensing.

Real time asset ratings

Asset ratings are applied in accordance with passive capacity ratings. For example, we ensure the capacity of a cable is not exceeded when considering network design and operating practices.

This conservative approach is perfectly sound when the actual performance and behaviour of assets is not monitored in real time and running them to failure is not an option.

Safely increasing an asset's use may be possible by having a real time view on its performance. For example, the limiting factor on a cable is the operating temperature, which is related to the current it conveys. Safely increasing the current throughput may be possible by monitoring the temperature in real time and ensuring safe operating levels are not breached.

We intend to conduct several proofs of concept of real time rating applications using different technology and asset types.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We will investigate and trial real time cable ratings for subtransmission cables to increase their effective capacity, using distributed temperature sensing.

17.3.5 OPERATE AND MAINTAIN

While cables are generally maintenance free, we do perform inspections and diagnostic testing. Oil-filled cables require additional maintenance due to their pressurisation systems. Maintenance and inspections for subtransmission cables are summarised below.

Table 17.4: Subtransmission cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Check and inspection of oil pressurisation systems.	1 monthly
Cable route inspections. Inspection of cable terminations and surge arrestors. Thermography of exposed cable terminations on oil pressurised cable circuits.	1 yearly
Sheath voltage limiter tests of XLPE and PILC cable.	2 ½ yearly
Sheath integrity and earthing diagnostic tests.	5 yearly

As some of our oil cables are known to leak we regularly top up the oil reservoirs to prevent cable failure. Insulating oil to top up these cables is held in stock in Palmerston North.

17.3.6 RENEW OR DISPOSE

We have identified the need to replace the oil pressurised cable circuits in the Palmerston North CBD area due to the excessive oil leaks from their joints and concerns about ongoing reliability. This is summarised above in Table 17.3.

Cost estimates for these projects have been developed from desktop studies of proposed cable routes using typical component costs or 'building block' costs.

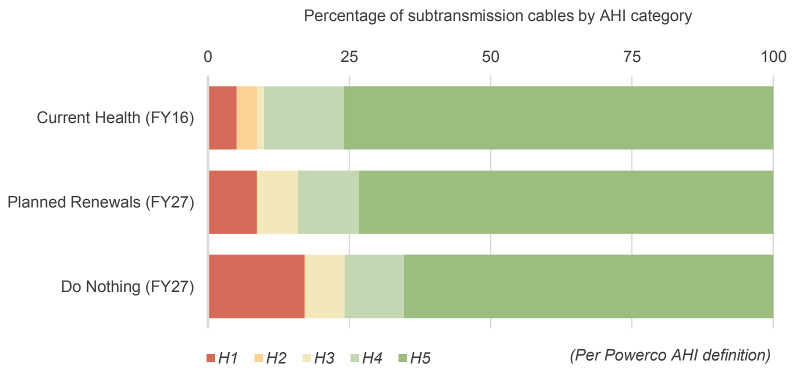
SUMMARY OF SUBTRANSMISSION CABLES RENEWALS APPROACH

Renewal trigger	Environmental and reliability risk
Forecasting approach	Identified projects
Cost estimation	Desktop project estimates

Apart from the issues with our Palmerston North cables, the subtransmission cable fleet is in good condition and no further renewals are expected in the medium-term.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our investment in replacing the Palmerston North pressurised oil cables will lead to an improvement in overall health.

Figure 17.3: Projected subtransmission cables asset health as at 2027



By 2027, the oldest of the XLPE circuits will be coming due for replacement, as indicated in the H2 and H3 portion in Planned Renewals (FY27).

Coordination with Network Development projects

New subtransmission cable circuits require significant planning and lead time due to consenting and securing easements for cable routes, and cable manufacturing time. Easements for underground circuits are more straightforward than overhead circuits with many councils restricting overhead lines in urban areas; they have become the preferred solution.

Subtransmission cable planning entails integrating growth and renewal needs. If a cable circuit requires renewal, we undertake an options analysis to ensure we deliver the best long-term solution. An example of the joint consideration of renewal and growth needs is the cable renewal in Palmerston North. An optimum solution has been planned that provides considerable benefits over a like-for-like solution.

17.4 DISTRIBUTION CABLES FLEET MANAGEMENT

17.4.1 FLEET OVERVIEW

The distribution fleet operates at 22kV, 11kV and 6.6kV. The main assets within the fleet are cables, joints and pole terminations. We use two main types of cable insulation at the distribution level – PILC and XLPE.

PILC has been used internationally for over 100 years and manufactured in New Zealand since the early 1950s. PILC uses paper insulating layers impregnated with non-draining insulating oil. The cable is generally encased by an extruded waterproof lead sheath covered in wrapped and tar impregnated fibre material, PVC, or polyethylene.

PILC cables have a good performance record in the industry. A potential risk with PILC cables work is the limited jointing experience within our field workforce. Jointing and terminating these cables requires a high level of skill and most New Zealand cable jointers with this experience are nearing retirement. It is difficult for new cable jointers to gain this practical experience since there are few failures.

The first generation of XLPE cables were installed from the late 1960s to mid-1970s. These first generation cables have a poor service record, with failures caused by 'water treeing'[79] in the insulation, causing it to break down.

As XLPE technology has developed over time, the construction, operational integrity and safety features have improved to a point where the current generation of XLPE cables is favoured over other cable types. Only small quantities of the first generation XLPE remain in service on our networks.

17.4.2 POPULATION AND AGE STATISTICS

We have approximately 2,000km of distribution cable, of which about 16% is PILC and 84% is XLPE. The following table shows the breakdown of distribution cables by insulation type.

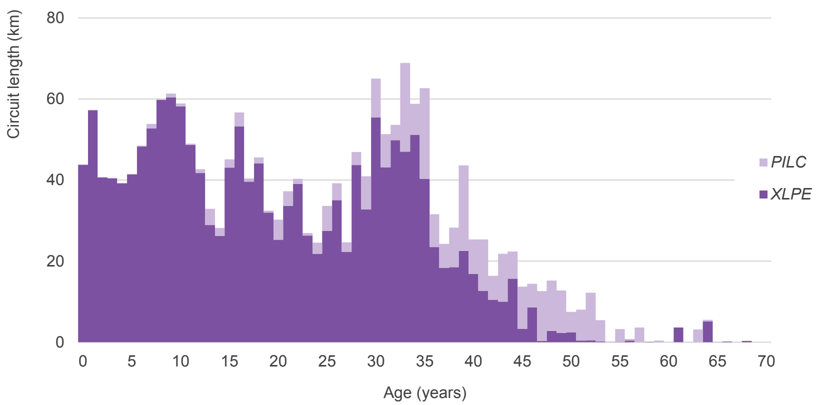
[79] 'Water treeing' results from condensed steam which was used to assist the polyethylene insulation curing as part of the manufacturing process.

Table 17.5: Distribution cable population by type at 31 March 2016

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	1,671	84
PILC	313	16
Total	1,984	

The figure below depicts our distribution cable age profile. A majority of cable installed over the past 40 years has been XLPE, with PILC being the predominant type before that.

Figure 17.4: Distribution cable age profile



Significant amounts of distribution cable were installed during the 1980s, coinciding with the general move by district councils to undertake or promote overhead to underground conversion in urban areas.

Overall, the distribution cable fleet is relatively young, with plenty of expected life remaining for the majority of cable circuits.[80] Significant levels of replacement are not expected for at least another decade.

We have two known type issues within the fleet that will drive our short-term renewal plans. These type issues are discussed in the next section.

[80] Expected lives for distribution cables are 55 and 70 years for XLPE and PILC respectively.

17.4.3 CONDITION, PERFORMANCE AND RISKS

Cable degradation is impacted by a combination of factors including:

- Insulation type
- Outer sheath design
- Fatigue from loading
- Cable quality (manufacturing batch issues, transportation storage)
- Fault currents through the cable
- Installation type (eg in ducts or direct buried)
- Armouring
- Soil type/environment
- Corrosion
- Age
- Third party damage

Most of these factors influence operating temperatures which in turn influence the life of insulation, screens and cable finishes.

Cables are more likely to fail in situations where there has been nearby works that may cause ground movement, damage during installation and PILC cables have been disturbed for jointing or termination works. Cable faults are more likely to occur at terminations or joints than within a section of cable, with the exception of a ‘treeing’ failure which can occur at any point.

There are two predominant type issues that affect the distribution cable fleet. Some of the early 11kV PILC cables installed in the New Plymouth region have brittle lead sheaths that are prone to cracking which allows water ingress. Any movement of the cables can cause cracking and potential failure. Additionally, where cables are grouped in a common trench, jointing is difficult.

The other type issue involves the first generation XLPE cables installed during the late 1960s and early 1970s. These were manufactured using steam-curing, making them more prone to water treeing (caused by partial discharge in the XLPE insulation brought on by the presence of water). Incompatible semi-conductive materials and lack of triple extrusion also contributed to earlier failures. This, coupled with a lack of knowledge and subsequent poor handling of cables during installation, has resulted in some cable failures.

These two types of cables have relatively high rates of failures and we are progressively replacing both.

Meeting our portfolio objectives

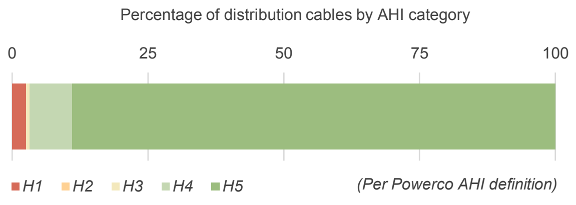
Asset Stewardship: Distribution cables with known high rates of failure are replaced to maintain overall fleet reliability, and manage network SAIDI and SAIFI.

Distribution cables asset health

As outlined in Chapter 7, we have developed a set of AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise their health based on a set of rules. For distribution cables, we define end-of-life when the asset can no longer be relied upon to operate reliably and the cable should be replaced.

The figure below shows current overall AHI for our population of distribution cables. The AHI calculation is based on our knowledge of specific cable type issues and asset age.

Figure 17.5: Distribution cables asset health as at 2016



The health of the distribution cable fleet is generally very good, with over 80% of the fleet not likely to require replacement in the next 20 years (H5). The small number of issues with some cable types (approximately 2% of the fleet) will require renewal in the short term (H1).

17.4.4 DESIGN AND CONSTRUCT

We use three standard sizes of distribution cable – 35, 185 and 300mm^2. These cables are multicore aluminium with XLPE insulation. Single core cables and other conductor sizes may be used for specific applications, such as when additional current rating is required. This standardisation assists us in our ongoing management of this asset fleet.

17.4.5 OPERATE AND MAINTAIN

Cables themselves are generally maintenance free as they are buried for most of their length. We perform inspections and diagnostic testing on above ground components such as breakouts, terminations and risers. We routinely inspect above ground exposed sections of cable and associated terminations to identify any condition degradation (UV is a major cause of degradation).

Our distribution cable maintenance tasks are summarised in the table below. The detailed regime for each type of cable is set out in our maintenance standard.

Table 17.6: Distribution cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Cable riser terminations visually inspected. Thermography and acoustic diagnostic tests of cable riser and breakouts, cast metal potheads.	2 ½ yearly

Cable faults most commonly occur due to third party interference such as digging. When cables or their protection have degraded or been damaged we undertake repairs to avoid a fault occurring. Corrective actions for cables include:

- Replacement of damaged cable riser mechanical protection on poles
- Replacement of cable terminations due to degradation
- Fault repairs due to third party damage or other cable faults

Spare cable and associated cable jointing equipment is held in strategic locations to enable fault repairs to be undertaken.

17.4.6 RENEW OR DISPOSE

Our renewal approach for distribution cable is to replace based on condition (including type issues and health). As previously mentioned, we have identified two type issues within the fleet affecting a number of PILC cables with brittle lead sheaths and first generation XLPE cable which is prone to water treeing. We plan to proactively replace these cables by 2021.

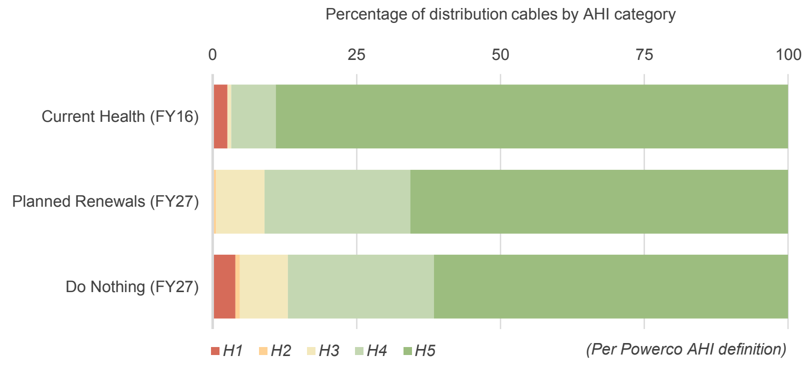
Cable insulation generally degrades over time, with the largest influences being operating temperatures and exposure to UV (which in turn influences the life of insulation, screens and cable finishes). Condition assessment, inspections and multiple failures can indicate a cable in poor condition and these cables are replaced. In the longer term, we use age as a proxy for condition to inform our renewal forecasts.

SUMMARY OF DISTRIBUTION CABLE RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Type issues and age
Cost estimation	Volumetric, adjusted for terrain

Distribution cable renewals are expected to remain fairly constant over the next decade. Apart from the type issues the fleet is in good condition. In the longer term we expect a large increase in distribution cable replacement expenditure as significant quantities of XLPE and PILC are expected to reach their renewal age of 55 and 70 years respectively.

The figure below compares projected asset health in 2027 (following planned renewals) with a ‘do nothing’ scenario. Our relatively small investment to address type issues and undertake condition-based replacement will keep the health of the fleet generally stable.

Figure 17.6: Projected distribution cables asset health in 2027



Coordination with Network Development projects

We work closely with other utilities, particularly those with road reserve buried services to ensure coordination of trenching works. At times we bring forward cable replacements to coincide with other excavating or road works. This allows us to replace the cable at a lower cost and limit road traffic disruption.

Road safety or widening projects initiated by NZTA often drive the need to relocate cables or to underground an existing overhead line. This work is classified as asset relocation and is discussed further in Chapter 21.

Meeting our portfolio objectives

Customers and Community: Cable development and replacement is coordinated with other excavation works to minimise road traffic disruption and minimise cost.

17.5 LOW VOLTAGE CABLE SYSTEMS FLEET MANAGEMENT

17.5.1 FLEET OVERVIEW

The LV cable fleet operates at below 1kV (230/400V). The main assets within the fleet are cables, link boxes, LV cabinets, service boxes and pillar boxes. We collectively refer to link boxes, pillar boxes and service boxes as LV boxes.

The number of consumers on a particular LV network section depends on the load density. The distance from the distribution transformer to the furthest consumer is usually limited to around 400 metres.

Customer service lines connect to our LV cable network by a cable from a service box usually located on the property boundary. The integrity of LV boxes is a key public safety concern. We have a variety of different styles and materials installed on our network.

Figure 17.7: LV boxes

17.5.2 POPULATION AND AGE STATISTICS

Our LV underground network consists of 5,718 circuit km of cable. This includes 1,701m of dedicated street lighting circuits and 403km of hot water pilot circuits.

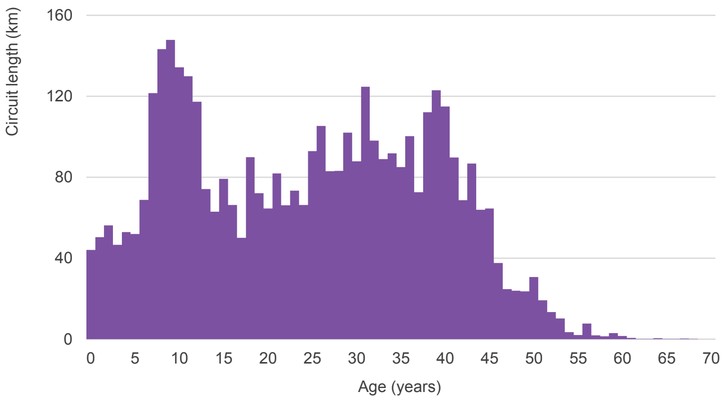
Data on our LV cable fleet is incomplete as detailed information was normally not recorded prior to 2000. We intend to significantly lift our knowledge of the LV network over the planning period. We plan to undertake a detailed programme of LV box data capture and labelling.

Meeting our portfolio objectives

Operational Excellence: We are improving our knowledge of the LV underground network through asset inspections to improve our fleet management decision-making.

While our information on LV cable types is limited we have reasonable age information. The figure below shows the age profile of the LV cable fleet (excluding street lighting and hot water circuits).[81]

Figure 17.8: LV cable age profile



The average age of the LV cable fleet is 24. As the fleet is relatively young we do not expect a need for significant cable renewal.

17.5.3 CONDITION, PERFORMANCE AND RISKS

The key risk in the fleet relates to our LV boxes which can present a hazard to the public if the cover is not secure, exposing live terminals. There have been a small number of fires in LV boxes due to overheating contacts and fuses. Older style pull-cap fuses have proven prone to overheating as corrosion occurs between the tinned copper cap and aluminium conductor.

Through our inspections and surveys we noticed overcrowded LV boxes, typically at infill developments. These overcrowded LV boxes present a safety hazard during servicing and can lead to overheating. We schedule the replacement of identified LV boxes through the defects process.

A large number of defects and faults are due to physical damage, often caused by vehicles. Although an LV box may initially have been placed in a safe location, new driveways can leave the boxes more vulnerable to damage. Our LV inspection process identifies these issues and replacement is planned during the planning period.

Another safety issue relating to LV boxes are those of metallic construction which can be inadvertently livened. Affected LV boxes have been identified and replacement is planned during the planning period.

We have identified a total of approximately 5,200 LV box defects. The LV boxes will be replaced as part of our ongoing LV safety-related investment programme.

17.5.4 DESIGN AND CONSTRUCT

We use three standard sizes of LV cable – 120, 185 and 300mm^2 stranded aluminium cable with XLPE/PVC insulation. Different sizes are used depending on the application (eg commercial, residential, and industrial). Voltage drop, fault current capacity and mechanical performance are considered when designing LV cable networks.

LV box types are closely controlled before being approved for use on the network. We use LV boxes from two manufacturer ranges, both of which been through our asset specification approval process.

17.5.5 OPERATE AND MAINTAIN

Maintenance of the LV cable fleet focuses on the inspection of LV boxes. The frequency of inspections is based on the safety criticality of the asset, with boxes in areas of higher risk inspected more often.

The table below summarises our inspections of the LV cable fleet. The detailed maintenance regime is set out in our maintenance standard.

Table 17.7: LV cable network preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Thermal imaging of CBD distribution boxes	1 yearly
Detailed inspection of LV boxes located near parks, public amenities, schools and business districts	2 ½ yearly
Detailed inspection of LV boxes not located near parks, public amenities, schools and business districts	5 yearly

As part of our plan to improve our knowledge of the LV cable network, we are embarking on a programme of LV box data capture and labelling. This will improve our knowledge of the LV network. We expect that it will also identify further LV box defects. LV boxes will be labelled so they can be tracked in our GIS and work management systems, and to warn the public of the safety risk.

[81] Around 10% of the fleet's age is unknown and has been excluded from the chart.

Meeting our portfolio objectives

Safety and Environment: LV boxes are being tracked and labelled to improve our management of assets that are in a public space to minimise safety risks.

17.5.6 RENEW OR DISPOSE

Renewal of LV cable is generally managed using a run to failure strategy. Consequence of failure is low and poses very little safety risk.

As we improve our LV underground network condition information (primarily from improvements in capturing failure data from our OMS) we will be able to more proactively target cable known to be prone to failure. We forecast our LV cable expenditure based on historic trend analysis.

LV boxes present a safety risk to the public and their condition is more easily understood through visual inspection. We are continuing our programme of LV box replacement with known type issues. There will also be an ongoing need to reactively replace LV boxes damaged by third parties. Forecasts are based on quantities of known defects and historic rates of replacement.

SUMMARY OF LV CABLE RENEWALS APPROACH

Renewal trigger	Run to failure (cable) and condition/type (LV boxes)
Forecasting approach	Historic trend (cable) and defect rates (LV boxes)
Cost estimation	Volumetric average historic rate

LV cable fleet renewal investment is expected to remain relatively constant over the next 10 years. After this, cable renewals may need to increase as larger quantities of cable may need to be replaced. Condition and failure data analysis will help us better understand LV cables life expectancy.

Coordination with Network Development projects

The LV underground network is typically expanded through the addition of new subdivisions. As a greenfield installation, subdivision development costs are much lower than cable renewal. Traffic management is avoided and trenching costs are often shared with other utilities.

In Tauranga city, changes to council development plans have resulted in growth being catered for through greater residential intensification, or infill development. This creates overloading of LV reticulation in the older areas of Tauranga and tends to be addressed reactively. Many of the smaller cables may need to be proactively replaced based on load growth rather than poor condition.

As levels of photovoltaic (PV) and EV penetration increase, we may also see overloading issues on the LV underground network, particularly where smaller legacy cables have been installed. We will monitor this along with PV and EV development and plan for upgrades accordingly.

17.6 CABLES RENEWALS FORECAST

Renewal Capex in our cable portfolio includes planned investments in our subtransmission, distribution and LV cable fleets. Over the planning period we will invest approximately $61m on cable renewal.

Managing safety risk is a key driver of expenditure on low voltage cable assets. Drivers for replacement of oil-filled subtransmission cables are a combination of environmental, reliability, cost and poor condition. In the case of distribution cable, increasing failure rates due to deterioration of asset health are the key drivers of increasing renewal volumes.

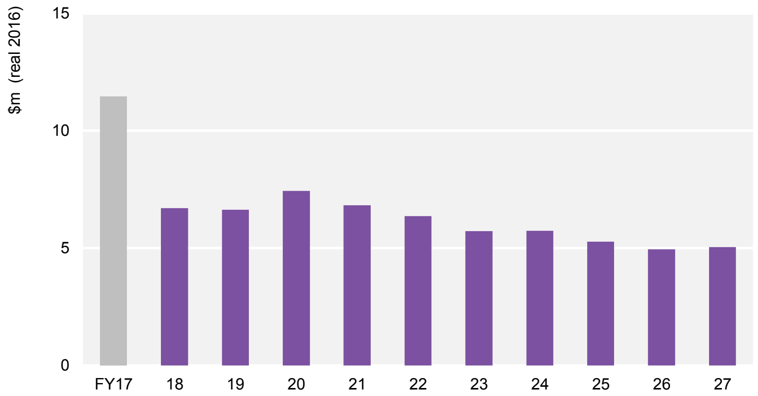
Our cable renewals are generally derived from bottom up models. Subtransmission cable expenditure is derived from detailed desktop estimates of planned projects. Distribution and LV cable forecasts are generally volumetric estimates (explained in Chapter 26).

Our forecasts are integrated with renewal needs from other fleets where appropriate to ensure efficient delivery. For example, the majority of subtransmission cable replacements in the Palmerston North CBD are delivered as part of a programme involving other new subtransmission circuits and zone substation developments.[82] Distribution cable replacement is often coordinated with ground mounted switchgear and transformer renewal.

The chart below shows our forecast Capex on cables during the planning period.

82 As the primary driver for the Palmerston North subtransmission cable replacement is condition, this expenditure is classed as renewals.

Figure 17.9: Cables renewal forecast expenditure



The forecast renewal expenditure for the cable portfolio is in line with historical levels. Additional expenditure in FY17 and FY20 is due to the subtransmission cable works in the Palmerston North CBD.

Further details on expenditure forecasts are contained in Chapter 26.

18.1 CHAPTER OVERVIEW

This chapter describes our zone substations portfolio. It summarises the zone substations fleet management plan used by the business. This portfolio includes the following six fleets:

- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control plant
- Other zone substation assets

The chapter provides an overview of asset population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary
During the planning period we expect to invest $121m in zone substation renewals. This accounts for 15% of our renewals Capex over the period.

Increased investment is needed to support our safety and asset stewardship objectives. The increase in renewals Capex is driven by the need to:

– Renew assets in poor condition. Most of the increase is driven by renewal programmes for power transformers, indoor switchboards, outdoor switchgear and two large projects at Greerton and Whareroa substations.

– Stabilise asset health. Our asset health models indicate the need for a step change in renewals. For example, 22% of our outdoor switchgear requires replacement over the next 10 years.

– Manage safety risk, particularly for field staff. A number of our 11kV switchboards have a higher than acceptable arc flash risk. Plans to reduce this risk include the installation of arc flash protection and arc blast proof doors. In some cases we will prioritise replacement of the complete switchboard.

Below we set out the asset management objectives that guide our approach to managing our six zone substation fleets.

18.2 ZONE SUBSTATIONS OBJECTIVES

Zone substations take supply from the national grid through subtransmission feeders. They provide connection points between subtransmission circuits, step-down the voltage through power transformers to distribution levels, and utilise switching and isolating equipment to enable the network to be operated safely.

Zone substations play a critical role in our network. Prudent management of these assets is essential to ensure safe and reliable operation. Zone substations provide bulk supply of electricity for distribution to end users. Supply for many thousands of customers depends on a few key assets within zone substations.

To guide our asset management activities, we have defined a set of portfolio objectives for our zone substation assets. These are listed in the table below. The objectives are linked to our asset management objectives as set out in Chapter 5.

Table 18.1: Zone substations portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No lost time injuries resulting from arc flash incidents. No oil or SF_6 leaks from zone substation assets. No unacceptable noise pollution from zone substation assets.
Customers and Community	Ensure design and aesthetics of zone substations integrate into the neighbouring community.
Networks for Today and Tomorrow	Improve zone substation compliance with our network security standards.
Asset Stewardship	Procure a mobile substation to help minimise outages during maintenance or planned installation work and provide cover during emergencies.
Operational Excellence	Further develop our use of asset health and criticality to support renewal decision-making, including the use of CBRM.

18.3 POWER TRANSFORMERS FLEET MANAGEMENT

18.3.1 FLEET OVERVIEW

Zone substation transformers are used to transform power supply from one voltage level to another, generally 33/11kV, but some are 33/6.6kV, 66/11kV or 11/22kV. Capacities range from 1.25 to 24MVA.

The major elements that collectively comprise a zone substation power transformer include the core and windings, housing (or tank), bushings, cable boxes, insulating oil conservator and management systems, breather, cooling systems and tap changing mechanisms.

Figure 18.1: Power transformer installation at Waharoa

18.3.2 POPULATION AND AGE STATISTICS

There are 191 power transformers in service on our network, of which 173 are 33/11kV units. The table below summarises our population of power transformers by rating.

Table 18.2: Power transformer population by rating at 31 March 2016

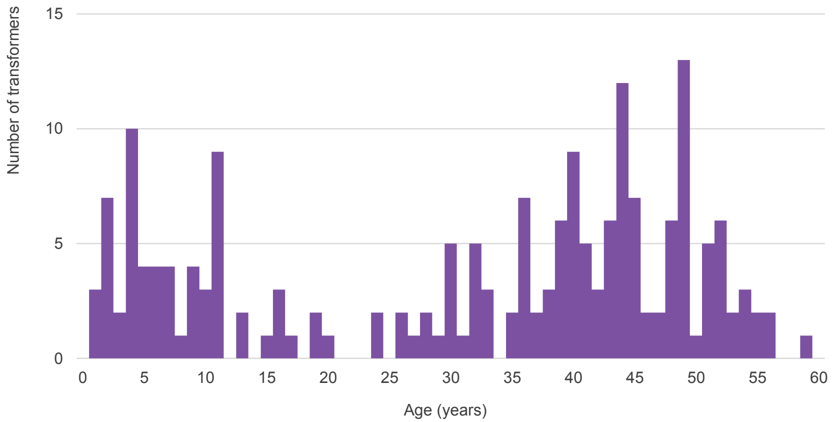
MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
<5	27	14
≥5 to <10	75	39
≥10 to <15	22	12
≥15 to <20	41	21
≥20	26	14
Total	191	

Although we purchase standard sizes and configurations, we have some legacy ‘orphan’ assets. This limits interchangeability and therefore operational flexibility.

The orphan category includes units with unique vector groups, tap changers with different tap steps, and a small number of autotransformers which cause issues for our protection systems. Orphan units will be prioritised for replacement over the planning period based on condition.

The figure below shows our power transformer age profile. The average age of all our zone substation transformers is 31 years.

Figure 18.2: Power transformer age profile



A number of our power transformers are approaching their expected 60-year life span and will soon likely require replacement.

18.3.3 CONDITION, PERFORMANCE AND RISKS

Power transformer failures are relatively rare. The main causes are manufacturing defects and occasionally on-load tap changer failures due to mechanical wear. There have also been several cable termination failures within transformer cable boxes arising from joint type issues and at times installation issues. Failure of a power transformer can result in loss of supply or reduced security of supply, depending on the network security level of the zone substation.

A small number of our existing power transformers have inadequate or no oil bunding. A transformer that leaks oil poses an environmental hazard (soil contamination).

We are addressing this risk by installing or upgrading bunding with an associated oil containment and separator system. We intend to continue to retrofit oil containment to all of our power transformer sites that do not already have them (and which are not scheduled for renewal). Implementing these measures may also reduce the fire risk in the event of an explosive transformer failure.

Meeting our portfolio objectives

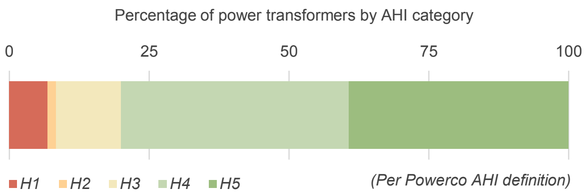
Safety and Environment: Power transformer bunding and oil containment systems are being upgraded to reduce the risk of oil spills.

Power transformers asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. The AHI for power transformers is condition-based. We explain our asset health model in more detail in the renewal, refurbishment and disposal section below.

The figure below shows current overall AHI for our population of power transformers.

Figure 18.3: Power transformer asset health as at 2016



Fourteen of our power transformers need replacement (H1). These transformers make up about 7% of the power transformer fleet.

18.3.4 DESIGN AND CONSTRUCT

The design phase for power transformers ensures we get quality assets from our suppliers. We work closely with a small panel of transformer manufacturers and conduct on-site design reviews for all new transformers.

To ensure good operational flexibility across the network we order transformers in standard sizes. Standard sizes[83] for 33/11kV transformers are:

- 5MVA
- 7.5/10MVA
- 12.5/17MVA
- 16/24MVA

[83] Some units have two cooling ratings. They represent natural and forced (i.e. with pumps and fans) cooling.

Sometimes a replacement power transformer is larger than the existing unit or it is anticipated to generate more noise. In those instances we undertake acoustic studies before installing the new transformer. Understanding the impact of noise on the immediate community allows us to implement necessary measures to minimise noise pollution.

Meeting our portfolio objectives

Safety and Environment: Noise levels are reviewed when new transformers are installed to minimise noise pollution.

18.3.5 OPERATE AND MAINTAIN

Power transformers and their associated ancillaries such as tap changers undergo routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in the table below.

Table 18.3: Power transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of insulating systems, cooling, bushing and insulators, tap changer compartment, foundations and other ancillaries.	3 monthly
Service dehydrating breathers. External paintwork touch-ups. Automatic voltage regulator operation checks. Buchholz gas check. Acoustic emission, thermal imaging and external partial discharge diagnostic tests.	1 yearly
DGA test, insulation and winding resistance tests. Tap changer service.	3 yearly

When power transformers reach mid-life (25-35 years) we have historically undertaken major workshop based overhauls. During overhauls a new or recently overhauled transformer is installed in its place. This means transformers can be rotated through the network and older transformers moved to less critical sites where the consequence of failure is lower.

Transformer rotations have allowed us to optimise the number of new transformers required on the network for growth reasons and extend the life of the transformer assets. However, many of the overhauled units are now in a condition where they require outright replacement. The cost of maintenance overhauls has also started to increase which lessens the potential benefits of this programme.

We are reconsidering rotations and the criteria used to assess when it is cost effective to overhaul an aged power transformer. The decision to proceed with an overhaul will continue to be on a case-by-case basis.

Mobile substation

Many of our rural zone substations have a single power transformer supply. Over the past few years it has become increasingly difficult to arrange the required shutdowns due to diminishing back-feed capability. Any maintenance or planned replacement work requires an outage for the communities supplied by these substations.

A mobile substation can reduce and, in some cases, eliminate the need for outages, can be used as a temporary switchboard for major failure events and during planned replacement of 11 kV switchboards (mitigates arc flash risk during installation of the new board).. We are planning to procure a mobile substation during FY18-19. Included in this is the installation of permanent connection points at key sites to allow straightforward connection of the mobile substation.

Meeting our portfolio objectives

Asset Stewardship: We are procuring a mobile substation to help minimise outages during maintenance or planned installation work, and provide cover during emergencies.

18.3.6 RENEW OR DISPOSE

Overall condition is used to assess when a power transformer is scheduled for renewal. Condition is used as a proxy for failure risk. Failure of power transformers is to be avoided, due to the potential network impacts (depending on the security of the associated zone substation) and safety risk of fire and explosion.

SUMMARY OF POWER TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Asset health
Cost estimation	Desktop project estimates

Renewals forecasting

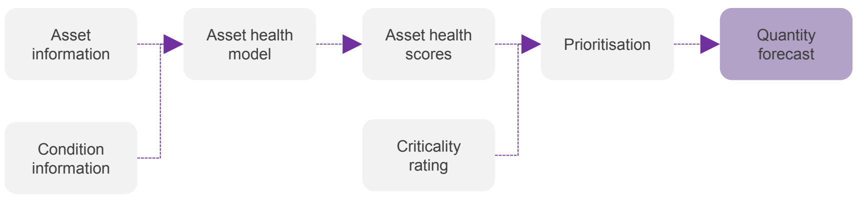
To help with long-term forecasting of power transformer replacements we have developed a condition-based asset health model. Asset health indices provide a more accurate assessment of where an asset is in its life cycle than age alone.

Our power transformer asset health model is based on work by the EEA[84], and our experience and asset information. Condition indicators used in the model include DGA, paper insulation DP, external tank condition and known type or design issues.

The asset health based renewal quantity forecast begins with determining an asset health score for each power transformer. The score is then used to adjust the remaining life of the asset. The criticality of the power transformer is then used to make a further adjustment to its planned renewal year. The criticality is derived from the size of the load served and the load's security (N or N-1).

The figure below provides an overview of the asset health based renewal quantity forecast.

Figure 18.4: Power transformer asset health based renewal quantity forecast



Meeting our portfolio objectives

Operational Excellence: Power transformer renewal is informed by condition-based asset health and criticality, which we will continue to refine across our asset fleets.

The forecast for the planning period is based on desktop studies of each replacement project and associated site specific renewal cost estimates.

As part of our power transformer renewal programme we will upgrade bunding, oil containment and separation systems, install transformer firewalls (where there is risk of fire spread), and review and upgrade transformer foundations to ensure appropriate seismic performance.

Over the planning period we expect to replace three to four power transformers per year. This will ensure our transformers in poor health are replaced while managing the remaining fleet's health through its life cycle.

Longer term we expect the number of power transformer replacements to remain at a similar level. A significant number of transformers installed in the 1960s and 1970s will become due for condition-based renewal.

Coordination with Network Development projects

A power transformer is usually replaced because it is in poor condition or it cannot serve its required load. Often both happen around the same time so we take a coordinated approach when planning for replacements. As part of our planning we ensure that a new power transformer can serve its expected future load at the zone substation.

Zone substation security requirements can also be a reason for needing additional transformers. We sometimes upgrade sites from one transformer to two. This provides N-1 security when the substation load has increased or the type of load

[84] EEA Asset Health Indicator Guide

requires additional redundancy. For further discussion refer to our zone substation security standards in Chapter 11.

Power transformer replacements are among the larger projects undertaken within a zone substation. For delivery and cost efficiency we often coordinate other zone substation works such as outdoor switchgear replacements with transformer projects.

18.4 INDOOR SWITCHGEAR FLEET MANAGEMENT

18.4.1 FLEET OVERVIEW

Indoor switchgear comprises individual switchgear panels assembled into a switchboard. These contain circuit breakers, isolation switches, busbars along with associated insulation and metering. They also contain protection and control devices along with their associated current and voltage transformers.

Indoor switchgear has been used extensively for applications at 11kV. More recently it is also preferred for 33kV applications. Indoor switchgear is generally more reliable than outdoor switchgear. It is more protected from corrosion as it is not exposed to pollution, weather and foreign interference (such as bird strikes). Indoor switchgear also has a much smaller footprint, making it useful in urban environments where it can be hidden within an appropriate building.

Figure 18.5: 11kV indoor switchboard at Main St, Palmerston North

18.4.2 POPULATION AND AGE STATISTICS

There are 923 circuit breaker panels within 119 indoor switchboards in service on our network. The majority of switchboards operate at 11kV but the number of 33kV boards is increasing. The table below summarises our indoor switchgear population by type and number of circuit breakers and switchboards.

Table 18.4: Indoor switchgear circuit breaker and switchboard populations by type at 31 March 2016

INTERRUPTER TYPE	CIRCUIT BREAKERS	SWITCHBOARDS
Oil	404	58
SF_6	128	21
Vacuum	391	40
Total	923	119

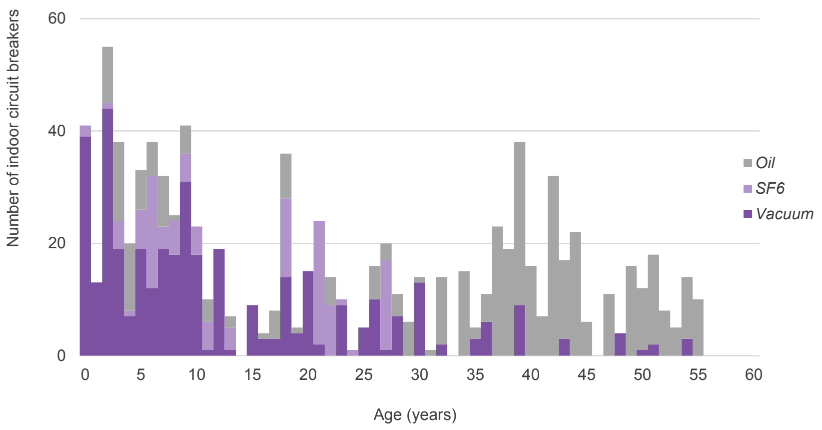
Indoor switchgear technology has evolved over time. Prior to the 1990s the majority of switchgear installed used oil as the circuit breaker insulation and arc quenching medium. The older segment of our population is primarily made up of oil-filled switchgear.

Modern switchgear uses vacuum or SF_6 based circuit breakers. We prefer vacuum due to its better environmental characteristics. Over the past 20 years the majority of the switchgear we installed has been vacuum or SF_6 based.

The level of arc flash protection has improved with modern switchboards. They offer arc flash venting, blast proof switchgear doors and are installed with dedicated arc flash protection to more quickly isolate a fault. Arc flash containment is now mandatory for new switchgear installed on our network.

The figure below outlines the age profile of the indoor switchgear fleet.

Figure 18.6: Indoor switchgear (circuit breakers) age profile



We generally expect a useful life of approximately 45-50 years from our indoor switchgear assets. A number of assets already exceed this guide and will likely need replacement over the next five to ten years.

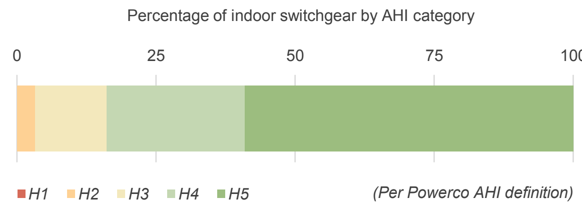
18.4.3 CONDITION, PERFORMANCE AND RISKS

Indoor switchgear asset health

As outlined in Chapter 12, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For indoor switchgear we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely and the switchgear should be replaced. The AHI is calculated using our prototype Condition-Based Risk Management Model (noting that actual replacement is informed by detailed condition assessment) CBRM is explained further in the box below.

The figure below shows current overall AHI of the indoor switchgear fleet.

Figure 18.7: Indoor switchgear asset health as at 2016



About 16% of our indoor switchgear requires replacement over the next 10 years (H1-H3)[85].

Condition-Based Risk Management (CBRM)

We have developed a prototype CBRM model to calculate asset health indices for our outdoor and indoor switchgear fleets. This approach has been successfully applied by electricity network companies around the world.

Our model uses asset condition, type, and criticality together with engineering knowledge and practical experience to define future condition, performance and risk for network assets. We have used it to report on asset health of the switchgear fleets and test our forecasting and prioritisation.

We expect that over time CBRM will become the primary forecasting technique for the indoor and outdoor switchgear fleets.

Arc flash risk

Arc flash risk is a considerable safety concern for our indoor switchgear fleet. An arc flash is a type of electrical explosion that can occur at any time but is most likely during operation of switchgear. An arc flash can release a large amount of energy, which can prove fatal or cause serious, permanent injury to personnel near the explosion. It can also cause material damage to the equipment.

We have undertaken arc flash assessments for our 11kV switchboards to determine their risk levels. We have defined a prudent level of arc flash energy[86] to be no more than 8 cal/cm^2. We use this alongside the switchgear type to categorise the arc flash risk.

The table summarises the arc flash risk of our 11kV indoor switchgear population, combining arc flash levels and asset health. It highlights that 17% of our 11kV

85 The CBRM model assumes the current fleet is in 'operational condition' and therefore calculates very little assets in H1 health. As the model runs forward in time asset health degrades and the number of H1 assets increases.

86 Arc flash energy is described in calories per centimetre squared (cal/cm^2). Our limit is based on the EEA's 'Guide for the Management of Arc Flash Hazards'.

switchgear has an increased arc flash risk when considering both the switchboard health and arc flash level (as shown in the yellow, orange and red areas below).

Table 18.5: 11 kV indoor switchgear arc flash risk as at 2016 (% of total asset fleet)

	ASSET HEALTH INDEX				
ARC FLASH CATEGORY	H5	H4	H3	H2	H1
≥ 8 cal/cm^2 (oil switchgear)	2%	9%	3%	1%	0%
≥ 8 cal/cm^2 (not oil switchgear)	11%	4%	0.2%	0.1%	0%
< 8 cal/cm^2	41%	16%	12%	2%	0%

We mitigate this risk through one of three approaches:

- Removing the entire switchboard from service when performing maintenance
- Reconfiguring the upstream network to reduce arc flash levels
- Ensuring personnel working close to the switchboard wear appropriate arc flash rated PPE gear

These solutions do not completely eliminate arc flash risks however.

All newly installed switchboards have full arc flash detection systems, arc containment and arc venting. We will install on many of our existing switchboards various arc flash retrofits (including blast proof doors, arc flash detection systems and arc venting) to mitigate arc flash risk. We have determined it is not appropriate to mitigate the arc flash risk on switchboards containing oil circuit breakers where the incident energy is high. We will replace these switchboards proactively in the short to medium term.

Meeting our portfolio objectives

Safety and Environment: Indoor switchboards with arc flash risk have mitigations in place and will progressively be replaced in order to reduce safety risks to our staff and service providers.

18.4.4 DESIGN AND CONSTRUCT

Our equipment class standards classify indoor switchgear as class A equipment as its function is critical to the reliable operation of the network. Before a new type of switchgear can be used on the network, it must undergo a detailed evaluation to ensure the equipment is fit for purpose on our network.

We currently specify withdrawable circuit breakers for indoor switchgear. We are evaluating whether we should allow non-withdrawable types.

Withdrawable circuit breakers generally sit on trucks, making them easy to maintain and replace. In the past this has been important for oil circuit breakers which require frequent servicing. However, they carry additional safety risk because incorrect racking can cause accidents.

Non-withdrawable breakers do not provide a visible break. The integral nature of these means individual panels cannot easily be replaced. The reliability of modern units has improved and vacuum and SF_6 circuit breakers do not need to be serviced. As such, a lack of visible break is no longer considered a significant issue. In addition, non-withdrawable units take up less space and therefore can reduce the cost of new substations.

18.4.5 OPERATE AND MAINTAIN

Indoor switchgear undergoes routine inspections and maintenance to ensure their continued safe and reliable operation. These preventive tasks are summarised in the table below.

Table 18.6: Indoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, cabinets and panels.	3 monthly
Operational tests on circuit breakers not operated in last 12 months. Condition-test switchgear including thermal, PD and acoustic emission scan.	1 yearly
Insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. SF_6 gas pressure checks.	3 yearly
Vacuum circuit breaker diagnostic tests (eg HV withstand). Switchboard partial discharge test.	6 yearly

18.4.6 RENEW OR DISPOSE

Indoor switchgear renewal decisions are based on a combination of factors that include:

- Switchgear condition (condition of the circuit breakers, busbars and other associated ancillaries)
- Known reliability type issues
- Fault level interrupting capacity
- Arc flash risk

We consider these factors holistically along with the criticality of the zone substation when we determine the optimum time for replacement.

SUMMARY OF INDOOR SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	Proactive condition based with safety risk
Forecasting approach	Age and arc flash levels
Cost estimation	Desktop project estimates

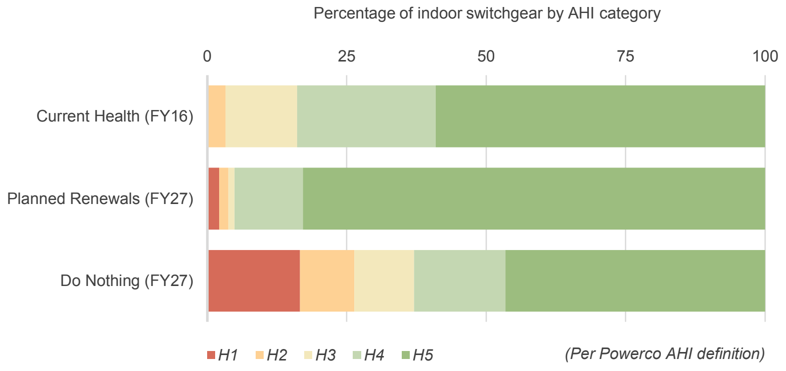
Renewals forecasting

Our indoor switchgear renewals forecast uses switchboard condition, reliability and arc flash risk information. Longer term, we also use age as a proxy for condition, to help us estimate likely future asset deterioration.

We need to invest significantly in indoor switchgear renewals to mitigate arc flash risks and address the asset health of some switchboards. We expect to replace three to four switchboards per year for the next 10 years.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario.

Figure 18.8: Projected indoor switchgear asset health in 2027



Overall indoor switchgear asset health will remain stable as we undertake planned replacement of switchboards with high arc flash risk and those in poor condition. After 2027 the renewal volume will be lower, as indicated H2-H3 in Planned Renewals (FY27).

The table below shows the make-up of our switchboard population in terms of arc flash risk. This table is similar to Table 17.5, but provides a projection of the risk in 2026 assuming our planned renewals occur.

Table 18.7: Projected 11kV indoor switchgear arc flash risk as at 2026 (% of total asset fleet)

	ASSET HEALTH INDEX				
ARC FLASH CATEGORY	H5	H4	H3	H2	H1
≥ 8 cal/cm^2 (oil switchgear)	0%	0%	0%	0%	0%
≥ 8 cal/cm^2 (not oil switchgear)	8%	4%	0%	0%	0%
< 8 cal/cm^2	75%	8%	1%	2%	2%

We have identified the need for a site rebuild project[87] for our Whareroa zone substation. The substation's indoor 11kV and outdoor 33kV switchgear and associated bus structure date back to when the site was established in 1973. The assets have significant condition deterioration and are now obsolete.

The site is located within a Fonterra dairy plant which no longer takes supply from the zone substation. The substation will be rebuilt on a new site called Mokia, closer to Livingstone substation where it will be better placed to serve the connected load. Further information on the project is contained in Appendix 9.

Our indoor switchgear forecasts also include expenditure for indoor conversions.[88] These are described in further detail in the outdoor switchgear section below.

Coordination with Network Development projects

New zone substation projects typically use indoor switchgear because it performs better than outdoor switchgear. In addition, at sites with more than four feeders the installation cost is usually lower. For urban substations, switchgear is installed in buildings that visually integrate into the surrounding neighbourhood to provide as little visual impact as possible.

Existing indoor switchboards often have their associated protection relays installed on the switchgear panels. Their protection is always replaced along with the switchboard. We align protection relay replacement with the switchboard replacement timing to minimise retiring protection equipment before the end of its useful life.

87 This expenditure is included within the indoor switchgear fleet, as this is the largest cost component of the project.

88 Outdoor to indoor conversion renewal expenditure is included in this fleet as it involves installing new indoor switchgear. Drivers for these projects are related to the outdoor switchgear and are described in the outdoor switchgear section.

18.5 OUTDOOR SWITCHGEAR FLEET MANAGEMENT

18.5.1 FLEET OVERVIEW

The zone substation outdoor switchgear fleet comprises several asset types including outdoor circuit breakers, air break switches, load break switches, fuses, and reclosers.

Outdoor switchgear is primarily used to control, protect and isolate electrical circuits in the same manner as indoor switchgear. It de-energises equipment and provides isolation points so our service providers can access equipment to carry out maintenance or emergency repairs.

Each asset type has specific uses to suit particular applications. Both circuit breakers and reclosers provide protection and control, while fuses provide protection and isolation only. Non-load break air break switches isolate but cannot be used to break the load current. Load break switches control and isolate and are used to break load current.

Figure 18.9: Typical outdoor 33kV switchgear bay

18.5.2 POPULATION AND AGE STATISTICS

The table below summarises our population of outdoor switchgear by type. Circuit breakers are also broken out by interrupter type.

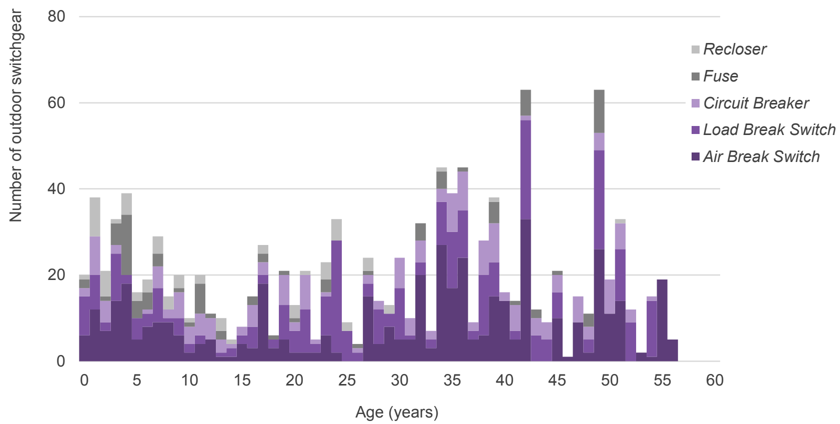
Table 18.8: Outdoor switchgear numbers by asset type at 31 March 2016

SWITCHGEAR TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Air break switch		460	40
Load break switch		330	29
Circuit breaker		195	17
of which:	Oil	137	
	SF_6	45	
	Vacuum	13	
Fuse		94	8
Recloser		69	6
Total		1148	

The majority of circuit breakers are oil interrupter based. Although unlikely, they can fail explosively if not properly maintained. They will be phased out over time and replaced by either vacuum of SF_6 based circuit breakers.

The figure below shows our outdoor switchgear age profile.

Figure 18.10: Outdoor switchgear age profile



We generally expect outdoor switchgear assets to require replacement at an age of around 45 years. Therefore a large number of assets (>25% of the fleet) may require replacement over the next decade (noting that actual replacement decisions are made on the basis of asset condition).

18.5.3 CONDITION, PERFORMANCE AND RISKS

Oil-based circuit breakers carry additional risks compared to their modern equivalents. A higher frequency of operations and energy of switching increases the likelihood of failure. This degrades the oil quality due to carbonisation.

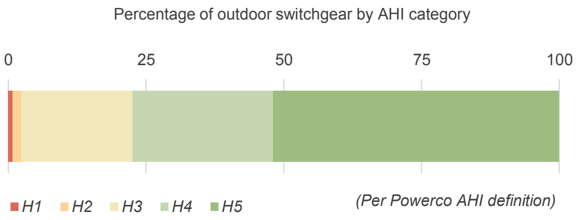
To minimise this failure risk we service our oil circuit breakers after they have performed a specified number of switching operations. The number is determined based on the type of circuit breaker and the fault current breaking energy.

Outdoor switchgear asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise their health based on a set of rules. For outdoor switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switchgear should be replaced. The AHI is based on our prototype Condition-Based Risk Management Model, explained in the Indoor Switchgear condition, performance and risks section.

The figure below shows current overall AHI for our population of outdoor switchgear.

Figure 18.11: Outdoor switchgear asset health as at 2016



The overall health of the outdoor switchgear fleet is poor as we expect that 22% of the fleet will require renewal over the next 10 years (H1-H3)[89]. A significant increase in renewal investment is required to stabilise the health of this fleet.

18.5.4 DESIGN AND CONSTRUCT

Like indoor switchgear, outdoor switchgear is classified as Class A equipment and undergoes a detailed evaluation process to ensure any new equipment is fit for purpose on our network.

For 33kV circuit breakers replacement, our current standard asset is a live tank SF_6 breaker. SF_6 circuit breakers are the current industry standard for HV outdoor applications. However, we are monitoring developments with equivalent vacuum-based circuit breakers. Vacuum circuit breakers would help reduce our holdings of SF_6 gas and its associated environmental risks. We are reviewing our reporting processes because we recently were classified as a major user of SF_6. [90]

Meeting our portfolio objectives

Safety and Environment: We continue to monitor developments in non-SF_6 based switchgear in order to reduce the potential environmental risks from gas leaks.

Whenever possible we manage outdoor switchgear replacements at the bay level. This ensures delivery efficiency. Replacements are also typically planned to coincide with power transformer replacements where practicable.

Figure 18.12: Live tank SF6 outdoor 33kV circuit breaker

[89] See footnote 85

[90] An SF_6 user becomes a major user when it has more than 1000kg of the gas in stock.

18.5.5 OPERATE AND MAINTAIN

Outdoor switchgear undergoes preventive maintenance to ensure safe and reliable operation. We also undertake preventive maintenance on the basis of circuit breaker operations to mitigate against failure modes associated with excess duty.

Our various preventive maintenance tasks are summarised in the table below. The detailed regime for each asset is set out in our maintenance standard.

Table 18.9: Outdoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, ABSs and reclosers.	3 monthly
Operational tests on CBs not operated in last 12 months. Condition-test circuit breakers including thermal, PD and acoustic emission scan.	1 yearly
Circuit breaker insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. ABS thermal scan. Recloser thermal and oil insulation tests.	3 yearly
ABS service of contacts and mechanism.	6 yearly
Vacuum and SF_6 recloser checks and insulation tests.	9 yearly
Replace oil (if relevant). Contacts checked and resistance measured.	Operations-based

Outdoor switchgear requires more preventive and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

18.5.6 RENEW OR DISPOSE

Our approach is to replace circuit breakers and other outdoor switchgear equipment on a condition basis. We aim to avoid outdoor switchgear failure. Network consequences can be large and failure modes can be explosive, particularly with oil-filled switchgear.

SUMMARY OF OUTDOOR SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Age
Cost estimation	Volumetric average historic rate

Renewals forecasting

Our longer term outdoor switchgear renewals quantity forecast uses age as a proxy for condition. Older switchgear is more likely to be in poor condition because of exposure to corrosion for longer periods. Its mechanical components are also likely to have more wear and tear.

Our renewals forecast also takes into account that older designs of switchgear generally have fewer safety features and are less reliable. In our experience design lives are highly correlated with actual service life on our network using a condition-based replacement approach.

Our expenditure forecast is based on forecast renewal quantities and averaged historical unit rates.

Outdoor to indoor conversion project[91] planning considers a range of drivers, including condition, safety and criticality. The high level scope of these projects is used to develop an indicative cost estimate. We intend to further refine our quantitative analysis to help identify the need for conversions.

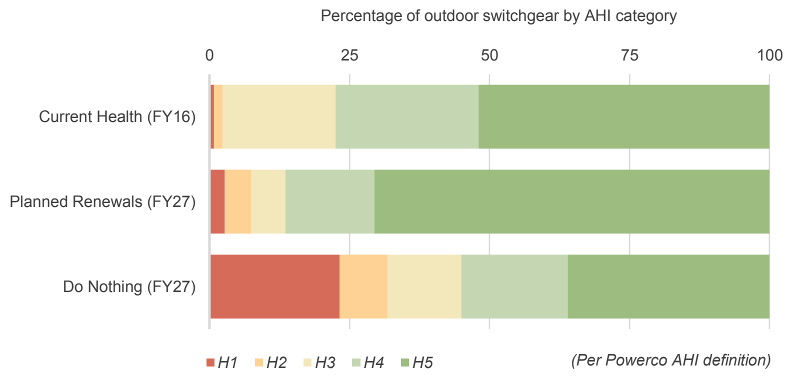
We have identified that Greerton zone substation needs to be converted to indoor switchgear. The site contains 10 circuit breakers and is a critical switching station for supply in the Tauranga area. The outdoor switchgear is in poor condition and requires replacement. The conversion to indoor switchgear is planned for FY19-20.

We also have outdoor to indoor conversions planned as part of projects for six other zone substations during the planning period. These projects are discussed in more detail in Appendix 9.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our increased investment targeting assets in poor condition will maintain asset health at the current level.

91 Outdoor to indoor conversion project expenditure is classified under indoor switchgear, but is discussed in this section. The drivers for the conversion relate to the existing outdoor assets, not new indoor switchboards.

Figure 18.13: Projected outdoor switchgear asset health in 2027



Replacement levels will reduce slightly beyond 2027 as indicated by the smaller H2-H3 portion in Planned Renewals (FY27).

Coordination with Network Development projects

The majority of new zone substations employ indoor switchgear as a preference to outdoor switchgear due to its cost, footprint, reliability and safety benefits. We also review existing zone substations for possible conversion to indoor switchgear when undertaking major development work.

18.6 BUILDINGS FLEET MANAGEMENT

18.6.1 FLEET OVERVIEW

Zone substation buildings mainly house protection, SCADA, communications and indoor switchgear equipment.

Zone substation sites need to be secure. Buildings and equipment must be well secured for earthquake exposure and designed to minimise the risk of fire.

We have undertaken a seismic survey of our existing zone substation buildings. This work identified a list of buildings that require strengthening to meet the NZ Building Code. We will address these requirements over the planning period.

Figure 18.14: Masonry constructed building

18.6.2 POPULATION AND AGE STATISTICS

We have 158 buildings[92] at our zone substations. These are constructed of various materials including concrete, timber and masonry.

18.6.3 CONDITION, PERFORMANCE AND RISKS

As building standards have evolved the requirements for seismic performance have changed. Older buildings, particularly those made of unreinforced masonry and concrete construction, are well below today's strength standards.

The seismic performance of our zone substation buildings is important for the safety of our people working in them and to maintain (or quickly restore) electricity in the event of a large earthquake.[93]

We have assessed 73 of our zone substation buildings[94] against the New Zealand Society of Earthquake Engineering (NZSEE) grades. Our standard dictates all zone substation buildings should be at least 67% of the new building standard (NBS), equivalent to B grade or better. The study indicated 55 of our buildings require seismic strengthening.

The table below shows our zone substation buildings by NZSEE seismic grade.

92 This excludes 'minor' buildings, such as sheds.

93 Zone substations buildings are considered a 'frequented location', and carry a considerable community importance due to our function as a lifeline utility. Therefore these buildings are of an Importance Level of 4 in accordance with AS/NZS 1170.5, along with buildings used for medical emergency and surgery functions and emergency services.

94 Zone substation buildings were excluded from this assessment as they had previously been assessed, had recently been strengthened, or had been constructed in the last 10 years. These buildings are assumed to be at least at grade B.

Table 18.10: Zone substation buildings by NZSEE seismic grade at 31 March 2016

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS	% OF TOTAL
A+	>100	7	4
A	80-100	29	18
B	67-79	8	5
C	34-66	20	13
D	20-33	25	16
E	<20	10	6
Not assessed[94]		59	37
Total		158	

Twenty seven of our zone substation buildings have also been identified as potentially containing asbestos. If the material is not disturbed, asbestos cannot be inhaled. We will remove the asbestos from buildings when we are undertaking seismic strengthening, switchboard replacements, building extensions or any other work that may disturb the asbestos.

18.6.4 DESIGN AND CONSTRUCT

When designing new zone substation buildings we carefully consider the visual aesthetics of the surrounding neighbourhood. This is particularly important in urban areas. We try to make our sites as unobtrusive as possible to the local community. A number of our new zone substation buildings in urban areas have been designed to look like modern family homes.

Meeting our portfolio objectives

Customers and Community: Urban zone substation buildings are integrated into the neighbourhood reducing their visual impact.

Figure 18.15: Urban zone substation building

18.6.5 OPERATE AND MAINTAIN

We routinely inspect our zone substation buildings to ensure they remain fit for purpose and any remedial maintenance work is scheduled as required. Ensuring our buildings are secure is essential to prevent unauthorised access.

Table 18.11: Building preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of building. Check emergency lighting system.	3 monthly
Detailed visual inspection, including weather-tightness, checks of structure, roof, plumbing, drainage, electrics and fittings. Check safety equipment and signs.	1 yearly

18.6.6 RENEW OR DISPOSE

Zone substation buildings that do not meet our standard for seismic compliance are part of a seismic strengthening programme planned for this planning period. This will ensure our buildings are safe and able to maintain a reliable supply in the event of a major earthquake.

SUMMARY OF BUILDINGS RENEWALS APPROACH	
Renewal trigger	Seismic risk
Forecasting approach	Desktop seismic study
Cost estimation	Historic rates

Our aim is to have all our zone substation buildings up to B grade or better by the end of the planning period. The timing of strengthening projects depends on other work at the zone substation, the current seismic grade of the building and the relative criticality of the site.

Cost estimates for the strengthening works are based on previously completed works. We intend to further refine these estimates as we complete more strengthening works.

Once the seismic upgrades are complete, other than ongoing maintenance we do not anticipate a need for further works in this fleet in the medium term.[95]

Coordination with Network Development projects

Zone substation buildings are typically built for new indoor switchgear, either a complete switchboard renewal or a switchboard extension to serve additional feeders. Planning for these two fleets is therefore done at the same time. We also time seismic upgrades to coincide with switchgear works to ensure upgrades are designed with the requirements of the new switchgear in mind.

New greenfield zone substations buildings are planned and designed to meet the needs of the overall development.

18.7 LOAD CONTROL INJECTION PLANT FLEET MANAGEMENT

18.7.1 FLEET OVERVIEW

Load control has been used in New Zealand for the last 60 years. Load control systems are used to manage the load profiles of customers with controllable loads (eg hot water or space heating).

Load control involves sending audio frequency signals through the distribution network from ripple injection plants at zone substations. Ripple receiver relays located at consumer main distribution boards receive the signals and turn the 'controlled load' on or off.

If configured well, load control systems are highly effective at reducing demand at peak times by deferring non time-critical power usage. Benefits of load control include more predictable peak demand and allowing us to defer distribution capacity increases. Wider benefits include a reduced need for peaking generation plants and transmission deferral.

Figure 18.16: Load control injection plant

18.7.2 POPULATION AND AGE STATISTICS

We currently operate 36 load control injection plants on our network, comprising both modern (and supported) and aged (and unsupported) equipment.

The table below summarises our load control injection plant population by type.

Table 18.12: Load control injection plant by type at 31 March 2016

TYPE	PLANT	% OF TOTAL
Modern ripple plant	19	53
Legacy ripple plant	7	19
CycloControl plant	10	28
Total	36	

One of the aged types is the CycloControl system which is a voltage distortion system used in the Stratford and Huirangi regions. Its method of transmitting load

95 Note that the cost of new buildings or building extensions is covered within the forecasts for the related asset (eg indoor switchgear).

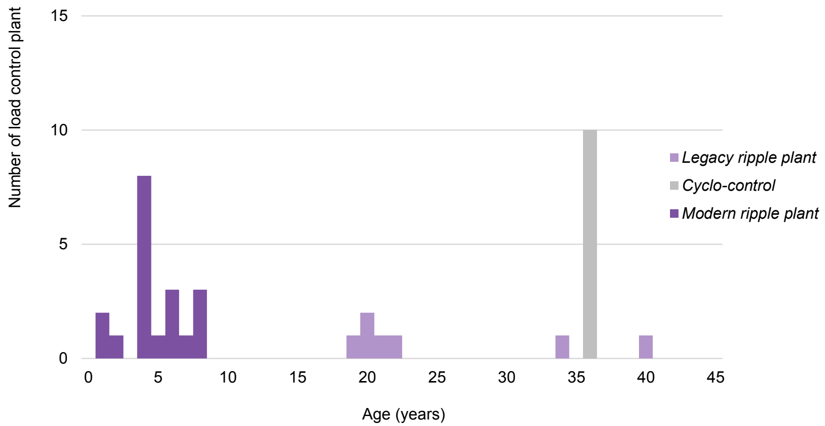
control commands differs from all other systems on our networks and has more faults.

These plants have now been superseded by newly installed ripple injection plants. The CycloControl systems will be decommissioned in the near term once relay owners have migrated over to the new standard.

Other legacy load control plant, although generally compatible with modern systems, are in poor condition and do not perform as well as modern plant.

The figure below shows the age profile of our load control fleet.

Figure 18.17: Load control injection plant age profile



In 2008 we undertook a modernisation programme to address issues with our legacy assets such as lack of technical support and spares. We have used advances in load control technology to optimise the number of plants required which reduces the total sites needed. The remaining legacy and CycloControl plants were installed from the mid-1970s through to the mid-1990s and will shortly require replacement or will be decommissioned.

18.7.3 CONDITION, PERFORMANCE AND RISKS

Our legacy load control plant is now considered obsolete. To ensure we can operate a reliable load control system the obsolete installations need to be retired.

Some installations use higher ripple frequencies (> 400Hz) and are no longer considered good industry practice. They are more affected by non-linear and capacitive loads that are now common in an electricity system. Other legacy systems (including the previously mentioned CycloControl) use obsolete code formats. Obtaining spares and manufacturer support is very difficult.

18.7.4 DESIGN AND CONSTRUCT

The standard for current and future plant is the DECABIT channel command format. We aim to exclusively use the DECABIT standard by FY25. The DECABIT standard has proven to be the most reliable and error free standard and is widely used in New Zealand.

Our Tauranga and Valley areas currently use Semagyr (Landis + Gyr) formats. We recognise the investment made in the past by the owners of these ripple receiver relays and will work with them to achieve the transition.

18.7.5 OPERATE AND MAINTAIN

Due to the specialist nature of load control plant, we have a backup and service support contract that covers our modern static installations. This covers annual inspections, holding of critical spares and after-hours emergency support.

Table 18.13: Load control injection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of plant. Operational tests.	3 monthly
Diagnostic tests, such as resonant frequency checks, signal injection levels and insulation resistance.	1 yearly

18.7.6 RENEW OR DISPOSE

Uncertainty over the role and use of load control equipment after the split of line and retail electricity businesses meant we deferred replacing the equipment for some years. The role and use has now been largely clarified and since 2008 we have returned to replacing load control plant (transmitters). The majority are now of modern technology.

We plan to replace or retire the remaining obsolete legacy transmitters as they operate to different standards, lack spares and are difficult to support. Once these are replaced or retired we expect little further renewal in this planning period.

SUMMARY OF LOAD CONTROL INJECTION PLANT RENEWALS APPROACH	
Renewal trigger	Obsolescence
Forecasting approach	Type
Cost estimation	Average historic rate

Coordination with Network Development projects

Load control plant continues to play a role on our network in managing peak loads. However, past distribution price structures and instantaneous gas hot water options have eroded the base of switchable load on the electrical network. The use of our load control plant is in a state of transition. However, we see traditional load control continuing to play a role alongside new non-network solutions as alternatives to traditional network capacity upgrades. For more information refer to Chapter 13.

18.8 OTHER ZONE SUBSTATION ASSETS FLEET MANAGEMENT

18.8.1 FLEET OVERVIEW

The other zone substation assets fleet comprises outdoor bus systems, fencing and grounds, earthing, lightning protection systems, security systems, and access control systems. We have 116 zone substations and 12 switching stations that contain outdoor buswork, fencing, earthing, lightning protection systems and support structures.

Outdoor bus systems are switchyard structures comprising gantries, lattice structures, HV busbars and conductors, associated primary clamps/accessories, support posts and insulators.

Most of our sites are designed with lightning protection systems to reduce the impact of a lightning strike on HV equipment. Lightning protection comprises overhead earthed conductors for outdoor sites and surge arrestors for equipment bushings and indoor sites.

18.8.2 CONDITION, PERFORMANCE AND RISKS

A key safety risk in our zone substations is managing step and touch potential hazards during faults. A layer of crushed metal (a type of rock) or asphalt is used to lessen step and touch potential hazards in outdoor switchyards by providing an insulating layer.

Some of our switchyards are grassed which need to be replaced with crushed metal. Other sites are no longer compliant with our earthing guidelines to the point where wholesale reinstatement of crushed metal is required. We plan to install or reinstate the switchyard metal on such sites.

Another key risk we manage is access and site security. Fencing around zone substations is very important to keep the site secure and prevent unwanted access. A number of our older sites do not have adequate fencing and security systems compared to modern zone substations. Some of the fencing needs replacing as the asset is at end of life (such as from corrosion). We intend to bring all sites up to our current fencing and security standards over the planning period. We will prioritise urban zone substations where the risk of unauthorised access is highest.

Some sites are not adequately protected from lightning strikes. To provide the required protection level we intend to install a combination surge arrestors on the terminals of high value equipment (such as power transformers), lightning rods on existing structures, and lightning masts.

Modern standards require flexible conductors for primary plant so the conductor can move during seismic events. Some of the primary plant bushings in older substations are connected directly to a rigid bus. We intend to undertake a programme to convert rigid bus to flexible connections.

18.8.3 OPERATE AND MAINTAIN

Our general zone substation preventive maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 18.14: Zone substation general preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Site vegetation work – mowing, weeding. Check waterways.	1 monthly
General visual inspection of outdoor structures, busbars, site infrastructure, security equipment and fencing.	3 monthly
Detailed visual inspection of site infrastructure. Thermal scan of busbar connections.	1 yearly
Detailed inspection of busbar connections, insulators, and bushings. Detailed condition assessment of outdoor structures.	6 yearly

18.8.4 RENEW OR DISPOSE

We plan four programmes of renewal within this fleet which are:

- Switchyard metalling
- Fencing and site security
- Lightning protection
- Rigid bus conversions

These programmes are planned to continue to until at least FY27.

SUMMARY OF OTHER ZONE SUBSTATION ASSETS RENEWALS APPROACH	
Renewal trigger	Safety and reliability risk
Forecasting approach	Programmes
Cost estimation	Historical rates

18.9 ZONE SUBSTATIONS RENEWALS FORECAST

Renewal Capex in our zone substations portfolio includes planned investments in the following fleets:

- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control plant
- Other zone substation assets

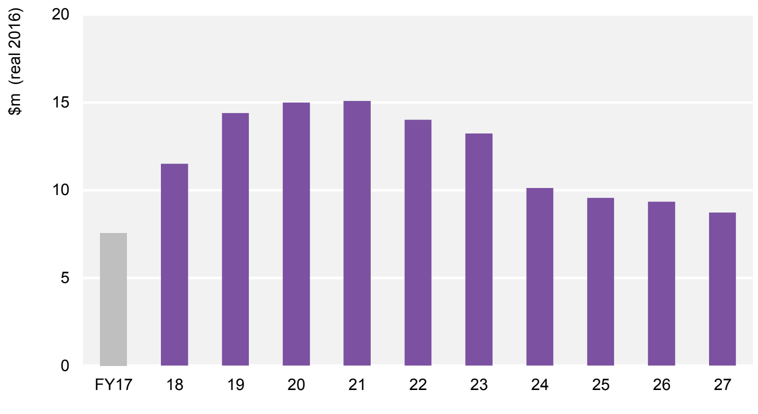
Over the planning period we plan to invest $121m in zone substation asset renewal.

A key driver for the replacement of our switchgear assets is managing safety risk, particularly to our field staff. Managing reliability risks from potential equipment failure, indicated by asset condition and health, is a further driver.

The combination of our six fleet forecasts, derived from bottom up models, drives our total zone substations renewal expenditure. Although initially forecasted as separate fleets, we combine the model outputs to allow us to identify delivery efficiencies. We coordinate and align projects so that smaller replacements such as individual circuit breakers occur in conjunction with larger replacements like power transformers. We also coordinate zone substation projects with protection relay replacements (covered by our secondary systems portfolio).

The chart below shows our forecast Capex on zone substation renewals during the planning period.

Figure 18.18: Zone substation renewal forecast expenditure



The forecast renewal expenditure for the zone substation portfolio represents a step change increase relative to historical levels. The majority of the increase is due to power transformer, indoor switchboard and outdoor switchgear renewal programmes. It also includes two larger projects at Greerton and Whareroa. While historically some replacement has been coordinated with growth augmentations, the deteriorating condition of the portfolio means that substantial renewal investment is now warranted.

Further details on expenditure forecasts are contained in Chapter 26.

19.1 CHAPTER OVERVIEW

This chapter describes our distribution transformers portfolio and summarises our associated fleet management plan. This portfolio includes three fleets:

- Pole mounted distribution transformers
- Ground mounted distribution transformers
- Other distribution transformers, which include voltage regulators, capacitors, conversion and SWER transformers

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we expect to invest $76m in distribution transformer renewals. This accounts for 9% of renewals Capex over the period. The forecast investment is generally in line with historical levels.

Our replacement programme reflects the large number of distribution transformer assets installed during the 1960s and 1970s that are becoming due for replacement.

The investment supports our safety and reliability objectives. Failures of distribution transformers can have a significant impact on both of these. Renewal works are driven by the need to:

– Reduce the risk related to some large pole mounted transformers not complying with seismic standards. We intend to complete a programme of converting these units to ground mounted equivalents or upgrading the associated poles by FY28.

– Continue our distribution transformer replacement programmes, using asset condition and defect information.

– Ensure the safety of pole mounted transformers by completing a programme to install LV fuses on 6,700 existing transformers (by FY23).

– Manage risk and ensure legislative compliance associated with unauthorised public access to our ground mounted transformers through replacement of 14,000[96] non-standard, aging or damaged padlocks over the CPP period.

Below we set out the asset management objectives that guide our approach to managing our distribution transformer fleets.

19.2 DISTRIBUTION TRANSFORMERS OBJECTIVES

Distribution transformers convert electrical energy of higher voltage to a lower voltage, generally from 11kV (but in some cases 6.6kV or 22kV) down to 400/230V. Their effective performance is essential for maintaining a safe and reliable network.

Transformers come in a variety of sizes, single or three phase, and ground or pole mounted. All of our transformers are oil filled, which carries environmental and fire risks. Managing our distribution transformers assets, including correctly disposing of these assets when they are retired, is critical to safeguarding the public and mitigating oil spills.

To guide our asset management activities, we have defined a set of objectives for our distribution transformers. These are listed in the table below. The objectives are linked to our asset management objectives as set out in Chapter 5.

Table 19.1: Distribution transformers portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reposition pole mounted transformers to limit risks related to working at heights. No explosive failures of, or fires caused by, distribution transformers. Installations compliant with seismic codes to avoid injury and property damage. Install compliant LV fusing on pole mounted transformers. No significant oil spills.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Consider the use of alternative technology to improve reliability or reduce service cost (eg transformer monitoring units).
Asset Stewardship	Expand the use of asset health and criticality techniques to inform renewal decision-making.
Operational Excellence	Improve and refine our condition assessment techniques and processes.

96 Further replacements will occur in other portfolios, primarily ground and pole mounted switchgear.

19.3 POLE MOUNTED DISTRIBUTION TRANSFORMERS FLEET MANAGEMENT

19.3.1 FLEET OVERVIEW

There are approximately 25,000 pole mounted transformers on our network. These are usually located in rural or suburban areas where the distribution network is overhead. Their capacity ranges from less than 15kVA to 300kVA.

Recent changes to our standards have set the maximum allowable capacity for a new pole mounted transformer generally at 100kVA.[97] This means any pole mounted transformers greater than 100kVA that require replacement are likely to be converted to a ground mounted equivalent (if practical).

Following a major change to national seismic standards in 2002, some larger pole mounted transformer structures are no longer compliant. We intend to continue to replace these with compliant pole mounted or ground mounted units.

Meeting our portfolio objectives

Safety and Environment: Larger pole mounted transformers are being reviewed for seismic compliance and will be either strengthened or replaced with ground mounted units to reduce safety risks.

Pole mounted transformers are generally smaller and supply fewer customers than ground mounted transformers. Reactive replacement can usually be undertaken quickly, affecting a relatively low number of customers. Suitable spare transformers are held in stock at service provider depots. This ensures a fast response time to return service.

[97] A transformer of up to 1,000kg is acceptable as pole mounted using standard designs. Those weighing 1,000-1,600kg must have specific design analysis and those above 1600kg must not be pole mounted. A 200kVA transformer weighs just over 1000kg.

Figure 19.1: 100kVA pole mounted transformer

19.3.2 POPULATION AND AGE STATISTICS

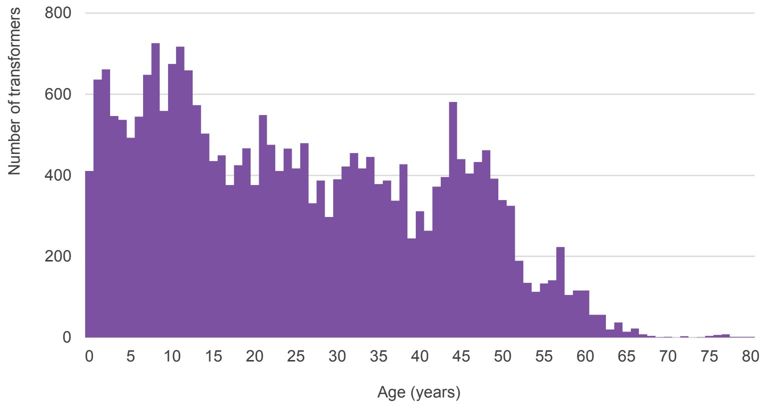
The table below summarises our population of pole mounted distribution transformers by kVA rating. Most are very small, with more than 40% at 15kVA or below. A transformer of this size typically supplies a few houses in a rural area.

Table 19.2: Pole mounted distribution transformer population by rating at 31 March 2016

RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
≤ 15kVA	10,359	41
> 15 and ≤ 30kVA	8,608	34
> 30 and ≤ 100kVA	5,675	22
> 100kVA	737	3
Total	25,379	

The figure below shows our pole mounted distribution transformer age profile. The expected life of these units typically ranges from 45 to 60 years. A significant number will exceed their expected life in the near future.

Figure 19.2: Pole mounted distribution transformer age profile



19.3.3 CONDITION, PERFORMANCE AND RISKS

Failure modes

The main reasons for replacing pole mounted transformers are equipment degradation and unexpected failures, usually caused by third parties (eg. vehicle accidents) or lightning strikes. The predominant causes of equipment degradation are:

- Deterioration of the insulation, windings and/or bushings
- Moisture and contaminant concentrations in insulating oil
- Thermal failure because of overloads
- Mechanical loosening of internal components, including winding and core
- Oil leaks through faulty seals
- External tank/enclosure damage and corrosion

Risks

Some of our larger pole mounted transformer structures do not meet modern seismic standards. This is a safety risk if the pole fails during a seismic event. These larger units also supply a larger number of customers compared with more typical pole mounted transformers. Maintenance work needs to be carried out at height, which presents a safety risk for our service providers.

Some of our older pole mounted transformers do not have LV fuses which means there is no direct protection against downstream faults. When a fault occurs it is not cleared until it is manually isolated or the HV fuse blows, posing a safety risk to both our service providers and the public.

In 2013 we initiated a programme to install LV fuses on approximately 6,700 pole mounted transformers, predominantly in the Taranaki, Valley and Wairarapa areas. This programme will be completed by 2023.

Meeting our portfolio objectives

Safety and Environment: Low voltage fuses are being installed on our pole mounted distribution transformers (where not already present) to improve public safety in the event of a fault on the LV network.

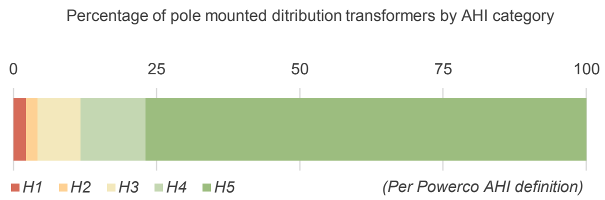
We work with the NZTA to identify distribution lines and poles alongside highways and roads with a high likelihood of vehicle accidents. Once identified, we aim to underground the overhead line to eliminate the risk of vehicles hitting our poles. The associated pole mounted distribution transformers are converted to ground mounted equivalents. For more information refer to the Asset Relocations Chapter 25.

Pole mounted distribution transformer asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's 'end-of-life' and categorise their health based on a set of rules. For pole mounted transformers we define end-of-life as when the asset fails due to condition. The overall AHI is based on survivorship and defect analysis.

The figure below shows current overall AHI for our population of pole mounted distribution transformers.

Figure 19.3: Pole mounted distribution transformer asset health as at 2016



The overall health of the pole mounted transformer fleet is generally good, with few assets currently requiring replacement. During the next 10 years we expect to replace 15% of the fleet (H1-H3).

19.3.4 DESIGN AND CONSTRUCT

To improve seismic compliance, pole mounted transformers above 100kVA are, where practical, replaced with a ground mounted transformer of equivalent or greater size (see condition, performance and risks section). Smaller pole mounted transformers are replaced like-for-like.

We intend to fit distribution transformer monitors on certain existing and new pole mounted transformers. The monitoring programme is outlined below. For more details refer to Chapter 13 Network Evolution.

Network Insight

The existing equipment fitted on distribution transformers provides readings of transformer peak load through maximum demand indicators (MDIs). This assists system planning and helps avoid overloading. However, MDIs need to be read manually, and so are used in a more reactive manner than is ideal.

To address this, we are trialling a more advanced automated load monitoring system for distribution transformers. The data is available immediately through wireless or fibre communications for immediate data visibility.

A network-wide load monitoring system would significantly improve the management and planning of distribution transformer upgrades and the service to customers following an outage. This work is being developed under our Network Insight programme, which plans to install several hundred monitoring devices over the next six to ten years.

The programme is still in the trial stage. We expect to update our design standards soon to ensure that modern assets, particularly larger ones, have some form of integral demand monitoring.

Meeting our portfolio objectives

Safety and Environment: Distribution transformer monitoring will improve our knowledge of the LV network and allow us to improve reliability by gathering information regarding network issues at an earlier stage.

19.3.5 OPERATE AND MAINTAIN

Pole mounted transformers are reasonably robust and do not require intrusive maintenance. Maintenance is generally limited to visual inspections. Pole mounted distribution transformers are usually small and less critical than ground mounted equivalents. It is often cost effective to replace them when they are close to failure, rather than carry out rigorous maintenance to extend life.

Our preventive inspections are summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 19.3: Pole mounted distribution transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Inspect tank and general fittings for corrosion and inspect earthing connection.	5 yearly

The five-yearly inspection interval for pole mounted transformer fleet is based on defects analysis and historical mandated requirements.

Typical corrective work on a pole mounted transformer includes:

- Replacing corroded hanger arms
- Replacing blown fuses
- Replacing damaged surge arrestors
- Topping up oil

Pole mounted transformers are managed through a rotating spare pool strategy and an appropriate level of spares are kept for each part of the network at service provider depots.

Fault response generally involves replacing transformers with internal, tank or bushing damage. Defective pole mounted transformers are taken to spares warehouses where they are assessed for workshop based repairs or overhaul, while a new unit is used to replace the defective unit.

Repair and overhaul work is undertaken according to our specifications. Cost criteria are used to ensure the repair or overhaul works are cost effective. If they are not, the unit is disposed of, and a new unit is added to the spares stock.

Repair work includes electrical and mechanical tasks, tank repairs, painting, and reassembly. Testing is done before and after repair work.

19.3.6 RENEW OR DISPOSE

Pole mounted transformer renewal is primarily based on condition. The renewal need is often only identified when the transformer is close to failure and for smaller and less critical units sometimes after they fail. We accept some in-service failure of smaller and less critical units because the customer impact is limited, the cost of obtaining better condition information is high, and their maximum asset life is realised. Renewals may be combined with pole replacement for delivery efficiency.

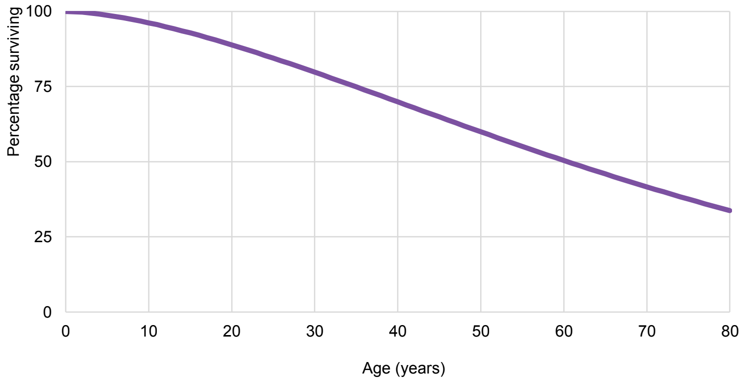
SUMMARY OF POLE MOUNTED DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Reactive and condition based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

Our pole mounted distribution transformer replacement quantity forecast incorporates historical survivorship analysis. We developed a survivor curve and used this to forecast expected renewal quantities.

The figure below shows a pole mounted distribution transformer survivor curve. The curve indicates the percentage of transformer population remaining at a given age.

Figure 19.4: Pole mounted distribution transformer survivor curve



We found that pole mounted distribution transformer replacement occurs over a wide range of ages, primarily because of factors such as type, manufacturer, location or inherent durability. The survivorship forecasting approach is therefore more robust than a purely age based approach.

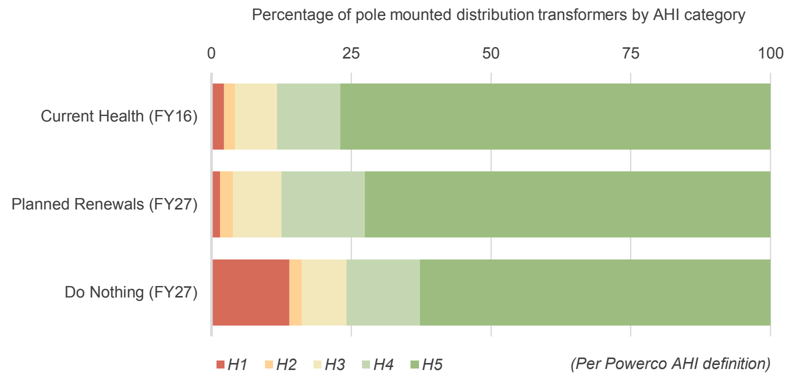
We have also identified approximately 250 larger pole mounted distribution transformers on pole structures that may be at risk of failing during seismic events. These units will be replaced and converted to ground mounted equivalents over a ten year programme FY18-FY28.

Current standards require LV fuses to be fitted on transformers to protect outgoing circuits. In 2013 we initiated a programme of installing LV fuses on existing pole mounted transformers that do not have them. This programme is expected to be completed by 2023.

As discussed above (condition, performance and risks section), our pole mounted transformer fleet is in good health.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our investment targets the minimum renewal needed to maintain the health of the fleet.

Figure 19.5: Projected pole mounted distribution transformer asset health as at 2027



The figure indicates stable renewal levels continuing beyond 2027, as indicated by the H1-H3 portion in Planned Renewals (FY27).

Pole mounted transformer refurbishment

Life-extending refurbishment is rarely undertaken for the pole mounted distribution transformer fleet. Such work would include replacing the core and windings, which is not cost effective.

Pole mounted transformer disposal

Pole mounted distribution transformers are decommissioned and disposed of when they are replaced. The principal transformer components (steel, copper and oil) are recycled.

The oil in pre-1970 transformers often contained a substance called Polychlorinated Biphenyls (PCB), which is now known to be carcinogenic. We believe we have removed all models containing PCBs. However, we continue to test older models for PCB before removing oil. If we find PCBs a specialist disposal company is employed to undertake removal.

Coordination with Network Development projects

Pole mounted transformer replacement can be instigated by a range of growth related factors, including thermal uprating of the overhead line or increases in customer load. This can involve larger overhead line projects (including renewal reconductoring and pole replacements). Where possible, pole mounted transformer renewal is coordinated with larger projects to ensure cost and customer disruptions are minimised.

Meeting our portfolio objectives

Customers and Community: Pole mounted transformer replacements are, where possible, coordinated with other works to minimise disruption to customers.

New connections in urban areas, such as new residential subdivisions, are generally underground and use ground mounted transformers. New connections for single customers in rural areas generally require pole mounted transformers.

There are some ‘end-of-line’ remote rural distribution feeders with only a single customer connected. If the overhead line, transformer and switchgear require condition based replacement, it may be more cost effective to install a RAPS unit. We use cost benefit analysis to determine the preferred option. RAPS units are also considered for new remote rural customers wishing to connect to our network. For more information, refer to the Overhead Conductors Fleet, Chapter 15.

19.4 GROUND MOUNTED DISTRIBUTION TRANSFORMERS FLEET MANAGEMENT

19.4.1 FLEET OVERVIEW

There are approximately 8,000 ground mounted distribution transformers on our network. These are usually located in suburban areas and CBDs with underground networks. Ground mounted transformers are generally more expensive and serve larger and more critical loads compared with pole mounted transformers.

Ground mounted transformers may be enclosed in a consumer’s building, housed in a concrete block walk-in enclosure, or berm mounted, either as unenclosed units or in a variety of enclosures. Ground mounted transformers require separate foundations (if not housed in a building), along with earthing and a LV panel.

Their size depends on load density but is generally 50 or 100kVA in lifestyle areas, 200 or 300kVA in newer suburban areas, and 500kVA to 1.5MVA in CBD areas. A few larger units at industrial sites are up to 8MVA.

Ground mounted distribution transformers must be secured against unauthorised public access. A padlock and key system is used for this, but a large number of the padlocks are non-standard or in poor condition. As our register of key holders is incomplete we have concerns over key access.

Figure 19.6: 300 kVA ground mounted transformer

19.4.2 POPULATION AND AGE STATISTICS

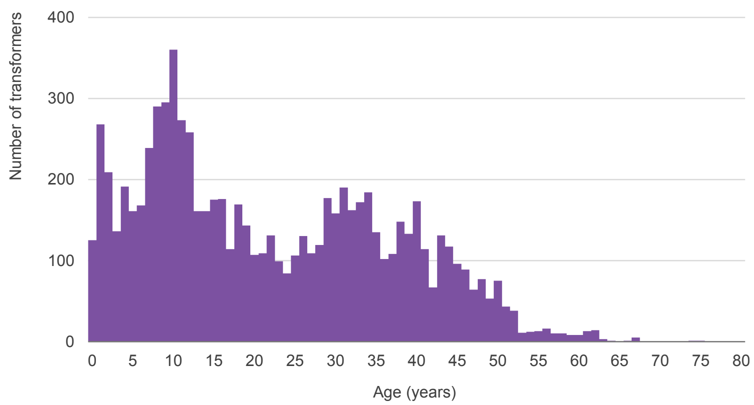
The table below summarises our population of ground mounted distribution transformers by kVA rating. The smallest units have a size of approximately 100kVA, with larger units used for higher capacity installations.

Table 19.4: Ground mounted distribution transformer population by rating at 31 March 2016

RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
≤ 100kVA	2,779	35
> 100 and ≤ 200kVA	1,927	24
> 200 and ≤ 300kVA	1,881	24
> 300kVA	1,413	18
Total	8,000	

The figure below shows our ground mounted distribution transformer age profile.

Figure 19.7: Ground mounted distribution transformer age profile



The ground mounted transformer fleet is relatively young, with an average age of 22 years. Ground mounted transformers generally have longer expected lives (55 to 70 years) than pole mounted units. They are more frequently maintained (due to their higher criticality) and are often located inside enclosures, which provide greater protection from corrosion. Because of this, we expect only a relatively small number of renewals in the near future.

19.4.3 CONDITION, PERFORMANCE AND RISKS

Failure modes

Ground mounted transformers are mainly replaced because of equipment deterioration. Some unexpected failures occur and are usually caused by third parties (eg vehicle damage). The predominant causes of equipment degradation are:

- Deterioration of insulation, windings and/or bushings
- Moisture and contaminant concentrations in insulating oil
- Thermal failure because of overloads
- Mechanical loosening of internal components, including winding and core
- Oil leaks through faulty seals
- External tank/enclosure damage and corrosion

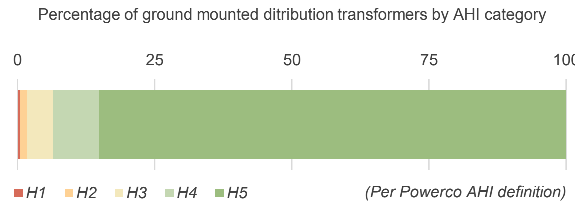
LV panels are treated as separate assets. Renewals of LV panels can occur separately to the transformer unit (typically in the case of reactive replacement following a failure). LV panels fail mainly because of overheating or insulation failure.

Ground mounted distribution transformer asset health

As outlined in Chapter 12, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For ground mounted transformers, we define end-of-life as when the asset fails due to condition drivers. The AHI is based on survivorship and defect analysis.

The figure below shows current overall AHI for our population of ground mounted transformers.

Figure 19.8: Ground mounted distribution transformer asset health as at 2016



Like the pole mounted fleet, the overall health of our ground mounted transformers is generally good, with few assets requiring replacement in the short term. Over the next 10 years we expect to replace 9% of the fleet (H1-H3).

> **Meeting our portfolio objectives**
>
> Asset Stewardship: We are continuing to refine our asset health and criticality approaches to improve our asset renewal decision-making.

Locks and keys

Ground mounted distribution transformers (and distribution switchgear assets) are made secure from the public by the use of padlocks. We have several legacy padlocking systems that have been inherited from previously separate networks. We do not have complete control over key access to these padlocks as not all keys have been returned when staff have left, and therefore our register of legacy key holders is incomplete. This raises risk associated with unauthorised public access and prevents us from complying with legislative obligations.

Due to the need to ensure access to our assets is appropriately controlled we plan to standardise all padlocks and keys on a high security type that cannot be copied without authorisation. This work will be completed over the CPP period.

19.4.4 DESIGN AND CONSTRUCT

The scope of the transformer monitoring initiative discussed above (pole mounted distribution transformers section) also includes the ground mounted fleet. Some ground mounted distribution transformers may be fitted with monitors when renewed. For more details refer to Chapter 13 Network Evolution.

To ensure distribution transformer monitors can be retrospectively installed we will fit new ground mounted distribution transformers with larger LV frames.

19.4.5 OPERATE AND MAINTAIN

Ground mounted transformers are more expensive and generally supply more critical loads compared with the pole mounted fleet. Because of this, ground mounted transformers undergo more maintenance.

Our various preventive maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 19.5: Ground mounted distribution transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of transformer, check asset is secure.	6 monthly
General visual inspection, check transformer tank, fittings for corrosion and damage. Log MDI readings.	1 yearly
Detailed inspection and condition assessment. Oil sample and diagnostic voltage test if >499kVA.	5 yearly

Ground mounted transformers are managed through a rotating spare pool strategy. Service provider depots have an appropriate stock of spares for each part of the network. Spares are available for fault response and for condition-based replacement.

Defective ground mounted transformers are taken to the spares warehouses where they are assessed for workshop repairs or overhaul. A new or refurbished unit is used to replace a defective unit. Repair and overhaul work is undertaken according to our standards. Cost criteria are used to ensure the repair or overhaul works are cost effective. If they are not, the unit is disposed of, and a new unit is added to the spares stock.

Typical corrective work for this fleet includes:

- Re-levelling base pads
- Replacing blown fuses
- Removing vegetation from enclosures
- Removing graffiti
- Tank repairs, painting, and reassembly

Testing is done before and after repair work.

19.4.6 RENEW OR DISPOSE

Ground mounted distribution transformers undergo condition assessment and inspections to avoid in-service failure thereby minimising safety risk to the public and the risk of unplanned outages. Ground mounted distribution transformers are proactively renewed using prioritisation criteria, including failure consequence, safety risk, and security.

Meeting our portfolio objectives

Safety and Environment: We proactively replace ground mounted distribution transformers before they fail in order to reduce public safety risks.

SUMMARY OF GROUND MOUNTED DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

Our ground mounted distribution transformer replacement quantity forecast incorporates historical survivorship analysis. We developed a survivor curve and used this to forecast renewal quantities.

The figure below shows our ground mounted distribution transformer survivor curve. The curve indicates the percentage of transformer population remaining at a given age.

Figure 19.9: Ground mounted distribution transformer survivor curve

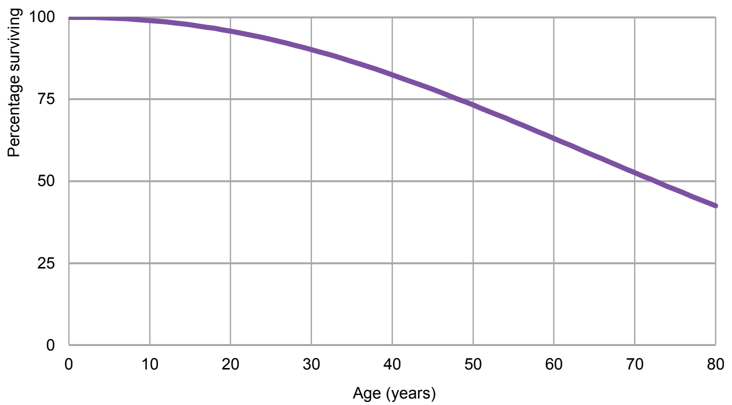
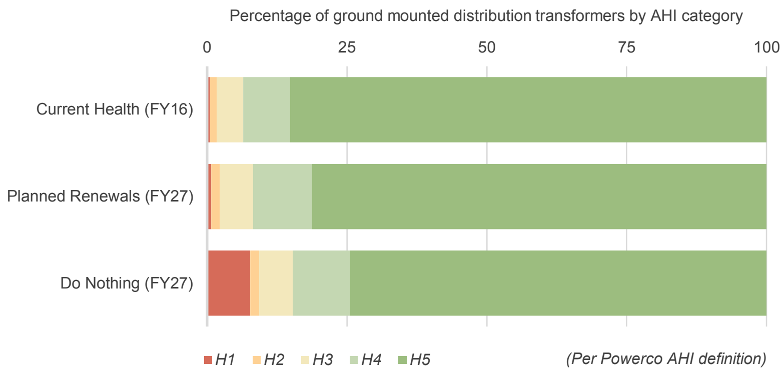


Figure 19.10: Projected ground mounted distribution transformer asset health as at 2027



We have found that, similar to pole mounted distribution transformers, ground mounted distribution transformer replacement occurs over a wide range of ages, primarily because of factors such as type, manufacturer, location or inherent durability. The survivorship forecasting approach is therefore more robust than a purely age based approach. Compared with pole mounted transformers, ground mounted units typically last an additional five years before needing to be replaced.

LV panels are sometimes renewed reactively and not in conjunction with the associated ground mounted transformer. Our forecast allows some of replacement of LV panels based on historical levels.

As previously discussed, replacement of many of the locks securing our ground mounted transformers is warranted. Our forecast allows full replacement of all locks and keys that have not already been replaced with the standardised, high security units over the five year period FY19-23.

As discussed above (condition, performance and risks section), our ground mounted transformer fleet is in good health. The figure below compares projected asset health in 2027 (following planned renewals) with a ‘do nothing’ scenario. Our investment targets the minimum renewal needed to maintain the health of the fleet.

The figure indicates stable renewal levels continuing beyond 2027, as indicated by the H1-H3 portion in Planned Renewals (FY27).

Ground mounted transformer refurbishment

Life-extending refurbishment is rarely undertaken for the ground mounted distribution transformer fleet. Such work would include replacing the core and windings, and it is usually more cost effective to install a new transformer.

Ground mounted transformer disposal

Ground mounted distribution transformers are decommissioned and disposed of when they are replaced. The principal transformer components (steel, copper and oil) are recycled.

As with pole mounted transformers, the oil in pre-1970 transformers often contained PCBs, which are now known to be carcinogenic. We believe we have removed all models containing PCBs. However, we continue to test older models for PCB before removing oil. If we find PCBs a specialist disposal company is employed to undertake the work.

Coordination with Network Development projects

Ground mounted transformer replacement can be instigated by a range of growth related factors, including thermal uprating of the associated distribution circuit. Underground networks are relatively young. To date there have been few growth upgrades involving ground mounted distribution transformers and underground networks, but we expect the number of these upgrades to increase. The majority of recent upgrades have occurred as a result of increased customer load specific to the individual transformer.

New customer connections (eg new residential subdivisions) are usually underground and the associated distribution transformers are ground mounted.

19.5 OTHER TYPES OF DISTRIBUTION TRANSFORMERS

19.5.1 FLEET OVERVIEW

Other types of distribution transformers include conversion and single wire earth return (SWER) isolation transformers, capacitors and voltage regulators. The population of this sub-fleet is a small part of the distribution transformer portfolio and is quite varied.

Conversion transformers convert between two distribution voltages (as opposed to converting from distribution to LV), for instance, 11kV to 22kV or 11kV to 6.6kV. A conversion transformer is similar to a distribution transformer but is typically of higher capacity and supplies a downstream distribution network. Therefore it has a higher reliability impact than a distribution transformer.

SWER isolating transformers convert from 11kV phase to phase, to a single wire earth return system at 11kV phase to ground. SWER is a cost effective form of reticulation in remote rural areas to supply light loads over long distances. SWER transformers are generally pole mounted.

Capacitors are used on the distribution network to provide voltage support and reactive compensation where poor power factor exists. Capacitors are generally pole mounted.

Voltage regulators are typically a pair of single phase 11kV transformers fitted with controls that are used to adjust (buck or boost) the voltage to load conditions. They are used where the existing reticulation suffers from excessive voltage fluctuation, particularly on long lines where voltage rises with light load and drops with heavier load. Voltage regulators are generally pole mounted.

Figure 19.11: Collection of other distribution transformers

Capacitors | Voltage regulator | SWER isolating transformer

19.5.2 POPULATION AND AGE STATISTICS

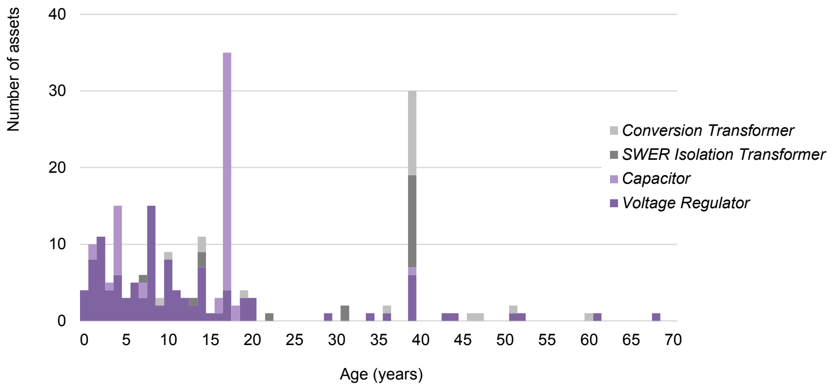
The table below summarises our population of other distribution transformers by type. Voltage regulators make up the largest portion of the fleet. We have been installing these devices during the last 15 years to manage voltage issues on the network.

Table 19.6: Other distribution transformer population by type at 31 March 2016

TYPE	NUMBER OF ASSETS	% OF TOTAL
Voltage regulator	112	55
Capacitor	50	25
Conversion transformer	21	10
SWER isolation transformer	19	9
Total	202	

The figure below shows our 'other' distribution transformers age profile. The population is young, with an average age of 17 years. This is largely because of the recent prevalence of voltage regulators and capacitors. They are used to compensate for undersized and/or long rural lines where load growth has created voltage issues on the network. A small number of assets exceed their expected life of 50 years.

Figure 19.12: Other distribution transformer age profile



19.5.3 CONDITION, PERFORMANCE AND RISKS

These transformers are of similar construction as pole or ground mounted distribution transformers and so (apart from capacitors) their failure modes are similar. Although rare, capacitors can suffer catastrophic failure, which may pose a safety risk to the public. They are therefore maintained more thoroughly than pole mounted transformers.

The condition of the fleet is relatively good with no known type issues. We do not anticipate a need for a significant renewals programme.

19.5.4 DESIGN AND CONSTRUCT

We have processes in place that ensure that ratings, installation configuration and range of operation is standardised across the fleet.

We use either two (configured two-phase arrangement) or three (configured three-phase arrangement) single phase voltage regulators banked together to regulate the three-phase distribution network. Voltage regulators are generally configured with ancillary bypass switches and isolator/protection links. Typical ratings are 100A, 150A and 200A nominal capacity.

19.5.5 OPERATE AND MAINTAIN

SWER isolation and conversion transformer maintenance is similar to ground mounted or pole mounted transformers. As discussed above, they share physical attributes and failure modes. While voltage regulators share some of the same attributes, they are much more expensive compared with pole mounted transformers and the majority of ground mounted transformers. Therefore this sub-fleet undergoes a more thorough maintenance regime.

Capacitors are built differently than transformers and have different types of failure modes. They have their own maintenance regime.

Our various preventive maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 19.7: Other distribution transformer preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Capacitors	Thermal imaging scan of connections and leads.	2 ½ yearly
	Detailed visual inspection, checking for corrosion, damage, leaks.	5 yearly
	Diagnostic tests including capacitance measurements, insulation and contact resistance depending on capacitor configuration. Condition assessment of bushings and tank.	10 yearly
Voltage regulators	General visual inspection of voltage regulator and housing, check asset is secure (ground mounted only).	6 monthly
	Thermal imaging scan.	2 ½ yearly
	Inspect tank and general fittings for corrosion. Carry out oil dielectric strength, acidity and moisture testing.	5 yearly
	Winding insulation tests.	15 yearly
SWER and conversion transformers	See pole and ground mounted distribution transformer maintenance.	

19.5.6 RENEW OR DISPOSE

Our renewal strategy for this fleet is condition-based replacement. Units are generally replaced as part of the defect management process when a significant defect is identified. Some units fail and they are immediately replaced to minimise the impact on customers.

SUMMARY OF OTHER DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Age based
Cost estimation	Historical average unit rates

Renewals forecasting

Our renewals forecast uses age as a proxy for condition. We expect renewals for this fleet to remain fairly constant over the planning period and in line with historical quantities.

Coordination with Network Development projects

There are a number of solutions for voltage issues particularly on long rural feeders. It is usually more cost effective to install a voltage regulator than upgrading the overhead line, or to install a RAPS if the line also requires renewal.

As rural businesses (.eg in the dairy sector) grow and more reactive and voltage support is required, we expect to install more voltage regulators and capacitors on our network.

SWER isolation and conversion transformers are used only in special cases and we do not expect to install many over the planning period.

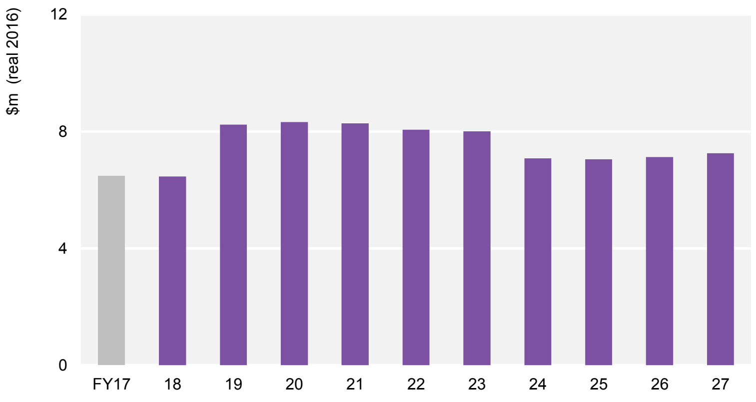
19.6 DISTRIBUTION TRANSFORMERS RENEWALS FORECAST

Renewal Capex in our distribution transformer portfolio includes planned investments in our pole mounted, ground mounted and 'other' distribution transformer fleets. Over the planning period we plan to invest approximately $76m in distribution transformer renewals

Renewals are derived from bottom up models. These forecasts are volumetric estimates (explained in Chapter 26). The work volumes are relatively high, with the forecasts primarily based on survivorship analysis. We use averaged unit rates based on analysis of equivalent historical costs.

The chart below shows our forecast Capex on distribution transformers during the planning period.

Figure 19.13: Distribution transformer renewal forecast expenditure



Forecast renewal expenditure is generally in line with historical levels. Additional expenditure from FY19 to FY23 is to address issues with larger pole mounted transformers that are not compliant with seismic standards.

Further details on expenditure forecasts are contained in Chapter 26.

20.1 CHAPTER OVERVIEW

This chapter describes our distribution switchgear portfolio and summarises our associated fleet management plan. The portfolio includes four fleets:

- Ground mounted switchgear
- Pole mounted fuses
- Pole mounted switches
- Circuit breakers, reclosers and sectionalisers

The chapter provides an overview of these assets including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we plan to invest $74m in distribution switchgear. This accounts for 9% of renewals Capex over the period. This level of renewals is in line with historical levels, with the exception of FY18-22 due to a planned circuit breaker renewal programme at Kinleith.

Increased investment will support our safety and condition objectives. The renewals Capex is driven by the need to:

– Replace certain types of oil switchgear. Older models of oil switchgear have the potential to fail explosively, require more intensive maintenance, carry environmental risks, and many have exceeded their expected life.

– Address performance issues and deteriorating condition. Several renewal programmes target specific assets for which an issue has been identified, while others deal with general asset deterioration across the four fleets. For example, asset health modelling of our circuit breaker population indicates the fleet is in poor health.

– Manage risk and ensure legislative compliance associated with unauthorised public access to our ground mounted transformers through replacement of about 20,000[98] non-standard, aging or damaged padlocks over the CPP period.

Below we set out the asset management objectives that guide our approach to managing our distribution switchgear fleets.

20.2 DISTRIBUTION SWITCHGEAR OBJECTIVES

The distribution switchgear portfolio contains a large number of diverse assets with a wide range of types and manufacturers. Switchgear technology has evolved over time, improving safety and reliability.

[98] Further replacements will occur in other portfolios, primarily ground mounted transformers.

Oil switchgear is very rarely used in new installations as it requires intensive maintenance, has the potential to fail explosively and carries environmental risks. We still have large quantities of oil-based switchgear (over 50% of the ground mounted switchgear fleet). This is replaced when their condition is poor or there are known specific type issues that affect the safety and performance of the asset.

To guide our asset management activities, we have defined a set of portfolio objectives for our distribution switchgear assets. These are listed in the table below. The objectives are linked to our asset management objectives as set out in Chapter 5.

Table 20.1: Distribution switchgear portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No injuries or incidents from explosive failure or mal operation of switchgear. No significant oil or SF_6 leaks from distribution switchgear assets.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works.
Networks for Today and Tomorrow	Increase use of remote switching to improve fault isolation and restoration times for customers. Continue to evaluate new technology for general or specific use on the network with a view to improving network operation and safety and managing life cycle cost.
Asset Stewardship	Reduce fleet diversity over time in order to optimise asset whole-of-life costs and improve safety and performance. Maintain today's level of distribution switchgear reliability into the future.
Operational Excellence	Complete development of criticality frameworks for distribution switchgear.

20.3 GROUND MOUNTED SWITCHGEAR FLEET MANAGEMENT

20.3.1 FLEET OVERVIEW

Ground mounted switchgear incorporates switching equipment that provides distribution network isolation, protection and switching facilities. Ground mounted switchgear includes ring main units (RMUs), switches, fuse switches, links and associated enclosures. In general, ground mounted switchgear is associated with our underground network, though some support overhead sections.

Our fleet comprises a range of makes and models with various insulating media. Over the past five years we have predominantly installed SF_6 (sulphur hexafluoride) but historically we have used oil-filled and cast resin switchgear.

Figure 20.1: Ground mounted switchgear

20.3.2 POPULATION AND AGE STATISTICS

The table below shows our population of ground mounted switchgear by configurations and insulating media.

There is significant diversity within this fleet, with more than 20 manufacturers represented. This diversity increases maintenance cost, the amount of training required for field personnel and safety risks as field personnel are less familiar with each model. Our replacement strategies will result in removal of many of the older and less represented models from the fleet.

Table 20.2: Ground mounted switchgear population by type at 31 March 2016

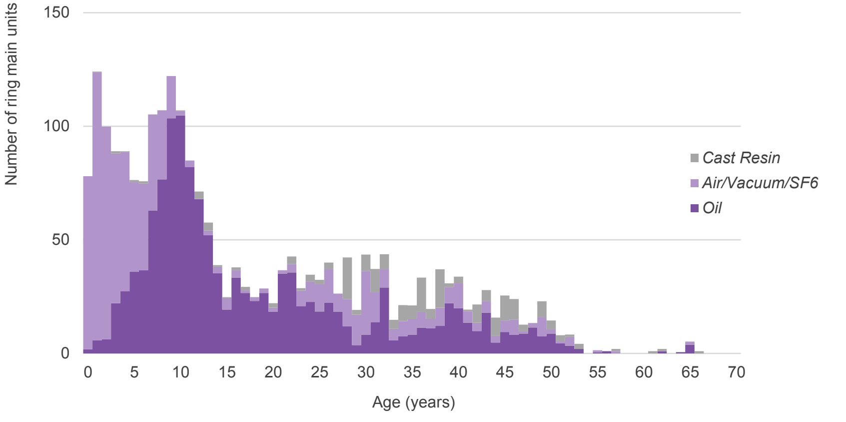
INSULATION TYPE	NUMBER OF RING MAIN UNITS	NUMBER OF INDIVIDUAL SWITCH UNITS
Oil	1,322	318
Air/Vacuum/SF_6	845	135
Cast resin	198	11
Total	2,364	464

Meeting our portfolio objectives

Asset Stewardship: Asset replacement over time is expected to reduce diversity in the ground mounted switchgear fleet, helping us to manage whole-of-life costs.

The figure below shows age profile of our population of RMUs.

Figure 20.2: Ring Main Units age profile

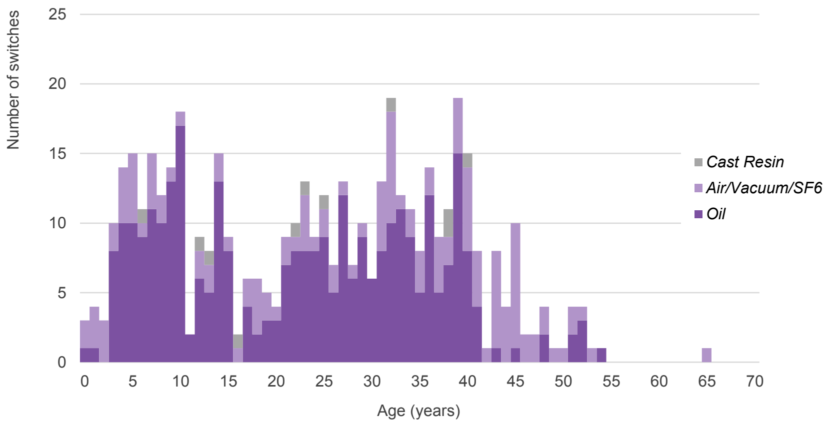


RMUs have been installed on our network for more than 40 years. Their use has increased markedly over the past decade as they have replaced individual switches to enable better network connectivity.

We now install predominantly SF_6 RMUs, having transitioned away from oil switchgear once SF_6 equipment became cost competitive and the environmental risks were better understood. Our standards recently approved a vacuum device for use on the network (when installed in an approved enclosure) which we have begun installing.

The figure below shows the age profile of our population of individual ground mounted switches. These assets are generally much older than the RMUs and have a much greater level of manufacturer diversity.

Figure 20.3: Individual switch age profile



Many units exceed their expected life of approximately 45 years. We expect an increasing amount of renewals in this area (noting that renewal decisions are based on asset condition and risk).

20.3.3 CONDITION, PERFORMANCE AND RISKS

The condition of the majority of our ground mounted switchgear fleet is reasonable. The primary issues relate to the condition of cast resin switchgear and the specific safety measures and maintenance requirements that affect the performance of early oil switchgear.

Cast resin switchgear

Cast resin switchgear performs satisfactorily if located in dust-free, dry environments and is regularly maintained. If installed in cubicles without heating or in a dusty environment, surface condensation results in electrical tracking and degradation. This issue is prevalent in fog prone areas such as Taranaki, Thames Valley and Waikato.

Condition data for the cast resin switchgear located in the Taranaki region suggests that a significant proportion will require replacement within 10 years, likely reflecting faster degradation in that location.

Meeting our portfolio objectives

Asset Stewardship: Ground mounted distribution switchgear is replaced when reliability degrades, helping us maintain overall network reliability including SAIDI and SAIFI.

The design of cast resin switchgear also creates issues due to the way each phase is switched individually. This results in operational constraints when transferring load and presents a potential safety issue for operators. Replacing cast resin switchgear with other switchgear can take time and be expensive because non resin switchgear tends to have a larger footprint. Wholesale removal of the entire population is not necessary at this stage but we expect more intensive condition monitoring will be required as the fleet ages.

Oil switchgear

The potential for oil switchgear to explosively fail and cause fatalities was highlighted recently in Australia in an incident that occurred during switchgear maintenance. While the full details are not yet known, we have imposed safety measures on certain models of oil switchgear. They may not be switched live and if possible must be switched remotely and the asset physically contained.

The consequence of failure of such aged oil switchgear includes damage and injury or death, and is much higher than for modern equivalent assets. Oil switchgear with identified type issues will be prioritised for replacement.

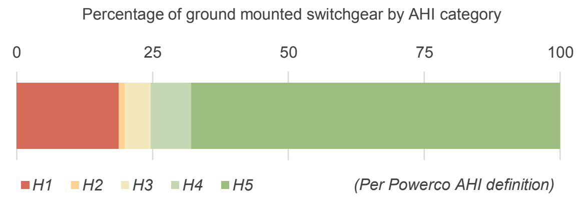
While the condition of other oil-filled switchgear assets is reasonable, most models of oil switchgear are no longer supported by manufacturers. Many have extensive maintenance requirements relative to their modern equivalent asset.

Ground mounted switchgear asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For ground mounted switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely and the switchgear should be replaced. The AHI is based on asset age and known type issues.

The figure below shows current overall AHI for our ground mounted switchgear fleet.

Figure 20.4: Ground mounted switchgear asset health as at 2016



Approximately 20% of the fleet (H1) is in poor health and requires renewal. This is primarily comprised of older oil switchgear, which we are planning to replace over the next 10 years.

Locks and keys

There are risks associated with the legacy padlocking systems used to protect our ground mounted switchgear from unauthorised access.[99] To manage these risks we plan to replace all locks and keys that have not already been replaced with the standardised, high security units, over the CPP period.

20.3.4 DESIGN AND CONSTRUCT

Ground mounted distribution switchgear is classified as Class A equipment[100] and undergoes a detailed evaluation process to ensure any new equipment is fit for purpose on our network.

As we have migrated to SF_6 based RMUs (in preference to oil-based switchgear) our SF_6 holdings (across all assets) has risen to more than 1000kg. We are now classed as a major user under the ETS and are required to have in place an auditable reporting regime that records our SF_6 transactions.

To minimise our SF_6 holdings and the potential for harm to the environment, we have recently approved a vacuum circuit breaker based RMU for indoor use. We expect to adopt this also for outdoor use once a suitable enclosure has also been approved.

Major SF_6 user

SF_6 is classified as a greenhouse gas, so our SF_6 switchgear requires particular environmental management. We are now classified as a Major User under the Emissions Trading Scheme as our SF_6 holdings have recently increased to more than 1,000 kg. Requirements of Major Users include having in place an auditable reporting regime that records SF6 transactions and holdings. We have implemented systems that meet these requirements over the past year.

We are endeavouring to limit new SF_6 usage to applications without a viable alternative. As SF_6 products are highly toxic specialist handling is required in the event of a switchgear internal fault.

20.3.5 OPERATE AND MAINTAIN

Regular maintenance and inspection of our ground mounted switchgear is essential to ensure the safe operation of our distribution network. As this switchgear is often close to the public, it is vital their enclosures are locked and secure at all times.

Our various preventive maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standard.

[99] For more detail refer to the same section in the ground mounted transformers fleet within Chapter 19 of this document.

[100] Refer to Chapter 7 for more information on our asset specification and approval processes.

Table 20.3: Ground mounted switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General inspection of switchgear buildings / enclosures	6 monthly
General inspection of switchgear condition. Partial discharge and acoustic diagnostic tests	1 yearly
Switchgear service and operating checks. Diagnostic thermal scan	5 yearly
Oil sample test for oil switchgear	10 yearly

Maintenance requirements have typically been driven by manufacturers' recommendations, alongside our specific experience in maintaining and operating the asset. The six-monthly and yearly inspections are non-invasive, whereas the five-yearly service requires an outage on the switchgear, carrying SAIDI implications.

Switchgear components degrade over time and with the number of individual operations that they perform. Older style oil switchgear requires more maintenance than SF_6 or vacuum gear. Switchgear is generally berm mounted and therefore exposed to damage from vehicles. We minimise the possibility of damage by carefully choosing the location of switchgear and in some cases by installing protective bollards.

Corrective actions for switchgear include:

- Routine servicing and post fault servicing – oil change, contact alignment and dressing
- Levelling of switchgear – particularly important for oil switchgear, where changing ground conditions have caused misalignment
- Fuse replacement (fused switch units) after a fault

20.3.6 RENEW OR DISPOSE

Renewal of ground mounted distribution switchgear is prioritised based on asset condition and any known type issues that affect its safe and reliable operation. We plan replacement programmes to address the following issues:

- Older cast resin switchgear, which has proven unreliable especially in the Taranaki, Thames Valley and Waikato areas.
- Certain types of oil switchgear, where obsolescence, design issues or poor reliability increase safety and network risks. This switchgear also tends to be more difficult and expensive to maintain.

SUMMARY OF GROUND MOUNTED SWITCHGEAR RENEWALS APPROACH	
Renewal trigger	Proactive condition-based with safety risk
Forecasting approach	Type issues and age
Cost estimation	Volumetric average historical rate

Meeting our portfolio objectives

Safety and Environment: We proactively replace ground mounted switchgear when it presents unacceptable safety risks to the public, our staff or service providers.

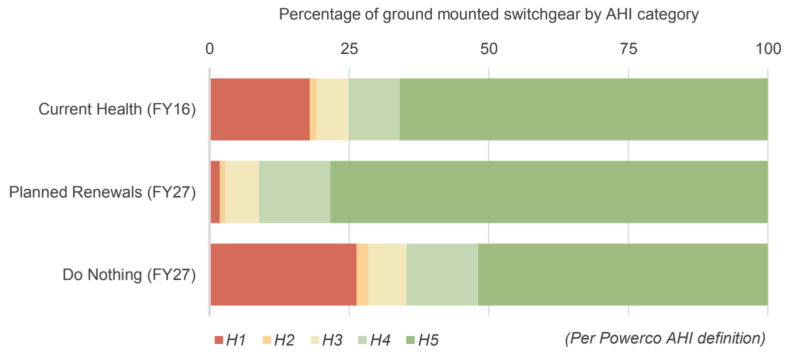
Renewals forecasting

Our ground mounted switchgear renewals forecast is based on asset condition (for the shorter term) and age as a proxy for condition (for the longer term). Age is a useful proxy for condition as over time switchgear insulation degrades, mechanical components wear and enclosures corrode.

Our approach also takes into account that older designs of switchgear generally have fewer safety features (eg arc flash containment) and are less reliable compared to modern equivalent assets. The evolution in design of switchgear has improved safety and reliability.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. Our investment will lead to an improvement in overall health as all units with known type issues are replaced.

Figure 20.5: Projected ground mounted switchgear asset health as at 2027



Further replacements will still be needed post 2027, as indicated by the H1-H3 portion in Planned Renewals (FY27). However, we expect the renewal quantity to drop as the majority of older, poor performing, ground mounted switches will have been replaced by then.

As discussed (condition, performance and risks section), replacement of many of the locks securing our ground mounted switchgear is warranted. Our forecast allows full replacement of all locks and keys that have not already been replaced with the standardised, high security units over the five year period FY19-23.

Coordination with Network Development projects

When existing ground mounted switchgear is replaced, including both RMUs and individual switches, we typically use modern equivalent SF_6 RMUs because they perform better and are more reliable. We also intend to introduce more vacuum RMUs in the near future.

In urban areas new distribution substations typically use ground mounted switchgear to minimise visual impact to the surrounding neighbourhood. Where possible we coordinate ground mounted switchgear replacements with underground cable network or ground mounted distribution transformer renewals. This is more efficient and causes less network and traffic disruption.

20.4 POLE MOUNTED FUSES FLEET MANAGEMENT

20.4.1 FLEET OVERVIEW

Pole mounted fuses provide protection and isolation ability on the network. Their main role is to isolate and protect distribution transformers. They are also used on distribution feeders to provide cost effective fault isolation for spur lines or cables at the tee-off from the main feeder. This reduces the number of customers affected by a fault and improves network reliability.

Pole mounted fuses are non-ganged, single pole devices and are fairly simple and mature. Some fuse models have issues with corrosion, insufficient gap clearance to meet minimum approach distances and stress-cracking insulators. Later models have addressed these issues.

Models with noted corrosion issues and non-compliant models have largely been replaced. Models prone to cracking are reactively replaced based on condition, as are older style fuses that remain in service.

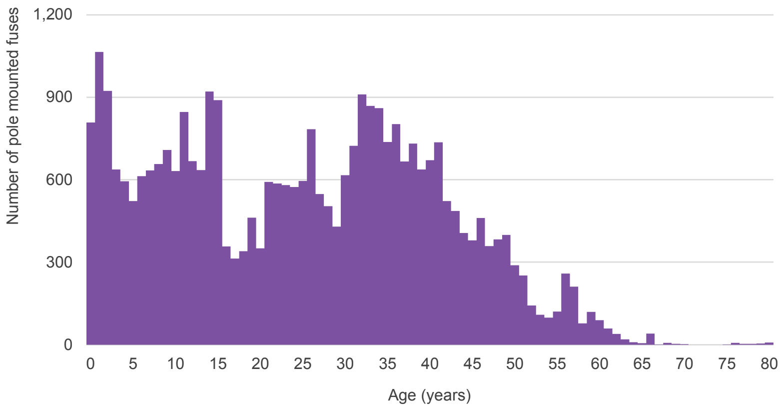
Figure 20.6: Pole mounted drop out fuse

20.4.2 POPULATION AND AGE STATISTICS

The current population of our pole mounted fuse fleet is approximately 33,000. A large number of manufacturers are represented but equipment is all very similar in design and function.

The figure below shows the age profile of our population of pole mounted fuses.

Figure 20.7: Pole mounted fuses age profile



The fleet has a relatively flat age profile, falling off after 50 years. Because of this profile, levels of renewal expenditure are likely to remain fairly constant over the planning period.

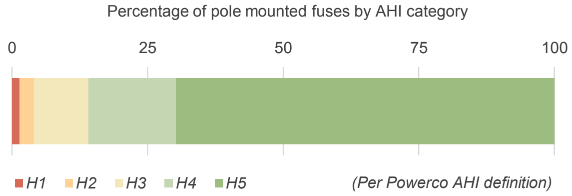
20.4.3 CONDITION, PERFORMANCE AND RISKS

Pole mounted fuses asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For pole mounted fuses, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the fuse assembly should be replaced. The AHI is calculated using our survivorship analysis.

The figure below shows current overall AHI for our population of pole mounted fuses. The health of the fleet is stable.

Figure 20.8: Pole mounted fuses asset health as at 2016



This suggests that 10-15% of the fleet is likely to require renewal over the next 10 years (H1-H3), with some fuses requiring renewal replacement in the short-term (H1).

Risks

Certain types of pole mounted fuses present fire risks when installed in dry areas as they can potentially drop molten fuse wire. We aim to prioritise the renewal of these fuses in areas of fire risk in the near term.

20.4.4 DESIGN AND CONSTRUCT

Fuse selection is based on the specific protection and operating needs associated with the network asset. When a distribution line is renewed the entire distribution line network design is reviewed. Fuses may be replaced with smarter devices such as reclosers or sectionalisers to enhance network operability and reliability.

The fuses used on our network must comply with a number of industry standards. Before a new type of fuse can be used on the network it must undergo a detailed evaluation process to ensure the equipment is fit for purpose.

20.4.5 OPERATE AND MAINTAIN

Our pole mounted fuse fleet is inspected as part of our overhead line inspections which check for corrosion and general condition degradation. Any remedial work is captured as part of our defects process. The inspection task is summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 20.4: Pole mounted fuse preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection for corrosion and defects.	5 yearly

20.4.6 RENEW OR DISPOSE

Our renewal strategy for pole mounted fuses is condition-based. If an inspection identifies a defect, the fuse is scheduled for renewal as part of the defect management process, generally within 12 months.

Some fuses are replaced after a fuse link failure because of their poor condition. The consequences of failure are minor and replacement can be carried out quickly.

To replace a greater proportion of fuses proactively would require more frequent inspections. However, the volume of fuses on the network (around 33,000) and the minor consequences of failure mean that a systematic replacement would not be cost effective.

SUMMARY OF POLE MOUNTED FUSES RENEWALS APPROACH	
Renewal trigger	Reactive and condition based
Forecasting approach	Survivor curve
Cost estimation	Volumetric average historical rate

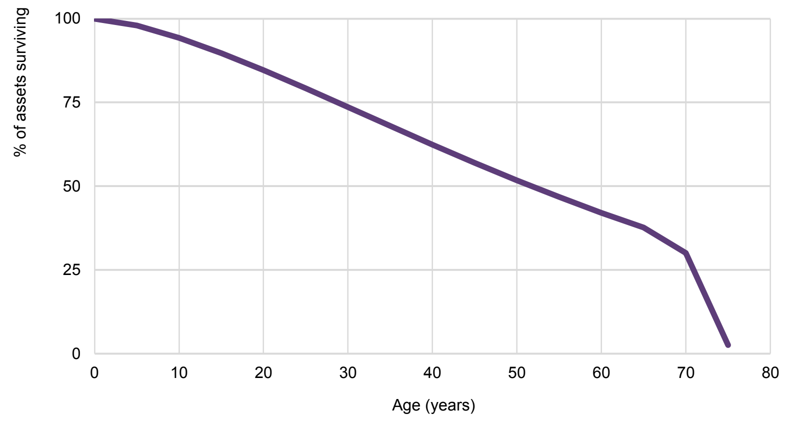
Renewals forecasting

Our pole mounted fuse replacement quantity forecast incorporates historical survivorship analysis of our pole mounted fuse fleet. We developed a survivor curve, and use this to forecast renewal quantities.

Over the past 10 years we have collected detailed information on the fuses disposals and failure modes. Our survivor analysis reveals that fuse replacement age varies, primarily due to location and inherent durability. Our forecasting approach incorporating a survivor curve is therefore more robust than an age based approach that purely relies on standard asset lives.

The figure below shows the pole mounted fuse survivor curve. The curve indicates the percentage of population remaining at a given age.

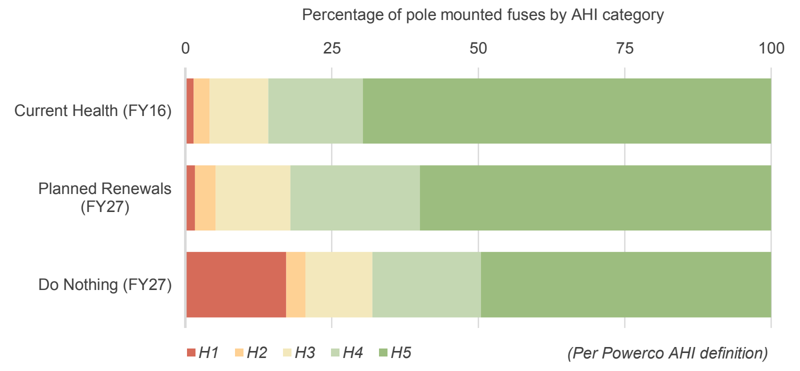
Figure 20.9: Pole mounted fuse survivor curve



Due to the relatively uniform age profile (see Figure 21.7), we expect pole mounted fuse renewals to remain relatively constant over the current planning period. As we inspect and replace further fuses we will use this data to refine the survivor curve.

The figure below compares projected asset health in 2027 (following planned renewals) with a 'do nothing' scenario. The health of the fleet is forecast to remain stable out to 2027.

Figure 20.10: Projected pole mounted fuses asset health as at 2027



Coordination with Network Development projects
Before renewing a network fuse we review the ongoing need for the equipment in that position. This review may find that a fuse should be upgraded to a recloser, installed elsewhere, or retired.

We are slowly introducing fuse-savers, an electronically controlled, single phase fault interrupting device. It is designed to be partnered with a fuse on a spur distribution line to provide a one-shot attempt to clear a downstream transient fault. The partnered fuse is protected from intermittent transient faults and will rupture if the fault is permanent.

The main application of a fuse-saver is the protection of fused rural or remote rural distribution spur lines that have a history of transient faults. If the initial rollout proves successful, these will allow us to improve network performance for these spur lines and reduce costs related to fuse call outs.

When fuse assemblies require end-of-life replacement, we coordinate this work where possible with overhead line reconstruction projects to minimise costs.

20.5 POLE MOUNTED SWITCHES FLEET MANAGEMENT

20.5.1 FLEET OVERVIEW

The pole mounted switch fleet comprises ABSs, vacuum insulated isolators and SF_6 gas insulated isolators.

Air break switches (ABSs)
ABSs are typically a three-phased, ganged rocker-style manual switch that can be operated using a handle mounted at ground level. They are used for sectionalising feeders to find and isolate faults, as open points between feeders, and as an additional worker safety mechanism. The latter provides a visual break isolation point while working on network equipment.

A standard air break switch has limited capacity to break load current and should not be used to close into a potentially faulted network. It is generally opened for sectionalising while the line is de-energised. Load break capability can be added to the standard switch to improve its load breaking capability, but this is still limited.

ABSs have undergone various design and material specification improvements over time. Newer types have improved alignment, which has reduced operating issues. We continue to install ABSs in applications where remote control capability is not essential and load breaking is not required. However, as the technology matures we expect to eventually stop installing new ABSs and transition to vacuum and SF_6 types.

Vacuum and SF_6
Vacuum or SF_6 insulated switches are modern equivalents of ABSs that have been used where remote control is required, and where load currents need to be switched. They are considered safer and more reliable to operate when compared to a standard ABS. Our fleet of vacuum and SF_6 switches is relatively young. They can be specified with motorised operation and full automation capabilities.

Figure 20.11: Air break switch

20.5.2 POPULATION AND AGE STATISTICS

We have approximately 5,000 pole mounted switches on our network. There is significant diversity in our ABS fleet with a large number of manufacturers represented, although many are sourced from one supplier. The diversity increases the costs of maintaining equipment, the amount of training required for field personnel and the safety risks they face, because they are less familiar with each model.

The table below summarises our population of pole mounted switches by type.

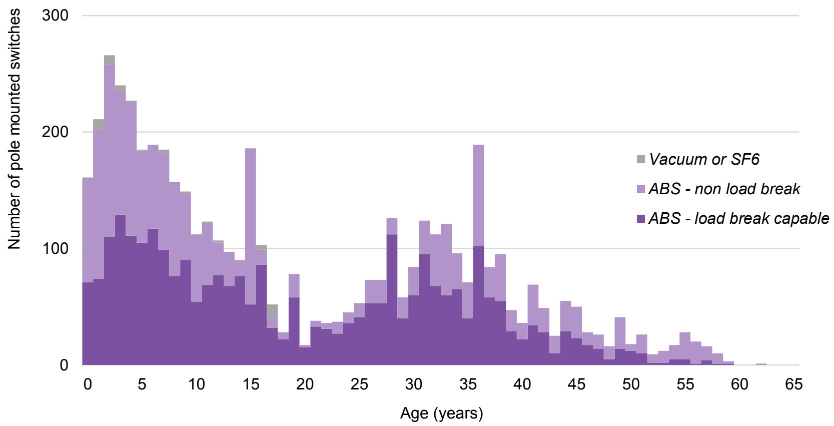
Table 20.5: Pole mounted switch population by type at 31 March 2016

TYPE	NUMBER OF ASSETS	% OF TOTAL
ABS - load break capable	2,889	57
ABS - non-load break	2,146	42
Vacuum or SF_6	49	1
Total	5,084	

As we have only recently started installing vacuum and SF_6 based switches the number in use is small (approx. 1%). As ABSs are replaced with vacuum or SF_6 switches their share will grow.

The figure below shows our pole mounted switch age profile. Only a small proportion of pole mounted switches exceed their 45-year expected life.

Figure 20.12: Pole mounted switch age profile



We have undertaken significant ABS renewal over the past years in order to replace poor condition switches, and those with insufficient maintenance (in part due to the difficulty in obtaining shutdowns). This is reflected in the large number of younger ABSs on the network.

20.5.3 CONDITION, PERFORMANCE AND RISKS

Risks

Pole mounted switches have several performance issues. Attempting to close an air break switch when contacts are misaligned can cause an insulator to fail, resulting in a flashover. This potential safety issue is managed by using appropriate protective equipment and following operational guidelines.

The design of older ABS is such that faults can result in contacts welding together. Older designs can also cause corrosion or rupturing of flexible jumpers. This is not a significant issue, and as the failure mode does not have any safety impact, a certain level of reactive replacement is cost effective.

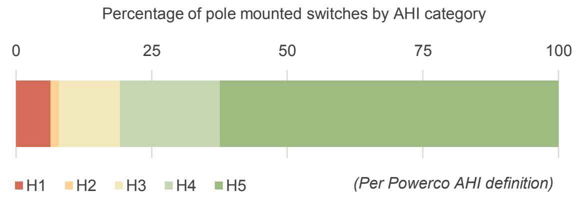
Another issue relates to operating mechanisms which tend to seize up when switches are not operated. This is addressed through our maintenance regime which specifies periodic operation of switches, alongside inspection and alignment of units. This frees up the operating mechanism and new contacts are installed as needed. This work can be done live-line, but this is costly and carries additional safety risk that needs to be managed. The alternative is to isolate the switch, which has supply and SAIDI implications. A combination of live-line and isolation approaches are used.

Pole mounted switches asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For pole mounted switches, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switch should be replaced. The AHI is primarily calculated using asset age and typical expected lives.

The figure below shows current overall AHI for pole mounted switch fleet.

Figure 20.13: Pole mounted switches asset health as at 2016



The figure indicates that around 20% of our fleet will require renewal the next 10 years (H1-H3). Around 7% of pole mounted switches have already exceeded their expected life and likely require replacement (H1).

Locks and keys

There are risks associated with the legacy padlocking systems used to protect our pole mounted switchgear from unauthorised access.[101] To manage these risks we plan to replace all locks and keys that have not already been replaced with the standardised, high security units, over the CPP period.

20.5.4 DESIGN AND CONSTRUCT

We have started introducing vacuum and SF_6 switches onto our network in place of standard ABSs. We are planning on moving to sealed SF_6 or vacuum pole mounted switch types for the majority of switch replacements (apart from urgent reactive ABS replacements where we use a like-for-like renewal approach). This change in approach will be phased in over the next five years. This will allow for further trials of makes and models and for personnel training for the updated operating procedures.

Even when specified for manual operation only, there are considerable benefits to SF_6 or vacuum pole mounted switchgear. Only periodic visual inspections are required compared to the more intensive servicing of ABSs.

[101] For more detail refer to the same section in the ground mounted transformers chapter of this document.

As the switching contacts are contained in a fully enclosed tank, internal components no longer corrode and the risk of molten components falling on an operator during switching is eliminated. The switching operation is also consistent and controlled and not dependent on the manual energy provided by the operator. The increase of SF_6 volumes on the network needs to be monitored because of the environmental risk.

A manually operated SF_6 or vacuum switch costs roughly the same as an ABS to purchase and install, although its life cycle costs are considerably less. Fully automated versions cost more but provide remote switching benefits. When renewing an ABS, we will consider these additional benefits and select the best configuration for its particular function on the network.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We are introducing SF_6 based switches onto our network in order to improve network operation and safety and manage life cycle cost.

20.5.5 OPERATE AND MAINTAIN

Our ABS maintenance regimes differ depending on the location of the switch and the load it is serving. Switches in built up areas undergo more frequent inspections and servicing compared with rural switches.

Our preventive maintenance tasks for this fleet are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 20.6: Pole mounted switch preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
ABS – built up area	Operation and major maintenance of contacts, pantographs, mechanisms Contacts and jumpers thermal scan (Both tasks done 5 yearly, but alternate 2 ½ years apart)	5 yearly
ABS – rural area	Visual Inspections of contacts, pantographs. Inspect, lubricate and operate switch	5 yearly
	Operation and major maintenance of contacts, pantographs, mechanisms	10 yearly
Vacuum and SF_6	External visual inspection and thermal scan	5 yearly

20.5.6 RENEW OR DISPOSE

Our renewal strategy for pole mounted switches is condition-based replacement. Switches with identified defects are generally scheduled for replacement as part of the defect management process.

We have some reactive replacements. When a switch fails it is replaced immediately like-for-like to minimise the impact on customers.

SUMMARY OF POLE MOUNTED SWITCHES RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Age
Cost estimation	Volumetric average historical rate

In reviewing our approach to this fleet, we have considered potential areas of improvement to allow us to proactively and cost effectively identify additional defects. We are trialling alternative inspection methods including acoustic testing and high resolution cameras to improve data quality. In addition, better implementation of our inspection procedures via training of field personnel is expected to improve the quality of incoming information.

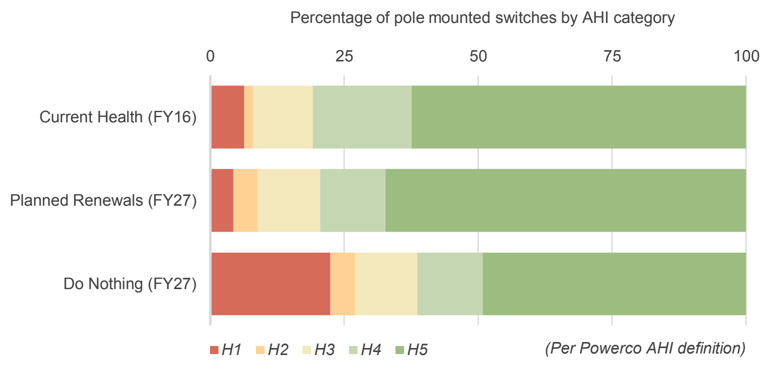
Renewals forecasting

Our renewals forecast uses age as a proxy for condition. ABSs are relatively simple mechanical devices, exposed to the elements, and therefore their condition worsens over time through corrosion and mechanical wear.

We expect levels of renewal expenditure for pole mounted switches to remain fairly constant over the planning period.

The figure below compares projected asset health in 2027 (following planned renewals) with a ‘do nothing’ scenario. Our investment will lead to an improvement in overall health as we replace those assets in worst health. It will also manages the increasing number of switches requiring replacement during the planning period, indicated by the H1 portion in Do Nothing (FY27).

Figure 20.14: Projected pole mounted switches asset health as at 2027



As discussed previously (condition, performance and risks section), replacement of many of the locks securing our pole mounted switchgear is warranted. Our forecast allows full replacement of all locks and keys that have not already been replaced with the standardised, high security units during the five year period FY19-23.

Coordination with Network Development projects

Similar to fuses, before renewing a pole mounted switch we review the ongoing need for the equipment in that position.

Where feasible, we coordinate pole mounted switch replacements with overhead line reconstruction projects. This allows for more efficient delivery and minimises costs.

20.6 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS MANAGEMENT

20.6.1 FLEET OVERVIEW

Circuit breakers, reclosers and sectionalisers are used when distribution switchgear needs to fulfil a protection function such as the isolation of network faults. This type of switchgear often contains logic that can be programmed for distribution automation schemes.

Circuit breakers

Circuit breakers, in the context of this fleet, are associated with distribution substations.[102] Circuit breakers are not widely used on the distribution network but are typically installed within major customer facilities.

[102] Zone substation circuit breakers are discussed in Chapter 18.

In the distribution network they are used in a similar manner as pole mounted reclosers. They are generally used in underground parts of the network to provide mid-feeder isolation to reduce the impact of a network fault.

Circuit breakers at major customer sites take on a similar function to those located in a zone substation. They provide isolation of faults on downstream equipment elsewhere on a customer site. Insulating media include oil, SF_6 and vacuum.

Reclosers

Reclosers are pole mounted devices with on-board protection capability. They are designed to detect downstream faults and isolate the faulted part of the circuit before the upstream supply circuit breaker reacts. This reduces the area affected by a fault.

The term recloser refers to the device's ability to attempt to automatically restore supply in a very short space of time. It will 'reclose' on the faulted section to automatically restore supply if the fault has self-cleared. The objective is to clear transient faults caused by tree branches, vermin or windblown debris and avoid lengthy outages.

Figure 20.15: A pole mounted recloser

A recloser at the boundary between an urban area and outer rural sections protects the higher density urban portions of feeders from the higher fault rate on the rural sections.

Technology in these devices has undergone a great deal of change over time. Most of the advances relate to the electronic control functionality of the devices which now have greater capability to support distributed automation. The electronic controls require management of firmware and settings (like a protection relay) and the control equipment will likely need replacement before the switchgear itself.

Sectionalisers

Sectionalisers are similar to reclosers. They are generally pole mounted with a limited amount of on-board intelligence. A sectionaliser differs from a recloser in that it does not open to clear the fault. It opens after the upstream circuit breaker or recloser has reacted to the fault. It sectionalises the downstream portion of the feeder during the brief period when the feeder is de-energised. It relies on the upstream device to then reclose and restore supply to the upstream portion.

20.6.2 POPULATION AND AGE STATISTICS

The table below summarises our populations of circuit breakers, reclosers and sectionalisers on our network, split by interrupter type. This split is important because oil-based interrupters have higher safety risks (potential for catastrophic failure with associated fire risk).

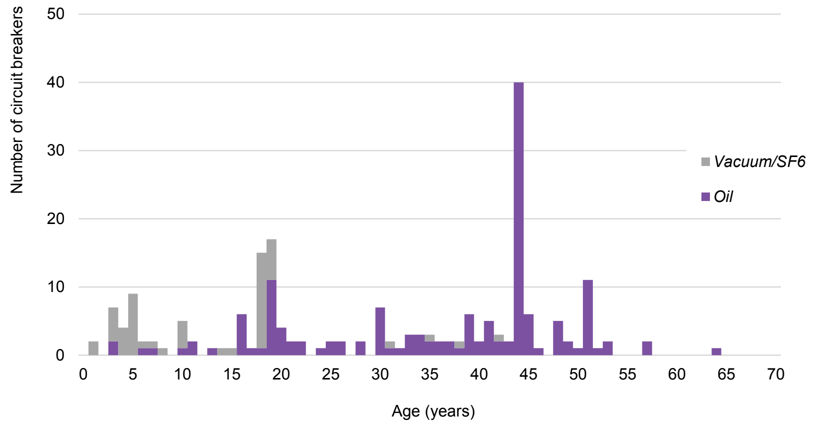
Approximately 80% of the circuit breaker fleet is oil-based, almost half of which are located at a single customer site at Kinleith.

Table 20.7: Circuit breakers, reclosers and sectionalisers population by type at 31 March 2016

TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Circuit Breakers	Oil	153	24
	SF_6/Vacuum	53	8
Reclosers	Oil	11	2
	SF_6/Vacuum	295	47
Sectionalisers	Oil	16	3
	SF_6/Vacuum	101	16
Total		629	

The figure below shows our circuit breaker age profile. Our circuit breakers are ageing, with a large number close to or exceeding an expected life of 45 years (noting that replacement is a condition-based decision).

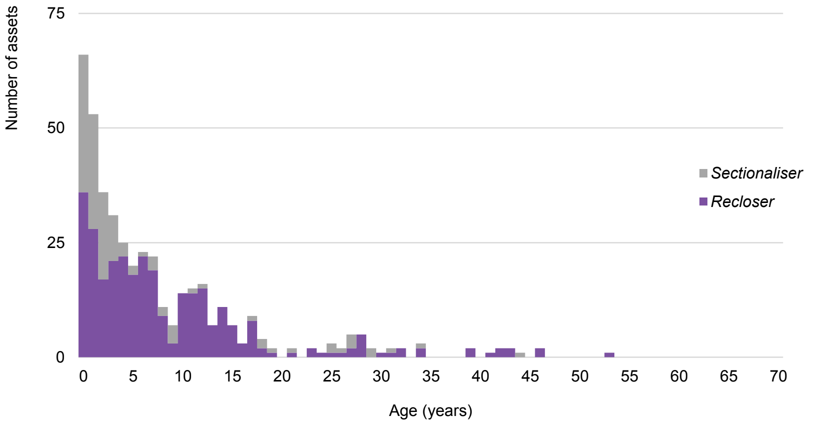
Figure 20.16: Circuit breaker age profile



Older assets are primarily made up of the oil-filled circuit breakers at Kinleith. A planned replacement programme at that site from 2018-2022 will remove many of these. Oil-filled circuit breakers are no longer purchased. All new circuit breakers are SF_6 or vacuum types.

In contrast, our reclosers and sectionalisers are newer and many have been installed in the last 10 years. As such, this small fleet is expected to require little renewal over the planning period.

Figure 20.17: Recloser and sectionaliser age profile



20.6.3 CONDITION, PERFORMANCE AND RISKS

Working with oil-based circuit breakers raises many of the same issues as zone substation indoor switchboards. These include catastrophic failure, fire risk, restricted access for maintenance work and arc flash risk. These risks particularly affect our circuit breaker assets installed at Kinleith.

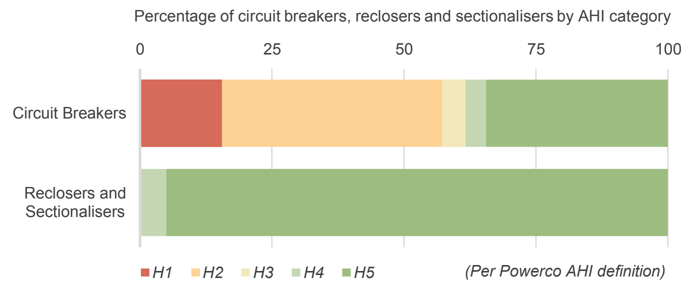
The 11kV fault levels at Kinleith are some of the highest on our network. The number of faults, coupled with the longer protection operating times prevalent at the site, presents a high arc flash safety risk. Many of the circuit breakers are manually operated. This is considered unsafe especially given arc flash risk. Some switches have interlocked circuit earthing facilities which we are unsure of the fault rating and the switchboard itself. We have prioritised these circuit breakers for replacement.

Circuit breakers, reclosers and sectionalisers asset health

As outlined in Chapter 7, we have developed AHI that reflect the remaining life of an asset. In essence, our AHI models predict an asset's end of life and categorise its health based on a set of rules. For circuit breakers, reclosers and sectionalisers we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switchgear should be replaced. The AHI is based on our knowledge of specific assets with reliability or safety issues (such as arc flash risk related to oil switchgear discussed above) and asset age.

The figure below shows current overall AHI for our population of circuit breakers and reclosers/sectionalisers.

Figure 20.18: Circuit breakers, reclosers and sectionalisers asset health as at 2016



The asset health of the combined recloser and sectionaliser sub-fleet is very good. Less than 1% (H1-H3) will likely require replacement in the next 10 years.

In contrast, the health of our distribution circuit breakers is very poor as there is concern with their safe and reliable operation. This is based on our experience of operating this switchgear and the experience of others within the industry. As such we have categorised a large number of our oil circuit breakers as having type issues. There are also considerable aged circuit breakers at Kinleith where arc flash levels are high and require replacement. We are planning significant investment in this area to improve our circuit breaker asset health.

20.6.4 DESIGN AND CONSTRUCT

Circuit breakers, reclosers and sectionalisers are classified as class A equipment. Any new equipment undergoes a detailed evaluation process to ensure it is fit for purpose on our network. This includes construction material checks (such as grades of stainless steel) which from previous experience have proven critical in ensuring the assets reach their intended expected life.

20.6.5 OPERATE AND MAINTAIN

We regularly inspect and test our circuit breaker, recloser and sectionaliser assets to ensure their safe and reliable operation. Oil-based devices require more intensive maintenance and therefore cost more to operate. As we replace oil-based circuit breakers in poor condition with modern SF_6 or vacuum devices, the volume of maintenance work will decrease.

The table below summarises our preventive maintenance tasks for this fleet. The detailed regime is set out in our maintenance standards.

Table 20.8: Circuit breakers, reclosers and sectionalisers preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Reclosers and sectionalisers	Inspections and tests of actuator / RTU batteries Communications check	1 yearly
	Thermal imaging scan	2 ½ yearly
	Major contacts and tank maintenance of oil reclosers External inspections of vacuum and gas interrupter units	5 yearly
	Interrupter condition tests and major maintenance of mechanisms for vacuum and gas devices	10 yearly
Circuit breakers	General visual inspection. Operational tests.	1 yearly
	Major contacts and tank maintenance of oil circuit breakers. Vacuum and gas interrupter contacts wear and gas pressure checks. Operational, acoustic and partial discharge tests.	5 yearly
	Vacuum and gas circuit breaker interrupter withstand tests.	10 yearly

20.6.6 RENEW OR DISPOSE

Renewal of circuit breakers, reclosers and sectionalisers is based on asset condition. Routine maintenance identifies assets that require replacement to ensure their ongoing reliability in the medium-term. We have also identified safety issues with the operation of certain types of oil circuit breakers, either due to design issues with the equipment or stricter risk tolerances (such as for arc flash). These assets are prioritised for replacement.

SUMMARY OF CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based with safety risk
Forecasting approach	Type issues and age
Cost estimation	Volumetric average historical rate

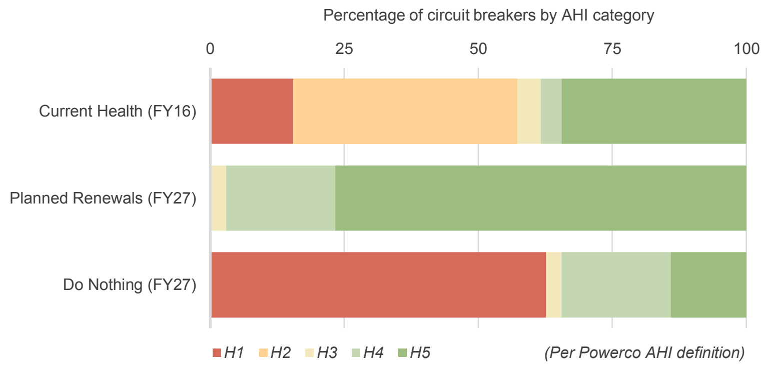
Renewals forecasting

Our renewals forecast uses age as a proxy for asset condition. As with ground mounted switchgear, over time insulation degrades, mechanical components suffer wear and enclosures corrode. This makes age a useful proxy that also captures that older designs of switchgear generally have fewer safety features, such as arc flash containment. The evolution in design of switchgear has improved safety and reliability.

The renewal need for this fleet is higher than in the past. This is because of the need to renew oil circuit breakers with safety issues and the significant quantities of circuit breaker renewal at Kinleith. Once this has been completed expenditure levels are expected to return to earlier levels.

The figure below compares projected asset health in 2027 of the circuit breaker sub-fleet (following planned renewals) with a 'do nothing' scenario. Our investment will return the health of the sub-fleet to sustainable levels by the end of the planning period. Projected recloser and sectionaliser asset health is not shown, due the small number of expected renewals during the planning period.

Figure 20.19: Projected circuit breakers asset health as at 2027



Coordination with Network Development projects

The increasing use of network automation is a key part in the development planning of this fleet. Network automation seeks to improve network SAIFI and SAIDI performance. It improves the network's sectionalising capability following faults and through providing better network operational visibility. This is achieved through the targeted installation of additional reclosers and sectionalisers. Our network automation programme is discussed in more detail in Chapter 12.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We are increasing our use of automation devices, such as reclosers and sectionalisers, to improve fault isolation and restoration.

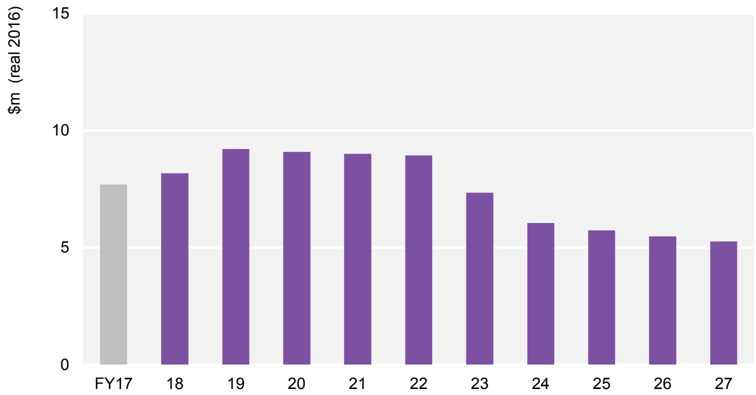
20.7 DISTRIBUTION SWITCHGEAR RENEWALS FORECAST

Renewal Capex in our distribution switchgear portfolio includes planned investments in our ground mounted switchgear, pole mounted fuses, pole mounted switches, and circuit breakers, reclosers and sectionalisers fleets. Over the planning period we intend to invest approximately $74m in distribution switchgear renewal. Safety is a key driver of renewal, particularly of our oil-filled ground mounted switchgear, link and fuse boxes, and oil filled circuit breakers.

Distribution switchgear renewals are derived from bottom up models. These forecasts are generally volumetric estimates (explained in Chapter 26). The work volumes are relatively high, with the forecasts based on survivor curve analysis, type issues and asset age. We primarily use averaged unit rates based on analysis of equivalent historical costs for like-for-like replacement. For new technology, costs have been estimated based on purchase and installation costs.

The chart below shows our forecast Capex on distribution switchgear during the planning period.

Figure 20.20: Distribution switchgear renewal forecast expenditure



The forecast renewal expenditure is generally in line with historical levels. Additional expenditure from FY18-22 is required for the circuit breaker renewal programme at Kinleith. Elsewhere the investment in the distribution switchgear fleets remains relatively constant over the planning period.

Further details on expenditure forecasts are contained in Chapter 26.

21.1 CHAPTER OVERVIEW

This chapter describes our secondary systems portfolio and summarises our associated fleet management plan. The portfolio includes four asset fleets:

- SCADA and communications
- Protection
- DC supplies
- Metering

This chapter provides a description of these assets, including their population, age and condition. It goes on to explain our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we expect to invest $39m in secondary systems. This accounts for 5% of renewals Capex over the period. This is an increase over current spend, mainly driven by our Extended Reserves and Tauranga Information Initiatives programmes. Levels of renewal in the other secondary systems fleets are in line with historical expenditure.

The main driver for asset replacement in the secondary systems portfolio is obsolescence. Capex is driven by the need to:

- Replace our legacy electromechanical and static protection relays, which suffer from a lack of spares, lack support from manufacturers, and provide inadequate functionality compared to modern equivalents.
- Consolidate the communications protocols for our SCADA system which requires the replacement of SCADA base station and remote radios.
- Control and operate the network more efficiently to provide better value to our customers. Modern assets are more functional and perform better.
- Replace several legacy RTUs that do not provide the functionality required for our network.
- Meet regulatory requirements in relation to the new Extended Reserves arrangements
- Implement our smart ripple receiver replacement programme in the Tauranga region.

Below we set out the asset management objectives that guide our approach to managing our secondary systems fleets.

21.2 SECONDARY SYSTEMS OBJECTIVES

Secondary systems are crucial for enabling the safe and reliable operation of our electricity network. Their replacement cost is usually lower but their useful lives are shorter than assets in other portfolios. Some are technically complex and require a high degree of strategic direction and careful design to operate effectively.

Protection assets ensure the safe and correct operation of the network. They detect (and allow us to rectify) network faults that may otherwise harm the public and our field staff, or damage network assets. Our SCADA and communications assets provide network visibility and remote control, allowing our operators to efficiently and effectively operate the network.

To guide our management, we have defined a set of objectives for our secondary systems assets. These are listed in the table below. The objectives are linked to our overall asset management objectives as set out in Chapter 5.

Table 21.1: Secondary systems portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Effective protection of primary systems No injuries or incidents resulting from incorrect operation of protection systems. The SCADA system allows reliable control and monitoring of the electricity network at all times.
Customers and Community	HV metering units provide accurate consumption information for appropriate billing and meet the requirements of the Electricity Industry Participation Code.
Networks for Today and Tomorrow	Increase our levels of SCADA and monitoring, in particular giving better visibility of the distribution and LV networks to anticipate and effectively manage capacity and voltage pinch points, and enabling increasing levels of distribution automation. Trial the use of smart devices to understand their potential operational, asset management and customer benefits
Asset Stewardship	DC supply systems provide their specified carry-over time in the event of an outage.
Operational Excellence	Continue to use improved asset information gathered and recorded by modern numerical relays.

21.3 SCADA AND COMMUNICATIONS FLEET MANAGEMENT

21.3.1 FLEET OVERVIEW

The SCADA system provides visibility and remote control of our network. Their coverage includes major communication sites and zone substations, as well as distribution assets such as voltage regulators and field pole-top and ground mounted switches. A central master station communicates with RTUs over a communications system made up of various carriers, such as radio, microwave and fibre optic cable. RTUs interface with the network equipment such as transformer control units and circuit breaker control systems.

The technology is diverse as it was installed by a range of preceding network companies with different standards and requirements. We have undertaken significant work to improve standardisation.

Master stations

The master station is essentially a central host computer server that manages the SCADA system. We currently have two master stations – the primary one is located in New Plymouth and the backup in Auckland.

Our network is the result of amalgamating many networks. We previously ran multiple master stations from several different vendors. During the past decade, we have standardised and consolidated the SCADA network into one system.

We have selected an industry standard communications protocol – Distributed Network Protocol version 3.0 (DNP3) – as our standard communications protocol.

In 2009, the Eastern Region SCADA platform was upgraded to incorporate legacy networks. In 2014, the Western Region was converted to DNP3 which made it compatible with the Eastern Region's upgraded SCADA platform. These upgrades provide a single flexible platform that will meet the network's SCADA needs for the foreseeable future.

Remote terminal units (RTUs)

RTUs are electronic devices that interface network equipment (such as transformer control units, DC supplies, protection relays, and recloser controls) with SCADA. They transmit telemetry data to the master station and relay communications from the master system to control connected devices.

A range of different RTUs are used across the eastern and western networks. The majority of RTUs are modern devices, providing adequate service. However, many of the devices in the Eastern Region communicate via the Conitel protocol rather than the preferred DNP3 protocol. The majority of these devices operating on the Conitel protocol are also DNP3 compatible and will be slowly transitioned to the new standard as their corresponding radios and base stations are replaced.

There are also a small number of legacy RTUs at zone substation sites and load control plants. These are being prioritised for replacement as they lack DNP3 communications capability, are proprietary hardware and are incompatible with modern numerical relays.

Figure 21.1: A modern RTU

Communications

The communications network supports our SCADA system as well as our protection, metering and telemetry systems. Examples of its use include data exchange between field devices and the SCADA master station, and between protection relays at multiple substations (protection circuits). The communications network consists of different data systems and physical infrastructure, including fibre optic circuits, UHF point-to-point digital radios, microwave point-to-point digital radios, point-to-multipoint VHF/UHF repeaters and Ethernet IP radio circuits.

While some analogue technology also remains in use, we are progressively moving to digital systems to provide a communications network that better meets our needs. Any remaining analogue equipment will be prioritised for replacement over the planning period.

We have recently implemented a digital microwave backbone to cover the Eastern Region. This system provides a communications network capable of carrying both voice and SCADA data while also providing the ability to implement Ethernet circuits to selected substations. Several DNP3 repeaters have also been installed at various locations around the region, although the majority of RTUs are still using the Conitel protocol over analogue radio systems. In the Western Region, a new DNP3 digital radio system is used.

The scope of the communications network also includes the infrastructure that houses communication systems, including masts, buildings, cabinets and antennae. Infrastructure services are leased from service providers or shared with third parties.

Figure 21.2: Communications mast with associated radio antennae

21.3.2 POPULATION AND AGE STATISTICS

During the past five years, we have undertaken a number of projects to modernise our RTUs in order to provide acceptable levels of service. In the planning period, we intend to focus on replacing any remaining legacy RTUs. Although they have provided good service, they no longer provide the functionality we require.

The table below summarises our population of RTUs by type. [103]

[103] This population excludes telemetered sites with Intelligent Electronic Devices (IEDs) directly connected to the SCADA network, such as those on modern automated reclosers.

Table 21.2: RTU population by type at 31 March 2016

TYPE	RTUS	% OF TOTAL
Modern	290	98
Legacy	7	2
Total	297	

Converting the remaining eastern RTUs from Conitel to DNP3 is a lower priority. We expect to convert one or two channels each year (average of 12 RTUs per channel).

As these modern Conitel RTUs already have the ability to support the DNP3 protocol, these channel conversions require the replacement of the associated SCADA radios to DNP3 capable units. At the end of this programme, we will have the SCADA network standardised on the industry standard DNP3 protocol. Use of the open DNP3 standard allows direct connection of some Intelligent Electronic Devices (IEDs) to the SCADA master without requirement of an intermediary RTU.

Age information for our communications network is disparate, and is typically inferred from related assets or from drawings of the installations. We are working to improve our records.

21.3.3 CONDITION, PERFORMANCE AND RISKS

Condition

The small numbers of legacy RTUs on the network are based on proprietary hardware, software and communications protocols. They cannot communicate with modern numerical relays using standard interfaces (serial data connection). Instead, they rely primarily on hard-wired connections which are more prone to failure, are difficult to maintain and troubleshoot, and require specialist knowledge to understand how they work. These RTUs rarely fail but a lack of experienced service personnel and original, first-use, spares increases risk.

Risks

With regard to the SCADA system, the key risk is loss of network visibility and control. We prefer to operate equipment remotely for a number of reasons, including safety, speed of operation and improved operational visibility. Lack of status information from the field can lead to switching errors such as closing on to a faulted piece of equipment or circuit.

Another significant risk is of a third party gaining control of our switchgear through a cyber-attack on our SCADA system. The increasing risk of a cyber-attack on our network is driving us to improve the security levels of our SCADA system. As more devices become visible and controllable on the network (eg automation devices including reclosers) the potential safety, reliability and cost consequences from an attack on the system become increasingly serious. Improving our levels of cyber security is a key theme of our Information Services Strategic Plan (ISSP) and is discussed in more detail in Chapter 22.

Meeting our portfolio objectives

Safety and Environment: We continually review the security of our SCADA against cyber-attack to ensure the operational safety of the network.

21.3.4 DESIGN AND CONSTRUCT

Technology changes are affecting SCADA in a number of ways. As numerical protection relays and other IEDs become more prevalent and powerful, more data is collected. This requires alternative polling strategies to manage data requirements and increased communications bandwidth.

There is potential to use satellite communications for distributed equipment, the cellular radio network for engineering access where coverage exists, or fibre optic cables (where available) for some RTU communications. Wide area network communication could be used between main centres and communication hubs.

Improvements in interface standards and protocols will enable easier transfer of data between systems. Web-based inter-control centre communications protocol is a new technology that will allow us to see Transpower's circuit breaker statuses, indications and analogue data on our SCADA without the need to go through a third party.

We will monitor these changes in technology closely to ensure that any benefits to our SCADA system can be promptly identified and implemented as appropriate.

The latest standard RTU types that we are installing provide remote engineering access (REA) support for the majority of our numerical relays. REA allows our technicians and protection engineers to access relay 'downloads' of event information remotely, removing the need to download the data at site from the relay. This could potentially reduce the time required to understand and react to a fault – reducing the length of power cuts for customers.

In terms of communications, moving from analogue to digital technology will allow for greater data throughput and manageability. Greater intelligence within the communications system, between IED controlled switches and the master station, will allow for automatic fault restoration.

Communications systems also enable emerging technology in other areas such as providing mobility solutions to our field workforce. Expected improvements include providing improved access to up-to-date asset information and integration with work packs.

21.3.5 OPERATE AND MAINTAIN

SCADA and communications assets are regularly inspected and tested to ensure their ongoing reliability. Operational tests are carried out to ensure the communications equipment remains within specifications, including checks to ensure transmitting equipment is within radio licence conditions.

Table 21.3: SCADA and communications preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Communications equipment, including RTUs	General equipment inspections to test asset reliability and condition. Transmitter power checks and frequency checks. Site visual inspection for dedicated communications sites, checking building condition and ancillary services. RTU operational checks.	6 monthly
	Visual inspection of communication cables/lines, checking for condition degradation. Attenuation checks. Antennae visual inspections, with bearing and polarity verified.	1 yearly
SCADA master station	Maintenance covered by specialist team.	As required

21.3.6 RENEW OR DISPOSE

SCADA and communications asset renewal is primarily based on functional obsolescence. As detailed earlier, we have a small number of legacy RTUs on the network which are based on proprietary hardware and communications protocols. They are unable to communicate through standard interfaces with modern IEDs. There is a lack of knowledgeable personnel and a lack of spares to undertake related work. The replacement of these legacy RTUs is a high priority.

Other communications assets, such as radio links and their associated hardware, are also typically replaced due to obsolescence. Modern primary assets and protection relays have the ability to collect an increasing amount of data that is useful for managing the network. To support this, legacy communication assets are replaced with modern, more functional assets. Our future communications strategy is discussed in more detail in Chapter 11. Some condition-based renewal is also carried out, typically for supporting communications infrastructure such as masts and buildings.

SUMMARY OF SCADA AND COMMUNICATIONS RENEWALS APPROACH	
Renewal trigger	Functionality based obsolescence
Forecasting approach	Identified assets
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewal forecasts are based on identifying asset types that require replacement (see discussion above). This includes the legacy RTUs, SCADA radios and base stations that still operate on the Conitel or other non-supported protocols.

The renewal forecast of supporting communications infrastructure is an estimate of the expected annual replacement quantity based on historical renewals.

Longer term, we expect SCADA and communications renewals to remain at least at current levels. Future capability requirements and an expansion of the communications network are likely to increase the renewal need.

Coordination with Network Development projects

The SCADA system already provides real time monitoring and control at our zone substations. The system is largely mature and fully developed. As discussed above, our eastern and western systems are on a common platform.

Specific SCADA system needs are considered as part of network development. For example, a zone substation project includes developing the SCADA RTU, configuration and communications. Similarly, our network automation programme[104] is extending the control and monitoring capability out to selected distribution switches.

21.4 PROTECTION FLEET MANAGEMENT

21.4.1 FLEET OVERVIEW

Protection assets ensure the safe and appropriate operation of the network. They detect and isolate network faults that could otherwise harm the public and our service providers or damage network assets.

Protection relays or integrated controllers are used to detect and measure faults on our HV electricity network. Protection relays communicate with circuit breakers, either directly or through SCADA, to clear and isolate faults. When working correctly, they can have a significant impact in improving network performance.

Protection systems include auxiliary equipment such as current and voltage instrument transformers, communication interfaces, special function relays, auxiliary relays and interconnecting wiring.

Protection relays have evolved over time and this fleet can be broken down into three main technologies – electromechanical, static and numerical protection devices.

Electromechanical relays

Electromechanical relays are a mature protection technology which have provided many years of reliable performance. While mechanically basic and simple to operate, they are not as functional as more modern protection technology. As their name suggests, they operate on electromechanical principles – currents and voltages driving mechanical components such as rotating discs and relays, which in turn operate output contacts.

Figure 21.3: Electromechanical relays providing transformer protection

Electromechanical relays require ongoing calibration due to ‘drift’ of components. They have an expected life of approximately 40 years. Most electromechanical relays on our networks have been in service for more than 30 years and some more than 45 years.

Static relays

Static relays gain their name from the absence of moving parts to create the relay characteristic. Essentially, they are an analogue electronic replacement for electromechanical relays. They use analogue electronic devices rather than the coils and magnets in electromechanical relays.

Being solid-state they have improved sensitivity, speed and repeatability compared with electromechanical relays. Static relays have limited microprocessor capacity and memory. This means they can only be used for protection purposes and are more susceptible to changes in temperature than electromechanical relays. Static

[104] We discuss the network automation programme in Chapter 12.

relays have an expected life of approximately 20 years. Spare parts can be difficult to obtain, and carrying out internal repairs is challenging and typically not economic.

Numerical relays

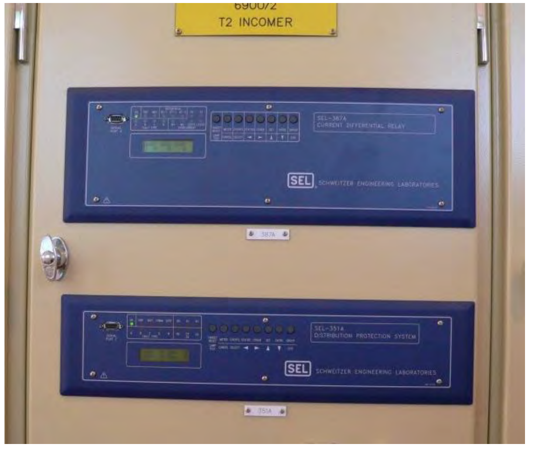
Numerical relays convert measured analogue values into digital signals. Being digital computer technology, these relays are extremely flexible. They can be programmed and configured to provide a wide range of protection applications. They also have multiple control inputs and relay outputs available.

Numerical relays have significant advantages over previous technologies. These include the ability for data to be accessed remotely and ability to be integrated directly into the SCADA system. Numerical relays also offer real time and historical information about the power system, the protection and control systems, and selected substation equipment (eg fault location and type, before, during and post fault currents and voltages, and relay status).

Numerical relays are by far the most popular choice for new protection and control installations today. Modern numerical relays are extremely reliable and offer vastly improved functionality at reduced cost compared with those available in the past.

As they are an electronic device, the expected life of a numerical relay is shorter than electromechanical relays at approximately 20 years. Obsolescence is also a driver for replacement, which is typically dictated by protocol, software and firmware, and compatibility with other devices.

Figure 21.4: Modern numerical relays



21.4.2 POPULATION AND AGE STATISTICS

The protection fleet is relatively diverse, with a large number of electromechanical and numerical relays. As electromechanical and static relays are replaced over time, numerical relays will become the main relay type used. This will also reduce the total number of relays in the fleet, as modern numerical relays can be programmed to provide multiple protection functions that currently require several individual electromechanical relays.

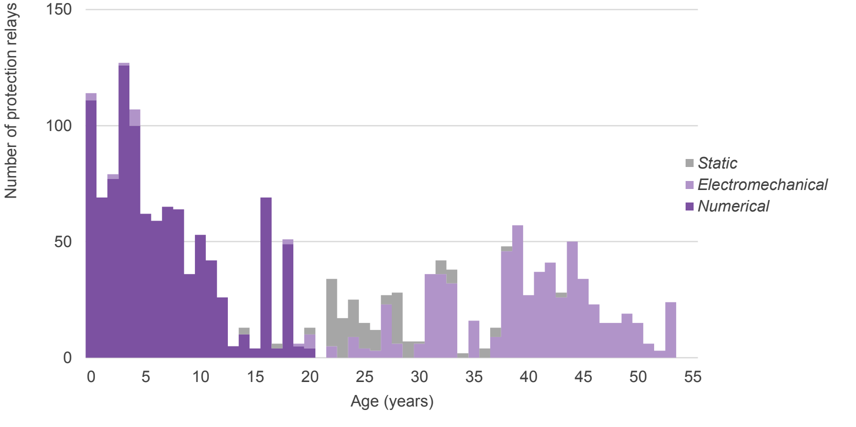
Table 21.4: Protection asset population by type at 31 March 2016

TYPE	RELAYS	% OF TOTAL
Electromechanical	643	35
Numerical	1,042	57
Static	150	8
Total	1,835	

The type of relay used on the network has changed over time as technology has evolved. Electromechanical relays were generally superseded by static relays approximately 30 years ago. During the past 20 years, we have almost exclusively installed numerical relays. The first generation of these numerical relays will begin to require renewal during the next five years.

The figure below shows our age profile of population of protection relays. A large number of electromechanical relays exceed 40 years of life and are now due for replacement.

Figure 21.5: Protection relay age profile



21.4.3 CONDITION, PERFORMANCE AND RISKS

Condition

While older relays are proven and have a long life, they are partially mechanical and wear out with use. Experience and routine tests suggest electromechanical relays are prone to poor performance and reliability after their expected life of approximately 40 years. Such relays may suffer from sticky contacts, inconsistent timing, and/or sluggish operating times. As a result they may not reliably detect and discriminate network faults.

In contrast, newer numerical relays can provide much greater functionality, richer information and higher reliability and system stability. However, they have a shorter life due to their microprocessor-based technology. Excessive heat may also cause them to fail, which we manage through the use of air conditioning. Numerical relays generally provide indication when they malfunction which allows maintenance intervals to be extended.

Risks

The key safety risk for the protection fleet is that a fault does not clear due to a faulty relay. This can put the public or service provider in danger, cause network equipment failure, or overload.

Backups are in place but these are designed to take longer to clear the fault to ensure protection discrimination. However, longer fault clearance times can sometimes result in fires or live power lines on the ground. Numerical protection relays can be configured to operate faster than the other types, but this may reduce the margins for protection coordination. However, the functions they provide can assist in determining the fault location, reducing restoration times.

Meeting our portfolio objectives

Safety and Environment: We continually review our protection coordination to ensure faults are cleared in a fast but reliable manner.

Regulatory compliance

The Electricity Authority is currently implementing new requirements for Extended Reserves (to be applied from 2019). The new requirements include tripping on the rate of frequency decay, which requires a more sophisticated relay unit. A very high percentage of our existing load shedding relays are many decades old and incapable of meeting the new specifications. To meet our obligations we need to replace and re-programme existing under-frequency relays at approximately 100 substations over the 2019-21 period.

21.4.4 DESIGN AND CONSTRUCT

Protection system design must balance many competing requirements to ensure the overall system is effective. These requirements include:

- **High reliability** − the protection equipment must operate correctly when required, despite not operating for most of its life.
- **Stability** − the protection equipment must remain stable when events that look like faults occur (eg power swings and current reversals) and continue to operate the way it should during the length of its life.
- **Dependability** − relays should always operate correctly for all faults for which they are designed to operate.
- **Security** − relays should not operate incorrectly for any fault (eg an out-of-zone fault).
- **Sensitivity, speed and selectivity** − individual protection equipment must operate with the appropriate speed and coverage as part of an overall protection scheme.
- **Safety and reliability of supply** − the protection scheme must provide safety to the public and field staff, as well as minimise damage to the network equipment. Correct operation is the key to providing reliable supply.
- **Simplicity** − the protection system should be simple so that it can be easily maintained. The simpler the protection scheme the greater the reliability.
- **Life cycle cost** − an important factor in choosing a particular protection scheme is the economic aspect. The goal is to provide protection and supporting features consistent with sound economic evaluation.

IEC 61850

We have recently started to adopt IEC 61850 (within substations) – an international standard (not a protocol) for communication in substations that is gaining widespread support in the industry. It enables integration of all protection, control, measurement and monitoring functions within a substation. It also allows for high-speed substation protection applications, interlocking and inter-tripping. It combines the convenience of using Ethernet, with robust performance and security.

21.4.5 OPERATE AND MAINTAIN

We regularly inspect and test our protection assets to ensure they remain ready to reliably operate in the event of a fault. Electromechanical relays require more detailed inspections due to their mechanical nature and possible degradation in performance. Numerical relays require less detailed and less frequent checks, so cost less to maintain. They are also able to provide alerts regarding their condition, prompting a maintenance callout if necessary.

Our preventive maintenance schedule for protection relays is outlined in the table below. The detailed regime is set out in our maintenance standards.

Table 21.5: Protection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of protection assets, checking for damage, wear and tear. Any alarms, flags and LEDs reset.	3 monthly
Detailed condition assessment and operational checks for **electromechanical and static relays**. Perform diagnostic tests relevant to relay function (eg overcurrent, distance).	3 yearly
Detailed condition assessment and operational checks for **numerical relays**. Perform diagnostic tests relevant to relay function (eg overcurrent, distance).	6 yearly

21.4.6 RENEW OR DISPOSE

Our strategy is to replace electromechanical and static relays on the basis of functional obsolescence. Older technology relays continue to work but do not provide the modern functionality of numerical relays that we require for the improved operation of the network. They also have high maintenance costs and few spares, and reliability may reduce with wear (for electromechanical relays). First generation numerical relays will soon no longer provide the required functionality, and we are concerned about their potential reliability degradation from heat related wear.

SUMMARY OF PROTECTION RENEWALS APPROACH	
Renewal trigger	Functionality based obsolescence
Forecasting approach	Age
Cost estimation	Project building blocks

Meeting our portfolio objectives

Operational Excellence: Protection relays are renewed in part to enable new functionality available in modern devices, allowing us to utilise the improved asset information they gather.

Renewals forecasting

Our renewal forecast is based on age as a proxy for obsolescence. Our older relays have limited functionality and are more likely to become unreliable (though the likelihood is low). Our forecast identifies relay renewal quantities and accounts for projects where associated primary assets are replaced (eg switchboard replacements) to ensure efficient delivery. This may mean some relay replacements are brought forward or deferred for a period.

The forecast also includes expenditure from 2019-21 for the replacement of load shedding relays, to ensure compliance with the new Extended Reserves requirements. The forecast is based on desktop assessments of our zone substation load shedding needs, the number of feeders, and a bottom up engineering estimate of the costs of a replacement system.

Forecast renewals are higher than historical levels, due to the need to retire our electromechanical and static relays and replace them with modern numerical devices, and significant expenditure during 2019-21 for the replacement of load shedding relays. Longer term, protection renewals (excluding load shedding replacement) are expected to remain at these levels as increasing numbers of first generation numerical relays require replacement. In addition to providing better functionality numerical relays have lower maintenance costs.

Coordination with Network Development projects

Protection relay replacement work is, as far as practical, coordinated with zone substation works – typically power transformer or switchboard replacements. Where this work is driven by network development requirements, the protection systems may also be replaced depending on the technology and condition of the existing relay assets.

21.5 DC SUPPLIES FLEET MANAGEMENT

21.5.1 FLEET OVERVIEW

Our DC supply systems are required to provide a reliable and efficient DC power supply to the vital elements within our network (eg circuit breaker controls, protection equipment, SCADA, emergency lighting, radio, metering, communications and security alarms). DC supplies are located within substations and communication sites on the network.

Our DC supply assets comprise a large range of systems and configurations. This is the result of amalgamations of legacy networks over several decades. Some schemes are not fully compliant with our DC supply system standards. These are generally reconfigured to achieve compliance when major items such as batteries or chargers are replaced.

The general DC supply system can be divided into two main components - the battery bank and the battery charger (along with its associated monitoring system and cabling).

Most of the chargers use technology that monitors several parameters, such as battery voltage and battery condition, and are fitted with remote monitoring facilities. All components have to provide effective and reliable service, as redundancy is not generally built into DC supply systems. The systems vary in power rating and complexity based on load and security requirements.

DC supply systems are used in five key areas:

- SCADA and communications (12V, 24V and 48V DC)

- Circuit breakers mounted in distribution substation kiosks without SCADA (24V, 36V, 48V)
- Supply for switchgear (24V, 36V, 48V and 110V)
- Supply for protection equipment (24V, 48V and 110V)
- Backup supply for grid connected repeater stations and cyclic storage for solar powered repeater stations

In recent years, we have made a significant investment in replacing many DC supply systems that were found to either have inadequate capacity, were in poor condition, lacked spares, or no longer provided the functionality we required (such as self-diagnosis and monitoring). As such, our existing DC supply systems are generally up-to-date technology and provide acceptable levels of service.

Figure 21.6: DC charger and battery bank

21.5.2 POPULATION AND AGE STATISTICS

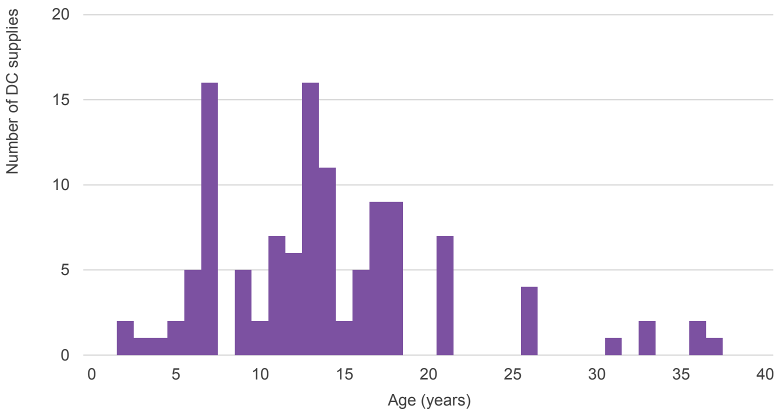
The table below summarises our population of DC supply systems by type. DC systems have been installed using many different supply voltages because of different load requirements and network amalgamation. We expect the diversity to reduce as we replace non-standard voltage systems with modern equivalents.

Table 21.6: DC supplies population by voltage at 31 March 2016

VOLTAGE	DC SYSTEMS	% OF TOTAL
110V	73	43
48V	25	15
36V	1	1
24V	17	10
12V	2	1
Communications[105]	50	30
Total	168	

The figure below shows the age profile of our population of DC supplies. Most of our DC supply assets are newer than their approximate 20-year expected lifespan. A small number have provided reliable service beyond 20 years of life but with an increasing risk of failure, these will be prioritised for replacement.

Figure 21.7: DC supplies age profile



[105] Communication DC supplies refer to 48V DC rectifiers with 12V and 24V DC converters.

21.5.3 CONDITION, PERFORMANCE AND RISKS

The various DC supply systems on our network have generally provided acceptable levels of service. However, as improved performance can be achieved from some newer equipment, we are now more prescriptive with DC supply system requirements and aim to standardise our systems as far as practicable. In doing so, we have removed all high-ripple content chargers from service and have moved to using gel batteries for their improved deep cycle properties.

The most common mode of failure of the charger systems is dry solder joints and capacitors swelling within the power circuitry. The consequence of failure is high, which can include lack of protection at substations and lack of control. The need to revert to manual operation can put workers at increased risk from switchgear failure and arc flash.

21.5.4 OPERATE AND MAINTAIN

We undertake regular inspections and testing of our DC supply systems to ensure they operate reliably and provide backup supply during outages. Our preventive inspection regime for DC supply systems is outlined in the table below. The detailed regime is set out in our maintenance standard.

Table 21.7: DC supplies preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of **zone substation** DC systems. Check batteries for distortion, correct electrolyte levels and secure connections. Charger alarms operational, giving correct statuses.	3 monthly
Visual inspection of **radio repeater and communication hub** DC systems. Check batteries for distortion, correct electrolyte levels and secure connections. Charger alarms operational, giving correct statuses.	6 monthly
DC system detailed condition assessment and diagnostic tests. Charger and battery type, capacity and performance correct for site load. Test battery discharge, charging current and voltage. Check charger float voltage and float and boost currents.	12 monthly
Distribution actuator DC system detailed condition assessment and diagnostic tests. Charger and battery type, capacity and performance correct for site load. Test battery discharge, charging current and voltage. Check charger float voltage and float and boost currents.	2 ½ yearly

Experience shows that the average life of lead acid batteries is approximately seven years, while for gel/absorbent glass mat batteries it is approximately 10 years.

21.5.5 RENEW OR DISPOSE

DC supplies are critical assets as failure means we potentially lose visibility and control of our field sites. We therefore aim to proactively replace DC supplies once they no longer provide the functionality expected or the capacity required, ensuring continued reliability and performance.

Chargers are assumed to have a 20-year expected life. Renewal before this time sometimes occurs because of additional demand on the system, such as protection upgrades, where the additional DC load triggers the need to upgrade.

Meeting our portfolio objectives

Asset Stewardship: DC supply systems are replaced to ensure specified carry-over times can be met in the event of an outage.

A small number of condition-based renewals are undertaken reactively as solder joints and components fail over time.

SUMMARY OF DC SUPPLIES RENEWALS APPROACH	
Renewal trigger	Capacity / functionality based obsolescence and condition
Forecasting approach	Age
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewals forecast is based on age as a proxy for the replacement drivers discussed above. Older DC systems are more likely to require improvements in carry-over time[106] and do not have modern features such as intelligent chargers with battery condition monitoring. Condition-based replacement is also related to age because heat related ageing to the charger circuitry will worsen over time.

Replacement levels are forecast to be steady over the long-term. Replacements will be coordinated where possible with other zone substation work, such as switchgear or protection.

106 ‘Carry over time’ means the time the DC system can supply the connected load in the event of an outage.

21.6 METERING FLEET MANAGEMENT

21.6.1 FLEET OVERVIEW

The metering fleet is comprised of three sub-types – grid exit point (GXP) and HV metering units, and ripple receiver relays.

GXP metering provides 'check metering' of power supplied from Transpower at grid exit points. We have replaced most of the older and unsupported meters that were used for monitoring network load at our GXPs. Due to their technology, the few remaining older meters are limited to only providing kWh data in the form of impulse to the SCADA and load management systems. Modern GXP meters are able to communicate via the DNP3 protocol and provide remote access functionality and rich data (eg peak and average kVA, and power factor).

HV metering units are used to transform and isolate high voltages and currents (through the use of voltage and current transformers) into practical and readable quantities for use with revenue metering equipment. They are used to provide revenue metering information where customers are directly connected to the HV distribution network. The units have no moving parts and are normally not subjected to overload, required to interrupt fault current or subjected to thermal stress.

HV metering units may be pole mounted, stand alone, embedded in RMUs or other ground mounted switching kiosks, or form part of the equipment in a zone substation.

We own a small number of ripple receiver relays. They are used to control water and space heating as well as street lighting. Ripple receiver relays are not metering equipment as such, but are included in this fleet for convenience. They receive audio frequency signals from load control plants (also known as ripple injection plants) in order to switch on or off the load they control.[107]

21.6.2 POPULATION AND AGE STATISTICS

The table below summarises our population of GXP meters by type. Our GXP meter replacement programme has upgraded the majority of metering units to modern ION meters. A small number of legacy metering units remain which are being prioritised for replacement.

[107] We discuss our load control plant fleet in Chapter 18.

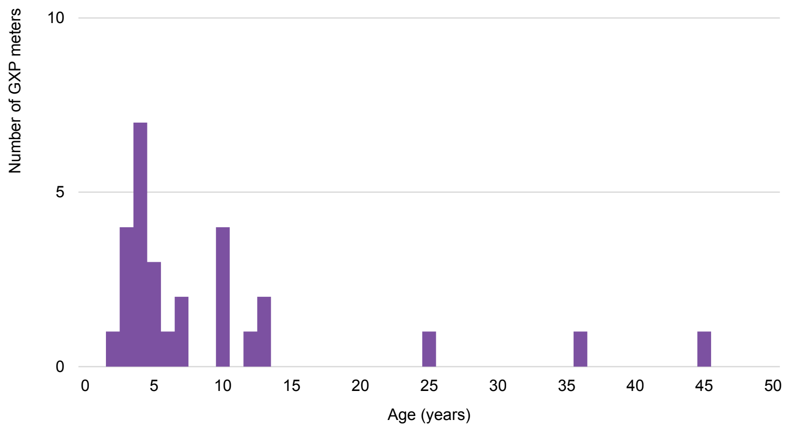
Table 21.8: GXP metering population by type at 31 March 2016

TYPE	SUB-TYPE	GXP METERS
ION meter		25
Legacy	Enermet	1
	L&G FF34	2
		28

In addition to the GXP meters, we have 99 HV metering units and approximately 1,100 ripple receiver relays.

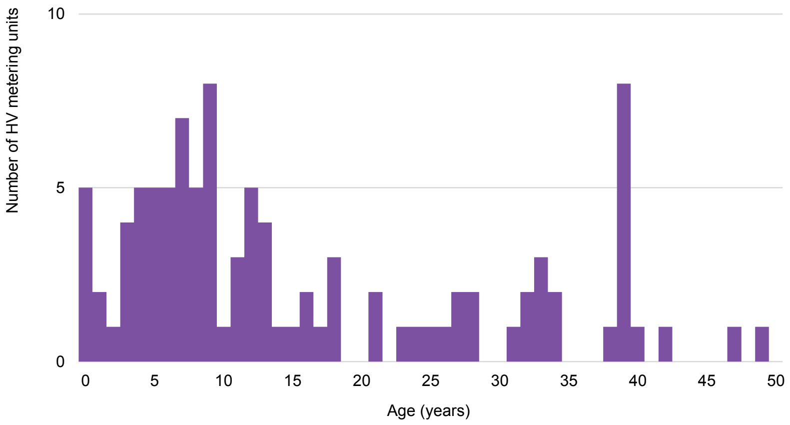
The figure below shows the age profile of our GXP meter population. The young age of the GXP metering fleet reflects recent modernisation of the assets. The three legacy units are now overdue for replacement and will be a priority for renewal in the planning period.

Figure 21.8: GXP metering age profile



The figure below shows the age profile of our HV metering unit population. The HV metering unit fleet is relatively young. Experience has shown that life spans of more than 20 years are common for most metering units, with replacement or upgrade normally being related to changes in the load profiles of connected customers. In the absence of other information, we assumed that units located within switchboards have a life of 40-45 years, similar to the associated switchgear. There are three meters more than 40 years old that will likely require replacement during the planning period.

Figure 21.9: HV metering unit age profile



21.6.3 CONDITION, PERFORMANCE AND RISKS

HV metering unit accuracy is important as they are used for calculating distribution charges. Any metering inaccuracy may result in overcharging customers or lost revenue. The metering units are required to meet the accuracy standards prescribed in Part 10 of the Electricity Industry Participation Code (2010). All of the instrument transformers used for this purpose that we own are compliant. These assets are therefore in good operable condition.

Smart ripple receiver relay investment

We are planning a programme called 'Tauranga Information Initiatives' over the period 2019-21. As part of this programme, we plan to renew the acquired fleet of legacy ripple relay receivers with new smart ripple relay receivers. This will ensure the ongoing viability of the ripple control functionality, which is essential to ongoing load control in the region.

For a modest additional cost (over like-for-like replacement), smart receivers provide secondary benefits. The mesh communications network in the region will permit an increase in the number of available data points from which electricity consumption information can be captured in real time. This greater capacity for more granular and timely data will improve asset management and network operations capabilities, which will in turn benefit customers through improved fault rectification and pre-emptive maintenance. It is also consistent with our longer term strategy to move to a distribution system integrator business model.

Meeting our portfolio objectives

Networks for the Future: We will invest in a 'smart' ripple receiver relay trial in the Tauranga region to understand the operational, asset management and customer benefits associated with more granular and timely data.

21.6.4 MAINTENANCE AND OPERATIONS

We regularly inspect our metering assets to ensure their ongoing reliability. The re-calibration tests carried out on HV metering units every 10 years are particularly important. They must be conducted to ensure compliance with the participation code. These tests are only carried out by certified service providers.

Our preventive metering inspection tasks are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 21.9: HV metering preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of metering units installed within switchboards. Check cabling for damage and ensure secondary terminal block enclosure is sealed.	1 yearly
Detailed inspection of ground and pole mounted metering units. Check external condition and signage. Check cabling for damage and ensure secondary terminal block enclosure is sealed.	5 yearly
Perform metering equipment re-calibration tests to comply with participation code.	10 yearly

GXP meters do not undergo preventive maintenance but provide alerts when they are faulty.

21.6.5 RENEWAL, REFURBISHMENT AND DISPOSAL

Obsolescence is the primary driver for renewal of metering assets. A small number of legacy GXP meters have limited functionality and accuracy, exceed their expected life and are only able to provide kWh data in the form of impulse to the SCADA and load management system. Unlike modern meters they not provide easy and reliable access to a range of information. They are not supported and few spares are available.

HV metering units are replaced because of capacity related obsolescence or they no longer comply with the participation code. HV metering units at customer sites are typically located within a switchboard. They must be adequate to meet the needs of the customer installation which may change over time.

SUMMARY OF METERING RENEWALS APPROACH	
Renewal trigger	Capacity and functionality based obsolescence
Forecasting approach	Asset identification and historical rates
Cost estimation	Volumetric average historical rate

Renewals forecasting

The forecast expenditure for this fleet primarily consists of the replacement of ripple relays in the Tauranga area with 'smart' ripple relays. The programme is forecast to run from 2019-21, with the overall costs developed from a bottom up per relay estimate including installation.

Our GXP metering renewals forecast is based on our scheduled replacement of the remaining legacy meters over the next two years. After this the entire fleet will consist of modern devices and we expect no further renewal over the planning period.

We believe our HV metering units are in good condition. Our renewals forecast is based on the historical rate of renewals and we do not expect an increase during the planning period.

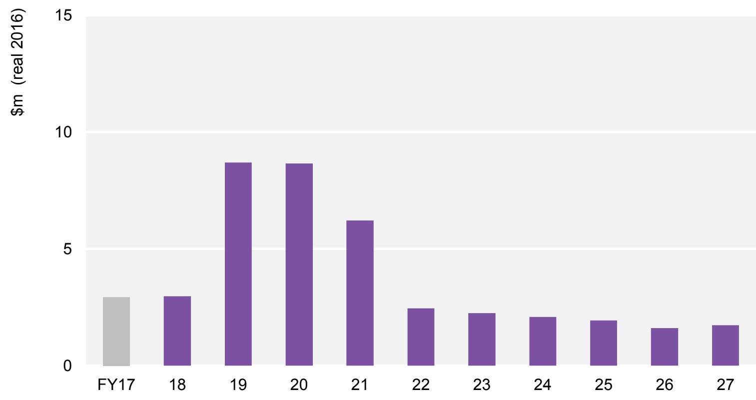
21.7 SECONDARY SYSTEMS RENEWALS FORECAST

Renewal Capex in our secondary systems portfolio includes planned investments in the SCADA and communications, protection, DC supplies, and metering fleets. Over the planning period we intend to invest $39m in secondary systems renewals. Key drivers are functionality, meeting regulatory requirements and investing in smart ripple receiver replacements.

Most renewals are derived from bottom up models, based on identified replacement needs, asset age and historical replacement rates. These forecasts are generally volumetric estimates (explained in Chapter 26). We typically use averaged unit rates based on analysis of equivalent historical costs, along with building block costs for protection replacements.

The figure below shows our forecast Capex on secondary systems during the planning period.

Figure 21.10: Secondary systems renewal forecast expenditure



The forecast renewal expenditure is higher than 2017 levels, primarily due to investments in smart ripple relays and complying with the new Extended Reserves requirements, but also due to the need to modernise our protection and RTU fleets. Longer term, we expect an underlying renewal level of $2-3m per year, though large one-off upgrades (such as to the SCADA system) may result in increased expenditure.

Further details on expenditure forecasts are included in Chapter 26.

22.1 CHAPTER OVERVIEW

This chapter sets out the basis for reshaping our Information Services approach as set out in our Information Services Strategic Plan (ISSP) and the projects that flow from this new approach. It also discusses our other non-network assets such as our office buildings and vehicles.

This chapter is structured as follows:

- 22.2 Our rational for reshaping our ISSP
- 22.3 Needs analysis
- 22.4 Current state and proposed future state ICT architecture
- 22.5 Planned ICT initiatives and investments during the period
- 22.6 ICT capex forecasts
- 22.7 Facilities portfolio approach and forecast

22.2 RESHAPING OUR ISSP

Our business is continually evolving, and our business plan and investment plans reflect this. The chapters of our AMP listed below set out some key areas where material change to our approach is required:

- Chapter 5 highlights changes to improve our asset management.
- Chapter 13 notes changes to support our future networks strategy.
- Chapter 26 summarises increased expenditure volumes over time.

Our ISSP has been reshaped to ensure that our approach to IS investments appropriately supports these proposed changes.

We recognise that the changes we are proposing will trigger a fundamental change in the way our staff, our contractors, and our stakeholders will access and use information. Our new ISSP has been shaped in recognition of these new requirements.

22.3 NEEDS ANALYSIS

22.3.1 OVERVIEW

In the following commentary we identify the particular ICT requirements for an enhanced ICT platform that will support our business objectives now and into the future.

22.3.2 SUPPORTING EFFICIENT DELIVERY

A key focus of our business strategies is Operational Excellence. As a business of considerable scale, it is critical that our processes and systems enable efficient delivery of works and outcomes for customers.

A core focus of our new ISSP is to ensure our ICT investments enable this outcome across our customers, our staff, our service providers, and our other key stakeholders. Below we discuss how different groups will use our services towards the end of the planning period, with expected improvements in ICT to enable Operational Excellence.

A customer:

Is served real time access to energy consumption, public safety and power cut information via computer, phone, tablet or other means.

Is able to query the network company, retailer or a third party energy service provider quickly and easily through whatever communication channel they prefer on issues of price, plans, faults or related products and services and receive consistent information.

Has access to energy calculators that use consumption patterns to provide recommendations for bundled energy solutions, highlighting the up-front and ongoing costs of each alternative to aid decision-making about their energy options.

A network contractor:

Is able to access work instructions, hazard information standards, forms and related information in the field.

Has access to a fully mobile information system with geographical, historical asset and/or customer installation information for each work site.

Upon completing work, enters and validates data at the point work is done quickly and easily, minimising their administrative workload.

Is able to complete as-built documentation in the field and report any divergence from the initial design as works are being undertaken.

Has an unbroken communication link from anywhere on the network back to our control room or resource management centre to ensure two-way real time information flow.

A contract manager:

Has instant access to work in progress reports, job status, costs incurred, any cost overruns or work programme exceptions, safety-related metrics and tender information.

Has a live feed of resource availability and contractor competency information. The information the contractor has provided is in customisable dashboards.

A network operator:

Has access to a distribution management system that optimises network performance during power outages (both planned and unplanned), manages safety, protects network assets and minimises the number and duration of power cuts.

Has access to live network load flows and storm management systems to predict the impacts of forecasted severe weather events on the network and recommends configuration changes before the event.

Has access to automated restoration sequences on the network to minimise impacts on customers during unplanned outages.

Has access to an increased flow of field data from the network and customers on which to base operational decisions.

Has visibility of the location of all field staff to monitor safety and job progress in real time.

An asset manager:

Is able to access multiple data sources, both internal and external, for scenario modelling, benchmark against other industry participants, undertake predictive analysis and develop prescriptive works plans.

Will link capital expenditure and operating expenditure forecasts to company financial models to understand financial implications of decisions and model risk scenarios. Will optimise investments, ensuring the increased quantum of work and associated expenditure is managed.

Is able to visualise real time and historic data including existing and previous defects, asset condition and recent maintenance history.

A commercial manager:

Has access to a live view of customer and regional energy consumption, and areas with low asset utilisation.

Will link customers to the information they want through a customer relationship management system.

Is able to highlight high-use customers who could benefit from a bespoke energy solution and is able to link this information to asset management tools to optimise network investment and decision-making.

Is able to offer new and existing customers a range of options to meet their energy needs based on their budget and requirements.

An information manager:

Provides our business with good quality information and tools that support condition-based, criticality-based and predictive analytics.

Is able to manage a wide variety and volume of real-time data and provide tools that help business users and customers create value from that information.

Operates a flexible digital environment that enables sharing and sourcing information from our service providers and partners, and empowers customers to satisfy a wide range of constantly changing energy needs.

A council or other key stakeholder:

Has access to detailed network investment information focused on their areas of interest.

Has the ability to submit feedback or suggestions on asset strategy via multiple channels.

Has access to real time information on energy availability to critical public infrastructure such as street lighting, sewerage pumps and city water supply infrastructure to aid operational decision-making.

Has access to asset location data to aid planning, construction and maintenance eg for UFB rollout.

22.3.3 SUPPORTING OUR FUTURE NETWORK STRATEGY

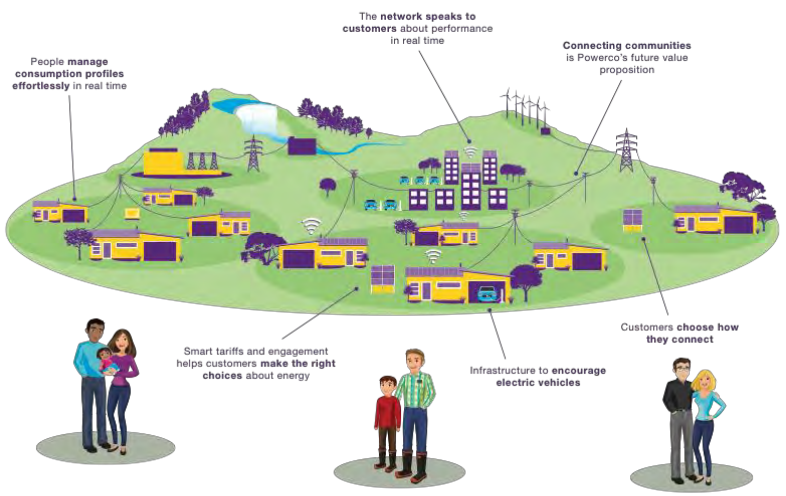
As well as ensuring efficient access to, and application of information, it is important that our ICT investments are a critical enabler of our future network strategy as discussed in Chapter 13.

We are already seeing increased levels of information available from the technologies deployed on our networks such as automated switches and control relays, and the equipment we deploy comes preloaded with communication, measurement, and information storage capability.

Over the planning period we anticipate increasing integration of traditional energy distribution services with emerging digital services. We will require a more flexible information infrastructure with a focus on scalable communications, more layered cyber security and the ability to capture, store and distribute reliable data in real time in an accessible format. This future energy system from the perspective of our customers is shown in **Figure 22.1**.

Whist these more future facing ICT capabilities are not the primary driver for our ISSP, it is important that the investments we make support a progressive shift over time.

Figure 22.1: Potential future energy 'eco-system' in 10 years



22.4 CURRENT SYSTEMS

22.4.1 OVERVIEW

Our revised ISSP seeks to build on our current systems, with rationalisation of some systems to reduce the number of interfaces.

The ICT systems(current and future) need to provide the following broad capabilities:

- Asset management – tools to support our work, field and asset maintenance and management
- Corporate support – tools to support our corporate functions: Finance, HR, Payroll, Health and Safety
- Network operations – tools to support real-time network operations and the network controllers
- Customer-facing – tools to support our direct interaction with customers, ranging from applications for new connections to contact management
- ICT platform – the hardware, operating systems, corporate communications network and enabling IS environment that support the five business services above
- Cyber Security – specialist tools to manage and protect our IS environment from the risk of attack or penetration by unauthorised parties

22.4.2 CORE IT SYSTEMS

Our core systems that currently support our business are set out below. The majority of these systems will remain relevant and core to our delivery under our revised ISSP:

- JDE – asset and financial information system
- GIS – geographical information system
- CWMS – customer works management system
- Billing – billing system
- OMS – outage management system
- Safety manager – safety management system

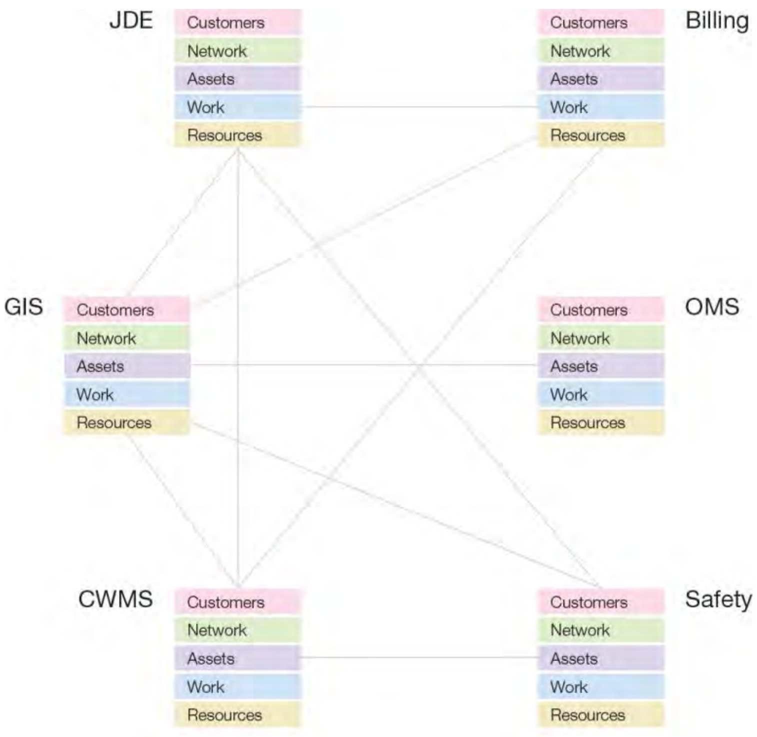
GIS is our main asset register, but each system holds certain information on electricity network and non-network assets.

These and other ancillary systems that we use are described in detail in Appendix 12.

The lines in the diagram below show the levels of integration between systems. Currently these links are created with bespoke software or involve manual updates.

We have a range of mechanisms to communicate asset knowledge held by service providers back to our engineers, analysts and IS systems. For example, service providers have hand-held devices that can store information and photos of assets, which is fed into systems such as GIS.

Figure 22.2: Our current core systems and their integration



Note: Lines represent current integration (bespoke or manual).

22.4.3 PERFORMANCE

Our legacy IS strategy and set of systems does not adequately enforce standardisation or economies of scope and scale in our business. Nor will it deliver the nature of service required to support our business goals.

The current architecture is complicated and reflects the compromises required to integrate a range of legacy solutions with new applications to meet changing business needs. Due to the complexity of integration, information does not move seamlessly between systems, and in many cases manual processes have had to be developed to compensate.

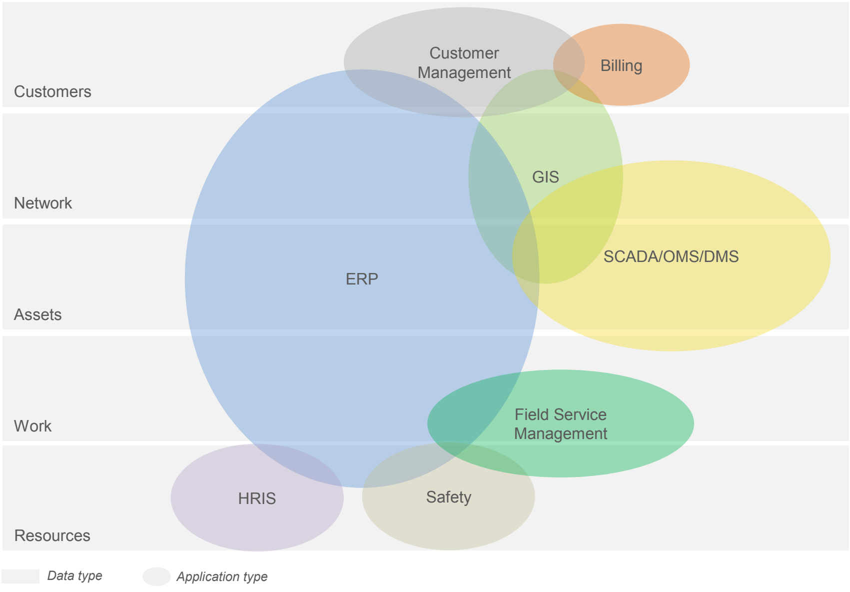
22.4.4 DESIRED STATE ICT ARCHITECTURE

Consolidating all of the needs identified in Section 0**,** we have developed a desired future state systems architecture (illustrated in **Figure 22.3**).

This architecture represents a material simplification of our current ICT environment, a move that we consider essential to deliver the level and nature of services critical to support our business requirements.

The most significant change to our existing systems will be the retirement of our existing JDE based set of financial systems, and replacement with a more fully featured Enterprise Resource Planning (ERP) system.

Figure 22.3: Desired future state architecture



The ERP system when fully implemented will deliver the required outcomes for users and the business. It will result in a simpler, more efficient information systems foundation.

We term the shift to this new ERP enabled architecture “New Foundations.” It is a multi-year programme to re-platform our legacy asset management and corporate services. While it will require an initial uplift in Capex to support the transition this will stabilise as operational efficiencies are realised.

22.5 PLANNED ICT INITIATIVES AND INVESTMENTS DURING THE PERIOD

22.5.1 ASSET MANAGEMENT

The focus for these tools in the CPP period is to retire point applications where possible and migrate them into a new ERP.

Expenditure for the asset management service in the period is almost entirely the lifecycle management of existing tools that will not be replaced by the ERP.

22.5.2 CORPORATE SUPPORT

Like asset management, many of the point applications that currently support this IS service will be migrated into a standardised ERP environment from FY18 to FY20 as we retire the core financial functions in JDE and constellation of bespoke supporting systems for regulatory and accounting management and reporting that we have evolved to complement it.

We are an asset intensive business and the synchronisation of data and processes around our assets is fundamental to our ability to manage the upcoming step-change in work efficiently. Given the link between financial and physical asset data, the replacement of finance functions in our legacy JDE system with a new ERP, tightly integrated with the existing GIS, is a priority for the CPP period.

In FY20 we plan to deliver more tools to allow customers to initiate work with us electronically across multiple channels. Also in FY20, our legacy billing system will require a lifecycle upgrade. The replacement tools are expected to allow us to bill for use of system at an ICP level using cost-reflective prices. As part of this project we will retire satellite point solutions for customer billing, moving their functionality into a standard application framework (possibly the ERP if it offers suitable capability).

22.5.3 NETWORK OPERATIONS

We are investing in the first phase of automating our network operations in the years immediately prior to the CPP period.

The second phase of our network operations modernisation is planned for FY22 and FY23 when we will implement an advanced distribution management system to provide the core smart grid platform that will allow us to maintain network quality and reliability as our customers take increasing advantage of distributed energy resources such as solar PV generation and local battery storage.

22.5.4 CUSTOMER FACING

In FY20 and FY21 phase 2 of New Foundations will establish a platform for customer relationship management that we can use to synchronise all the interactions that we have with our customers, regardless of which part of Powerco they are dealing with.

We have planned for an advanced customer interaction project in FY23, to manage and automate customer service requirements individually as their service requirements become increasingly varied. This is not possible with our current tools which segment customer interaction in terms of the engineering characteristics of our network rather than customer preferences.

22.5.5 NEW FOUNDATIONS

This IS service comprises the largest proportion of planned ICT expenditure. We are planning to migrate to an ERP system from FY18 to FY20. This will enable us to retire the work management functions in JDE and constellation of bespoke supporting systems for work and asset management planning that we have evolved to complement it. A particular benefit of this migration will be to synchronise asset data across all information systems and tools so that we only need to maintain this data in one place.

The pre-built integration between work and asset management available in a modern ERP (and related other business activities) will simplify the task of aligning work management to changing customer and asset needs. It will also improve our ability to provide accurate and timely information about the condition and state of all our assets. Ultimately this will allow us to implement advanced analytic approaches to asset management planning and optimise the effectiveness of our asset-related expenditure against the value of the services that it delivers and the risks and costs of doing so.

Table 22.1 lists the activities that we will be undertaking over the three phases of our ICT systems upgrade process.

Table 22.1: Proposed ERP Phasing

PHASE 1	PHASE 2	PHASE 3
Plant Maintenance	CRM	Advanced Asset Management
Business-to-business integration with suppliers	Advanced Analytics and Predictive Maintenance	Human Resources (excluding Payroll)
Geographic Information integration	Enterprise Health & Safety	Quality Management
Mobility (Part 1)	Mobility (Part 2)	
Project management	Real Estate (including Easements)	
Materials management	Business Planning and Consolidation Budgeting Enhancement	
Service management	Human Resources (Qualifications)	
Purchasing	Treasury	
Sales		
Finance		
Asset Accounting		
Accounts Payable		
Accounts Receivable		
Human Resources (Baseline)		

Phase 1 is planned for FY18 and FY19, phase 2 FY20 and phase 3 in FY21.

22.5.6 ICT PLATFORM

We have invested extensively in our IS platform services in the last few years as part of our risk management and service standardisation initiatives. This consolidation is almost complete with a final phase planned for FY18-19 when we aim to move our second datacentre to Tauranga to align our data recovery facilities with the location of our fail-over network operations centre in Tauranga.

We have also provided for the establishment of a new infrastructure platform in FY18 to provide a development, testing and ultimately operating environment for the new ERP. While we are able to host and support the new platforms in our existing operations, a new solution will require new operating systems which will be installed on new hardware as required.

22.5.7 CYBER SECURITY

Security services are modest by comparison with the other six IS services. FY18 sees the final year of the reinforcement of our cyber risk management capability begun in FY16. Later expenditure will focus on the lifecycle renewal of the cyber security tools that we have recently implemented.

22.6 ICT CAPEX AND OPEX

22.6.1 OVERVIEW

We distinguish between two ICT portfolios.

- **ICT Capex** – portfolio includes investments in ICT change initiatives and network related ICT. It covers the ICT programmes and projects that ensure our processes, technology and systems help deliver our asset management objectives.
- **ICT Opex** – portfolio covers ICT costs associated with operating our business. It covers software licensing, software support, data and hosting, and network running costs.[108]

Our expenditure forecasts are based on historical costs, expected unit cost, and price trends. We have worked with trusted suppliers to determine unit costs for current technologies or their likely replacements.

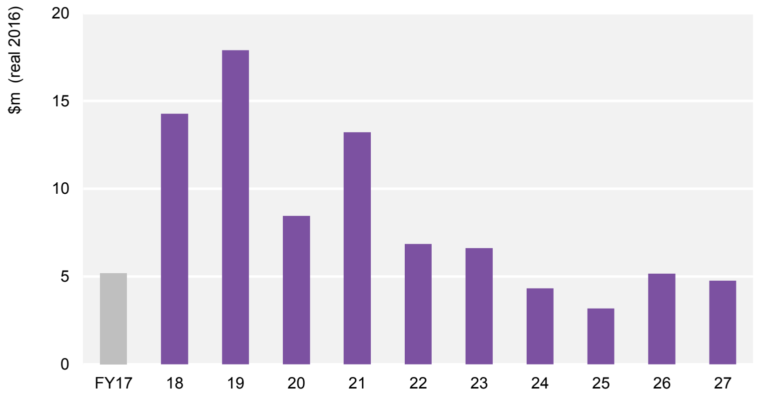
An uplift in ICT expenditure is be required over the early years of the planning period due to our ERP investment. Later in the period expenditure is expected to stabilise.

22.6.2 EXPENDITURE FORECASTS

The chart below shows how our forecast ICT capital expenditure for the planning period.

[108] ICT Opex is included as part of our business support expenditure forecasts (refer to Chapter 26).

Figure 22.4: ICT Capex forecast



The increase in capital expenditure in FY18 is due to the start of our planned rationalisation of business applications into an ERP and implementation of new work management functionality. Annual average capital expenditure returns to historical levels in FY24 when we complete the enhancement of our network management platform – planned for FY22 and FY23.

22.7 FACILITIES

22.7.1 OFFICES AND DEPOTS

Our facilities management programme aims to ensure our offices and depots:

- Are safe and secure for our employees and contractors
- Are functional and fit for purpose
- Can support future staff growth
- Support improved productivity and efficiency
- Are cost effective

We have five major regional offices in four cities that match our broad geographical coverage and ensure that we are close to our assets and the work being undertaken across our network.

Our main corporate office is located in the New Plymouth CBD (Liardet St) and we have a second location on the outskirts of New Plymouth (Junction St), where the majority of our New Plymouth staff are located. Our five major regional offices and our depot locations are shown in **Table 22.2**.

Table 22.2: Office and Depot facilities

LOCATION	OWNERSHIP
Junction St office and depot (New Plymouth), Mihaere Dr office and depot (Palmerston North), Coromandel, Masterton, Pahiatua, Taihape, Raetihi	Owned
Grey St office (Wellington), Liardet St office (New Plymouth), Tauranga office	Leased

We have re-evaluated our facilities strategy in light of the expected increase in employee and contractor numbers during the CPP period.

Current New Plymouth facilities (Junction St and Liardet St) are nearing capacity and are not meeting the objectives of our facilities expenditure. We are therefore planning an upgrade to our Junction St facility to accommodate the increase in employee and contractor numbers, in addition to relocating the Head Office and Corporate functions from the Liardet St facility.

22.7.2 NETWORK OPERATIONS CENTRE

In addition to the broader requirement for increased capacity and upgrade of the Junction St site, the Network Operating Centre (NOC) at Junction St requires substantial upgrade to meet future requirements. The current facility is at 100% capacity and is no longer fit-for-purpose. An alternative to the current facility is required to ensure that we can continue to effectively monitor our network, especially as we undergo a step change increase in asset maintenance, renewal and vegetation management.

22.7.3 VEHICLES

There are currently 40 vehicles in our fleet associated with the Electricity division, with another 10 associated with corporate functions.

All but 4 of the vehicles are leased with full maintenance included.

All but 3 of the leased vehicles are due to be replaced within the next 12 months. We will be replacing them predominantly with plug-in hybrid electric vehicles (PHEV).

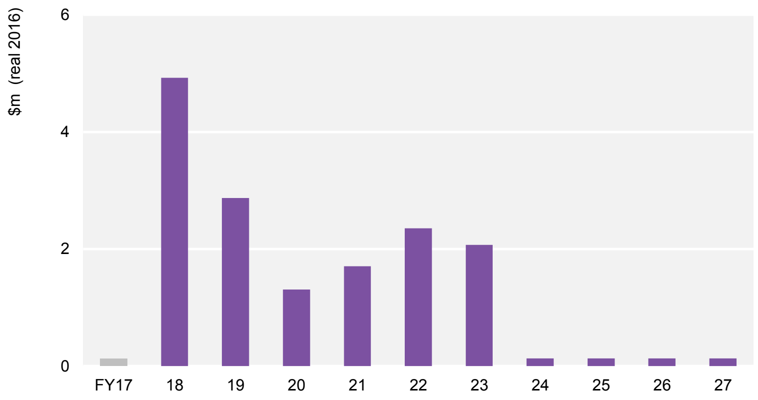
Lease costs for selected vehicle types have been sought from a range of leading fleet providers in New Zealand. The choice of provider was based on the best fit for us including pricing, servicing and location of support.

Our vehicle leasing costs are generally included within our business support Opex category.

22.7.4 FACILITIES CAPEX FORECAST

Figure 22.5 shows our facilities Capex forecast.

Figure 22.5: Facilities Capex forecast



The key drivers of facilities Capex for the period are the upgrade of our Junction St facility (planned for FY19-23) and our Network Operations Centre resiliency upgrade (planned for FY18-19). These upgrades will provide sufficient capacity to accommodate our staff, allow them to work in modern and productive environment, and ensure our operations are scalable for the future.

23.1 CHAPTER OVERVIEW

Network operational expenditure plays a central role in ensuring we deliver our Asset Management objectives and achieve our asset management targets. Appropriate and well-focused operational expenditure helps ensure our assets are maintained appropriately and ensures we have the information necessary to support effective expenditure in other areas.

We plan to increase our investment in operational activities over the planning period. This will help us arrest and control emerging issues on our networks such as higher than desired defect numbers and unacceptable rates of vegetation encroachment. It will also help ensure that activities key for effective asset management, such as inspections and condition assessment, are developed to support appropriate and well targeted renewal programmes.

Increased levels of capex investment in the key renewal, security, and reliability areas necessitates an enhanced approach to asset management and works delivery capability. By investing in these capabilities, we can be more efficient in the way we target and plan investment works, and deliver a net benefit overall. Our plans for the period include progressive enhancement of our asset management functions, which is reflected in our SONS (System Operations and Network Support) portfolio.

This chapter describes our three portfolios of maintenance activities, vegetation management and SONS. For each of these portfolios we set out our forecast Opex for the planning period.

23.2 MAINTENANCE PORTFOLIOS

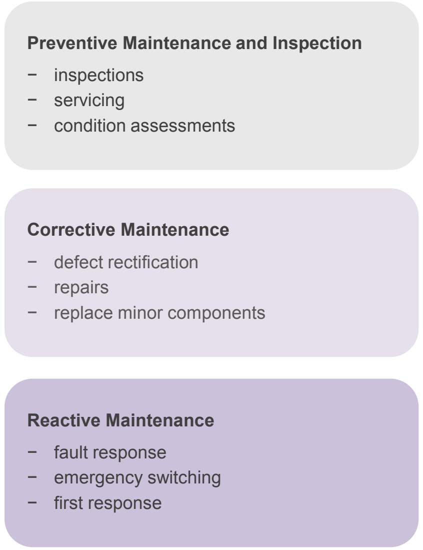
For planning and budgeting purposes, we group our maintenance work into three network Opex portfolios. These are:

- **Preventive Maintenance and Inspection[109].** This portfolio deals with routine maintenance activities like testing, inspecting and asset servicing
- **Corrective Maintenance.** This portfolio is mainly concerned with fixing defects (after they are identified and scheduled appropriately), through activities such as replacement of defected asset components or minor assets
- **Reactive Maintenance**. This portfolio is about responding to faults and other network incidents, including immediate work to make a situation safe, or to repair broken assets

The figure below summarises how we categorise our maintenance activities.

[109] Our Preventive Maintenance and Inspection portfolio was previously named Routine Corrective Maintenance and Inspections (RCI). The corrective maintenance component of this work is now part of our Corrective Maintenance portfolio. This has been done to better reflect the drivers for these activities and the way we plan and deliver these works. Our information disclosure schedules reflect the RCI definition consistent with our historical disclosures.

Figure 23.1: Our maintenance portfolios



23.3 PREVENTIVE MAINTENANCE AND INSPECTION

23.3.1 OVERVIEW

Preventive Maintenance and Inspection works are undertaken on a scheduled basis to ensure the continued safety and integrity of our assets, and to compile condition information for analysis and renewal planning. It is our most regular asset intervention process and is a key source of feedback in our Asset Management System.

The main types of activities are set out below.

- **Inspections** – checks, patrols and testing to confirm the safety and integrity of assets, assess fitness for service and identify follow up work
- **Servicing** – regular maintenance tasks performed on an asset to ensure its condition is maintained at an acceptable level
- **Condition Assessments** – activities performed to monitor asset condition and to provide systematic records for analysis

Our maintenance standards are the cornerstone of our maintenance regime. Our standards incorporate knowledge of specific maintenance, operational and service requirements. Maintenance practices and scheduled intervals as recommended by equipment manufacturers are reflected in our standards. Our standards also take into account the regulatory requirements for safety and integrity inspections and reflect optimal operational experience developed over the last decade.

Preventive maintenance and inspections work frequencies for each of our asset types are specified in our maintenance standards. These activities are then scheduled in our Gas and Electricity Maintenance Management (GEM) system. GEM uses our asset register to create schedules of work. It also stores the data collected from the field as a record of our maintenance activity for the scheduled asset.

The Preventive Maintenance and Inspection portfolio also includes other activities such as 'stand-overs' and cable location when third parties are working close to our network. These activities are critical for safe network operation.

23.3.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified a number of high level objectives for our Preventive Maintenance and Inspection activities.

Table 23.1: Preventive Maintenance and Inspection portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Ensure our inspection regimes effectively identify safety hazards. Protect the integrity of our network assets by monitoring and managing the activities of other parties.
Customers and Community	Minimise planned interruptions to customers by coordinating servicing with other works. Minimise landowner disruption when undertaking maintenance.
Networks for Today and Tomorrow	Consider the use of alternative technology to improve effectiveness or reduce cost of inspections and servicing.
Asset Stewardship	Maximise asset life by ensuring that required maintenance is undertaken. Ensure that deteriorating components are identified for repair or replacement in a timely manner. Ensure that high quality, complete asset data is available.
Operational Excellence	Improve the quality and completeness of asset data through improved inspections and innovative techniques.

23.3.3 PREVENTIVE MAINTENANCE AND INSPECTION INITIATIVES

As set out in Chapter 10, we are looking to improve our asset management approach. As part of these efforts we have identified several opportunities to improve our overall scheduled maintenance performance. More significant additions and changes to Preventive Maintenance and Inspection activities are set out below.

Table 23.2: Preventive Maintenance and Inspection Improvement Initiatives

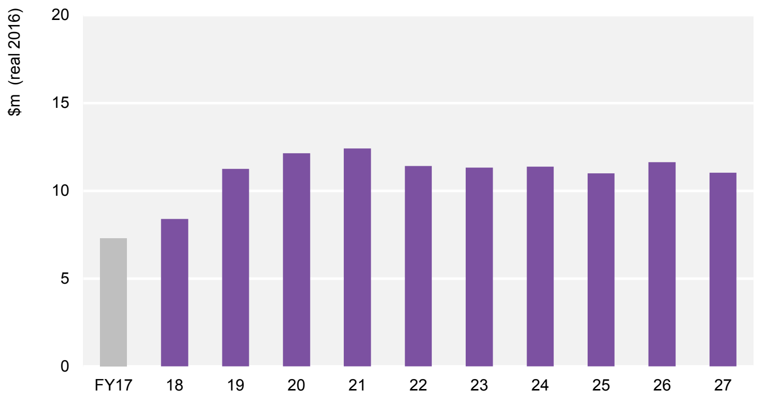
INITIATIVE	COMMENT
Pole top photography	We are planning to introduce enhanced pole top inspections. This involves a cyclical pole top photography programme for all overhead lines to enable identification of currently unknown defects which will improve our overall asset condition knowledge and allow us to proactively act on it. The images will be captured using high quality digital cameras attached to a helicopter or Unmanned Aerial Vehicle (UAV).
Improved asset data collection methods	Refining and expanding the standards, methodologies and processes for collecting field data on the condition of our assets will improve asset data quality. This will enable us to make better decisions on required maintenance and renewal, and sharpen focus on areas where the network or assets are not performing as expected.
Expanded sub-transmission line patrols	We are planning to extend our current scheduled rapid inspection programme to cover selected subtransmission lines and critical feeders. All defects that are assessed to have the potential to cause an outage will be recorded. Defects identified through the inspection process will be assessed by performance engineers and will be scheduled for rectification in order of relative priority.
Acoustic testing of overhead line components	Acoustic testing of overhead line components is one of the proposed new technologies to be introduced that will deliver additional, previously unavailable condition data. It will enable us to identify insulator defects and incipient faults that cannot be detected by our current visual ground based inspection process.
Wood pole acoustic resonance testing	Acoustic resonance testing will supplement the current visual assessment process and will provide accurate and non-subjective structural condition data for wood poles.
Expanded partial discharge (PD) testing	This initiative involves a cyclical partial discharge testing programme for all zone substation switchboards, transformers, outdoor circuit breakers and exposed cables within substations to ascertain the electromagnetic signature of these assets. Partial discharge testing will identify assets that need remedial work or replacement before any abnormal condition results in a fault.

INITIATIVE	COMMENT
HV fuse element replacement	The proposed involves proactive fuse element replacement for HV DDO fuse assemblies where these are fitted to our distribution lines running through forested areas. When a fuse blows, the molten fuse element can be expelled from the fuse assembly and can fall to the ground resulting in a fire hazard.
LV pillar box data capture	We have underway a programme of capturing LV pillar box information (fuse type and size), identifying the asset location, labelling the box and uploading the captured data to GIS. Having accurate pillar box information reduces time to find assets for repairs. The information also provides detail of asset types and customer types connected to our network. Minor repairs will also be undertaken where necessary (repairs classified as corrective maintenance)

23.3.4 PREVENTIVE MAINTENANCE AND INSPECTION OPEX FORECAST

Our Preventive Maintenance and Inspection forecast is shown in the figure below. Increased levels of investment in this area reflect the considerable value of this activity in achieving investment efficiency in other areas such as asset renewal.

Figure 23.2: Forecast Preventive Maintenance and Inspection expenditure



23.4 CORRECTIVE MAINTENANCE

23.4.1 OVERVIEW

The Corrective Maintenance portfolio includes corrective interventions, triggered by asset condition. Our Corrective Maintenance portfolio includes corrective maintenance that was previously included in the RCI portfolio of work.

The main types of corrective activities are set out below.

- **Reactive repairs** – unforeseen works to repair damage and prevent failure or rapid degradation of equipment
- **Asset replacements** – the replacement of minor, low cost assets or asset components
- **Defect management** – correcting condition-based defects that are identified from Preventive Maintenance and Inspection and Reactive Maintenance activities

The main purpose of Corrective Maintenance work is to restore an asset that is damaged, or does not perform its intended function. We undertake corrective maintenance to restore asset condition, make it safe and secure, prevent imminent failure, or address defects. Work may be identified during fault response, or preventive maintenance inspections.

Corrective Maintenance work is prioritised through our defect assessment process into red (high priority), amber (medium priority) or green (low priority) defects. Work is scheduled for completion based on assessed priority.

Red defects are high priority and are dealt with immediately. Amber defects are unlikely to cause an immediate fault and our preferred approach is to fix the problem within 12 months. Green defects are managed through planned work programmes because they can be scheduled over a longer period of time.

As we have improved our inspection regime, and as a direct result of more assets being operated at near end of live we have seen a steady increase in the number of amber defects. As a result, our defect pool is larger than we would like and this increase indicates a higher risk of asset failure and associated faults.

Over the planning period, our aim is to reduce the amber defect pool to a level of no more than six months' work to help ensure resolution within target times.

What are asset defects?

Defect is an industry term that means an asset has an elevated risk of failure or reduced reliability. Defect categories are assigned during inspections and condition assessments.

We use three categories that reflect operational risk.

- Red defects require immediate rectification (repair or replacement)
- Amber defects are targeted for rectification within 12 months
- Green defects are targeted for rectification within 36 months

Whilst resolution of defects within the targeted times reflects good industry practice, our internal processes allow discretion for asset to remain in service provided appropriate risk assessment has been completed.

23.4.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high level objectives for our Corrective Maintenance activities.

Table 23.3: Corrective Maintenance portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Ensure asset replacements are undertaken in a timely manner. Reduce safety hazards by prioritising safety driven corrective work, particularly red defects.
Customers and Community	Minimise planned interruptions to customers by coordinating maintenance with other works. Minimise landowner disruption when undertaking maintenance.
Networks for Today and Tomorrow	Maximise asset life by ensuring that required maintenance is undertaken. Consider the use of alternative technology to reduce cost of corrective works.
Asset Stewardship	Ensure that deteriorating components are repaired in a timely manner. Reduce the number of amber defects to an inventory of no more than six months.
Operational Excellence	Undertake works in a coordinated manner to ensure economies of scale and scope. Review and modify our defect assessment process to improve data accuracy and fault risk exposure.

23.4.3 CORRECTIVE MAINTENANCE INITIATIVES

Our defect assessment and prioritisation process depends on staff identifying specific condition details of a range of assets. Assessments and prioritisation are somewhat subjective and there is room to improve consistency. We have identified a number of improvement opportunities, with the more significant items listed below.

Table 23.4: Corrective Maintenance Improvement Initiatives

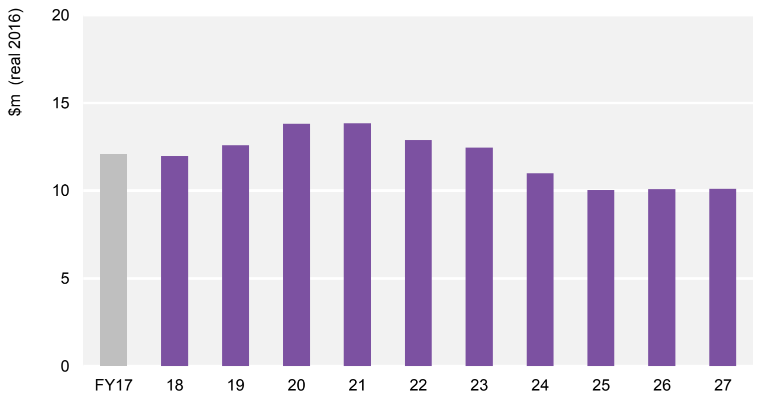
INITIATIVE	COMMENT
Defect control	Our investment plans include a targeted approach to reduce amber defect pools to a level that reflects six months of typical delivery volume. Introduction of more scientific, systematic field inspection methods will also identify more defects and risks, which we have projected will require a step-change in Opex to address (discussed in Preventive Maintenance and Inspection improvement initiatives).
Storm Hardening	This programme involves the storm hardening of critical sub-transmission and distribution lines in storm prone areas. Structural components of these lines will be renewed or maintained to prevent storm induced damage from wind or from wind borne foreign objects.
Distribution Transformer Repairs	Corrosion occurs on ground mounted transformer tanks, cubicles and associated kiosks due to location and environmental conditions. With this programme we plan to remediate corroding transformers through proactive permanent repair, before any oil leakage can occur.

23.4.4 CORRECTIVE MAINTENANCE OPEX FORECAST

Our Corrective Maintenance Opex forecast for the planning period is shown in the chart below. As discussed above, this varies from disclosed Corrective Maintenance expenditure because of the corrective maintenance component that was previously contained within RCI.

Our planned investments include necessary short term focus to reduce defect pools and implement improved processes for the management of defects. In the longer term we expect expenditure in this category to reduce as defect numbers reduce and we utilise more efficient ways of managing defects.

Figure 23.3: Forecast Corrective Maintenance expenditure



23.5 REACTIVE MAINTENANCE

23.5.1 OVERVIEW

The Reactive Maintenance portfolio involves reactive interventions in response to unplanned network events.[110]

The main types of activities are as follows:

- **First response**: involves the attendance of a service provider fault person to assess the cause of an interruption, potential loss of supply, or safety risk. They assess the cause of the fault and may undertake switching or cut away a section of line in order to make safe or to alleviate the imminent risk of a network outage. The provision of standby fault personnel for first response work is included in this activity.
- **Fault restoration**: is undertaken by the service provider fault person and includes switching, fuse replacement or minor component repair in order to restore supply.

Reactive Maintenance work is prioritised and dispatched by the NOC with the physical work carried out by our service provider. There is limited forward planning for Reactive Maintenance work other than ensuring there are sufficient resources on standby to respond to network faults.

Our service provider operates a service management centre, used to receive instructions and directions from the NOC to quickly and effectively dispatch fault response staff and additional resources as needed to fix a fault. Staff levels are set to ensure target fault response times can be achieved.

Reactive Maintenance work volume is driven by a variety of factors including asset condition, weather, environmental conditions, the levels of work being undertaken in other portfolios (such as Corrective Maintenance), and our protection philosophies.

23.5.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high level objectives for our Reactive Maintenance activities.

Table 23.5: Reactive Maintenance portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reduce fault response time to reduce the potential for public safety incidents. Reduce safety hazards by prioritising safety driven faults.
Customers and Community	Minimise landowner disruption when responding to network faults. Reduce fault restoration times to ensure we return supply to customers quickly.
Networks for Today and Tomorrow	Consider the use of alternative technology to reduce cost of reactive works and improve fault response times.
Asset Stewardship	Minimise outage events and durations to support our overall reliability objectives. Ensure that faults are repaired in a timely manner.
Operational Excellence	Improve dispatch processes and field work communications to reduce fault response times.

23.5.3 REACTIVE MAINTENANCE INITIATIVES

Our Reactive Maintenance work is dependent on technology to enable a timely response from information available to the NOC and our service provider staff through communications systems, SCADA and OMS. Effective management is critical to ensuring safe outcomes on our networks and so we have identified a number of improvement projects that will enable us to better meet our Reactive Maintenance objectives, with the more significant items listed below.

[110] The Reactive Maintenance portfolio does not include second response, which is covered under the Corrective Maintenance portfolio.

Table 23.6: Reactive Maintenance Improvement Initiatives

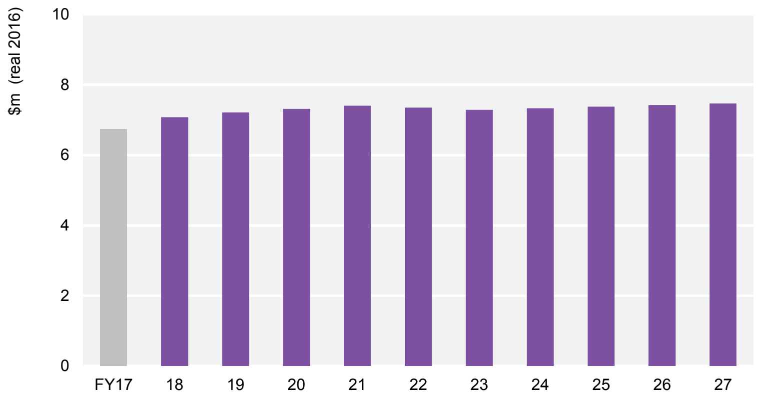
INITIATIVE	COMMENT
Increase in field resources	To allow us to effectively respond to outages within reasonable timeframes, we need to increase the available field service resources. This is necessary to ensure that existing reliability levels can be maintained.

23.5.4 REACTIVE MAINTENANCE OPEX FORECAST

Our Reactive Maintenance expenditure forecast for the planning period is shown in the chart below. Our forecasts reflect additional investment in personal to ensure required service standards and response times can be achieved.

Whist it would be reasonable to assume fault rates will increase in the short term until renewal programmes arrest current adverse trends, we have assumed these factors will be offset by improvements in vegetation management and other reliability focused programmes.

Figure 23.4: Forecast Reactive Maintenance expenditure

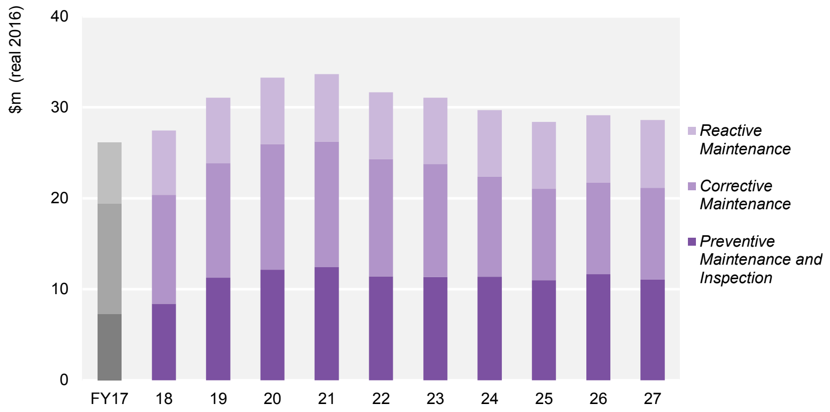


23.6 OVERALL MAINTENANCE EXPENDITURE

Changes in our overall maintenance forecast over the planning period are influenced most heavily by the Preventive Maintenance and Inspections expenditure, with this due primarily to our focus on improving condition assessment information to support improved expenditure and efficiency outcomes in other areas.

A moderate increase in Corrective Maintenance expenditure also has an impact on overall forecast expenditure, bringing amber defects into our target range.

Figure 23.5: Overall maintenance expenditure



23.7 VEGETATION MANAGEMENT

23.7.1 OVERVIEW

The main activities undertaken in the vegetation management portfolio are:

- **Tree trimming** – the physical works involved in trimming or removal
- **Inspections** – periodic inspections of tree sites to determine whether trimming is required
- **Liaison** – interactions with landowners to identify those trees that require trimming or removal
- **Traffic management** – is often necessary to manage traffic on public roads to accommodate tree trimming

These activities are undertaken by our vegetation management service providers. Liaison personnel discuss the scope of work with the tree owner and issue formal notification of the required work.

Compliance

Network operators are required to meet several compliance obligations in respect to vegetation management. Key among these are the Tree Regulations[111], which prescribe the minimum distance that trees must be kept from overhead lines, and sets out responsibilities for tree trimming. The New Zealand Electrical Code of Practice for Electrical Safe Distances (NZECP 34) sets minimum safe electrical distance requirements for overhead lines, including the minimum safe approach distances for the public, and requirements for workers who need to work within this distance.

Following an initial cut or trim, tree owners have an obligation to maintain their trees clear of our network. Our contractor liaison staff identify trees in this category and issue appropriate notification to tree owners. We have an ongoing responsibility to ensure that tree owners take action. Where tree owners fail to act, we are obliged to trim trees to remove any danger.

> **Tree regulations**
>
> The Electricity (Hazards from Trees) Regulations 2003 require us to identify trees or vegetation that is within the growth limit zone of any network conductor and to issue a notice to the tree owner advising of trimming/clearance requirements.
>
> These regulations specify both the tree owners' and our responsibilities with regard to actions and cost.

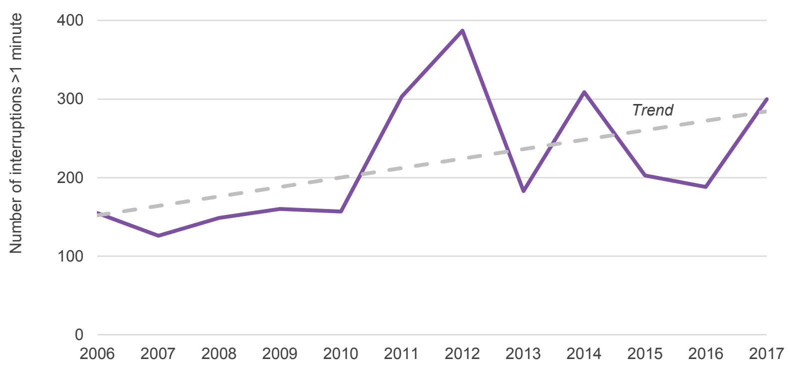
Under the Tree Regulations, if we become aware of a (potential) breach of minimum clearance distances, we have to correct it in a prescribed time. Currently we largely respond to issues as we become aware of them, through line inspections, when notified by affected parties or following faults. This practice is still common in New Zealand, but good practice involves a more proactive approach – to have ongoing, regular visibility of the status of vegetation around lines and taking action to prevent issues from arising. Moving to this cyclical approach is part of the strategy we are adopting.

Newly planted or self-seeded trees are also subject to an initial trim or removal at our cost. Wherever possible we remove self-seeded trees and apply growth retardant to minimise the ongoing vegetation management cost.

Performance

Outages caused by vegetation are a significant contributor to our overall SAIDI and SAIFI. Our network performance is being adversely affected by an increasing number of interruptions (see figure below) caused by vegetation over recent years.

Figure 23.6: Number of vegetation related events causing >1 min outages



A management review of the reasons for this trend has concluded that (in retrospect) our historical approach to trimming has been overly reactive and at too low a volume. Public safety has also been of concern as tree owners attempt to undertake tree trimming and removal work themselves.

The appropriate planning and management of tree trimming is highly effective in reducing these outages.

[111] Electricity (Hazards from Trees) Regulations 2003 (SR 2003/375)

23.7.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high level objectives for Vegetation Management.

Table 23.7: Vegetation management portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reduce the potential risk of incidents affecting tree owners undertaking trimming work to improve public safety and comply with regulations. Reduce safety hazards by prioritising higher risk trees.
Customers and Community	Minimise landowner disruption when undertaking tree trimming. Improve relations with tree owners to better align incentives around the timing and scale of vegetation trimming.
Networks for Today and Tomorrow	Reduce the number of vegetation related faults on our network to deliver improved network performance.
Asset Stewardship	Reduce vegetation related interruptions to support our overall reliability objectives. Achieve good practice vegetation management through enhanced cyclical work programmes.
Operational Excellence	Improve the efficiency of our vegetation management delivery approaches. Achieve efficiencies by refining our tree owner liaison processes.

23.7.3 VEGETATION MANAGEMENT IMPROVEMENT INITIATIVES

Vegetation management has a significant impact on network reliability and public safety and our current approach to vegetation management cannot provide necessary assurance that required clearances can be maintained.

Our aim is to stabilise reliability, reduce damage from trees during storms, improve safety performance, ensure we comply with relevant regulation and lower the cost of work per tree site. To achieve this we need to reach a sustainable and prudent level of vegetation works on our network.

Key initiatives to achieve this are outlined in **Table 23.8**.

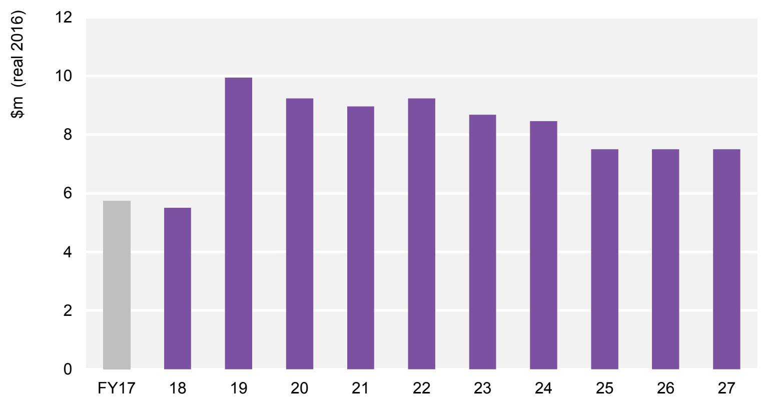
Table 23.8: Vegetation management initiatives

INITIATIVE	COMMENT
Cyclical trimming	Develop and implement a full cyclical trimming programme that ensures vegetation is managed across our entire network.
Risk-based approach	Develop a risk-based approach to vegetation assessment with a view to achieving greater than mandated clearances, based on assessed risk for targeted sites.
Improved education	Develop an enhanced public awareness programme to improve public safety. We plan to develop and deliver an improved communications programme to make tree owners aware of the safety issues and their responsibilities.
Improved public liaison	Move from an outsourced (where liaison is carried out by the vegetation contractor) to an independent liaison model to better align objectives with that of the business. Through focussed and incentivised negotiation we can achieve greater than mandated clearances, which we expect will lead to improved network reliability.

23.7.4 VEGETATION MANAGEMENT OPEX FORECAST

Our vegetation management Opex forecast for the planning period is shown in **Figure 23.7** below. Increased expenditure relates to the expected increase in effort to meet compliance obligations and arrest the increasing trend in vegetation-related faults that we are experiencing.

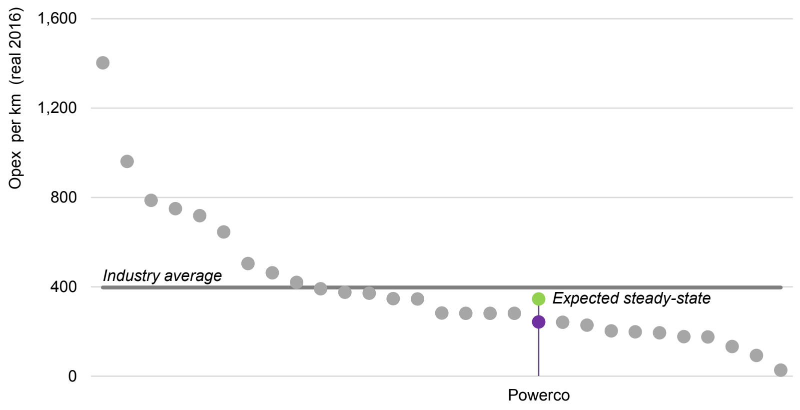
Figure 23.7: Vegetation management expenditure



We will require higher expenditure in the first six years of the trimming programmes to implement our new cyclical and risk based approach. Once these programmes have been embedded we anticipate a sustainable position will be achieved.

Figure 23.8 below compares our current (purple dot) and steady state (green dot) vegetation management expenditure per kilometre of overhead line with other EDBs. It shows that our forecast steady state expenditure per kilometre is more in line with, but below the industry average.

Figure 23.8: Vegetation opex per km of overhead line compared with other EDBs (FY14-16 average)



23.8 SYSTEM OPERATIONS AND NETWORK SUPPORT

23.8.1 OVERVIEW

Our investment plans include a material increase in expenditure and work volumes over the planning period.

To support these increased work volumes, we have made appropriate provision to lift our internal capability. The main increases will come from work related to:

- network engineers to plan and scope additional works
- project managers to manage construction in the field
- NOC resource to manage network access for construction
- associated project support functions

Our investment plans also included targeted capability enhancements to support efficient delivery over time. In particular the following:

- improved analytical capability to enable more targeted asset planning
- developing proofs of concepts for future network technology and applications
- enhancing our asset management maturity over time
- more focus on changing customer needs

Specific capability and capacity requirements are outlined in Chapter 10.

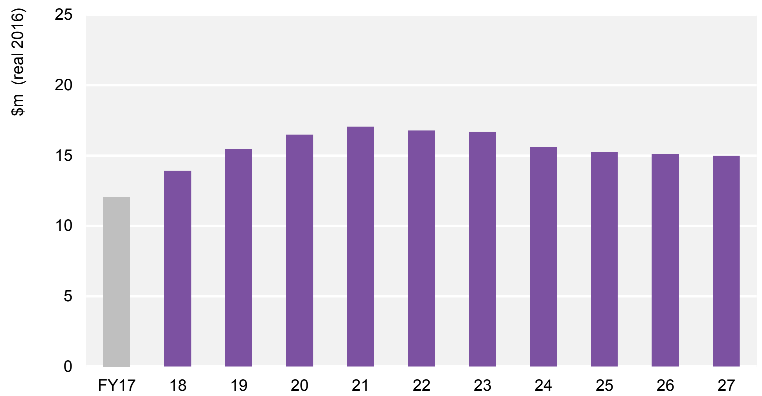
23.8.2 FORECAST EXPENDITURE

Forecast increases in SONS expenditure reflect our targeted focus on lifting capacity and capability. Increases are influenced most heavily by capacity enhancements to support increased work volumes.

Towards the end of the period, expenditure reduces due to reductions in Network Capex programmes, and as a result of targeted improvements in delivery efficiency.

The following figure shows our forecast SONS Opex for the planning period.[112]

Figure 23.9: Forecast Systems Operations and Network Support Opex



[112] People in the SONS portfolio also support and enable capital works. Expenditure relating to capital works is capitalised in accordance with our capitalisation policy and included in the relevant capital assets.

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Customer works

This section summarises our approach to consumer connection and asset relocation projects.

Chapter 24	Consumer Connections	**273**
Chapter 25	Asset Relocations	**275**

24.1 CHAPTER OVERVIEW

This chapter explains our approach to connecting new consumers and how we forecast expenditure on these connections. The process we use to connect new customers is designed to ensure the cost of connection is efficient, and that connections can be completed in a timely way.

- Sections 24.2 and 24.3 includes an overview of our connection process and how these works are funded
- Section 24.4 sets out our forecast expenditure over the planning period.

Further detail on our customers and how they affect our investment plans can be found in Appendix 4

24.2 OVERVIEW OF CONSUMER CONNECTIONS

Every year several thousand homes and businesses connect to our electricity network.

New connections require investment in network infrastructure. Residential connections range from a single new house to subdivisions with hundreds of residential plots. It includes connecting a range of businesses and infrastructure, from small connections such as water pumps and telecom cabinets, to large connections such as factories and supermarkets. The consumer connections portfolio also includes works for customers, typically commercial, who want to upgrade the capacity of their existing electricity supply.

The expenditure we directly incur in connecting new consumers (ie net of any contribution they make) is defined as consumer connections Capex.

24.3 OUR CONNECTION PROCESS

24.3.1 OVERVIEW

Residential customers requiring a new connection will generally first contact an electrician. Some electricians will manage the whole connection process for customers, while others will direct them to our customer service team.

Once a customer contacts us, we supply them with our list of approved contractors. These contractors will work with the customer to determine what is required to provide supply and provide a quote for the work. The contractor will obtain approval from us for their proposed design concept and notify the customer of any special requirements such as easements.

The benefit of this system is that it allows the customer to seek competitive quotes from more than one approved contractor. The customer can then be confident of getting a fair price and good customer service. Ensuring contestability and customer choice is a key aim for our connections process.

Some larger businesses or large subdivision developers will contact us directly to discuss their connection requirements, or work with large industrial power specialists who are familiar with our requirements and standards for connection. We work with these larger providers to facilitate connection of these larger loads.

Our consumer connection process is set out on our website.

24.3.2 FUNDING

Where a customer connection request (new connection or upgrade of existing assets) impacts assets owned by us, we contribute towards the cost of constructing those assets. This is because we receive some benefit from ongoing network charges, and in some cases new assets benefit our existing customers.

In most cases customers requesting new connections fund the majority of the cost. This is to ensure that these customers pay a fair amount for the assets that are used to serve their connection over its lifetime, and ensures our existing customers are not disadvantaged. We generally require contributions for the following works.

- Extensions or reinforcements that solely benefit individual customers
- Network connections that require new assets to be built

We have a customer contribution policy that we follow to determine the need for and amount of contribution. We publish a guide online to explain this.

In calculating contributions, it is important to demarcate our assets from the customers'. Customer service lines, the assets inside a customer's property boundary, are owned by the customer and we do not contribute towards their construction. In these circumstances, a service fuse is required and we contribute a nominal amount to complete this connection. This type of investment is not considered by us to be of a capital nature and is not included in our Capex forecasts.

Consumer connection Capex contributes to network development at LV and distribution levels. However, incremental growth from existing customers can lead to upgrades at distribution level, which are funded by us. Similarly, reinforcement of our network at subtransmission levels is funded through our system growth expenditure.

24.4 FORECAST EXPENDITURE

Below we set out and explain our forecast consumer connections Capex over the planning period.

24.4.1 EXPENDITURE DRIVERS

Consumer connection Capex is largely driven by growth in population (residential) and the overall economy (commercial/industrial). Specifically, investment levels tend to be driven by the following.

- New residential properties driven by population growth, land supply and Government policy which impacts small connection requests, and large subdivision developments
- Growth in commercial activity, impacts requests for new premises and load changes as businesses seek to expand operations

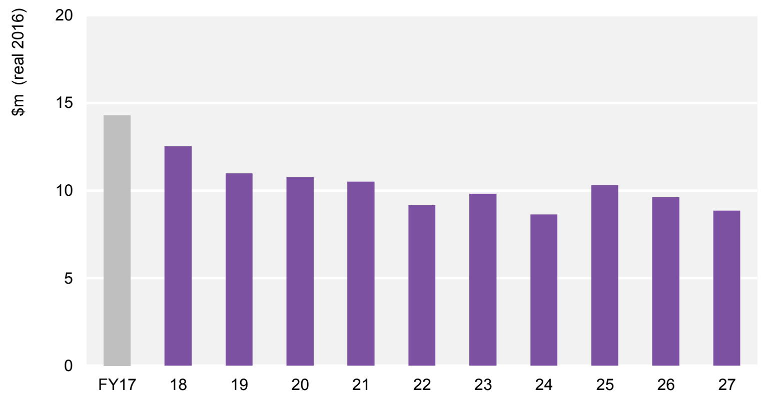
24.4.2 FORECAST CAPEX

Consumer connection Capex is externally driven with short lead times so our ability to accurately forecast medium-term requirements based off known projects is limited. As such, our forecast is based on trending historical activity. We use FY16 expenditure as a baseline as we believe it to be a reasonable indication of future activity. We then use forecast ICP growth to modify the base into a final forecast.

Our ICP forecast is based on household growth data, derived from econometric parameters. ICP growth correlates well with historical consumer connection expenditure. Forecast ICP growth is also used to inform our demand forecast for growth and security investments.

Our forecast assumes continuing our current capital contributions policy.

Figure 24.1: Forecast consumer connection Capex (net of contributions)



Forecast consumer connection expenditure is expected to reduce over the forecast period. Expenditure in this portfolio has been high in recent years due to strong growth on our network, particularly in the eastern region. We expect this level of growth to slowly reduce, thereby impacting forecast ICPs.

We expect to see a degree of variation year-on-year as major subdivision and upgrade works are completed. However, we have limited ability to forecast this as it is driven by third parties. We also have limited scope to reschedule this work year-to-year as we look to satisfy customer requirements as promptly as possible.

We are not at the time of writing aware of any specific projects of material size coming up in the forecast period.

25.1 CHAPTER OVERVIEW

This chapter explains our approach to relocating assets on behalf of customers and other stakeholders. It includes an overview of typical relocation works, our process for managing these works, and how they are funded. Our forecast Capex (net of capital contributions) during the planning period is also discussed.

Further detail on our stakeholders and how they affect our investment plans can be found in Appendix 3.

25.2 OVERVIEW OF ASSET RELOCATIONS

The assets most often needing to be relocated are poles, overhead conductors and underground cables. These are often located alongside other infrastructure such as roads, water pipes, and telecommunications cables. A common example of this is moving poles and lines to accommodate the widening of a road.

Asset relocations Capex is driven by third party applications, which typically fall in one of the following four categories.

- **Roading projects** – road widening and realignment projects by the NZTA and councils require our assets to be relocated
- **Infrastructure projects** – infrastructure owners may need us to relocate our assets as part of their developments (eg storm water pipelines, electricity transmission lines or telecommunications assets)
- **Development** – Local councils, commercial organisations, farmers and residential land owners may require us to relocate our assets so they can redevelop sites or existing buildings
- **Aesthetics** – Customers make requests for electricity lines disrupting their views to be moved underground to improve aesthetics.

Expenditure is capitalised where assets, usually in poor condition, are replaced as part of the relocation. Relocating assets from one location to another, without increasing service potential, is treated as Opex.

25.3 OUR ASSET RELOCATION PROCESS

Our asset relocation process allows flexibility to facilitate development by other utilities, our customers and third parties.

The process for small relocation works is usually an externally-managed design and build approach. We find this provides the most customer-centric service. When a customer seeks asset relocation we provide a list of approved service providers. During the design and pricing stage, the customer may choose to work with more than one contractor to create a competitive environment. The customer's contractor then works with us to deliver the relocation work. In this process, the contractor works for the customer to meet their needs, while we ensure the contractor complies with our technical, safety and commercial requirements. Typically, we undertake between 75 and 125 relocation projects each year.

In most circumstances we receive contributions from the third party requesting the relocation, reducing the amount of our investment in these projects. For roading and other infrastructure projects, the level of our investment is governed by legislation which often requires us to fund the materials portion of the project.[113] For smaller projects, our level of investment is guided by our electricity capital contributions policy. The funding mix will vary based on the type of projects in any given year.

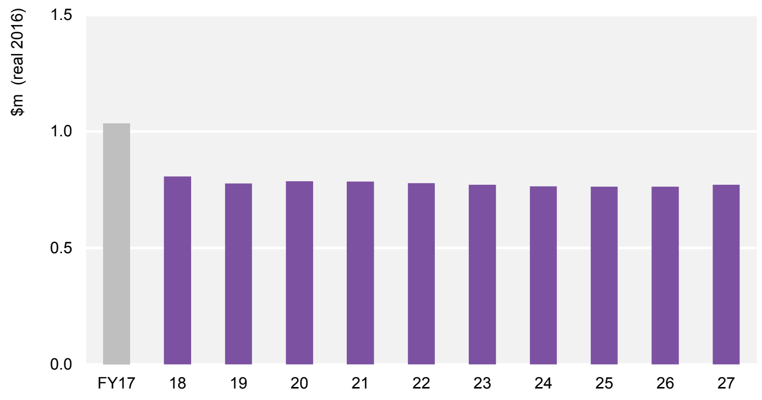
25.4 FORECAST EXPENDITURE

Because asset relocations are customer driven, often with short lead times, our ability to forecast this expenditure on a volume or project basis is limited and we also have limited ability to smooth the expenditure across years.

As such, our forecast is based on our FY16 asset relocations expenditure, which is our best indicator of future asset relocations Capex. This is modified by any significant project expenditure that we become aware of through consultation with councils and the Land Transport Authority, internal cost assumptions and future efficiency targets.

The chart below shows our expected investment (net of contributions) in asset relocation works during the planning period. The FY17 expenditure is based on an in-year budget forecast, and shows the higher than average works undertaken in the year.

Figure 25.1: Forecast asset relocation Capex (net of contributions)



[113] Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act

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Expenditure forecasts

This section provides an overview of our Capex and Opex forecasts for the planning period.

Chapter 26 Expenditure Forecasts 277

26.1 CHAPTER OVERVIEW

This chapter provides a summary of our expenditure forecasts over the planning period. It is structured to align with our internal expenditure categories and forecasts provided in earlier chapters.

We supplement our expenditure forecasts by providing high level commentary and context for our forecasts including key assumptions. We also discuss our cost estimation methodology and how this has been used to develop our forecasts for the planning period.

Note on expenditure charts and tables

The charts depict budgeted expenditure (grey column) in our 2017 financial year (2016/17) and our forecasts (purple columns) for the remainder of the planning period.

Expenditure is presented according to our internal categories in this section. Expenditure is also provided in Information Disclosure categories (which differ in minor ways) in Schedules 11a and 11b in Appendix 2.

All dollars are denominated in constant price terms using FY16 dollars. This is to ensure consistency with our customised price-path proposal. The schedules in Appendix 2 also show expenditure in FY17 constant price terms.

26.2 FORECAST EXPENDITURE SUMMARY

Below we summarise our Capex and Opex forecasts for the planning period. To avoid duplication we have not restated discussions in previous chapters. Instead, we have focused on providing high level commentary and context for the overall forecasts and provided cross references to chapters with more detailed information.

26.2.1 CAPEX

Our forecast for total Capex increases significantly over the planning period. It represents our current best view, based on our asset management strategies and using available network information.

Total Capex includes the following four expenditure categories:

- **Growth and security Capex**: Discussed in Chapters 11 and 12
- **Renewals Capex**: Discussed in Chapters 15-21
- **Other network Capex**: Discussed in Chapters 13, 24 and 25
- **Non-network Capex**: Discussed in Chapter 22

The forecast increase over the planning period relates almost entirely to network expenditure. There is a minor increase in non-network Capex arising from our investments in systems and capability that will enable delivery of increased Network Capex work volumes. Reductions later in the period relate in part to efficiencies we expect to make, due to improvements such as in our asset management capability. Below we set out our total Capex for the planning period.

Figure 26.1: Total forecast Capex for the planning period

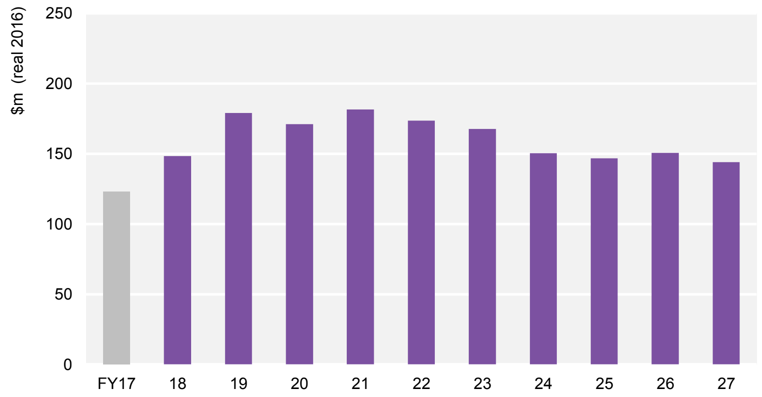


Table 26.1: Total forecast Capex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
123.2	148.5	179.1	171.2	181.5	173.6	167.6	150.4	146.7	150.7	144.2

Our Capex profile reflects the underlying network needs discussed in this AMP. The rate of increase in early years has been designed to balance a focus on ensuring network targets are achieved, and the need to mobilise increased service provider resources and internal engineering capacity and capability.

26.2.1.1 GROWTH AND SECURITY CAPEX

As discussed in Chapter 7, our network development Capex is split into three portfolios. These are:

- Major projects
- Minor growth & security works
- Reliability

The combined expenditure in these portfolios is shown below.

Figure 26.2: Total growth and security Capex for the planning period

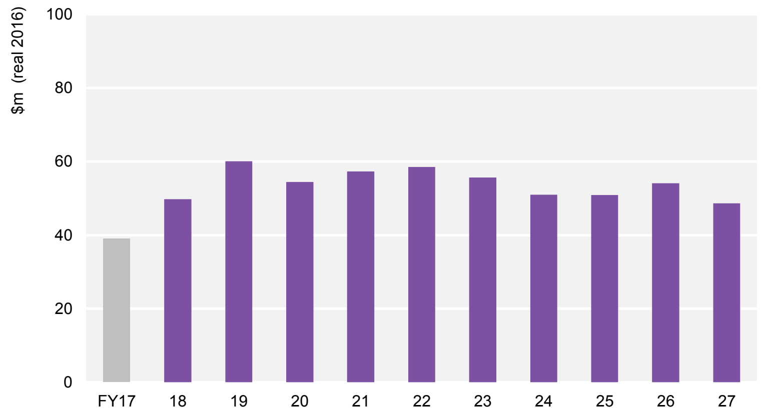


Table 26.2: Total growth and security Capex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
39.1	49.8	60.1	54.5	57.3	58.5	55.6	51.0	50.9	54.1	48.6

Growth and Security forecast expenditure is higher than historical levels, reflecting in part constrained historical expenditure in line with regulatory settings. Increased levels of expenditure are required to address existing security exposures and ensure appropriate and stable network security position in the longer term.

26.2.1.2 RENEWALS CAPEX

As discussed in Chapter 14, our fleet management Capex is split into seven portfolios. These are:

- Overhead Structures
- Overhead Conductors
- Cables
- Zone Substations
- Distribution Transformers
- Distribution Switchgear
- Secondary Systems

The combined expenditure in these portfolios is shown below.

Figure 26.3: Total renewals Capex for the planning period

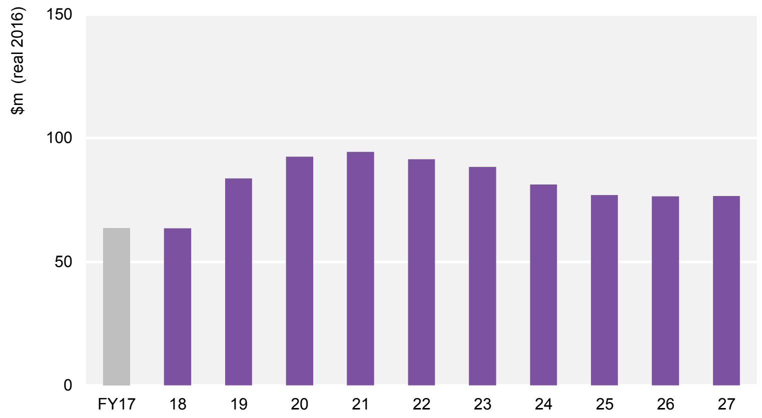


Table 26.3: Total renewals Capex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
63.5	63.5	83.7	92.5	94.4	91.5	88.3	81.2	77.0	76.4	76.6

The main driver for our increased forecasts over the planning period is to address deteriorating condition and asset health trends, and to accommodate an increasing percentage of our assets reaching the end of their practical service life. Expenditure is forecast to reduce late in the planning period as we stabilise asset health, and from expected efficiencies arising from improved asset management.

26.2.1.3 OTHER NETWORK CAPEX

As discussed in Chapter 13, 24 and 25, other network Capex is split into three portfolios. These are:

- Network Evolution
- Consumer Connections
- Asset Relocations

The combined expenditure in these portfolios is shown below.

Figure 26.4: Total other network Capex for the planning period

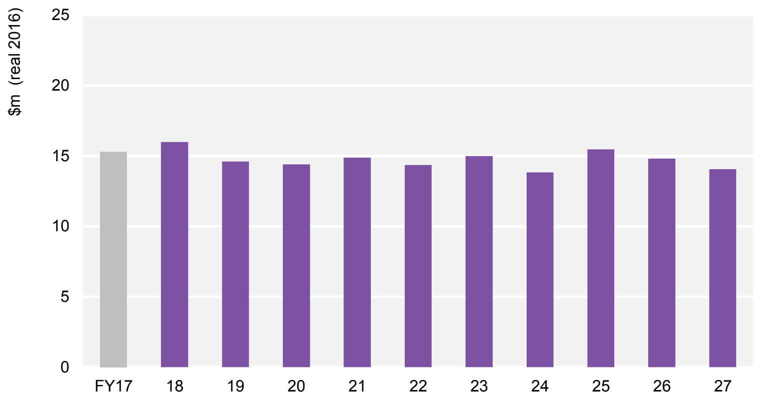


Table 26.4: Total other network Capex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
15.3	16.0	14.6	14.4	14.9	14.4	15.0	13.8	15.5	14.8	14.1

The profile above shows a generally flat forecast of expenditure over the planning period. Forecast reductions in consumer connection expenditure is offset by our Network Evolution programme of technology proof of concepts to ensure we are able to accommodate new edge technologies such as EV and PV as they grow in significance.

26.2.1.4 NON-NETWORK CAPEX

As discussed in Chapter 22, our non-network Capex is split into two portfolios. These are:

- ICT Capex
- Facilities Capex

The combined expenditure in these portfolios is shown below.

Figure 26.5: Total non-network Capex for the planning period

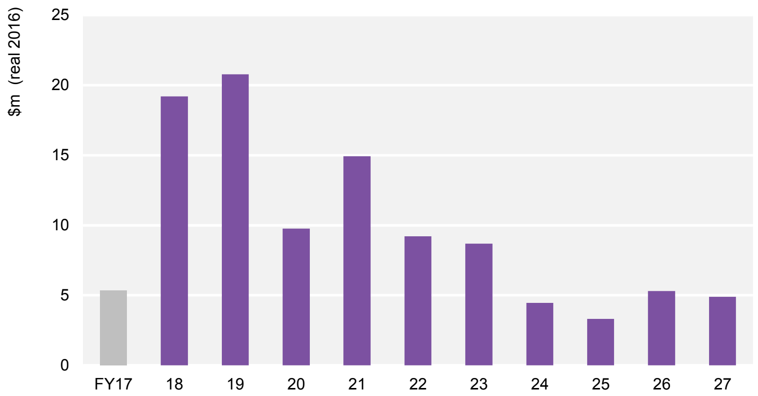


Table 26.5: Non-network Capex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
5.3	19.2	20.8	9.8	14.9	9.2	8.7	4.5	3.3	5.3	4.9

Our main non-network investments in the planning period include an upgraded Network Operating Centre and Junction St facility, and development of an ERP system during FY18-21. These investments are critical enablers of capacity and capability improvements needed to deliver increased work volumes and lift asset management capability. Given the rapidly changing nature of ICT solutions the exact solutions implemented and associated costs are less certain later in the period.

26.2.2 OPEX

Our current Opex forecast increases over the planning period. These represent our best forecasts using currently available information.

Total Opex includes the following two expenditure categories:

- **Network Opex**: Discussed in Chapter 23[114]
- **Non-network Opex**

Similar to Capex, increases during the planning period relate almost entirely to network Opex. Appropriate Opex expenditure is a critical enabler of effective capital

[114] SONS is part of our Network Opex category.

delivery and increased capability will allow us to optimise total Capex over the period. Below we set out our forecast for total Opex during the planning period.

Figure 26.6: Total Opex for the planning period

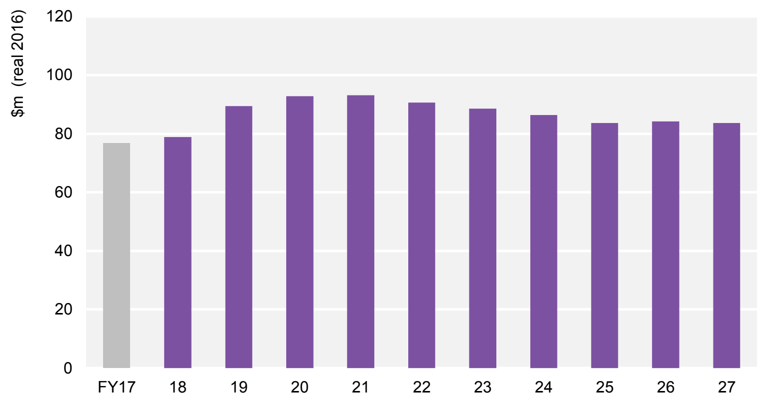


Table 26.6: Total forecast Opex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
76.8	78.9	89.4	92.8	93.1	90.6	88.6	86.3	83.7	84.2	83.6

Our Opex profile reflects the underlying network needs discussed in this AMP. The higher levels during the middle years of the period will address our backlog in defects, allow more sophisticated condition assessment techniques, and allow us to reach sustainable levels of vegetation management. It includes investment in our people to ensure we can undertake our work programmes and lift asset management maturity.

26.2.2.1 NETWORK OPEX

Our network Opex forecast includes our planned expenditure in the following portfolios[115]. Further information on the forecasts can be found in Chapter 23.

- Preventive maintenance and inspection
- Corrective maintenance
- Reactive maintenance

115 Ibid

- Vegetation management
- SONS

The combined expenditure in these portfolios is shown below.

Figure 26.7: Network Opex for the planning period

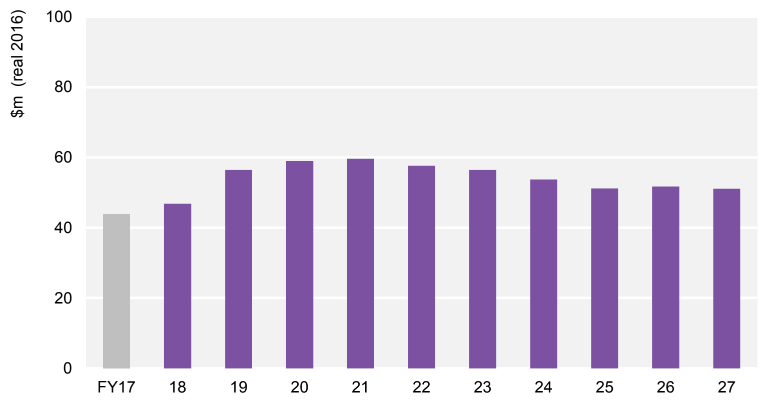


Table 26.7: Network Opex over the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
43.9	46.9	56.5	59.0	59.7	57.7	56.5	53.8	51.2	51.7	51.1

The higher Opex levels during the middle years of the period are mainly due to increased expenditure in our corrective maintenance portfolio to address a high number of end of life component replacements (defects), and increases in our SONS portfolio to support increasing work volumes. Our SONS forecast also reflects the need to continue developing our people and their capabilities to support more advanced asset management maturity.

Towards the end of the period we expect to reach a sustainable level of network Opex. This reflects the expected benefits of increased renewals, our cyclical vegetation programme being embedded, reduced Capex work volumes, and efficiencies in our asset management approach.

26.2.2.2 NON-NETWORK OPEX

Our non-network Opex forecast includes expenditure related to the divisions that support our electricity business. It includes direct staff costs and external specialist advice. The other material elements are office accommodation costs; legal, audit and governance fees; and insurance costs. A portion of our non-network Opex is allocated to our gas business in accordance with our cost allocation policy and is excluded from the forecasts in this AMP.

Figure 26.8: Non-network Opex for the planning period

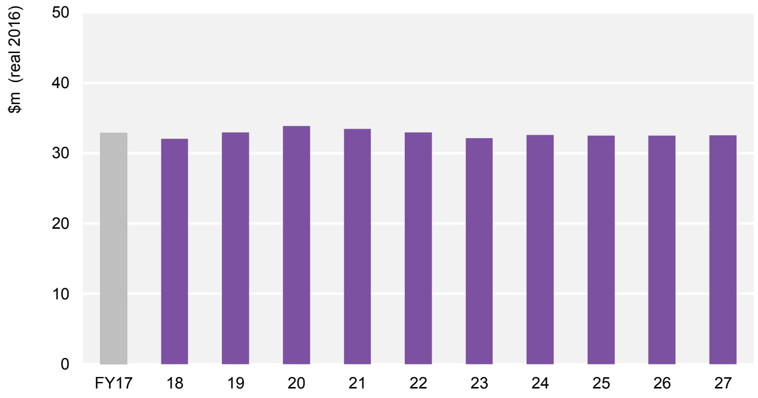


Table 26.8: Non-network Opex for the planning period ($m real 2016)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
32.9	32.0	33.0	33.8	33.5	32.9	32.1	32.6	32.5	32.5	32.5

Our forecast expenditure is consistent with historical costs over the planning period.

26.3 INPUTS AND ASSUMPTIONS

This section sets out some of the key inputs and assumptions underpinning our forecasts for the planning period. We have set them out in the following two categories:

- Inputs and assumptions relating to our forecasts and underlying forecasting approaches; and
- Our approach to escalating our forecasts to nominal dollars including our estimates of capitalised interest and the timing of commissioning.

26.3.1 FORECASTING INPUTS AND ASSUMPTIONS

The table below sets out the main inputs and assumptions underpinning our forecasts for the planning period.

Table 26.9: Forecasting inputs and assumptions

INPUTS AND ASSUMPTIONS	DISCUSSION
Work Volumes	
Historical asset failure rates provide an appropriate proxy for expected asset fleet deterioration (used in our survivorship analysis).	Except where specific type issues or localised accelerated deterioration have been identified, we have assumed that asset condition will degrade at similar rates to historical evidence when accounting for age and type. Through survivorship analysis we can then use this information to estimate likely quantities of future asset replacements. In some cases (eg concrete poles) we have found we are able to operate assets well past industry design lives and our forecasts reflect this. We use this approach across a number of our volumetric asset fleets (refer Chapter 15-21).
Expected asset lives, based on experience operating our network, provide an appropriate proxy for longer term asset replacement forecasting.	For longer term forecasting we at times use expected asset lives to estimate future replacement needs. This assumption is appropriate for forecasting work on large asset populations. Actual replacement works are triggered by other factors including condition and safety. This is only used on asset fleets of lower value, and where more detailed information is not available such as asset condition or degradation data. Where we have applied this approach in the past we have found it to be a reasonable proxy for actual service life. Refer Chapter 15-21 for more information.
Historical relationships between load growth and related drivers (local GDP, ICP growth, etc) continue to apply in the short-term	Our demand forecasting approaches have performed well in recent years and we expect this to continue to be the case over the medium term. In the longer term the increasing adoption of new technologies (see Chapter 13) may alter these relationships and we are monitoring these trends carefully. Our standard investment planning approach is designed to ensure that we do not invest in new capacity until we are sure it is required, which moderates the risk of overinvestment.

INPUTS AND ASSUMPTIONS	DISCUSSION
Embedded generation will not have a material impact on network investment in the planning period.	We have assumed that the installation of PV and energy storage will not materially affect peak load growth and related investments over the planning period. The requirement for network reinforcement, which is largely driven by peak load or network stability requirements, is therefore not anticipated to change noticeably due to embedded generation. We note that industry studies such as Transform (carried out by the ENA Smart Grid Forum) suggest that high rates of embedded generation such as PV would be likely to increase capital requirements rather than reduce them and so our assumption is conservative.
Brownfield asset replacement quantities are based on like-for-like replacement.	For volumetric fleets we assume that the quantity of assets forecasted for replacement will be replaced with an equal number of assets, except where consolidation strategies are in place, such as with ground mounted switchgear. Actual replacement may involve quantity variances such as during line construction where the number of poles may increase or decrease. However these variances are assumed to balance out resulting in an appropriate forecast.
Customers do not expect our network performance to degrade over the long term.	Customer surveys indicate that they want us to at least maintain current performance levels (also considering price impacts). Our work volume models are therefore designed to ensure no reduction in performance over the planning period. In practice there are parts of our network that will require more investment to ensure appropriate safety outcomes, or to reflect changing customer needs and demographics.
Unit Rates (Costs)	
Historical unit rates are appropriate for use in volumetric forecasts.	Historical unit rates for volumetric works reflect likely future scopes and risks, on an aggregate or portfolio level. While we continue to target efficiency in all aspects of our work delivery and have made some allowances for this later in the planning period, our experience has shown that increased efficiency tends to be offset by increased safety related costs (such as traffic management) and increased costs associated with accessing the road corridor and private land.

INPUTS AND ASSUMPTIONS	DISCUSSION
Current network Capex unit rates reflect likely costs over the planning period.	We expect historical unit rates for capital works to reflect costs over the planning period, with some capacity to reduce costs in the latter part of the planning period as efficiencies are identified. Some of these efficiencies are likely to be somewhat offset by factors such as requirements to manage network outages (eg using portable generators).
Current maintenance unit rates reflect likely costs over the planning period.	We expect historical unit rates for maintenance to reflect costs over the planning period. We may realise some efficiencies in future years due to increased maintenance volumes, though these may be somewhat offset by more stringent maintenance requirements reflecting improved asset management practices as well as the result of more sophisticated equipment rolled out across the network. We have allowed for some efficiencies in later years of our forecasts.
Materials and labour forecasts reflect likely future trends.	We assume that the independent cost escalation indices (as noted below) will appropriately reflect input price trends over the planning period.
Brownfield asset replacement costs are based on today's modern equivalent assets.	Unit costs used in brownfield asset replacements assume the continued use of today's modern equivalent costs except where future technology changes are known (such as where SF_6 switches will generally replace air break switches over the planning period – refer Chapter 20).

26.3.2 ESCALATION OF FORECASTS

Over the planning period we will face different input price pressures to those captured by a general measure of inflation like the consumer price index (CPI). We expect that the input price increases we face over the planning period will be greater than CPI due to factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.[116]

Our approach to developing cost escalators involves applying different cost escalators to our real price expenditure forecasts. Our escalators have been developed using:

- Independent forecasts of input price indices that reflect the various costs that we face, including material, labour and overhead components.
- CPI forecasts consistent with the Commission's input methodologies (used in limited circumstances).

[116] The DPP also recognises that electricity distributors face different cost pressures from the economy overall by applying Labour Cost, Producer Price and Capital Goods Price indices as appropriate.

- Weighting factors for cost categories, such as transformers, that are made up of a range of inputs.[117]

We have used the above inputs to develop tailored cost escalators for our cost categories. These are then applied to our real expenditure forecasts to produce the forecasts in nominal dollars for our Information Disclosure schedules in Appendix 2.

26.4 COST ESTIMATION

In general our AMP forecasts have been developed using forecasting techniques that estimate necessary work volumes. These will then have associated unit rates applied to them. This so-called ‘bottom-up’ approach has been developed alongside cost estimates that are:

- Transparent
- Repeatable
- Linked to outturn costs
- Inclusive of appropriate allowances for forecasting uncertainty

Long-term cost estimates do carry estimation risk. We have not included any ‘blanket’ contingency in our estimates to account for uncertainty over the planning period. Instead, we have sought to develop forecasts to a confidence level of P50.[118] The use of P50 is considered appropriate as it equates to an equal allocation of estimation risk between us and our customers.

Our forecasts beyond two years use a combination of the following approaches: [119]

- **Customised Estimates (Capex)**: Used for large single projects (>$500k) that require individual tailored investigation. Those above $5m are also supported by independent external cost estimates.
- **Volumetric Estimates (Capex and Opex)**: Used for smaller, high-volume works that are reasonably routine and uniform. These are generally related to defect rectification, reactive works and scheduled maintenance.
- **Base-step-trend (Capex and Opex)**: Is mainly used for forecasting network and non-network Opex. It is also used for certain trend-based Capex forecasts such as asset relocations.

These estimate types are discussed below.

117 The weighting factors strike the right balance between appropriately reflecting the cost structure of the assets that make up our network and avoiding unnecessary complexity. Approaches that are more complex may reduce the transparency without necessarily better reflecting the cost pressures we expect to face.

118 The P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.

119 Budgeting for the earlier part of the period is based on tendered work, detailed project-specific estimates, or maintenance delivery plans.

26.4.1 CUSTOMISED ESTIMATES

This approach involves developing cost estimates based on project scopes, with larger projects supplemented with cost estimates from external consultants. Project scopes are determined from desktop reviews of asset information such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities.

Activity costs are based on historical costs, service provider rates, quotes, and external reviews. Material costs are determined with reference to supply contracts and historical installation costs contained in our price-book. Installation costs are informed by similar previous projects and updated with current prices from service providers.

There are risks associated with estimating projects up to 10 years in advance. The costs that are subject to material estimation risk will vary by project type. In general the main cost items that lead to estimation risk include:

- Site location (eg remoteness of site and likely impact on construction costs)
- Cable or conductor lengths
- Building requirements
- Geotechnical/ground condition and the potential need for ground improvements
- Excavation requirements and the potential for contaminated soil to be present.

For investment in large non-network systems or facilities works we have based our forecasts on a combination of tender responses and desktop estimates for later in the period. These desktop estimates are mainly informed by historical tenders and discussions with vendors.

26.4.2 VOLUMETRIC ESTIMATES

Programmes with relatively large volumes of similar works are categorised as volumetric works for estimation purposes. The key determinant of accurate cost estimates for volumetric works is the feedback of historical costs from completed equivalent projects. This feedback is used to derive average unit rates to be applied to future work volumes. These unit rates are often combined to form building block costs that include the main components of typical works.

Using this approach we consider that our volumetric works will be based on P50 estimates, given the following assumptions:

- Project scope is reasonably consistent and well defined.
- Unit rates based on historical outturns capture the impact of past risks. The aggregate impact of these risks across portfolios is unlikely to vary materially over time.

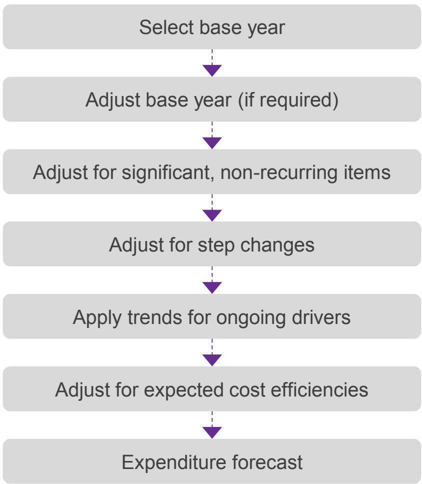
- To maintain a portfolio effect[120] a large number of future projects are likely to be undertaken.
- The volume of historical works is sufficiently large to provide a representative average cost.

For investment in non-network assets and systems (eg IT hardware) we have used expected volumes and unit rates informed by discussions with vendors and historical outturns.

26.4.3 BASE-STEP-TREND

We have used a 'base-step-trend' approach to forecast part of our expenditure.[121] The approach is used by many utilities and economic regulators for forecasting expenditure that is recurring.[122] The figure below sets out the steps in developing base-step-trend forecasts.

Figure 26.9: Base-step-trend forecasting steps



The base-step-trend approach starts with selecting a representative base year. The aim is to identify a recent year that is representative of recurring expenditure we expect in future years. If there are significant events (eg major storms) an adjustment is made to remove its impact.

Expenditure in the base year is then projected forward. To produce our AMP forecasts we adjusted the resulting series for anticipated significant, non-recurring expenditure, permanent step changes, trends due to ongoing drivers, and expected cost efficiencies.

26.4.4 COST ESTIMATION PRICE-BOOK

Our Capex cost estimation process is built around a cost estimation 'price-book'. Using this, we can develop robust cost estimates using a centrally managed dataset. We continue will continue to ensure our processes to capture actual project cost and then feed it back into relevant future cost estimates over time.

26.5 INFORMATION DISCLOSURE CATEGORIES

26.5.1 NETWORK CAPEX

For the purposes of Information Disclosure in Schedule 11a, we use the following network Capex categories. These differ somewhat from the categories we have used in our Capex expenditure forecasting (and which are discussed in this AMP). We use our categories as they better reflect the way we manage the associated assets, but we maintain mappings to allow us to meet our disclosure requirements.

- **System growth:** These investments are classified under our Growth and Security category (excluding reliability investments), and also includes our Network Evolution investments. The investment plans are described in detail in Chapter 11 and 13.
- **Asset replacement and renewal:** These investments are classified under our Renewals category. The investment plans are described in detail in Chapters 15-21.
- **Reliability, safety and environment:** Safety and environment capital investments are generally managed as part of our Renewals processes but are separately identified to reflect their particular drivers. The investment plans described in detail in Chapters 15-21. Reliability investments include our automation programme (part of Growth and Security), discussed in Chapter 12.
- **Consumer connections:** Our consumer connections portfolio is consistent with the information disclosure definition. These investments are discussed in Chapter 24.
- **Asset relocations:** Our asset relocations portfolio is consistent with the information disclosure definition. These investments are discussed in Chapter 25.

[120] The net impact of cost variances will tend to diminish in a portfolio containing a large number of P50 estimates.

[121] This includes reactive maintenance and SONS. It is also used to a lesser extent for non-network Opex and certain Capex forecasts, such as asset relocations and consumer connections.

[122] The base-step-trend approach has been used by energy network businesses regulated by the Australian Energy Regulator. See its forecast assessment guidelines available at www.aer.gov.au/node/18864. The approach is also conceptually similar to the Commission's approach to Opex used in setting DPPs in 2012 and 2014.

26.5.2 NETWORK OPEX

Like with network Capex, for the purposes of Information Disclosure in Schedule 11b, we use the following network Opex categories. These differ somewhat from the categories we have used in our Opex expenditure forecasting (and which are discussed in this AMP in Chapter 23).

- **Service interruptions and emergencies:** This category is consistent with our Reactive Maintenance portfolio.
- **Vegetation management:** Our vegetation management portfolio is consistent with the information disclosure definition.
- **Routine and corrective maintenance and inspections:** This category covers expenditure from our Preventive Maintenance and Inspection portfolio, as well as the Commission's 'corrective' work within our Corrective Maintenance portfolio.
- **Asset replacement and renewal:** This category is generally consistent with our Corrective Maintenance portfolio, (though our Corrective Maintenance portfolio also includes the corrective work from the Commission's routine and corrective maintenance and inspections category).
- **System operations and network support:** Our system operations and network support portfolio is consistent with the information disclosure definition (though we classify SONS as network Opex).

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Appendices

This section provides additional information to support our AMP. It includes our Information Disclosure schedules.

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AAAC means All Aluminium Alloy Conductor which is a commonly used type of overhead conductor.

AAC means All Aluminium Conductor which is a commonly used type of overhead conductor.

ABS means Air Break Switch which is a type of equipment used for isolating parts of a circuit.

ACSR means Aluminium Conductor Steel Reinforced which is a commonly used type of overhead conductor.

Adequacy means the ability of the electrical power network to meet the load demands under varying steady state conditions while not exceeding component ratings and voltage limits.

ADMD means After Diversity Maximum Demand. This refers to the average maximum demand assigned to a customer or load for network dimensioning purposes during design. Typical domestic ADMDs are in the order of 4kVA at reticulation level and 2kVA at a feeder level.

AHI means Asset Health Indices. These reflect the expected remaining life of an asset and act as a proxy for probability of failure. AHI is used to inform levels of investment within and between portfolios. AHI is calculated using a number of factors including asset condition, survivor curves, asset age relative to typical life expectancy, known defects or type issues and factors that affect degradation rates such as geographical location.

ALARP means As Low As Reasonably Practical and is one of the principles of risk management.

AMMAT means Asset Management Maturity Assessment Tool.

Availability means the fraction of time an asset is able to operate as intended, either expressed as a fraction, or as hours per year.

Backfeed is the ability for certain network circuits to be switched to supply part of another circuit during a planned or unplanned outage. This is usually done to minimise the impact of outages to customers.

Capex refers to capital expenditure, investments to create new assets or to increase the service performance or service potential of existing assets.

CBD means the Central Business District.

CBRM means Condition-Based Risk Management.

CCA is Copper Chrome Arsenic, a treatment method for softwood poles

Class Capacity means the capacity of the lowest-rated incoming supply to a substation, plus the capacity that can be transferred to alternative supplies on the distribution network within the timeframe required by the substation security classification.

Contingency means the state of a system in which one or more primary components are out of service. The contingency level is determined by the number of primary components out of service.

CPI means the Consumers Price Index.

CPP is Customised Price-quality Path.

Critical Spares are specialised parts that are stored to keep an existing asset in a serviceable condition. Critical spares may also include entire asset spares in case of serious failures.

CWMS means Connections Works Management System, which is an online workflow management system that facilitates and tracks the processes associated with customer connection applications, approvals, and works completion.

DAS means Distribution Automated Switches which is one of the many HV devices that can help us develop a network of the future.

Defect means that the condition of an asset has reached a state where the asset has an elevated risk of failure or reduced reliability. Defects are identified during asset inspections and condition assessments. There are three defect categories: Red, Amber and Green. These categories signify the risk of the defect. Defects may be Capex or Opex depending on the type of remediation action.

DPP means default price-quality path.

DRAT is Powerco’s Defect Risk Assessment Tool, a tool that is used to systematically analyse defects and the risks presented by them.

DER means Distributed Energy Resources which are small scale power generation or storage technologies used to provide an alternative to or an enhancement of traditional electricity networks

Development means activities to either create a new asset or to materially increase the service performance or potential of an existing asset.

DFA means Delegated Financial Authority.

DGA means Dissolved Gas Analysis which is a type of oil test, typically carried out on transformers. It analyses the different gas traces found inside the oil. Different levels and combinations of gas traces provide an indication of the internal condition of the transformer.

DG/ESS is Distributed Generation/Energy Storage Systems (refer section 11.4.1.6)

Distribution System Integrator (DSI) is a utility that is able to utilise intelligent networks to enable widespread use of local generation sources connected to the network at multiple points and open access to customers to allow them to transact over the network.

DMS means Distribution Management System

DNP3 is Distributed Network Protocol version 3, which is our standard communications protocol.

DP or Degree of Polymerisation is a type of test carried out on a transformer's paper insulation. This test provide an indication of insulation condition.

DPP means Default Price-quality Path.

Eastern Region is the part of our electricity network supplying Tauranga, Western Bay of Plenty, Coromandel Peninsula and the area immediately to the west of the Kaimai and Mamaku ranges as far south as Kinleith.

EDGS means the Electricity Demand and Supply Generation Scenarios produced by MBIE.

EEA is the Electricity Engineer's Association which aims to provide the New Zealand electricity supply industry with expertise, advice and information on technical, engineering and safety issues affecting the electricity industry.

EDB means Electricity Distribution Business.

EFSA is the Electricity Field Services Agreement which is the agreement we have with our main field works service provider for undertaking routine capital works and maintenance work.

Emergency Spares means holdings of equipment to provide a level of protection against a catastrophic failure of assets.

EMS means Environmental Management System

ENA is the Electricity Networks Association.

EPR means Earth Potential Rise (or Ground Potential Rise) which occurs when a large current flows to earth through an earth grid impedance and creates a change of voltage over distance from the point of injection. EPR can be hazardous to the public and field staff and is an ongoing safety concern.

ERP means Enterprise Resource Planning which is a suite of applications that collect, store, manage and interpret data.

ESCP is Powerco's Electricity Supply Continuity Plan.

ETS is the Emissions Trading Scheme.

EV means Electric Vehicles.

EWP means Electricity Works Plan which is our annual scheduled works plan.

Failure means an event in which a component does not operate or ceases to operate as intended.

FIDI (Feeder Interruption Duration Index) means the total duration of interruptions of supply that a consumer experiences in the period under consideration on a distribution feeder. FIDI is measured in minutes per customer per year.

FIDIC is the International Federation of Consulting Engineers (its acronym is derived from its French name).

Firm Capacity means the capacity of the lowest-rated alternative incoming supply to a substation. In the case of a single supply substation, it is zero.

Forced Outage means the unplanned loss of electricity supply due to one or more network component failures.

GIS means Geographical Information System which is a system we use to capture, analyse, manage and present our assets in a spatial manner.

GEM means Gas and Electricity Maintenance Management System which uses the asset register to create scheduled RMI work.

GXP means transmission grid exit point.

HILP means High Impact Low Probability events .

HV refers to High Voltage which is associated with assets on our network above 1,000 Volts.

ICAM is Incident Cause Analysis Method, and is used in incident investigations.

ICP means Installation Control Point, which is the point of connection of a consumer to our network.

ICT means Information Communications Technology.

Incipient faults are faults that slowly develop and can result in catastrophic failure if not monitored and acted on appropriately.

ID means Information Disclosure which suppliers of electricity lines services are subjected to under regulatory requirements by the Commerce Act.

IED means Intelligent Electronic Device.

Interruption means an unplanned loss of electricity supply of one minute or longer, affecting three or more ICPs, due to an outage on the network.

IoT means Internet of Things

ISO 55000 is an internationally recognised standard for asset management. It replaced PAS 55.

ISSP means Information Services Strategic Plan.

JDE means JD Edwards which is our maintenance, work management and financial system.

LFI means Line Fault Indicator.

LTI means Lost Time Injury.

LTIFR means Lost Time Injury Frequency Rate which is calculated as the 12 month rolling number of LTIs per 1,000,000 hours worked.

LV refers to low voltage which is associated with parts of our network below 1,000 Volts.

MBIE is the Ministry of Business, Innovation and Employment

N-1 is an indication of power supply security and 'N-1' specifically means that in the event of one circuit failing, there will be another available to maintain the power supply, without interruption.

NBS is New Building Standard. We use this seismic standard to determine which of our substation buildings require strengthening.

NOC is our Network Operations Centre which is responsible for dispatch, coordinating/planning works, restoring supply and operating our network.

NZSEE is the New Zealand Society of Earthquake Engineering.

NZTA which is the New Zealand Transport Agency

OMS means Outage Management System which is a system we use to capture, store, manage and estimate fault location, and control and resolve outages.

Opex means operational expenditure which is an ongoing cost for running the business. It includes key network activities such as maintenance and fault response.

Outage means a loss of electricity supply.

PAS 55 is Publicly Available Specification 55, which is an asset management standard published by the British Standards Institution in 2004. While still in use, it has been superseded by ISO 55000.

PCB is Polychlorinated Biphenyls, a carcinogenic substance contained in the oil of pre-1970s transformers

PD is Partial Discharge testing

PILC means Paper Insulated Lead Covered which is a type of power cable.

PMI means Preventive Maintenance and Inspection

PMO means Project Management Office

PPE means Personal Protective Equipment.

Protection Discrimination is a coordinated electrical protection system which isolates part of the network circuit due to faults while keeping the remaining parts in service.

PV means Photovoltaics.

PVC means Poly Vinyl Chloride, which is a type of outer sheath on some of our cable and overhead conductor.

RAPS means Remote Area Power Supplies which provide a cost effective alternative for replacing long, end of line, remote rural distribution feeders.

Refurbishment means activities to rebuild or replace parts or components of an asset, to restore it to a required functional condition and extend its life beyond that originally expected. Refurbishment is a Capex activity.

REA means Remote Engineering Access. This is provided by the latest standard RTUs, and allows remote download of engineering information such as on faults.

R&D means Research and Development.

RMU means Ring Main Units which is a collection of switchgear (load break switches, fused switches or circuit breakers) used to isolate parts of the underground network.

RTU means Remote Terminal Unit which is a device that interfaces our network devices to our SCADA system.

SaaS means Software as a Service.

SAIDI (System Average Interruption Duration Index) means the average length of time of interruptions of supply that a consumer experiences in the period under consideration.

SAIFI (System Average Interruption Frequency Index) means the average number of interruptions of supply that a consumer experiences in the period under consideration.

SCADA means Supervisory Control And Data Acquisition, is a system for remote monitoring and control that enables us to operate our network in a safe and reliable manner.

Scheduled Outage or Planned Outage means a planned loss of electricity supply.

Security means the ability of the network to meet the service performance demanded of it during and after a transient or dynamic disturbance of the network or an outage to a component of the network.

Service Provider means a contractor or business that supplies a service to us.

SF_6 means sulphur hexafluoride.

SMC means the Service Management Centre operated by our Service Providers.

SONS means System Operations and Network Support.

SPS means Special Protection Scheme.

SSDG means Small Scale Distributed Generation.

Survivor Curve is a probabilistic survival likelihood curve for a given asset type, with associated rates of replacement at different ages. Survivor curves are derived from the analysis of historical replacements or defects. The replacement or defect likelihood can then be applied to an asset population to forecast required asset replacements.

SWER means Single Earth Wire Return which supplies single phase electrical power to remote areas.

Switching Time means the time delay between a forced outage and restoration of power by switching on the network.

Western Region is the part of our network supplying the Taranaki, Egmont, Manawatu, Tararua, Whanganui, Rangitikei and Wairarapa.

XLPE means Cross-Linked Poly Ethylene which is a type of power cable.

A2.1 SCHEDULE 11A

We include two versions of schedule 11a. One version uses constant prices in 2016 real dollars (for alignment to this AMP and our CPP application). The other version uses constant prices in 2017 real dollars, as per the Commerce Commission's information disclosure requirements for a 2017 AMP and for consistency with other electricity distributors' disclosures.

A2.1.1 CONSTANT PRICES (2016 REAL DOLLARS) AND NOMINAL DOLLARS

Company Name Powerco
AMP Planning Period 1 April 2017 – 31 March 2027

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	37,108	36,453	33,825	33,724	33,768	30,017	32,796	29,756	36,314	34,681	32,334
11		System growth	36,529	50,976	63,340	57,694	63,423	67,303	66,267	63,333	65,424	72,303	67,489
12		Asset replacement and renewal	61,618	63,762	84,237	96,052	100,567	101,325	99,948	96,905	94,753	96,657	99,784
13		Asset relocations	2,686	2,347	2,367	2,433	2,484	2,513	2,543	2,593	2,654	2,717	2,788
14		Reliability, safety and environment:											
15		Quality of supply	2,886	2,725	3,320	4,888	5,134	5,046	4,938	3,951	3,194	2,687	2,115
16		Legislative and regulatory	-	-	1,617	1,662	1,701	-	-	-	-	-	-
17		Other reliability, safety and environment	2,464	1,263	3,124	3,622	3,479	3,852	4,329	1,485	1,204	1,363	760
18		**Total reliability, safety and environment**	5,350	3,988	8,061	10,172	10,314	8,898	9,267	5,436	4,398	4,050	2,875
19		**Expenditure on network assets**	143,291	157,526	191,830	200,075	210,556	210,056	210,821	198,023	203,543	210,408	205,270
20		Expenditure on non-network assets	5,375	19,658	21,659	10,372	16,161	10,211	9,870	5,178	3,949	6,468	6,115
21		**Expenditure on assets**	148,666	177,184	213,489	210,447	226,717	220,267	220,691	203,201	207,492	216,876	211,385
22													
23	*plus*	Cost of financing	1,138	2,119	3,784	1,545	2,347	2,659	2,457	431	489	-	-
24	*less*	Value of capital contributions	24,333	25,154	23,425	23,150	23,206	20,731	22,429	20,543	24,669	23,604	22,077
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	125,471	154,149	193,848	188,842	205,858	202,195	200,719	183,089	183,312	193,272	189,308
28													
29		Assets commissioned	110,926	116,022	226,538	179,142	186,939	221,145	226,430	179,706	188,701	188,615	190,418

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
32			**$000 (in 2016 constant prices)**										
33		Consumer connection	36,771	35,608	32,018	31,075	30,447	26,443	28,249	25,053	29,877	27,883	25,480
34		System growth	36,198	49,794	59,719	52,732	56,123	58,417	55,711	52,019	52,672	56,378	51,411
35		Asset replacement and renewal	61,059	62,284	79,285	87,827	89,938	88,310	84,823	80,009	76,057	75,408	76,027
36		Asset relocations	2,661	2,292	2,263	2,273	2,270	2,245	2,220	2,213	2,212	2,211	2,220
37		Reliability, safety and environment:											
38		Quality of supply	2,860	2,662	3,184	4,591	4,720	4,529	4,322	3,369	2,653	2,175	1,668
39		Legislative and regulatory	-	-	1,551	1,558	1,556	-	-	-	-	-	-
40		Other reliability, safety and environment	2,442	1,234	2,828	3,137	2,933	3,176	3,496	1,181	949	1,040	559
41		**Total reliability, safety and environment**	5,302	3,896	7,563	9,286	9,209	7,705	7,818	4,550	3,602	3,215	2,227
42		**Expenditure on network assets**	141,991	153,874	180,848	183,193	187,987	183,120	178,821	163,844	164,420	165,095	157,365
43		Expenditure on non-network assets	5,327	19,202	20,774	9,764	14,931	9,213	8,696	4,456	3,318	5,308	4,900
44		**Expenditure on assets**	147,318	173,076	201,622	192,957	202,918	192,333	187,517	168,300	167,738	170,403	162,265
45													

Subcomponents of expenditure on assets (where known)

Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
Difference between nominal and constant price forecasts	$000										
Consumer connection	337	845	1,807	2,649	3,321	3,574	4,547	4,703	6,437	6,798	6,854
System growth	331	1,182	3,621	4,962	7,300	8,886	10,556	11,314	12,752	15,925	16,078
Asset replacement and renewal	559	1,478	4,952	8,225	10,629	13,015	15,125	16,896	18,696	21,249	23,757
Asset relocations	25	55	104	160	214	268	323	380	442	506	568
Reliability, safety and environment:											
Quality of supply	26	63	136	297	414	517	616	582	541	512	447
Legislative and regulatory	-	-	66	104	145	-	-	-	-	-	-
Other reliability, safety and environment	22	29	296	485	546	676	833	304	255	323	201
Total reliability, safety and environment	48	92	498	886	1,105	1,193	1,449	886	796	835	648
Expenditure on network assets	1,300	3,652	10,982	16,882	22,569	26,936	32,000	34,179	39,123	45,313	47,905
Expenditure on non-network assets	48	456	885	608	1,230	998	1,174	722	631	1,160	1,215
Expenditure on assets	1,348	4,108	11,867	17,490	23,799	27,934	33,174	34,901	39,754	46,473	49,120

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
*Consumer types defined by EDB**	**$000 (in 2016 constant prices)**					
All Consumers	36,771	35,608	32,018	31,075	30,447	26,443
[EDB consumer type]	-	-	-	-	-	-
[EDB consumer type]	-	-	-	-	-	-
[EDB consumer type]	-	-	-	-	-	-
[EDB consumer type]	-	-	-	-	-	-
**include additional rows if needed*						
Consumer connection expenditure	36,771	35,608	32,018	31,075	30,447	26,443
less Capital contributions funding consumer connection	22,485	23,085	21,029	20,319	19,931	17,282
Consumer connection less capital contributions	14,286	12,523	10,989	10,756	10,516	9,161

11a(iii): System Growth

Subtransmission	8,701	13,667	18,912	21,971	19,825	27,069
Zone substations	8,844	10,756	16,229	6,940	17,074	12,096
Distribution and LV lines	4,330	4,217	4,053	4,112	4,147	4,042
Distribution and LV cables	4,111	5,223	4,516	3,769	3,738	3,823
Distribution substations and transformers	762	743	3,001	3,613	1,481	712
Distribution switchgear	4,360	4,236	4,063	4,121	4,157	4,079
Other network assets	5,090	10,952	8,945	8,206	5,701	6,596
System growth expenditure	36,198	49,794	59,719	52,732	56,123	58,417
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	36,198	49,794	59,719	52,732	56,123	58,417

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**

11a(iv): Asset Replacement and Renewal

	$000 (in 2016 constant prices)					
Subtransmission	9,658	4,214	4,537	6,487	4,809	3,891
Zone substations	7,833	11,535	15,525	15,682	14,000	12,742
Distribution and LV lines	23,129	23,950	31,940	38,116	44,203	47,729
Distribution and LV cables	6,034	6,208	6,639	6,847	6,832	6,367
Distribution substations and transformers	5,604	5,597	7,007	7,091	7,211	7,036
Distribution switchgear	7,860	8,350	8,816	8,693	8,442	8,406
Other network assets	941	2,430	4,821	4,911	4,441	2,139
Asset replacement and renewal expenditure	61,059	62,284	79,285	87,827	89,938	88,310
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	61,059	62,284	79,285	87,827	89,938	88,310

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**

11a(v):Asset Relocations

*Project or programme**	**$000 (in 2016 constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other project or programmes - asset relocations	2,661	2,292	2,263	2,273	2,270	2,245
Asset relocations expenditure	2,661	2,292	2,263	2,273	2,270	2,245
less Capital contributions funding asset relocations	1,627	1,486	1,486	1,486	1,486	1,468
Asset relocations less capital contributions	1,034	806	777	787	784	777

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**

11a(vi):Quality of Supply

*Project or programme**	**$000 (in 2016 constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - quality of supply	2,860	2,662	3,184	4,591	4,720	4,529
Quality of supply expenditure	2,860	2,662	3,184	4,591	4,720	4,529
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	2,860	2,662	3,184	4,591	4,720	4,529

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

11a(vii): Legislative and Regulatory

*Project or programme**	$000 (in 2016 constant prices)					
Secondary systems (relay replacement for extended reserves)	-	-	1,551	1,558	1,556	-
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
Legislative and regulatory expenditure	-	-	1,551	1,558	1,556	-
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-
Legislative and regulatory less capital contributions	-	-	1,551	1,558	1,556	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

11a(viii): Other Reliability, Safety and Environment

*Project or programme**	$000 (in 2016 constant prices)					
Zone substations	1,735	533	1,194	1,497	1,295	1,600
Distribution transformers	707	701	1,070	1,074	1,073	1,032
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment	-	-	564	566	565	544
Other reliability, safety and environment expenditure	2,442	1,234	2,828	3,137	2,933	3,176
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	2,442	1,234	2,828	3,137	2,933	3,176

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

11a(ix): Non-Network Assets

Routine expenditure

*Project or programme**	$000 (in 2016 constant prices)					
ICT capex	5,204	14,277	17,902	8,457	13,225	6,860
Facilities capex	112	258	338	239	696	118
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	5,316	14,535	18,240	8,696	13,921	6,978

Atypical expenditure

*Project or programme**						
Facilities capex	11	4,667	2,534	1,068	1,010	2,235
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	11	4,667	2,534	1,068	1,010	2,235
Expenditure on non-network assets	5,327	19,202	20,774	9,764	14,931	9,213

A2.1.2 CONSTANT PRICES (2017 REAL DOLLARS) AND NOMINAL DOLLARS

Company Name	Powerco
AMP Planning Period	1 April 2017 – 31 March 2027

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	37,108	36,453	33,825	33,724	33,768	30,017	32,796	29,756	36,314	34,681	32,334
11		System growth	36,529	50,976	63,340	57,694	63,423	67,303	66,267	63,333	65,424	72,303	67,489
12		Asset replacement and renewal	61,618	63,762	84,237	96,052	100,567	101,325	99,948	96,905	94,753	96,657	99,784
13		Asset relocations	2,686	2,347	2,367	2,433	2,484	2,513	2,543	2,593	2,654	2,717	2,788
14		Reliability, safety and environment:											
15		Quality of supply	2,886	2,725	3,320	4,888	5,134	5,046	4,938	3,951	3,194	2,687	2,115
16		Legislative and regulatory	-	-	1,617	1,662	1,701	-	-	-	-	-	-
17		Other reliability, safety and environment	2,464	1,263	3,124	3,622	3,479	3,852	4,329	1,485	1,204	1,363	760
18		**Total reliability, safety and environment**	5,350	3,988	8,061	10,172	10,314	8,898	9,267	5,436	4,398	4,050	2,875
19		**Expenditure on network assets**	143,291	157,526	191,830	200,075	210,556	210,056	210,821	198,023	203,543	210,408	205,270
20		Expenditure on non-network assets	5,375	19,658	21,659	10,372	16,161	10,211	9,870	5,178	3,949	6,468	6,115
21		**Expenditure on assets**	148,666	177,184	213,489	210,447	226,717	220,267	220,691	203,201	207,492	216,876	211,385
22													
23	*plus*	Cost of financing	1,138	2,119	3,784	1,545	2,347	2,659	2,457	431	489	-	-
24	*less*	Value of capital contributions	24,333	25,154	23,425	23,150	23,206	20,731	22,429	20,543	24,669	23,604	22,077
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	125,471	154,149	193,848	188,842	205,858	202,195	200,719	183,089	183,312	193,272	189,308
28													
29		Assets commissioned	110,926	116,022	226,538	179,142	186,939	221,145	226,430	179,706	188,701	188,615	190,418

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
32			**$000 (in 2017 constant prices)**										
33		Consumer connection	37,108	35,934	32,311	31,360	30,726	26,685	28,508	25,283	30,151	28,138	25,713
34		System growth	36,529	50,251	60,265	53,216	56,637	58,952	56,221	52,496	53,155	56,895	51,882
35		Asset replacement and renewal	61,618	62,855	80,012	88,632	90,762	89,119	85,600	80,742	76,754	76,099	76,724
36		Asset relocations	2,686	2,313	2,284	2,294	2,291	2,266	2,240	2,233	2,232	2,231	2,240
37		Reliability, safety and environment:											
38		Quality of supply	2,886	2,686	3,213	4,633	4,763	4,570	4,362	3,400	2,677	2,195	1,683
39		Legislative and regulatory	-	-	1,565	1,572	1,570	-	-	-	-	-	-
40		Other reliability, safety and environment	2,464	1,245	2,854	3,166	2,960	3,205	3,528	1,192	958	1,050	564
41		**Total reliability, safety and environment**	5,350	3,931	7,632	9,371	9,293	7,775	7,890	4,592	3,635	3,245	2,247
42		**Expenditure on network assets**	143,291	155,284	182,504	184,873	189,709	184,797	180,459	165,346	165,927	166,608	158,806
43		Expenditure on non-network assets	5,375	19,378	20,964	9,853	15,067	9,297	8,776	4,497	3,348	5,357	4,945
44		**Expenditure on assets**	148,666	174,662	203,468	194,726	204,776	194,094	189,235	169,843	169,275	171,965	163,751
45													

Subcomponents of expenditure on assets (where known)

Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	519	1,514	2,364	3,042	3,332	4,288	4,473	6,163	6,543	6,621
System growth	-	725	3,075	4,478	6,786	8,351	10,046	10,837	12,269	15,408	15,607
Asset replacement and renewal	-	907	4,225	7,420	9,805	12,206	14,348	16,163	17,999	20,558	23,060
Asset relocations	-	34	83	139	193	247	303	360	422	486	548
Reliability, safety and environment:											
Quality of supply	-	39	107	255	371	476	576	551	517	492	432
Legislative and regulatory	-	-	52	90	131	-	-	-	-	-	-
Other reliability, safety and environment	-	18	270	456	519	647	801	293	246	313	196
Total reliability, safety and environment	-	57	429	801	1,021	1,123	1,377	844	763	805	628
Expenditure on network assets	-	2,242	9,326	15,202	20,847	25,259	30,362	32,677	37,616	43,800	46,464
Expenditure on non-network assets	-	280	695	519	1,094	914	1,094	681	601	1,111	1,170
Expenditure on assets	-	2,522	10,021	15,721	21,941	26,173	31,456	33,358	38,217	44,911	47,634

11a(ii): Consumer Connection

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
*Consumer types defined by EDB**	**$000 (in 2017 constant prices)**					
All Consumers	37,108	35,934	32,311	31,360	30,726	26,685
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	37,108	35,934	32,311	31,360	30,726	26,685
less Capital contributions funding consumer connection	22,691	23,297	21,222	20,505	20,114	17,440
Consumer connection less capital contributions	14,417	12,637	11,089	10,855	10,612	9,245

11a(iii): System Growth

Subtransmission	8,780	13,792	19,085	22,172	20,007	27,317
Zone substations	8,924	10,855	16,378	7,004	17,230	12,207
Distribution and LV lines	4,370	4,256	4,090	4,150	4,185	4,079
Distribution and LV cables	4,149	5,271	4,557	3,804	3,772	3,858
Distribution substations and transformers	769	750	3,028	3,646	1,495	719
Distribution switchgear	4,400	4,275	4,100	4,159	4,195	4,116
Other network assets	5,137	11,052	9,027	8,281	5,753	6,656
System growth expenditure	36,529	50,251	60,265	53,216	56,637	58,952
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	36,529	50,251	60,265	53,216	56,637	58,952

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
	$000 (in 2017 constant prices)					
Subtransmission	9,746	4,253	4,579	6,546	4,853	3,927
Zone substations	7,905	11,641	15,667	15,826	14,128	12,859
Distribution and LV lines	23,341	24,169	32,233	38,465	44,608	48,166
Distribution and LV cables	6,089	6,265	6,700	6,910	6,895	6,425
Distribution substations and transformers	5,655	5,648	7,071	7,156	7,277	7,100
Distribution switchgear	7,932	8,427	8,897	8,773	8,519	8,483
Other network assets	950	2,452	4,865	4,956	4,482	2,159
Asset replacement and renewal expenditure	61,618	62,855	80,012	88,632	90,762	89,119
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	61,618	62,855	80,012	88,632	90,762	89,119

11a(v):Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
*Project or programme**	**$000 (in 2017 constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other project or programmes - asset relocations	2,686	2,313	2,284	2,294	2,291	2,266
Asset relocations expenditure	2,686	2,313	2,284	2,294	2,291	2,266
less Capital contributions funding asset relocations	1,642	1,500	1,500	1,500	1,500	1,481
Asset relocations less capital contributions	1,044	813	784	794	791	785

11a(vi):Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
*Project or programme**	**$000 (in 2017 constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - quality of supply	2,886	2,686	3,213	4,633	4,763	4,570
Quality of supply expenditure	2,886	2,686	3,213	4,633	4,763	4,570
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	2,886	2,686	3,213	4,633	4,763	4,570

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136		for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

137 11a(vii): Legislative and Regulatory

Row	Project or programme*		$000 (in 2017 constant prices)					
139	Secondary systems (relay replacement for extended reserves)		-	-	1,565	1,572	1,570	-
140	[Description of material project or programme]							
141	[Description of material project or programme]							
142	[Description of material project or programme]							
143	[Description of material project or programme]							
144	*include additional rows if needed							
145	All other projects or programmes - legislative and regulatory		-	-	-	-	-	-
146	**Legislative and regulatory expenditure**		-	-	1,565	1,572	1,570	-
147	*less* Capital contributions funding legislative and regulatory		-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**		-	-	1,565	1,572	1,570	-
149								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
151		for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

151 11a(viii): Other Reliability, Safety and Environment

Row	Project or programme*		$000 (in 2017 constant prices)					
153	Zone substations		1,751	538	1,205	1,511	1,307	1,615
154	Distribution transformers		713	707	1,080	1,084	1,083	1,041
155	[Description of material project or programme]							
156	[Description of material project or programme]							
157	[Description of material project or programme]							
158	*include additional rows if needed							
159	All other projects or programmes - other reliability, safety and environment		-	-	569	571	570	549
160	**Other reliability, safety and environment expenditure**		2,464	1,245	2,854	3,166	2,960	3,205
161	*less* Capital contributions funding other reliability, safety and environment		-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**		2,464	1,245	2,854	3,166	2,960	3,205
163								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165		for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

166 11a(ix): Non-Network Assets

Row			$000 (in 2017 constant prices)					
167	**Routine expenditure**							
168	*Project or programme**							
169	ICT capex		5,251	14,408	18,066	8,534	13,346	6,923
170	Facilities capex		113	260	341	241	702	119
171	[Description of material project or programme]							
172	[Description of material project or programme]							
173	[Description of material project or programme]							
174	*include additional rows if needed							
175	All other projects or programmes - routine expenditure							
176	**Routine expenditure**		5,364	14,668	18,407	8,775	14,048	7,042
177	**Atypical expenditure**							
178	*Project or programme**							
179	Facilities capex		11	4,710	2,557	1,078	1,019	2,255
180	[Description of material project or programme]							
181	[Description of material project or programme]							
182	[Description of material project or programme]							
183	[Description of material project or programme]							
184	*include additional rows if needed							
185	All other projects or programmes - atypical expenditure							
186	**Atypical expenditure**		11	4,710	2,557	1,078	1,019	2,255
187								
188	**Expenditure on non-network assets**		5,375	19,378	20,964	9,853	15,067	9,297

A2.2 SCHEDULE 11B

We include two versions of schedule 11b. One version uses constant prices in 2016 real dollars (for alignment to this AMP and our CPP application). The other version uses constant prices in 2017 real dollars, as per the Commerce Commission's information disclosure requirements for a 2017 AMP and for consistency with other electricity distributors' disclosures.

A2.2.1 CONSTANT PRICES (2016 REAL DOLLARS) AND NOMINAL DOLLARS

Company Name Powerco
AMP Planning Period 1 April 2017 – 31 March 2027

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	6,795	7,249	7,524	7,788	8,058	8,148	8,243	8,460	8,683	8,912	9,147
11	Vegetation management	5,803	5,631	10,367	9,840	9,742	10,236	9,814	9,755	8,828	9,005	9,185
12	Routine and corrective maintenance and inspection	8,553	9,805	12,984	14,195	14,799	13,977	14,166	14,519	14,352	15,405	14,982
13	Asset replacement and renewal	11,015	11,054	11,900	13,471	13,772	13,003	12,769	11,330	10,436	10,685	10,940
14	**Network Opex**	32,166	33,739	42,775	45,294	46,371	45,364	44,992	44,064	42,299	44,007	44,254
15	System operations and network support	12,144	14,243	16,114	17,527	18,512	18,570	18,846	17,948	17,923	18,085	18,302
16	Business support	33,204	32,797	34,408	36,097	36,458	36,594	36,420	37,664	38,285	39,087	39,914
17	**Non-network opex**	45,348	47,040	50,522	53,624	54,970	55,164	55,266	55,612	56,208	57,172	58,216
18	**Operational expenditure**	77,514	80,779	93,297	98,918	101,341	100,528	100,258	99,676	98,507	101,179	102,470
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
21		**$000 (in 2016 constant prices)**										
22	Service interruptions and emergencies	6,733	7,081	7,214	7,311	7,409	7,348	7,288	7,333	7,379	7,425	7,471
23	Vegetation management	5,750	5,500	9,939	9,237	8,957	9,231	8,677	8,455	7,502	7,502	7,502
24	Routine and corrective maintenance and inspection	8,476	9,578	12,443	13,315	13,591	12,590	12,510	12,570	12,181	12,819	12,223
25	Asset replacement and renewal	10,915	10,797	11,403	12,636	12,648	11,712	11,276	9,809	8,857	8,891	8,925
26	**Network Opex**	31,874	32,956	40,999	42,499	42,605	40,881	39,751	38,167	35,919	36,637	36,121
27	System operations and network support	12,034	13,913	15,463	16,479	17,057	16,786	16,701	15,594	15,266	15,103	14,984
28	Business support	32,903	32,037	32,966	33,845	33,460	32,939	32,139	32,586	32,474	32,504	32,541
29	**Non-network opex**	44,937	45,950	48,429	50,324	50,517	49,725	48,840	48,180	47,740	47,607	47,525
30	**Operational expenditure**	76,811	78,906	89,428	92,823	93,122	90,606	88,591	86,347	83,659	84,244	83,646
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	62	168	310	477	649	800	955	1,127	1,304	1,487	1,676
43	Vegetation management	53	131	428	603	785	1,005	1,137	1,300	1,326	1,503	1,683
44	Routine and corrective maintenance and inspection	77	227	541	880	1,208	1,387	1,656	1,949	2,171	2,586	2,759
45	Asset replacement and renewal	100	257	497	835	1,124	1,291	1,493	1,521	1,579	1,794	2,015
46	**Network Opex**	292	783	1,776	2,795	3,766	4,483	5,241	5,897	6,380	7,370	8,133
47	System operations and network support	110	330	651	1,048	1,455	1,784	2,145	2,354	2,657	2,982	3,318
48	Business support	301	760	1,442	2,252	2,998	3,655	4,281	5,078	5,811	6,583	7,373
49	**Non-network opex**	411	1,090	2,093	3,300	4,453	5,439	6,426	7,432	8,468	9,565	10,691
50	**Operational expenditure**	703	1,873	3,869	6,095	8,219	9,922	11,667	13,329	14,848	16,935	18,824

A2.2.2 CONSTANT PRICES (2017 REAL DOLLARS) AND NOMINAL DOLLARS

Company Name	Powerco
AMP Planning Period	1 April 2017 – 31 March 2027

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7												
8	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	6,795	7,249	7,524	7,788	8,058	8,148	8,243	8,460	8,683	8,912	9,147
11	Vegetation management	5,803	5,631	10,367	9,840	9,742	10,236	9,814	9,755	8,828	9,005	9,185
12	Routine and corrective maintenance and inspection	8,553	9,805	12,984	14,195	14,799	13,977	14,166	14,519	14,352	15,405	14,982
13	Asset replacement and renewal	11,015	11,054	11,900	13,471	13,772	13,003	12,769	11,330	10,436	10,685	10,940
14	**Network Opex**	32,166	33,739	42,775	45,294	46,371	45,364	44,992	44,064	42,299	44,007	44,254
15	System operations and network support	12,144	14,243	16,114	17,527	18,512	18,570	18,846	17,948	17,923	18,085	18,302
16	Business support	33,204	32,797	34,408	36,097	36,458	36,594	36,420	37,664	38,285	39,087	39,914
17	**Non-network opex**	45,348	47,040	50,522	53,624	54,970	55,164	55,266	55,612	56,208	57,172	58,216
18	**Operational expenditure**	77,514	80,779	93,297	98,918	101,341	100,528	100,258	99,676	98,507	101,179	102,470
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
21		**$000 (in constant 2017 prices)**										
22	Service interruptions and emergencies	6,795	7,146	7,280	7,378	7,477	7,415	7,355	7,400	7,447	7,493	7,539
23	Vegetation management	5,803	5,550	10,030	9,322	9,039	9,316	8,757	8,532	7,571	7,571	7,571
24	Routine and corrective maintenance and inspection	8,553	9,666	12,557	13,437	13,716	12,705	12,625	12,685	12,293	12,936	12,335
25	Asset replacement and renewal	11,015	10,896	11,507	12,752	12,764	11,819	11,379	9,899	8,938	8,972	9,007
26	**Network Opex**	32,166	33,258	41,374	42,889	42,996	41,255	40,116	38,516	36,249	36,972	36,452
27	System operations and network support	12,144	14,040	15,605	16,630	17,213	16,940	16,854	15,737	15,406	15,241	15,121
28	Business support	33,204	32,331	33,268	34,155	33,767	33,241	32,433	32,885	32,772	32,802	32,839
29	**Non-network opex**	45,348	46,371	48,873	50,785	50,980	50,181	49,287	48,622	48,178	48,043	47,960
30	**Operational expenditure**	77,514	79,629	90,247	93,674	93,976	91,436	89,403	87,138	84,427	85,015	84,412
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	103	244	410	581	733	888	1,060	1,236	1,419	1,608
43	Vegetation management	-	81	337	518	703	920	1,057	1,223	1,257	1,434	1,614
44	Routine and corrective maintenance and inspection	-	139	427	758	1,083	1,272	1,541	1,834	2,059	2,469	2,647
45	Asset replacement and renewal	-	158	393	719	1,008	1,184	1,390	1,431	1,498	1,713	1,933
46	**Network Opex**	-	481	1,401	2,405	3,375	4,109	4,876	5,548	6,050	7,035	7,802
47	System operations and network support	-	203	509	897	1,299	1,630	1,992	2,211	2,517	2,844	3,181
48	Business support	-	466	1,140	1,942	2,691	3,353	3,987	4,779	5,513	6,285	7,075
49	**Non-network opex**	-	669	1,649	2,839	3,990	4,983	5,979	6,990	8,030	9,129	10,256
50	**Operational expenditure**	-	1,150	3,050	5,244	7,365	9,092	10,855	12,538	14,080	16,164	18,058

A2.3 SCHEDULE 12A

Company Name	Powerco
AMP Planning Period	1 April 2017 - 31 March 2027

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref											
7					**Asset condition at start of planning period (percentage of units by grade)**						
8	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	1.4%	1.9%	8.7%	88.0%	-	4	2.8%
11	All	Overhead Line	Wood poles	No.	11.6%	14.7%	36.6%	37.1%	-	4	22.0%
12	All	Overhead Line	Other pole types	No.	-	-	-	26.2%	73.8%	1	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.8%	0.6%	12.3%	85.3%	-	4	4.9%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	16.5%	83.5%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	8.6%	17.3%	74.1%	-	4	8.6%
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	-	-	4.1%	95.9%	-	4	-
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.	8.8%	43.1%	7.8%	37.4%	2.9%	3	20.6%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	4.8%	-	95.2%	-	4	3.2%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	2.2%	51.9%	45.9%	-	4	24.0%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	91.3%	8.7%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	17.9%	4.9%	35.6%	41.6%	-	4	15.6%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	100.0%	-	-	4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	36.8%	63.2%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	2.9%	39.5%	57.6%	-	4	19.3%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3.6%	-	14.3%	82.1%	-	4	3.6%
35											

36					Asset condition at start of planning period (percentage of units by grade)						
37	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5.2%	1.6%	52.4%	40.8%	-	4	7.9%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	15.7%	1.2%	16.5%	66.6%	-	3	5.8%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	18.3%	81.7%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1.8%	-	11.3%	86.9%	-	3	1.8%
44	HV	Distribution Cable	Distribution UG PILC	km	4.8%	-	6.7%	88.5%	-	3	4.8%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	100.0%	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	0.2%	5.4%	94.3%	-	4	0.2%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	11.3%	42.2%	7.3%	39.2%	-	4	51.7%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.8%	2.6%	28.6%	67.0%	-	3	7.3%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	10.9%	1.1%	38.8%	49.2%	-	4	8.9%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	17.1%	1.5%	11.0%	70.4%	-	4	15.1%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.2%	2.0%	19.7%	76.0%	-	3	5.5%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.5%	1.2%	13.3%	85.0%	-	4	3.0%
53	HV	Distribution Transformer	Voltage regulators	No.	3.6%	-	8.9%	87.5%	-	4	2.7%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.6%	1.3%	14.3%	83.8%	-	3	3.6%
55	LV	LV Line	LV OH Conductor	km	1.0%	1.4%	25.2%	72.5%	-	2	2.4%
56	LV	LV Cable	LV UG Cable	km	-	-	16.5%	83.5%	-	2	1.0%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.7%	1.0%	29.6%	68.7%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	1.9%	11.5%	39.0%	47.6%	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	28.5%	18.1%	53.4%	-	3	32.3%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	26.5%	15.1%	58.5%	-	3	14.9%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.0%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	27.8%	5.6%	66.7%	-	4	16.7%
63	All	Load Control	Relays	No.	6.9%	46.4%	4.4%	42.4%	-	1	51.5%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Notes:

1. We interpret Grade 1 condition as assets requiring replacement within one year, based on our asset health models. This does not mean the assets are at imminent risk of failure, but rather have reached the end of their useful life. With appropriate risk mitigations (such as operating constraints for switchgear), these assets can safely continue in service for more than one year, though we do not consider this a sustainable practice over the longer term.
2. The '% of asset forecast to be replaced in next 5 years' for Zone Substation Buildings is based on our seismic strengthening programme. The buildings will be strengthened via various means, but typically not replaced. This ensures consistency with our renewal Capex forecasts.
3. The '% of asset forecast to be replaced in next 5 years' is based on a denominator of operational network sites, whereas disclosure schedules 9a and 9b additionally include spares.

A2.4 SCHEDULE 12B

Company Name Powerco
AMP Planning Period 1 April 2017 – 31 March 2027

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

8	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Coromandel	4.7	-	N-1 SW	-		-	-	Subtransmission circuit	Single 66kV circuit.
10	Kerepehi	10.1	-	N	1.8	-	6.5	162%	Transformer	Upgrade removes single cct constraint, exposing Tx cap
11	Matatoki	5.6	-	N	1.7	-	-	-	Transformer	Single Tx
12	Tairua	8.6	7.5	N	-	115%	7.5	119%	Transformer	Subtr. Upgrades. Sub remains just over Tx firm capacity.
13	Thames T1 & T2	13.4	-	N-1	1.7	-	19.2	71%	No constraint within +5 years	66kV upgrade removes binding constraint
14	Thames T3	3.4	6.9	N-1 SW	6.9	49%	6.9	49%	No constraint within +5 years	
15	Whitianga	17.2	-	N-1	1.4	-	16.2	67%	No constraint within +5 years	Subtrans upgrades, Txs offloaded & protection upgrades
16	Paeroa	8.3	6.0	N	2.0	140%	10.2	84%	No constraint within +5 years	Transfs replaced during period.
17	Waihi	18.3	16.0	N-1	-	114%	16.0	119%	No constraint within +5 years	Customer agreed security.
18	Waihi Beach	5.9	3.3	N	3.3	178%	3.3	192%	Subtransmission Circuit	Single 33kV circuit
19	Whangamata	10.5	-	N	0.5	-	-	-	Subtransmission circuit	2nd circuit deferred o/s 5 yrs by non-network strategies
20	Aongatete	8.4	7.2	N	1.2	117%	12.0	80%	No constraint within +5 years	Upgrades on subtrans inc. allocated capacity
21	Bethlehem	9.4	8.0	N	8.0	117%	8.0	145%	Transformer	New 1 x Transf Sub - needs 2nd Tx soon after 2022
22	Hamilton St	15.5	22.4	N-1	10.7	69%	22.4	74%	No constraint within +5 years	
23	Katikati	8.3	5.3	N	5.3	158%	11.0	82%	No constraint within +5 years	2nd circuit & 2nd Tx just before 2022.
24	Kauri Pt	3.1	2.0	N	2.0	159%	2.0	165%	Subtransmission Circuit	Single Tx and 33kV circuit limit security.
25	Matua	10.2	7.2	N-1	7.2	141%	7.2	144%	Subtransmission circuit	Circuit & Tx upgrades planned just after 2022
26	Omokoroa	11.5	13.2	N-1	1.2	87%	13.2	94%	No constraint within +5 years	33kV upgrades pre 2022.
27	Otumoetai	14.0	13.6	N	-	103%	13.6	116%	Transformer	Minor constraint - managed operationally.
28	Waihi Rd	21.9	24.1	N-1	12.3	91%	24.1	93%	No constraint within +5 years	
29	Welcome Bay	22.6	21.4	N-1	4.5	106%	21.4	118%	Transformer	Constraint managed operationally. Possibly offloads.
30	Matapihi	14.4	24.1	N-1	14.1	60%	24.1	63%	No constraint within +5 years	
31	Omanu	15.6	24.3	N-1	11.1	64%	24.3	66%	No constraint within +5 years	
32	Papamoa	19.5	21.3	N-1	9.8	92%	21.4	90%	No constraint within +5 years	Offload to new Subs maintains security.
33	Te Maunga	8.4	9.1	N	6.9	92%	9.1	100%	No constraint within +5 years	New Substation - will require 2nd Tx in future.
34	Triton	21.4	21.3	N-1	11.2	100%	22.9	98%	No constraint within +5 years	Small constraint operationally managed or routine upgrade
35	Atuaroa Ave	8.1	-	N	6.3	-	-	-	Subtransmission Circuit	Single Tx & part single circuit. Possible upgr post 2022
36	Paengaroa	4.1	2.3	N	2.3	178%	2.3	178%	Subtransmission Circuit	New N security Sub - longer term plans to secure
37	Pongakawa	7.4	2.1	N-1	2.1	350%	2.1	360%	Subtransmission Circuit	Single 33kV circuit
38	Te Puke	20.4	22.9	N-1	11.1	89%	22.9	92%	No constraint within +5 years	
39	Farmer Rd	5.9	-	N-1	6.4	-	-	-	Subtransmission circuit	Switched backfeed o/s nominal security requirements
40	Inghams	3.8	3.6	N	3.6	105%	3.6	105%	No constraint within +5 years	Customer agreed security
41	Mikkelsen Rd	15.2	19.2	N-1	4.0	79%	19.2	80%	No constraint within +5 years	
42	Morrinsville	10.7	-	N	1.3	-	-	-	Subtransmission circuit	2nd 33kV circuit completed ~2022
43	Piako	15.0	15.2	N-1	1.2	99%	15.2	105%	Transformer	Minor constraint - managed operationally.
44	Tahuna	5.7	0.8	N-1	0.8	719%	0.8	731%	Subtransmission Circuit	Single 33kV circuit. Investigate 11kV backfeed upgrades
45	Tatua	4.5	1.2	N	1.2	390%	1.2	390%	No constraint within +5 years	Customer agreed security
46	Waitoa	12.7	18.8	N-1	-	68%	18.8	68%	No constraint within +5 years	
47	Walton	5.9	-	N	0.6	-	-	-	Transformer	Single Transformer. Risk managed operationally
48	Browne St	9.9	10.6	N-1	3.8	94%	10.6	101%	Transformer	Very minor, low risk. Managed operationally
49	Lake Rd	5.9	0.9	N	-	649%	14.0	43%	No constraint within +5 years	2nd transformer in 2019
50	Tirau	9.5	-	N	-	-	-	-	Transformer	Single transformer. 2nd Tx planned post 2022

51		Putaruru	11.6	-	N	0.5	-	17.0	70%	No constraint within +5 years	New GXP, Subtrans. & transf. upgrades by ~2022.
52		Tower Rd	9.8	-	N	3.5	-	17.0	63%	No constraint within +5 years	GXP and Subtrans upgraded, & 2nd Tx added
53		Waharoa	7.8	-	N-1	-	-	-	-	Subtransmission Circuit	Subtrans upgrades complete ~2023
54		Baird Rd	10.3	-	N-1	4.0	-	11.3	95%	No constraint within +5 years	Subtransmission upgraded ~2018
55		Midway / Lakeside	4.4	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security
56		Maraetai Rd	11.2	-	N-1	4.7	-	17.0	67%	No constraint within +5 years	Subtransmission upgraded ~2018
57		Bell Block	18.4	22.9	N-1	12.1	80%	22.9	91%	No constraint within +5 years	
58		Brooklands	15.3	27.0	N-1	9.5	57%	27.0	60%	No constraint within +5 years	
59		Cardiff	1.6	4.1	N-1 SW	4.1	39%	4.1	41%	No constraint within +5 years	
60		City	19.1	20.1	N-1	10.7	95%	20.1	98%	No constraint within +5 years	
61		Cloton Rd	10.7	13.0	N-1	1.0	82%	13.0	85%	No constraint within +5 years	
62		Douglas	1.7	1.7	N	1.7	101%	1.7	101%	Subtransmission circuit	Single circuit. Very low risk. Most load can be backfed.
63		Eltham	9.9	8.6	N-1	2.6	115%	15.3	65%	No constraint within +5 years	Transformer upgrade ~2021
64		Inglewood	5.4	6.2	N-1	1.8	87%	6.2	92%	No constraint within +5 years	
65		Kaponga	3.7	3.0	N-1	1.7	123%	3.0	124%	Transformer	Low risk of failure. Operationally managed.
66		Katere	13.5	24.3	N-1	10.0	56%	24.3	64%	No constraint within +5 years	
67		McKee	1.4	1.6	N-1 SW	1.6	89%	1.6	97%	No constraint within +5 years	
68		Motukawa	1.2	0.6	N	0.6	204%	0.6	210%	Transformer	Single transformer
69		Moturoa	22.5	21.4	N-1	11.2	105%	30.0	80%	No constraint within +5 years	33kV circuits and transformers replaced ~2019
70		Oakura	3.5	4.2	N-1 SW	4.2	83%	4.2	90%	No constraint within +5 years	Single cct & Tx. 11kV backfed adequate for ~10 years
71		Pohokura	5.2	9.2	N-1	-	57%	9.2	57%	No constraint within +5 years	
72		Waihapa	1.2	1.4	N-1	1.4	87%	1.4	87%	No constraint within +5 years	
73		Waitara East	6.3	10.1	N-1	1.1	62%	10.1	66%	No constraint within +5 years	
74		Waitara West	6.9	6.4	N	-	107%	6.4	109%	Transformer	Risk of failure is low. Managed operationally.
75		Cambria	15.6	17.0	N-1	5.2	92%	17.0	95%	No constraint within +5 years	
76		Kapuni	6.8	7.0	N-1	3.4	98%	7.0	97%	No constraint within +5 years	
77		Livingstone	3.2	3.1	N-1	0.7	106%	5.0	65%	No constraint within +5 years	Transformers scheduled for replacement (higher cap)
78		Manaia	7.8	5.0	N	5.0	157%	5.0	157%	Transformer	33kV Tee resolved ~2022. Single Tx bank (after renewal)
79		Ngariki	3.7	3.8	N-1 SW	3.8	97%	3.8	98%	No constraint within +5 years	
80		Pungarehu	4.5	4.5	N-1	1.9	100%	4.5	102%	Transformer	Low risk - operationally managed (e.g. backfeeds)
81		Tasman	7.1	6.4	N-1	2.8	111%	6.4	112%	Transformer	Low risk - operationally managed (e.g. backfeeds)
82		Whareroa	4.5	3.0	N	3.0	150%	5.0	93%	No constraint within +5 years	Sub to be relocated (Mokoia Sub) with higher capacity
83		Beach Rd	10.9	13.6	N-1	-	80%	13.6	83%	No constraint within +5 years	Subtrans upgrades complete pre 2022.
84		Blink Bonnie	4.4	2.3	N	2.3	193%	2.3	197%	Transformer	Single transformer. Low risk of failure
85		Castlecliff	11.5	8.7	N-1	0.5	132%	12.8	92%	No constraint within +5 years	33kV upgrades & Tx incomers within 5 years.
86		Hatricks Wharf	11.5	-	N	6.0	-	10.0	115%	Transformer	Single transf, but 11kV bus tie (Taupo Quay) mitigates risk
87		Kai Iwi	2.4	1.0	N	1.0	249%	1.0	257%	Subtransmission Circuit	Single 33kV cct & single Tx. Also N security GXP.
88		Peat St	19.4	-	N-1	5.6	-	-	-	Transpower	2nd 33kV circuit ~2021, but N secure GXP limits security
89		Roberts Ave	8.4	5.7	N	5.7	147%	5.7	150%	Transpower	2nd 33kV circuit ~2021, but N secure GXP limits security
90		Taupo Quay	11.4	-	N	3.9	-	10.0	115%	Transformer	2nd 33kV circuit built. Single Tx with bus tie limits security.
91		Wanganui East	8.6	3.1	N	3.1	279%	3.1	282%	Subtransmission Circuit	Single 33kV circuit & single transformer.
92		Taihape	5.1	0.7	N	0.7	730%	0.7	727%	Transformer	Single transformer
93		Waiouru	3.0	0.6	N	0.6	542%	0.6	536%	Subtransmission circuit	Single 33kV circuit & single transformer. N secure GXP
94		Arahina	8.9	2.9	N	2.9	307%	2.9	312%	Subtransmission Circuit	Single 33kV circuit & single transformer. N secure GXP
95		Bulls	5.7	4.0	N	4.0	143%	4.0	144%	Subtransmission Circuit	Single transformer. Low risk of failure.
96		Pukepapa	9.0	3.4	N	3.4	265%	3.4	270%	Transformer	Single transformer. Limited backfeed
97		Rata	2.3	0.7	N	0.7	334%	0.7	333%	Subtransmission circuit	Single 33kV circuit & single transformer
98		Feilding	22.0	23.7	N-1	1.9	93%	23.7	98%	No constraint within +5 years	Possible 33kV & substation upgrades in longer term plan.
99		Kairanga	19.6	19.1	N-1	7.4	102%	19.1	106%	Transformer	Transformer upgrade planned ~2023
100		Keith St	19.1	21.9	N-1	0.6	87%	21.9	90%	No constraint within +5 years	Upgrades offload 33kV circuits feeding Main and Keith St

101	Kelvin Grove	18.9	17.2	N-1	4.0	110%	23.7	90%	No constraint within +5 years	Transformers upgraded in ~2021.
102	Kimbolton	3.1	0.6	N	0.6	514%	0.6	520%	Subtransmission Circuit	Single 33kV circuit & single transformer. Remote Sub.
103	Main St	29.4	17.0	N-1	11.6	173%	24.8	90%	No constraint within +5 years	New Sub & 33kV cables address ex. high risk constraints.
104	Milson	18.9	18.1	N-1	5.0	105%	19.2	107%	Transformer	Possible upgrade just beyond 5 year period.
105	Pascal St	23.4	17.0	N-1	11.2	138%	24.6	81%	No constraint within +5 years	New Sub & 33kV cables address ex. high risk constraints.
106	Sanson	8.9	-	N-1	3.9	-	9.6	98%	No constraint within +5 years	33kV backfeed secures load. Tx upgrades post 2022
107	Turitea	16.0	-	N-1	2.1	-	-	-	Subtransmission Circuit	Single 33kV circuit - switched backfeed. Upgr post 2022.
108	Alfredton	0.5	1.4	N	0.2	33%	1.4	33%	No constraint within +5 years	Single Transf. but adequate backfeed.
109	Mangamutu	12.8	12.8	N-1	0.5	100%	12.8	100%	No constraint within +5 years	Major customer largely determines security requirements.
110	Parkville	2.0	-	N	-	-	-	-	Transformer	Single transformer
111	Pongaroa	0.7	2.9	N	0.3	26%	2.9	25%	No constraint within +5 years	Single transformer, but adequate backfeed
112	Akura	13.3	9.0	N-1	5.3	148%	15.0	91%	No constraint within +5 years	Txs replaced & section of 33kV circuit upgraded, pre 2022
113	Awatoitoi	0.7	3.0	N	0.5	24%	3.0	24%	No constraint within +5 years	
114	Chapel	15.3	13.8	N-1	7.3	111%	22.9	69%	No constraint within +5 years	Upgrade short section of 33kV cable pre 2022.
115	Clareville	11.5	10.9	N-1	2.8	106%	10.9	114%	Transformer	Possible upgrade during longer term renewal of Txs.
116	Featherston	5.0	1.5	N	1.5	341%	1.5	358%	Transformer	Single transformer. 2nd bank proposed in longer term
117	Gladstone	0.9	1.4	N	0.3	66%	1.4	66%	No constraint within +5 years	
118	Hau Nui	1.0	-	N	-	-	-	-	No constraint within +5 years	Generation site. Not economic to provide higher security
119	Kempton	5.0	2.1	N	2.1	244%	2.1	261%	Subtransmission Circuit	1 x 33kV circuit & 1 x transformer; Upgrades post 2022.
120	Martinborough	5.0	1.5	N	1.5	347%	1.5	373%	Transformer	Single transformer. 2nd Tx planned post 2022
121	Norfolk	7.1	7.0	N-1	1.7	101%	7.0	111%	Transformer	Risk is very low. Managed operationally.
122	Te Ore Ore	7.4	6.7	N	6.7	111%	6.7	114%	Transformer	Single transformer
123	Tinui	0.5	1.3	N-1 SW	0.6	39%	1.3	40%	No constraint within +5 years	
124	Tuhitarata	3.1	0.2	N	0.2	1,567%	1.0	327%	Subtransmission circuit	Single 33kV circuit & single transformer

126 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

A2.5 SCHEDULE 12C

Company Name: Powerco

AMP Planning Period: 1 April 2017 – 31 March 2027

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
11	*Consumer types defined by EDB**		**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
12	Small		5056	4,569	4,162	4,022	3,945	3,438
13	Commercial		37	33	30	29	28	24
14	Industrial		7	6	5	5	5	4
15								
16								
17	**Connections total**		5,100	4,608	4,197	4,056	3,978	3,466
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		822	822	822	822	822	822
21	Installed connection capacity of distributed generation (MVA)		3.2	3.2	3.2	3.2	3.2	3.2

sch ref									
22		**12c(ii) System Demand**							
23				*Current Year CY*	*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		760	767	774	781	788	795
26	*plus*	Distributed generation output at HV and above		141	143	144	145	146	148
27		**Sch 12c Maximum coincident system demand [MW]**		902	910	918	927	935	943
28	*less*	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**		902	910	918	927	935	943
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		4,311	4,351	4,390	4,430	4,470	4,510
32	*less*	Electricity exports to GXPs		180	182	183	185	187	188
33	*plus*	Electricity supplied from distributed generation		915	923	932	940	949	957
34	*less*	Net electricity supplied to (from) other EDBs							
35		**Electricity entering system for supply to ICPs**		5,046	5,092	5,139	5,185	5,232	5,278
36	*less*	Total energy delivered to ICPs		4,753	4,797	4,841	4,885	4,928	4,972
37		**Losses**		293	295	298	301	303	306
38									
39		**Load factor**		64%	64%	64%	64%	64%	64%
40		**Loss ratio**		5.8%	5.8%	5.8%	5.8%	5.8%	5.8%

A2.6 SCHEDULE 12D

Company Name	Powerco
AMP Planning Period	1 April 2017 – 31 March 2027
Network / Sub-network Name	Powerco - combined

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 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)	45.9	54.6	71.0	75.4	82.0	87.2
12	Class C (unplanned interruptions on the network)	196.2	208.8	210.8	205.5	201.1	199.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.21	0.24	0.31	0.34	0.36	0.38
15	Class C (unplanned interruptions on the network)	2.30	2.29	2.32	2.29	2.28	2.28

Company Name	Powerco
AMP Planning Period	1 April 2017 – 31 March 2027
Network / Sub-network Name	Powerco - Eastern Region

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 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)	45.9	54.6	71.0	75.4	82.0	87.2
12	Class C (unplanned interruptions on the network)	196.2	208.8	210.8	205.5	201.1	199.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.21	0.24	0.31	0.34	0.36	0.38
15	Class C (unplanned interruptions on the network)	2.30	2.29	2.32	2.29	2.28	2.28

Company Name	Powerco
AMP Planning Period	1 April 2017 – 31 March 2027
Network / Sub-network Name	Powerco - Western Region

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 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)	45.9	54.6	71.0	75.4	82.0	87.2
12	Class C (unplanned interruptions on the network)	196.2	208.8	210.8	205.5	201.1	199.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.21	0.24	0.31	0.34	0.36	0.38
15	Class C (unplanned interruptions on the network)	2.30	2.29	2.32	2.29	2.28	2.28

A2.7 SCHEDULE 13

Company Name	**Powerco**
AMP Planning Period	**1 April 2017 – 31 March 2027**
Asset Management Standard Applied	**PAS 55: 2008**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

Question No.	Function	Question	Score	Evidence—Summary
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.8	Our Asset Management Policy has been authorised by our CEO and circulated within Powerco. It is available on our document management system and referenced in our Asset Management Strategy and this AMP.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2.5	Our Asset Management Strategy was created as part of a wider document review, so has a high degree of consistency with the new suite of documentation discussed in this AMP. The Strategy used our Business Plan and Asset Management Policy as a starting point, ensuring a line of sight.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2.7	The Asset Strategy discusses the asset life cycle and its approach to this is summarised in this AMP. Specific asset life cycle strategies have been developed, and again, are summarised in this AMP.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2.6	We have continued to develop our suite of Fleet Management Plans that include work volumes across relevant time periods for all asset types, aligned to the asset information systems. The fleet plans identify inspection regimes and renewal programmes and future needs based on assessment of condition, age and trends in defects and failures.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2.5	We use the AMP as a key tool to communicate plans to our staff as well as external stakeholders The AMP provides a summary of a wide range of plans, and signposts staff to the source documentation of material. All our key standards are also communicated to people when the standards enter our Business Management System and Contractor Works Manual.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.2	There is a range of documents that detail asset management responsibilities. These include Powerco's Business Plan, business unit tactical plans, position descriptions and employees' annual review and development forms. Powerco has detailed documents on responsibilities of service providers as well. Powerco has undertaken process mapping as part of continuous improvement to better align responsibilities.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2.6	Our field contract arrangements have been arranged to provide demonstrable cost efficiency. Deliverability is central to asset management, and our processes consider the skills and competencies needed to ensure cost effective delivery. Powerco has new field service contract arrangements and has reviewed the end to end processes of service provision and now implemented most of the process changes.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2.8	Powerco has well developed and established procedures for dealing with emergencies and incidents that happen fairly regularly e.g. the process to manage storm response and incidents that have public risks, and adoption of a critical incident management system. We also have done a range of investigations on natural disasters, including the impact of earthquakes on key buildings, such as depots.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	2.8	Powerco has a strong organisational structure, that clearly provides roles and responsibilities on assets, operations and commercial work. The responsibilities of ownership are described in Chapter 6 on Governance.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.4	The AMP provides an overview of delivability capability and this is considered in the outsourcing arrangements through the EFSA refinements. The Electricity Division is undergoing restructuring with the purpose of aligning the organisations resources to the AM objectives. The purpose of the CPP application is to give the business sufficient resources to enable achievement of the AM objectives.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.5	As described in our 2013 AMP, and reflected in this AMP, we consider ourselves on a journey towards asset management excellence, and this has been driven from senior management. This includes emphasising the importance of meeting asset management requirements.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.8	Powerco appointed Downer Limited to a new Electricity Field Services Agreement in 2014. A major part of this new contract was ensuring that appropriate controls and incentives are in place. This includes a comprehensive suits of KPIs.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.5	Our Human Resources team has undertaken a range of analysis on training and competence needs and there is a structured approach to training in Powerco. As part of the process to retender service provider contracts, we have also undertaken a range of analysis on what training and competence is required in delivering field services. We have graduate and cadet programmes to bring in new engineering talent into the industry.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.8	We have documented our internal competence requirements for staff as well as for field staff. We are currently implementing these new competence requirements for all our contractors. Our HR team record training activity undertaken, oversee mentoring programmes and induction courses and have a dedicated learning and development role to support this.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.6	As described above, we have a new contractor competency management system that we are rolling out. This will improve the way we ensure contractors have an appropriate level of education, training and experience. Internally, we have useful training and development programmes and will seek to improve these through systematic oversight.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
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?	2.5	Powerco's Asset Management Policy is available to all employees. Powerco's progress on KPIs is reported on the intranet for all staff to view. Standards and notifications are made through the Contractor Works Manual portal. We also seek a range of ways for staff to feed back into the asset management process, e.g. via discussions on the Business Plan and via the standards update process. In addition, there are also a range of systems that communicate asset information e.g. outages, customer initiated work etc. Our AMPs are widely circulated to our stakeholders, including plans to develop an AMP summary.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.5	Powerco has an extensive range of documentation to support its asset management process, such as standards, approval documentation and process mapping. The range of documents we use are described extensively through-out this AMP.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1.9	Information requirements is an area we have continued to work on over the last few years and is a strategic priority in Powerco's Business Plan. In FY16 we undertook a comprehensive business needs exercise across the whole of Powerco. However a review of information criticality and quality remains to be fulfilled.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2.1	Powerco has a range of controls to ensure data is accurate and there is an adequate process of quality review at input and data cleansing plan, for example in the GIS system. We have an established internal assurance team, to provide increased checks on data accuracy, however, this is an area we are always seeking to continuously improve. In FY16 we undertook a project to improve the information we have on the completeness and accuracy of our data.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.5	As described in this AMP, we have recognised that we would benefit from a more fit for purpose asset information system, and details or our ERP Project are provided in Chapter 22. We have plans for a data architecture project (which will be forward looking), which is part of the project mentioned above.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2.3	Chapter 6 details Powerco's processes for risk management and we have a structured approach across the business for identifying risks and a detailed risk register. We have an Asset Lifecycle Plan that identifies specific asset risks. We have an authorised risk policy, management framework, risk matrix.
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?	1.0	Powerco has a structured approach to how risks are managed and actions, including monitoring that reports to the Board Risk and Assurance sub committee.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2.8	Powerco has invested significant resource in the last few years in all aspects of legal and regulatory compliance. The Risk and Assurance and Regulatory teams monitor changes and update the business. A comprehensive compliance review is undertaken each year to ensure compliance with legislation and regulations.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.6	Powerco has a high quality library of standards, with excellent coverage across planning, design, maintenance and safety. We continue to develop this further to remain ahead of the field.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.5	We have good documentation and contractual controls around maintenance. We have been continuously improving the way we manage our defects and techniques for gathering asset inspection data.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.3	Condition assessment programmes are in place and the data collected from the field is building a solid asset condition history. This is an area we are working to improve. We are primarily using lagging measures for scheduled work through worst performing feeders. We have implemented Asset Health Indicators and are planning to incorporate Asset Criticality, which will enable leading measures.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.4	Powerco has invested heavily in the last five years in health and safety and our Health, Safety, Environment and Quality Team. This has seen a marked level of improvement in our H&S maturity. The HSEQ team helps ensure that investigations occur, actions are taken and responsibilities clear. We also have weekly incident meetings and Executive Health and Safety meetings to monitor our work in this area.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2.0	We have strong auditing of financial processes and a process in place for field auditing. There are some areas we could improve, such as audits of the asset management system.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.1	We have a range of corrective action processes, for example, EFSA relationship meetings, HSEQ meetings and operational meetings all support these processes.
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?	2.0	Current asset management performance is assessed and gaps used to drive improvement programmes. Formal monitoring and reporting on improvements is undertaken by the Executive. We have a continuous improvement programme to identify areas of work.
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?	3.0	Powerco has good practices for seeking out new asset management technology and practices. We are active in the ENA and EEA, with employees on the Board of both organisations. Staff regularly attend and present at conferences and had discussions on practices with overseas EDBs. We have a Research and Development division that leads research into this area.

A2.8 SCHEDULE 14A – NOTES ON FORECAST INFORMATION

Below we comment on differences between our forecast capital expenditure (schedule 11a) and operational expenditure (schedule 11b) in nominal and constant prices:

- We explain our approach to forecast escalation in Chapter 26.
- We are required to identify any material changes to our network development plan disclosed in our previous AMP. We discuss our current plans in Chapter 11 and changes from our previous AMP in Appendix 5.
- We are required to identify any material changes to forecast Capex (Schedule 11a) and Opex (Schedule 11b). We explain both these forecasts and their basis throughout the AMP.
- To be consistent with our CPP application, we state our expenditure in constant prices in 2016 real dollars in the body of this AMP. We have produced two versions of schedules 11a and 11b. One versions uses constant prices in 2016 real dollars (for alignment to this AMP and our CPP application). The other version uses constant prices in 2017 real dollars, as per the Commerce Commission's information disclosure requirements for a 2017 AMP and for consistency with other electricity distributors' disclosures.

A2.9 MATERIAL CHANGES

This section discusses any material changes in the approach to the population of information disclosure schedules shown in the previous sections.

A2.9.1 MATERIAL CHANGES TO SCHEDULE 12A

Consistent with the 2016 AMP, but a change from previous AMPs is our method for populating Schedule 12A – Asset Condition. We have used Asset Health Indices to populate the majority of asset classes in the schedule. Our five asset health scores (H1-H5) are mapped to the schedule's condition grades 1-4. Asset health is discussed in more detail in Chapter 7, and is used extensively throughout our fleet management chapters of this AMP. These changes better align the asset condition schedule to the information underpinning our planned renewal programmes.

We also populate the '% of asset forecast to be replaced in next 5 years' from our renewal forecasting models, discussed in the fleet management chapters of this AMP. This ensures the disclosed numbers are consistent with the renewal Capex forecasts shown in this AMP. The models are also used to calculate the asset health projections in the fleet management chapters.

A2.9.2 MATERIAL CHANGES TO SCHEDULE 12B

Installed firm capacities and transfer capacities have been fully reviewed, and a more consistent interpretation of our security standards has been applied.[123] This has resulted in a drop in some firm capacities, particularly for substations of higher required security class where transfer capacity or alternate capacity is ignored as the changeover is not automated and doesn't meet our required restoration time.

A2.9.3 MATERIAL CHANGES TO SCHEDULE 12C

We have made significant improvements in our demand forecasting since the last AMP. Our forecasts of demand growth rates are now developed at feeder level, and these then determine zone substation and GXP growth rates.

A2.9.4 MATERIAL CHANGES TO SCHEDULE 12D

We have updated our approach to populating the SAIDI and SAIFI forecasts of schedule 12d. We have developed separate models to forecast unplanned and planned SAIDI and SAIFI. The forecasts are based on modelling historical fault data, and our planned work. The unplanned SAIDI and SAIFI forecasts are not normalised. The planned SAIDI and SAIFI forecast in this AMP is un-weighted, whereas last year's was weighted at 50%.

[123] See Chapter 7 for a description of our security standards.

A3.1 APPENDIX OVERVIEW

The main objective of our AMP is effective consultation with our stakeholders. In Chapter 2 we provide an overview of our main stakeholders and their interests. Given how important our stakeholders are to us, this appendix gives more details about each stakeholder and insights into what they tell us they want from our asset management.

A3.2 OUR CUSTOMERS

We exist to serve the needs of our customers. More than 600,000 New Zealanders rely on us for a safe, reliable and high-quality supply of electricity at a reasonable price.

We serve a diversified group of households, businesses and communities. These customers include:

- 330,078 homes and businesses comprising:
  - Residential consumers and small businesses ("Mass Market")
  - Medium sized commercial businesses
  - Large commercial or industrial businesses
- 24 directly-contracted industrial businesses, including large distributed generators

Electricity is an indispensable part of modern economic and social life. As use and dependence on electricity has grown, so too has customers expectation of the availability and quality of supply. In addition to excellent customer service, customers increasingly expect good, timely information on their service.

A3.2.1 STAKEHOLDER INTEREST

The interests of each of our main customer groups are described in Chapter 4. These are as identified through consumer surveys, meetings with customers and consumer groups, and feedback from our hotlines. Customer's interest can be summarised as:

- Reliability – our customers want us to minimise the frequency and duration of supply interruptions, as well as ensuring quality of supply and network capacity.
- Responsiveness – our customers expect us to respond quickly to issues on the network and reduce potential safety and reliability risks.
- Cost effectiveness – our customers expect our investments are appropriate to meet their expectations and that we are constantly evaluating our approach to optimise these investments and their underlying costs.
- Customer service and information quality – our customers value timely and accurate information about their supply, especially during supply interruptions. They want more real time information available through digital channels.

A3.3 COMMUNITIES, IWI AND LANDOWNERS

With almost 28,000km of network circuits, we interact with a range of communities, iwi and landowners. We are also an active corporate citizen and involved in a range of community projects and activities.

We recognise the importance of consulting with iwi and communities on significant new projects, particularly development of new subtransmission line routes. We regularly meet with landowners, iwi and local community groups to ensure their views, requirements, values, significant sites and special relationship with the land are taken into account early in the project development phase.

- Affected landowners wish to be advised when maintenance crews enter their property and wish to be assured their property will not be damaged or put at risk.
- Communities expect us to be an active and responsible corporate citizen, supporting the areas where our staff live and our network operates.

A3.4 RETAILERS

We currently have 15 electricity retailers operating on our network. Of these, three serve 70% of our customers.

Like most EDBs we operate an interposed model. This means retailers purchase our services, bundle them with energy supply and the cost of accessing the transmission grid, and provide a bundled price for delivered energy to their customers. Working with retailers to ensure a simple and effective energy supply for customers is a key part of what we do.

Retailer interest follows customer interest, as described above. In addition, retailers have an interest in:

- How we work with them to provide customers with information about outages and other information customers may require
- Our pricing structure and pricing changes
- How we resolve customer complaints (that may have been directed to the retailer)
- How we operate under the Consumer Guarantees Act
- Our use of system agreement

A3.5 THE COMMERCE COMMISSION

The Commerce Commission is the main agency that regulates us. It aims to ensure that regulated industries, such as electricity lines businesses, are constrained from earning excessive profits, and are given incentives to invest appropriately and share efficiency gains with consumers.

The Commerce Commission has responsibilities under Part 4 of the Commerce Act 1986, where it:

- Sets default or customised price/quality paths that lines businesses must follow
- Administers the information disclosure regime for lines businesses
- Develops input methodologies

Part 4 of the Commerce Act requires the Commission to implement an information disclosure regime for EDBs. The regime places a requirement on businesses to provide enough information publicly, such as via regulatory accounts and various performance indicators, to ensure interested parties are able to assess whether or not the regulatory objectives are being met.

We meet regularly with Commissioners and staff to compare notes.

A3.6 STATE BODIES AND REGULATORS

The state bodies and regulators that have jurisdiction over our activities include the Ministry of Business, Innovation and Employment, WorkSafe, and the Electricity Authority.

The Ministry of Business, Innovation and Employment administers the Health and Safety at Work Act 2015 and the Electricity (Safety) Regulations.

The new Health and Safety at Work Act comes into force on 1 April 2016 and we are confident our existing processes and systems meet all the new Act's requirements.

The Electricity (Safety) Regulations came into effect in April 2011 and set out the underlying requirements the electricity industry must meet. In particular, lines companies must set up and maintain a Safety Management System that requires all practicable steps to be taken to prevent the electricity supply system from presenting a significant risk of (a) serious harm to any member of the public, or (b) significant damage to property.

There are several codes of practice that apply to line companies. The most important of these are:

- ECP34 - Electrical Safe Distances
- ECP46 - HV Live Line Work

WorkSafe is the regulator for ensuring safe supply and use of electricity and gas. It conducts audits from time to time to ensure compliance with safety standards as well as accident investigations following serious harm or property loss incidents.

Radio Spectrum Management administers the radio licences needed for the operation of the SCADA and field communication systems.

The Electricity Authority regulates the operation of the electricity industry and has jurisdiction over our activities as they relate to the electricity industry structure. These include terms of access to the grid, use of system agreements with retailers, as well as metering, load control, electricity losses and distribution pricing methodologies.

We are committed to supplying electricity in a safe and environmentally sustainable manner and in a way that complies with statutes, regulations and industry standards. In the electricity distribution network context, the most noteworthy legislation to comply with is:

- Electricity Act 1992 (and subsequent amendments)
- Electricity Industry Act 2010
- Electricity (Hazards from Trees) Regulations 2003
- Electricity (Safety) Regulations 2010 (and pursuant Codes of Practice)
- Resource Management Act 1992
- Health and Safety in Employment Act 1992
- Electricity Industry Participation Code 2010
- Hazardous Substances and New Organisms Act 1996

A3.7 TERRITORIAL LOCAL AUTHORITIES

As the largest electricity distributor by geographical size, we cross a large number of local and regional councils.

These organisations are valued customers and have an interest in how electricity supports economic growth and how our activities interact with the Resource Management Act.

- Implementation of the Resource Management Act – local councils have a role in promoting the sustainable management of natural and physical resources. This includes how our network interacts with its environment. We consider ourselves a long-term and responsible corporate citizen. We aim to be actively involved in district and regional plan changes debates and take part in hearings and submissions on local issues.
- Economic growth – authorities have an interest in promoting economic growth in their communities, and we work with them to understand where investment may be needed by us to support this.
- A valued customer – local councils are also often our customers, supplying lifeline utility services, such as water and sewage. We work closely with councils to understand their supply needs and co-ordinate any outages.

A3.8 OUR EMPLOYEES

We have around 350 staff, based in offices in New Plymouth, Tauranga, Whanganui, Palmerston North and Wellington. The level of engagement with our teams and the strength of our culture is important to us. We regularly undertake engagement surveys to make sure we continually improve what we do.

Our employees wish to have interesting and varied careers, with the ability for career development. Safety, job satisfaction, working environment and staff wellbeing are key employee tenets.

Our teams have an interest in managing the network competently and doing the 'right thing', therefore the effective communication of our Asset Management Plan to them is of great importance.

Employees need to have a safe environment to work in and we also need to ensure our assets are safe for contractors and the public. Safety in design principles are a key part of our design and construction standards.

These principles are discussed in more detail in Chapters 5, 6 and 10.

A3.9 OUR SERVICE PROVIDERS

We operate an Electricity Field Services Agreement with Downer Limited, and will shortly be expanding the capital works contractor panel to include Northpower and Electrix. We also have a range of approved service providers who work on our network.

Our service providers require a sustainable and long-term relationship with us. As part of this relationship we expect our service providers will be profitable, but efficient. This means having a foreseeable and constant stream of work to keep their workforces productively employed. Focus areas, from our perspective as an asset owner, are safety, competency, crew leadership and alignment of business models.

Given the anticipated increase in expenditure over the AMP planning period, we will work closely with our service providers to ensure we are able to deliver the higher volume of work in the most efficient manner.

Workflow certainty allows our service providers to confidently build up the right level of resources to achieve efficient resource utilisation. It also allows service providers to achieve benefits of scale from their material purchases resulting in efficient pricing and a stable industry environment.

Electrical equipment is capable of causing serious harm and we take measures to ensure service provider employees work in a safe environment. This is accomplished through a competency certification framework, procedures and through audit processes.

These principles are discussed in more detail in Chapters 7 and 10.

A3.10 OUR INVESTORS

We are a privately-owned utility with two institutional shareholders: Queensland Investment Corporation (58%) and AMP Capital (42%).

As the electricity distribution sector is regulated, regulatory certainty is a key issue that affects our owners' investment decisions. Our investment plans are subject to certain aspects of the regulatory regime being changed and clarified through the Commission's formal review of the Input Methodology rules. These cover:

- Productivity and commercial efficiency: Delivery of asset management in a productive, efficient and commercially prudent manner.
- Optimal utilisation of assets represents the best trade-off between capital expended on the assets and network risk.
- Risk management processes seek to identify, recognise, communicate and accept or control risks that arise in the asset management process.

We have also just lodged a formal application for a Customised Price Path which will also have a material effect on our investment planning.

Owners (as represented by the directors) have overall responsibility for Powerco and expect our management team to address this wide range of business drivers.

A3.11 OTHER STAKEHOLDERS

Other stakeholders with an interest in our asset management process include Transpower, the media and groups representing the industry such as the Electricity Networks Association and the Electricity Engineers Association.

Transpower supplies bulk electricity through their grid. Operational plans (like outages and contingency planning) and long-term development plans need to be coordinated well in advance to ensure seamless supply.

The Electricity Engineers Association provides industry guidelines, training and a point of focus for inter-industry working groups. The Electricity Networks Association represents the interests of the distribution lines companies in New Zealand.

A4.1 APPENDIX OVERVIEW

As explained in Chapter 4, we have 581 customers with demand greater than 300 kVA, whom we class as large commercial or industrial customers. These customers account for 0.2% of our ICP numbers but consume 28% of the electricity we deliver.

Given the size and complexity of their operations, our large customers have more specific service requirements than the mass market. It's important that we understand the unique characteristics and requirements of these organisations and develop strong working relationships. For example, service interruptions can have significant operational and/or financial impacts and we need to work closely with these customers to co-ordinate any planned outages.

This appendix provides more details on our largest customers (defined as having installed capacity greater than 1.5MVA). These organisations have a significant impact on our network operations and asset management priorities, and it's very important that we provide the highest levels of service.

A4.2 DAIRY SECTOR

Dairy farms are spread across our footprint, and are particularly dominant in the Taranaki and Waikato regions. Many dairy farms are part of the Fonterra Co-operative, hence Fonterra is one of our key major customers.

The dairy industry peak demands occur in spring. The industry requires a reliable supply, so shutdowns for maintenance or network upgrade activities have to be planned for the dairy low season, especially in South Waikato and South Taranaki.

At an individual farm level, operations are intensifying due to increasing cooling and holding standards. There is greater use of irrigation and new technologies. The overall impact is that load is increasing and the operations require higher reliability of supply and better quality of supply than was previously the case. This is consuming existing spare capacity, creating a greater onus on effective network planning and operations.

We also have to be conscious that the subdued price of milk powder is putting financial strain on this sector, and likely to impact the number of dairy conversions or expansions in the future.

Major Dairy Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Fonterra - Mainland Products	Fonterra – Morrinsville
Fonterra - Pahiatua	Fonterra – Tirau
Fonterra - Longburn	Fonterra – Waitoa
Silver Fern Farms	Open Country Cheese
Open Country Dairy Ltd - Whanganui	Tatua Dairy

A4.3 TIMBER PROCESSING SECTOR

Forestry is a significant industry in New Zealand, and we have a number of commercial forests and timber processing operations across our footprint.

These timber processing facilities are often located away from other users, in remote areas with low network security. This means that outage planning may involve extensive customer consultation and that voltage fluctuations may occur.

Major Timber Processing Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Kiwi Lumber - Sawmill	Oji Fibre Solutions Ltd - Kopu
Juken Nissho	Kiwi Lumber
	Pacific Pine
	PukePine Sawmills
	Thames Timber
	Fletcher Challenge Forests
	Claymark Katikati

A4.4 FOOD PROCESSING SECTOR

Many of our larger customers are involved in food and beverage processing. As demonstrated by the table below, we have a significant number of meat cool stores and processing plants, as well products such as bakeries and pet food.

Outage requirements for customers in this sector can usually be coordinated if sufficient notice is given. Unplanned outages can lead to spoiled products, causing expensive wastage, disruption and environmental consequences. Cool stores are presently a significant growth sector and can have heavy, peaky loads on outer edges of the supply network. Careful planning is needed to ensure adequate capability is allowed for these loads. Cost effective redundancy for full site capacities are becoming more difficult to provide due to the size of the loads.

Major Food Processing Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Affco NZ Feilding	Apata Coolstores
Affco NZ Whanganui	Affco Rangiuru
ANZCO Foods	Baypac
Aotearoa Coolstores	Champion Flour
Canterbury Meat Packers	Cold Storage International
Cold Storage - Nelson	Eastpac Coolstores
DB Breweries	Greenlea Meats
Ernest Adams	Huka Pak Totara
Foodstuffs	Hume Pack N Cool
Foodstuffs Coolstores	Inghams Enterprises Mt Maunganui
Goodman Fielder Meats	Inghams Enterprises Waitoa
International Malting Company	Cold Storage Tauranga
Lowe Walker	Silver Fern Farms
Mars Pet Foods	Sanford
Riverlands Eltham	Seeka
Riverlands Manawatu	Trevalyan Coolstore
Tegel Foods	Wallace Corporation
Yarrows Bakery	Aerocool
	Cold Storage International

A4.5 TRANSPORTATION SECTOR

We have two major ports on our network – the Port of Tauranga and Port Taranaki. Both of these are on growth paths. The port of Tauranga is aggressively pursuing market share, and is already the largest port in the country in terms of total cargo volume. For Port Taranaki, improvements in the capacity of the rail link between New Plymouth and Marton have occurred, but the closure of the rail link from Stratford to Taumarunui could constrain their future growth.

Port operations are based around shipping movements and the quick turnaround of ships is important. When ships are in port, the facilities make heavy demands on the electricity distribution network and at these times a highly reliable supply is needed to ensure a fast turnaround.

A secure supply (N-1) is therefore needed by ports. The continued drive for efficiency and increasing demands in this sector has been squeezing the windows available for maintenance.

Major Transportation Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Port Taranaki	Port of Tauranga

A4.6 INDUSTRIAL SECTOR

We have a variety of large manufacturers and extractive companies connected to our network. This includes companies related to the oil and gas sector in Taranaki, as well as mining plants in our Eastern region.

The manufacturing sector is dependent on prevailing economic conditions, particularly the conditions within the industry’s niche. The requirements on the distribution network can therefore vary accordingly. The strong New Zealand dollar has put pressure on this sector, however, the large companies we serve are well established.

Major Manufacturing Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
MCK Metals Pacific	A & G Price
Ballance Agri-Nutrients	Fulton Hogan
Olex Cables NZ	Thames Toyota
Iplex Pipelines NZ	Katikati Quarries 2001
Taranaki By-Products	Waihi Gold
Waters & Farr	
Cavalier Spinners	
Van Globe	

A4.7 CHEMICALS SECTOR

The companies we serve in the chemicals sector are dominated by the oil and gas industry in Taranaki and the agri-nutrient industry in the Eastern region.

The chemical sector is heavily reliant on a reliable supply of electricity with few voltage disturbances. Some of the machines in this industry can create large voltage dips on the network when they start. This needs ongoing coordination with the customers on installation of variable speed drives or alternative options.

Major Chemicals Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Shell Exploration NZ - Pohokura	Ballance (Mt Maunganui)
Methanex NZ – Waitara Valley	Evonik
Shell Todd Oil Services - Oaonui	Ballance (Morrinsville)
Methanex NZ – Waitara Pumps	
Origin Energy – Waihapa TAG	

A4.8 GOVERNMENT SECTOR AND RESEARCH FACILITIES

We serve a range of public sector organisations, including hospitals, sewage and water plants, army and air force bases, universities and research facilities.

We recognise the impact a supply outage can have on these facilities and work carefully with district health boards, local councils and the New Zealand Defence Force to ensure our service meets their needs.

Given the critical nature of their activities, some of the government sector organisations have on-site generation. This needs to be coordinated with our network operations.

Major Government and Research Customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
AgResearch	Chapel St Sewage Plant
Dow AgroSciences NZ	Tauranga Hospital
Taranaki Healthcare	Bay of Plenty Polytech
Whanganui DC - Waste Water Treatment	Matamata Piako DC Waste Water Treatment Plant
NZDF – Army Training Waiouru	
TEI Works	
Fonterra Research Centre	
NZDF – Linton Military Camp	
MidCentral Health	
NZDF – RNZAF Base Ohakea	
Massey University – Turitea Campus	

A5.1 APPENDIX OVERVIEW

This appendix provides information on our progress against physical and financial plans set out in our 2016 AMP.

In summary, we completed 97% of our scheduled capital works programme for FY16, and overall completed 106% of our scheduled maintenance programme. Any incomplete capital and maintenance work was carried over to the FY17 programme.

A5.2 DEVELOPMENT PROJECT COMPLETION

During FY16 we undertook a series of network development projects. The table below provides a summary of key projects, their progress, and discussion of material variances against plan.

PROJECT	DESCRIPTION	PHYSICAL PROGRESS AT END FY16	REASONS FOR SUBSTANTIAL VARIANCES
Taranaki			
Bell Block Substation	Construction of dual 33kV line Huirangi GXP	Construction Complete	Project completed under budget
Whanganui			
Peat St Substation	New distribution feeder	Construction Complete	Route access construction requirements
Beach Rd Sub	New 11kV switchboard. Upgrade transformer	Construction Complete	Flooding mitigation and maintenance of supply
Palmerston			
Mangamutu	33kV line thermal upgrade	Construction Complete	No major variances
Sanson	33kV line capacity upgrade	Construction Complete	No major variances
Kimbolton substation	Transformer capacity upgrade bunding and switchgear	Construction Complete	No major variances
Tauranga			
Pyes Pa Reinforcement	Capacity increase new 11kV cable	Construction complete	Equipment supply delays and compliance issues
Otumoetai 33kV cabling	Bethlehem / Matua / Otumoetai security	Construction commenced	No major variances
Valley			
Piako GXP Stage 2	New 110/33kV transformer and switchboard	Construction Complete	Project completed under budget
Paengaroa Zone substation	Construct new green fields zone substation	Construction Complete	Project completed on budget
Tirau Substation	New 33kV switch-room and switchgear	Construction Complete	Project completed on budget
Minden Rd upgrade	11kV feeder capacity upgrade	Construction commenced	No major variances
Waotu Rd Lichfield	Distribution conductor upgrade	Construction Complete	No major variances

The majority of projects actual costs are in-line with the total project budgets. Where costs have increased these have been influenced by land access and construction route constraints along with additional requirements to mitigate the potential for flooding at Beach Rd zone substation. Pyes Pa distribution feeder reinforcement was delayed and cost escalation occurred due to equipment compliance and supply issues.

Land access and consenting issues continue to protract the assessment and scoping phases of some projects.

A5.3 MAINTENANCE PROGRAMME DELIVERY

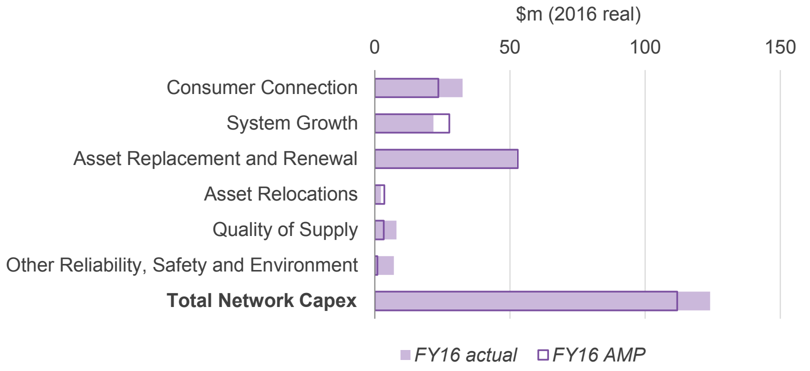
The FY16 maintenance programme was completed, with 106% of scheduled activities completed by year end. Over-delivery of the vegetation management programme occurred as a result of increased focused on improving performance of the sub-transmission network and some critical distribution feeders. along with focus on some critical distribution feeders to manage reliability performance. The minor volume of outstanding scheduled maintenance activities has been carried over to the FY17 programme.

A5.4 FINANCIAL PROGRESS AGAINST PLAN

A5.4.1 NETWORK CAPEX

Total network Capex for FY16 was above the 2016 AMP forecast. The primary driver behind this increase in expenditure was increased demand for new customer connections. There are some variances between categories which are shown in the figures below.

Figure A5.1: Network Capex variance FY16

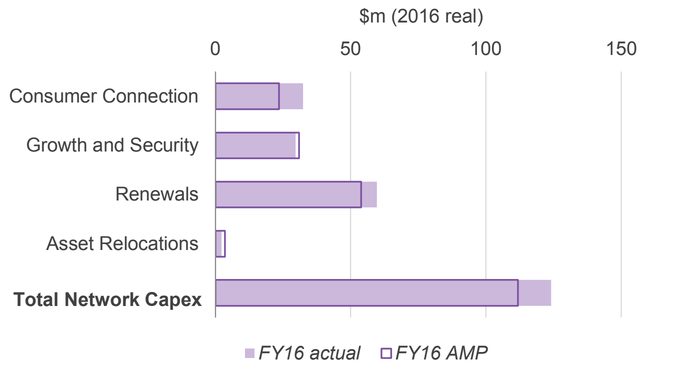


We are currently in the process of changing our approach to Capex categorisation to the information disclosure categories. We are doing this to better support our expenditure tracking and justification by providing more consistency in how expenditure is categorised, and to remove unnecessary variability between years.

Our AMP16 was disclosed under our new approach, were as our actuals were recorded using our old approach. Therefore an accurate comparison between the two is difficult.

A more valid comparison for FY16 is to add System Growth and Quality of Supply together to form 'Growth and Security', and to add Asset Replacement and Renewal and Other Reliability, Safety and Environment together to form 'Renewals'. This variance is shown below.

Figure A5.2: Network Capex variance FY16, adjusted categories



Consumer connection expenditure exceeded the forecast by $9.0m (38%). Expenditure was driven by increased rates of customer connection and customer upgrades not anticipated in original forecasts. Higher than anticipated customer connection expenditure was noted across all customer expenditure categories (residential, commercial and industrial) with additional expenditure weighted towards asset upgrades to support commercial and industrial load growth in the dairy and horticultural sectors

Growth and security expenditure is less than forecast by $1.2m (-4%). Decreased expenditure in this area reflects a targeted shift in the mix of works in the period towards renewal, as well as some practical delays in a number of growth related projects due to land access constraints.

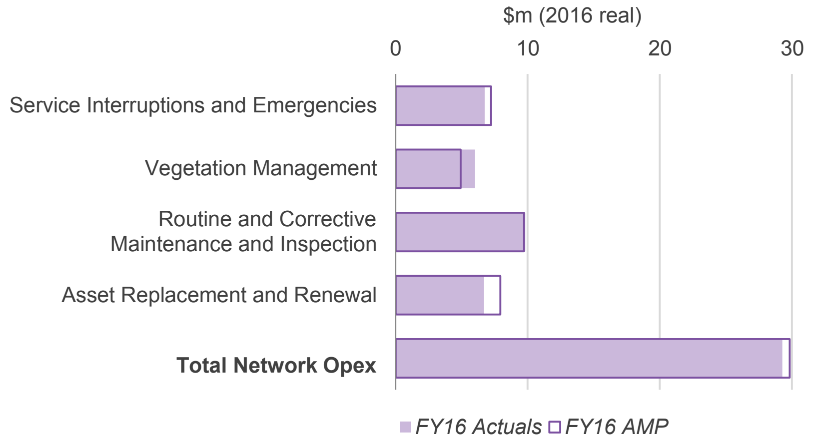
Renewals expenditure was $5.7m higher than forecast (11%). This has been driven by higher expenditure than expected on LV fusing, oil containment, and seismic strengthening programmes, and additional defect works and conductor replacement variations driven by safety considerations.

Capital expenditure on asset relocations was less than forecast by $1.2m (-34%). This is partially because expenditure for the NZTA Devon Rd project, New Plymouth, was partially delayed beyond FY16. Demand for asset relocations from third parties was lower than initial forecast.

A5.4.2 NETWORK OPEX

The figure below shows our FY16 Opex variance between AMP16 and actuals. Total Network Opex was $0.6m less than forecast (-2%).

Figure A5.3: Network Opex variance FY16



Service interruptions and emergencies (SIE) expenditure was $0.5m (-7%) less than forecast. This was due to calmer weather than normal resulting in fewer storms and lower-than-average fault volumes in FY16. This has also had an impact on asset replacement and renewal (ARR) Opex.

Expenditure on vegetation management exceeded the forecast by $1.1m (22%). Given the lower than expected expenditure on SIE and ARR Opex, an operational decision was made to lift vegetation expenditure. This additional spend focused on preventing degradation of network reliability and safety in specific areas.

Routine corrective and maintenance inspection expenditure was as forecast.

A6.1 APPENDIX OVERVIEW

This appendix provides summaries of key network risks from our corporate risk register. It also details the main controls we have in place and the expected likelihood and consequence of the risk under current controls. As described in this AMP, safety of our staff, service providers and the public is our most important priority. We have an extensive range of measures in place to reduce the likelihood of a serious incident occurring. We will continue to evaluate our practices to ensure these controls remain appropriate. We also have a variety of controls to minimise the risk of a loss of supply to a large number of customers.

In other cases, we have less influence on an event occurring, such as a major earthquake or significant storm. In these situations, our controls focus on reducing the consequence of the risk. For example, we have duplicate control centre facilities in different geographical locations to ensure we will always be able to operate our control centre.

Our assessment of risks also recognises the impact that technology may have on our business, such as an increased uptake of distributed generation. As described in our customer strategy in Chapter 4 and our future networks strategy in Chapter 13, we are creating a strong platform to be ready for these changes when they occur.

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
1. Health and Safety of Electricity Employees, Service Providers and the public.	Fatality or serious harm to employees, service providers or members of the public on our Network. This can result from: – Motor vehicle or road traffic incidents – Negligence and human error – Equipment failure eg LV line down – Asset failure eg pole – Weather event eg LV line down – Incorrect or inadequate information or instructions given to service providers or other 3rd parties – Lack of, or incorrect mix of competence – Stress – Not aware of potential hazards – Unauthorised access to our network – Vandalism	– Contractor Works Manual includes network asset, procedural, HSE and quality requirement – Contractor approval system – only Powerco-approved contractors permitted to work on our networks – Competency framework to ensure named persons allowed to carry out specific tasks based on competency and training records. – Key card technology linked to competency for increased security for access to substations. – Safety-in-design considerations are defined and integrated into the asset planning processes. – HSE risk management framework hazard management including performance monitoring, ongoing hazard identification and review process. – Asset strategy and planning processes including defect management and renewal process to manage end-of-life assets. – Increased focus on risk-based assessment of potential of asset failure and carrying out increased numbers of preventative renewals on assets to improve safety around our assets. – Formal H&S Management Processes, including monthly oversight reviews by electricity leadership team and H&S committee. – Formal network access processes which apply to HV assets managed via the NOC. – Compliance with NZS7901 including effective management of network defects and red tagged pole structures – external certification by Telarc. – Specialist and fully resourced internal Health, Safety, Environment and Quality team. – Independent network field audit process covers health and safety, technical and compliance as well as works in progress. – Public Safety Management System (NZS 7901) in place and independently certified / audited by Telarc. – EMT/manager safety observation process with monthly targets and KPIs. – Involvement with industry bodies like EEA and ENA reviewing industry safety standards and regulations. – Active public awareness programmes aimed at specific target audience (eg field days, seminars, art promoting safety in public places, Powerco website, videos, bus adverts). – Free cable location and stand-over service. – Signage and security around high risk areas. – All incidents are reviewed, corrective actions entered into Safety Manager and followed-up.	Unlikely	Major	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
2. Technology Change	Technology risk has a material impact on revenues, both from an asset stranding and from a customer defection potential. Note: – Population growth predicted to be the biggest driver of demand for the foreseeable future. – Lack of Government subsidies and winter evening peak nature of system limits the effectiveness and hence likely impact from PV generation. – Complete off-grid consumer solutions remain uneconomical for the large majority of customers for the foreseeable future, especially those with large industrial processes. Electric vehicle uptake forecast to somewhat offset reduction in throughput from distributed micro-generation (ie PV).	– We are moving to a more cost reflective pricing (FY18) to improve appropriate signals for usage which should help support improved utilisation/increased delivery efficiency for grid connected supply over time. – Network of the Future Distribution System Integrator initiative. – By continuing to offer services valued by the customer, including the provision of an open access platform, our exposure to reducing demand is limited.	Unlikely	Major	Medium
3. Business Continuity - Major Earthquake / Eruption / Pandemic.	Business continuity issues associated with: – Earthquake of similar magnitude to the Christchurch event or major eruption which severely impacts the network. Consequence is based on an earthquake impacting the Palmerston North region which has our greatest exposure. – Eruption of Mt Taranaki which impacts the Taranaki region only. – Major pandemic impacting us and NZ in general rather than just one region. Note: ENA and EEA facilitate Service Provider arrangements in event of a national disaster (eg Christchurch earthquake).	– Business Continuity plans (BMS documents) and regular desktop exercises for reviewed/scheduled for improvement and planning purposes. – Back-up NOC facilities are available at Bell Block in the event of a loss of the Junction St site and network oversight and control can be assumed from the Tauranga office (for network triage purposes) in the event that both New Plymouth facilities become inoperable – Materials Damages and Business Interruption policy for insured assets, mainly depots/offices and contents and zone substations. Special earthquake cover for Distribution transformers and substations (ground). – $70m revolving cash loan maintained for an event where the network fails and it is not covered by insurance eg lines and pipes	Rare	Major	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
4. Regulatory - Insufficient Cash Flow to Maintain Network Assets	The DPP process is unable to provide the level of capital we require to effectively maintain and renew Powerco electricity assets in the long-term. At current levels of expenditure an increasing proportion of assets will require operation beyond their target service lives, particularly our overhead network assets. There are also indications that underlying reliability performance at specific locations across our network is being impacted negatively by a combination of deteriorating condition, increasing age and model/type-related issues. The operational margin around our SAIDI/SAIFI quality targets is eroding at current levels of expenditure. Note: A CPP application, if successful, will alleviate the potential risk significantly over the medium to long term, but there is still a possibility that the final CPP decision does not provide the level of capital we will be requesting.	− Regulatory presence in Wellington ensures a continued focus on maintaining relationships with the Commerce Commission. − Current operational constraints, future investment requirements and Powerco's intention to progress a CPP process were clearly signalled in the disclosed 2016 AMP. − Powerco has formally announced its intention to apply for a CPP for the five-year period commencing 1 April 2018; public consultation has now been completed. − There is a continued dedicated focus on lifting the level of asset management maturity within Powerco to support and maximise the likelihood of a successful CPP application.	Likely	Moderate	Medium
5. Electricity Network – inherent hazards	Inherent hazards associated with electricity networks resulting in death or severe injury to a member of the public or severe damage to third party assets. For example: − Site or access security is compromised, and intruder severely injured despite deployment of industry standard security and access controls. − Vandalism or theft of network equipment (eg pillar boxes, ground mounted transformers, protective earths) creates an inherent network hazard which results in harm to public. − Faulty or damaged equipment (eg fallen power lines) creates a hazard which results in harm to the public. − Lack of care when working around network assets (eg cable strikes during construction, line contact by agricultural contractors etc) results in serious harm to a member of the public.	− Public safety education programme. − Asset identification and mark out processes. − Safety warning signage. Security fences. Security locks. − Asset renewal and routine maintenance inspection programmes. − Fast response processes/repair processes for high hazard situations. − Formal internal oversight of safety position, including monthly management team reviews of key incidents. − Active participation in and compliance with Electricity Engineers' Association Guidance on safe design etc. **Other Management Tools and/or Programmes** − Public Safety Management System (NZS 7901) in place and independently certified/audited. − Independent network audit process covers health and safety and compliance as well as works in progress. − Specialist and fully resourced internal Health, Safety, Environment and Quality team is in place. − We are developing a detailed safety-in-design process which will help identify and avoid safety-related problems with assets or at installations before construction.	Possible	Moderate	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
6. Electricity Network – inherent Security of Supply limitations	Loss of supply to a significant number of customers as a result of current security of supply being inadequate to prevent outage. For example: – Accepted risks associated with zone substations with one transformer only (eg Te Ore Ore, Bulls) and therefore N security only for maintenance purposes. – Accepted risks associated with remote but growing locations of the network (eg Coromandel and Whangamata) which have N security for maintenance and fault purposes. – Complex land access negotiations delay obtaining consents and easements for GXP, subtransmission or Transpower projects (eg Putararu, Tauranga North, Papamoa GXP projects; Palmerston North subtransmission, Valley spur). – Concurrent network security issues (N-2) due to multiple events occurring and resulting in long repair time and reputational damage despite meeting our own network security standards where (N-1) has been found to be appropriate.	– Network security standards reflect long-term practice and are generally reflective of industry norms. Our asset management processes seek to maintain and in some cases enhance this position. – Access and consents staff provides an improved focus and capability in the land access area and help mitigate the risk of delay. – Standard planning processes evaluate capacity and security issues, and a formal risk based approach is used to ensure that inherent limitations are considered and signed off. – Clear media responses are made to all network security events as they occur. – The contingency response includes calling in additional contractors to resolve issues in an effective and timely manner.	Possible	Moderate	Medium

RISK	DESCRIPTION	EXISTING CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
7. Business / Operational Continuity	Natural disaster, multiple event or severe weather event which adversely affect our ability to respond to network and customer issues in the timeframes required, as well as: – Increased propensity towards storm damage as assets age, particularly in the lead up to a CPP application. – Cost of replacing uninsured assets requires funding by us as no cost effective insurance facility exists for overhead assets. – Increased risk of fatigue-induced accidents and incidents due to abnormally long hours being worked by Control Centre, dispatch and service provision resources during extended storm events. – The wide geographical spread of our assets can result in widespread storm damage for some scenarios, resulting in extended loss of supply (2+ days) to customers. – Centralisation of operational control makes us vulnerable in some scenarios where the core operating centre at Junction St is damaged or unable to be accessed.	– Business continuity plans and regular desktop exercises for planning purposes. – Demonstrated ability to respond to significant storm events, and scale resources via access to broader industry resource pool; supported by good working relationships with other lines companies to use their Service Providers and materials in an emergency – The scale of Powerco's capital programme means that we typically have high levels of staff and plant to respond to storms and other events – Levels and locations of emergency and critical spares holdings are documented, also levels of general materials (eg poles, cable) and where located. There are contracts with some suppliers to hold contingency stock levels – Practice of splitting to local hubs for power rectification in major events reduces dependence on central Control Room coordination in peak events. – Resource rotation and maximum hours worked policies (both Powerco and its service providers) are adhered to – Back-up NOC facilities are available at Bell Block in the event of a loss of the Junction St site and network oversight and control can be assumed from the Tauranga office (for network triage purposes) in the event that both New Plymouth facilities become inoperable.	Possible	Moderate	Medium
8. Economic - Falling Demand Impacts revenue	Falling demand driven by population, energy efficiency and/or changed network utilisation. Note: The likelihood of falling demand in the foreseeable future is low. Population growth will continue to be the biggest driver of demand for the foreseeable future. Consequence/impact of demand changes will be muted in the first instance – this is because allowable revenue is set by building blocks methodology	– Design and implementation of a customer-led energy platform strategy will help position Powerco to ensure assets remain used and useful (avoid stranding) over a broad range of energy market scenarios. – By continuing to offer services valued by the customer, including the provision of an open access platform, our exposure to reducing demand is limited.	Possible	Moderate	Medium

A7.1 APPENDIX OVERVIEW

This appendix sets out our 15-year demand forecasts for our zone substations.

As discussed in Chapter 8, we are reviewing our demand forecast methodology which will further improve the robustness of our demand forecasts.

A7.2 DEMAND FORECAST FOR COROMANDEL AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coromandel	0.0	1.0%	4.7	4.8	4.8	4.8	4.9	4.9	5.0	5.0	5.1	5.1	5.1	5.2	5.2	5.3	5.3
Kerepehi	0.0	0.7%	10.1	10.2	10.3	10.3	10.4	10.5	10.5	10.6	10.7	10.8	10.8	10.9	11.0	11.0	11.1
Matatoki	0.0	0.9%	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.3
Tairua	7.5	0.7%	8.6	8.7	8.7	8.8	8.8	8.9	8.9	9.0	9.1	9.1	9.2	9.2	9.3	9.3	9.4
Thames T1 & T2	0.0	0.3%	13.4	13.5	13.5	13.5	13.6	13.6	13.6	13.7	13.7	13.8	13.8	13.8	13.9	13.9	13.9
Thames T3	6.9	-	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Whitianga	0.0	1.7%	17.2	17.4	17.7	18.0	18.3	18.5	18.8	19.1	19.3	19.6	19.9	20.2	20.4	20.7	21.0

A7.3 DEMAND FORECAST FOR WAIKINO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Paeroa	6.0	0.4%	8.3	8.4	8.4	8.4	8.5	8.5	8.5	8.6	8.6	8.6	8.7	8.7	8.7	8.8	8.8
Waihi	16.0	0.7%	18.3	18.4	18.5	18.6	18.7	18.9	19.0	19.1	19.2	19.4	19.5	19.6	19.7	19.8	20.0
Waihi Beach	3.3	1.4%	5.9	5.9	6.0	6.1	6.2	6.3	6.3	6.4	6.5	6.6	6.6	6.7	6.8	6.9	7.0
Whangamata	0.0	0.4%	10.5	10.5	10.6	10.6	10.7	10.7	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.1	11.1

A7.4 DEMAND FORECAST FOR TAURANGA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Aongatete	7.2	2.7%	8.4	8.6	8.8	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6	10.8	11.0	11.2
Bethlehem	8.0	4.4%	9.4	9.8	10.1	10.5	10.9	11.3	11.6	12.0	12.4	12.7	13.1	13.5	13.8	14.2	14.6
Hamilton St	22.4	1.3%	15.5	15.7	15.9	16.1	16.2	16.4	16.6	16.8	17.0	17.2	17.4	17.6	17.8	17.9	18.1
Katikati	5.3	1.6%	8.3	8.4	8.6	8.7	8.8	8.9	9.1	9.2	9.3	9.5	9.6	9.7	9.8	10.0	10.1
Kauri Pt	2.0	0.6%	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.4
Matua	7.2	0.3%	10.2	10.2	10.2	10.3	10.3	10.3	10.4	10.4	10.4	10.5	10.5	10.5	10.5	10.6	10.6
Omokoroa	13.2	1.5%	11.5	11.6	11.8	11.9	12.1	12.2	12.4	12.5	12.7	12.8	13.0	13.1	13.3	13.4	13.6
Otumoetai	13.6	2.1%	14.0	14.3	14.6	14.9	15.1	15.4	15.7	16.0	16.3	16.6	16.8	17.1	17.4	17.7	18.0
TAURANGA 11kV	30.0	3.2%	30.3	31.1	32.0	32.9	33.8	34.7	35.6	36.4	37.3	38.2	39.1	40.0	40.9	41.8	42.6
Waihi Rd	24.1	0.4%	21.9	22.0	22.0	22.1	22.2	22.3	22.3	22.4	22.5	22.6	22.6	22.7	22.8	22.9	22.9
Welcome Bay	21.4	2.0%	22.6	23.0	23.5	23.9	24.3	24.8	25.2	25.6	26.1	26.5	26.9	27.4	27.8	28.2	28.7

A7.5 DEMAND FORECAST FOR MOUNT MAUNGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atuaroa Ave	0.0	0.8%	8.1	8.1	8.2	8.3	8.3	8.4	8.5	8.5	8.6	8.7	8.7	8.8	8.9	8.9	9.0
Matapihi	24.1	1.0%	14.4	14.5	14.6	14.8	14.9	15.0	15.2	15.3	15.4	15.6	15.7	15.8	16.0	16.1	16.3
Omanu	24.3	0.6%	15.6	15.7	15.7	15.8	15.9	16.0	16.1	16.2	16.3	16.3	16.4	16.5	16.6	16.7	16.8
Paengaroa	2.3	0.6%	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Papamoa	21.3	6.3%	19.5	20.6	21.8	22.9	24.1	25.2	26.3	27.5	28.6	29.8	30.9	32.0	33.2	34.3	35.4
Pongakawa	2.1	0.5%	7.4	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6	7.7	7.7	7.7	7.8	7.8	7.8
Te Maunga	9.1	1.6%	8.4	8.5	8.6	8.7	8.8	9.0	9.1	9.2	9.3	9.5	9.6	9.7	9.8	9.9	10.1
Te Puke	22.9	0.6%	20.4	20.5	20.6	20.8	20.9	21.0	21.2	21.3	21.4	21.5	21.7	21.8	21.9	22.1	22.2
Triton	21.3	0.8%	21.4	21.6	21.8	21.9	22.1	22.3	22.5	22.6	22.8	23.0	23.2	23.4	23.5	23.7	23.9

A7.6 DEMAND FORECAST FOR WAIKATO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Browne St	10.6	1.3%	9.9	10.0	10.1	10.3	10.4	10.5	10.6	10.7	10.9	11.0	11.1	11.2	11.3	11.5	11.6
Farmer Rd	0.0	0.2%	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1
Inghams	3.6	-	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Lake Rd	0.0	0.4%	5.9	6.0	6.0	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.3
Mikkelsen Rd	19.2	0.3%	15.2	15.2	15.2	15.3	15.3	15.3	15.4	15.4	15.5	15.5	15.5	15.6	15.6	15.6	15.7
Morrinsville	0.0	0.5%	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4	11.4
Piako	15.2	1.0%	15.0	15.2	15.3	15.5	15.6	15.8	15.9	16.0	16.2	16.3	16.5	16.6	16.7	16.9	17.0
Putaruru	0.0	0.5%	11.6	11.7	11.7	11.8	11.9	11.9	12.0	12.0	12.1	12.2	12.2	12.3	12.3	12.4	12.4
Tahuna	0.8	0.3%	5.7	5.8	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	6.0	6.0	6.0
Tatua	1.2	-	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Tirau	0.0	0.5%	9.5	9.5	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.0	10.1	10.1
Tower Rd	0.0	1.6%	9.8	9.9	10.1	10.2	10.4	10.5	10.7	10.8	11.0	11.1	11.2	11.4	11.5	11.7	11.8
Waharoa	0.0	2.1%	7.8	8.0	8.1	8.3	8.4	8.6	8.8	8.9	9.1	9.2	9.4	9.5	9.7	9.9	10.0
Waitoa	18.8	-	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Walton	0.0	0.1%	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0

A7.7 DEMAND FORECAST FOR KINLEITH AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Baird Rd	0.0	0.6%	10.3	10.4	10.5	10.5	10.6	10.6	10.7	10.8	10.8	10.9	10.9	11.0	11.1	11.1	11.2
Maraetai Rd	0.0	0.3%	11.2	11.2	11.3	11.3	11.3	11.4	11.4	11.4	11.5	11.5	11.5	11.6	11.6	11.6	11.7
Midway / Lakeside	0.0	-	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4

A7.8 DEMAND FORECAST FOR TARANAKI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bell Block	22.9	2.3%	18.4	18.8	19.2	19.6	20.0	20.4	20.8	21.2	21.6	22.0	22.4	22.8	23.2	23.6	24.0
Brooklands	27.0	0.9%	15.3	15.4	15.6	15.7	15.8	15.9	16.1	16.2	16.3	16.5	16.6	16.7	16.8	17.0	17.1
Cardiff	4.1	0.6%	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
City	20.1	0.6%	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.4	20.5	20.6
Cloton Rd	13.0	0.6%	10.7	10.8	10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.3	11.4	11.4	11.5	11.5
Douglas	1.7	-0.0%	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Eltham	8.6	0.1%	9.9	9.9	9.9	9.9	9.9	9.9	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Inglewood	6.2	1.1%	5.4	5.4	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2
Kaponga	3.0	0.2%	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8
Katere	24.3	3.0%	13.5	13.8	14.2	14.5	14.9	15.2	15.6	16.0	16.3	16.7	17.0	17.4	17.7	18.1	18.4
McKee	1.6	1.6%	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7
Motukawa	0.6	0.5%	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Moturoa	21.4	1.2%	22.5	22.7	23.0	23.2	23.5	23.7	24.0	24.2	24.5	24.7	25.0	25.2	25.4	25.7	25.9
Oakura	4.2	1.4%	3.5	3.5	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1
Pohokura	9.2	-	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Waihapa	1.4	-	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Waitara East	10.1	1.3%	6.3	6.3	6.4	6.5	6.6	6.6	6.7	6.8	6.9	6.9	7.0	7.1	7.2	7.2	7.3
Waitara West	6.4	0.3%	6.9	6.9	6.9	6.9	6.9	7.0	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1

A7.9 DEMAND FORECAST FOR EGMONT AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambria	17.0	0.5%	15.6	15.7	15.8	15.8	15.9	16.0	16.1	16.2	16.2	16.3	16.4	16.5	16.6	16.7	16.7
Kapuni	7.0	-0.2%	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.6
Livingstone	3.1	0.0%	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Manaia	5.0	0.1%	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.9	7.9	7.9	7.9
Ngariki	3.8	0.3%	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Pungarehu	4.5	0.4%	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7
Tasman	6.4	0.2%	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Whareroa	3.0	0.6%	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.9

A7.10 DEMAND FORECAST FOR WHANGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Beach Rd	13.6	0.5%	10.9	11.0	11.0	11.1	11.1	11.2	11.3	11.3	11.4	11.4	11.5	11.5	11.6	11.6	11.7
Blink Bonnie	2.3	0.4%	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6
Castlecliff	8.7	0.5%	11.5	11.5	11.6	11.6	11.7	11.7	11.8	11.9	11.9	12.0	12.0	12.1	12.1	12.2	12.3
Hatricks Wharf	0.0	0.1%	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Kai Iwi	1.0	0.6%	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6
Peat St	0.0	0.6%	19.4	19.5	19.6	19.7	19.9	20.0	20.1	20.2	20.3	20.4	20.6	20.7	20.8	20.9	21.0
Roberts Ave	5.7	0.3%	8.4	8.4	8.4	8.5	8.5	8.5	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.8
Taupo Quay	0.0	0.1%	11.4	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.6	11.6	11.6	11.6	11.6	11.6
Wanganui East	3.1	0.1%	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.8	8.8	8.8

A7.11 DEMAND FORECAST FOR RANGITIKEI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Arahina	2.9	0.2%	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.2	9.2	9.2
Bulls	4.0	0.1%	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8	5.8
Pukepapa	3.4	0.3%	9.0	9.0	9.1	9.1	9.1	9.1	9.2	9.2	9.2	9.2	9.3	9.3	9.3	9.3	9.4
Rata	0.7	-0.1%	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Taihape	0.7	-0.1%	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Waiouru	0.6	-0.2%	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.9	2.9	2.9

A7.12 DEMAND FORECAST FOR MANAWATU AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Feilding	23.7	1.0%	22.0	22.2	22.4	22.6	22.8	23.0	23.2	23.4	23.7	23.9	24.1	24.3	24.5	24.7	24.9
Kairanga	19.1	0.5%	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7	20.8	20.9	21.0
Keith St	21.9	0.5%	19.1	19.2	19.3	19.4	19.5	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.1	20.2	20.3
Kelvin Grove	17.2	2.4%	18.9	19.4	19.8	20.2	20.6	21.0	21.4	21.8	22.3	22.7	23.1	23.5	23.9	24.3	24.8
Kimbolton	0.6	0.2%	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Main St	17.0	0.5%	29.4	29.5	29.7	29.8	30.0	30.1	30.2	30.4	30.5	30.7	30.8	31.0	31.1	31.2	31.4
Milson	18.1	1.6%	18.9	19.2	19.5	19.8	20.1	20.3	20.6	20.9	21.2	21.4	21.7	22.0	22.3	22.5	22.8
Pascal St	17.0	0.3%	23.4	23.5	23.6	23.6	23.7	23.8	23.8	23.9	24.0	24.0	24.1	24.2	24.3	24.3	24.4
Sanson	0.0	1.1%	8.9	9.0	9.1	9.2	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2
Turitea	0.0	1.5%	16.0	16.2	16.5	16.7	16.9	17.1	17.3	17.6	17.8	18.0	18.2	18.4	18.7	18.9	19.1

A7.13 DEMAND FORECAST FOR TARARUA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Alfredton	1.4	-0.0%	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Mangamutu	12.8	0.1%	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.9	12.9	12.9
Parkville	0.0	-0.1%	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9
Pongaroa	2.9	-0.2%	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

A7.14 DEMAND FORECAST FOR WAIRARAPA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Akura	9.0	0.5%	13.3	13.3	13.4	13.5	13.5	13.6	13.6	13.7	13.8	13.8	13.9	13.9	14.0	14.0	14.1
Awatoitoi	3.0	0.5%	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Chapel	13.8	0.5%	15.3	15.4	15.5	15.5	15.6	15.7	15.8	15.8	15.9	16.0	16.1	16.1	16.2	16.3	16.4
Clareville	10.9	1.5%	11.5	11.7	11.8	12.0	12.1	12.3	12.4	12.6	12.8	12.9	13.1	13.2	13.4	13.5	13.7
Featherston	1.5	0.9%	5.0	5.0	5.0	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.4	5.4	5.4	5.5	5.5
Gladstone	1.4	1.0%	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Hau Nui	0.0	0.5%	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Kempton	2.1	1.2%	5.0	5.1	5.1	5.2	5.2	5.3	5.4	5.4	5.5	5.5	5.6	5.6	5.7	5.8	5.8
Martinborough	1.5	1.3%	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.8	5.9
Norfolk	7.0	1.9%	7.1	7.2	7.3	7.4	7.6	7.7	7.8	7.9	8.0	8.2	8.3	8.4	8.5	8.6	8.8
Te Ore Ore	6.7	0.4%	7.4	7.5	7.5	7.5	7.5	7.6	7.6	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.9
Tinui	1.3	0.4%	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Tuhitarata	0.2	0.7%	3.1	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4

A8.1 APPENDIX OVERVIEW

This appendix provides additional details of the constraints, analysis options and preferred solution for the growth and security projects outlined in Chapter 11.

A8.2 MAJOR PROJECTS

This section provides detailed descriptions for all projects above $5m and expected to commence within the next five years.

A8.2.1 KAIMARAMA - WHITIANGA

NEW KAIMARAMA – WHITIANGA CIRCUIT

Constraint

The combined 2015 peak demand on the Coromandel, Whitianga and Tairua substations was ≈28MVA. During an outage of the 66kV line between Kopu and Tairua, the section of 66kV line between Kaimarama and Whitianga would be overloaded during peak conditions. During an outage of either 66kV circuit from Kopu, the remaining network is voltage constrained at peak demand. These three substations therefore do not meet our Security of Supply Standard, which requires a no break N-1 supply (security class AAA).

In addition to the above constraints, the subtransmission network supplying the Coromandel, Whitianga and Tairua substations has a history of poor reliability due to the long overhead lines that cross rugged and exposed terrain, coupled with the existing meshed configuration and tee connections. More specifically, the Coromandel area's subtransmission network is our worst performing area in terms of SAIDI. There is a particular issue with the Coromandel substation which is supplied via a 66kV line that tees off the Tairua-Whitianga 66kV line. The implementation of a robust electrical protection system on this three-terminal network has been found to be difficult. A number of significant trips/events have meant that we have not been able to operate the Kopu-Whitianga-Tairua-Kopu 66kV ring in a closed configuration.

Options

Both non-network and network solutions have been considered to address the existing constraints. Network options involved a range of upgrades or new overhead or underground circuits, and also a new switching station option. Non-network options such as demand-side resources or widely distributed small scale renewable generation (including with energy storage) did not offer sufficient capacity and availability. Large scale thermal generation could address the underlying security driver, but there are no acceptable fuel sources available in the region.

The following network solutions were shortlisted

1. Re-conductor existing Kaimarama-Whitianga 66kV lines.
2. New Kaimarama-Whitianga 66kV overhead line.
3. New Kaimarama-Whitianga 66kV underground cable.
4. New Kaimarama-Whitianga 110kV overhead line (initially operated at 66kV).
5. New Kaimarama-Whitianga 110kV underground cable (initially operated at 66kV).
6. Kaimarama 66kV Switching Station

Preferred Options

The currently preferred option is the installation of an 110kV underground cable between Kaimarama and Whitianga (Option 5 above). This is preferred due to the difficulties associated with acquiring the necessary consents and rights to construct or upgrade overhead lines, or to construct a new 66kV switching station (option 6). The installation of an 110kV cable aligns with our long-term strategy to upgrade the entire Kopu to Whitianga circuit to 110kV in future. Given the risks and costs related to this proposal, and the early stage of investigations, we need to retain a flexible future development path and continue to investigate a range of options.

A8.2.2 KOPU – TAIRUA

KOPU – TAIRUA LINE UPGRADE

Constraint

The combined 2015 peak demand on the Coromandel, Whitianga and Tairua substations was ≈28MVA. During an outage anywhere on the long 66kV line from Kopu GXP right through to Whitianga, the line between Kopu and Tairua does not have sufficient capacity to supply all three substations during peak loading conditions. The 66kV network would also experience voltage constraints at its extremities (ie Coromandel substation). These three substations therefore do not meet our Security of Supply Standard, which requires a no-break N-1 supply (security class AAA) in regard to the subtransmission network.

Options

Both non-network and network solutions have been considered to manage or remove the existing constraint. Of the non-network options, only large scale thermal generation resolves the underlying capacity and security issues adequately, and this is largely precluded on the grounds of fuel availability and environmental concerns. This meant only options involving investment in network infrastructure upgrades could adequately address the needs.

The following network solutions were shortlisted:

1. Re-conductor existing Kopu-Tairua 66kV line.

2. Duplex the existing Kopu-Tairua 66kV line.
3. Build a second Kopu-Tairua 66kV line.

To manage the post-contingency voltage step change when the 66kV network is operated in a closed ring, dynamic reactive support will eventually be required at Tairua and Whitianga to meet voltage quality standards.

Preferred Option

Option 1, to re-conductor the existing Kopu-Tairua 66kV line, is preferred. This is more cost effective than either alternative network option. The consenting and property issues of a new line are considered to be prohibitive through this area of sensitive landscapes and difficult physical access. Moving to a non-standard (for the distribution industry) duplex construction represents high risk – conductor fittings are scarce and the technology largely unproven in post or pin type construction. In addition to the line upgrade, 66kV capacitor banks will be needed to address the voltage constraints. This will occur as a separate project prior to the line upgrade.

A8.2.3 KOPU – KAUAERANGA

NEW KOPU – KAUAERANGA LINE

Constraint

During 2015 the total load on the Thames substation was ≈15MVA. The substation supplies a number of relatively large consumers including A and G Price and Thames Toyota. Under normal operating conditions the supply to Thames is via a single 66kV circuit. If there is a fault on the normal Thames supply a second overhead 66kV supply line can be switched in. However, the second circuit is shared with the Coromandel/Whitianga/Tairua substations and the shared section (≈5 km of Raccoon conductor between Kopu and Parawai) would be overloaded during peak loading conditions. The existing supply network to Thames does not meet the requirements of our Security of Supply Standard, which recommends a (N-1), no break supply network with a security class of AAA.

The section of overhead line between Parawai and Kauaeranga is overloaded when supplying Whitianga, Coromandel and Tairua in the event of a Kopu-Tairua outage.

In addition the subtransmission network in the Coromandel Area has a long history of poor performance due to the long overhead lines that cross rugged terrain. This is compounded by the meshed configuration that involves a number of 66kV tee connections. The simplification of the existing network is expected to deliver significant benefits to the consumers in the Coromandel Area.

Options

Both non-network and network options were considered during the long list evaluation. As for associated projects on the Coromandel 66kV subtransmission (refer sections A8.2.1 and A8.2.2), the magnitude of the required step change in capacity/security, together with environmental concerns and energy source availability, meant there were no feasible non-network options to resolve the constraints.

The following network solutions were shortlisted:

1. New 66kV/110kV line from Kopu GXP to Kauaeranga.
2. Thermal upgrade of the existing Kopu-Kauaeranga 66kV line.
3. Re-conductor the existing Kopu-Kauaeranga 66kV line.

Preferred Option

The preferred option is to construct a new ≈8km, 110kV capable, overhead line from Kopu GXP to Kauaeranga (Option 1 above). This is the only option that addresses the performance issues related to the meshed configuration and manually switched backup circuits, by separating the subtransmission for Thames from that for the peninsula (Coromandel, Whitianga and Tairua). The new line would initially be operated at 66kV, but be 110kV capable to align with our future plans to supply the Whitianga substation, from Kopu, via an 110kV supply line.

The proposed line route has been designated, and agreements are in place with most landowners. However one block of land is subject to Treaty settlement claims and is likely to delay the project by up to five years. To temporarily alleviate the existing constraint, it is proposed to reconductor the section of Mink conductor between Parawai and Kauaeranga and thermally upgrade the Kopu-Parawai section of Racoon as an interim measure to enable the deferral of the new line.

A8.2.4 WHENUAKITE SUBSTATION

WHENUAKITE SUBSTATION

Constraint

From 2007- 2013 the Whitianga substation experienced ≈3% growth per annum. This growth is generally supported by the published census information of the township's population growth. Whitianga already exceeds its secure capacity and in the future peak demand is forecast to grow by 1.6% per annum.

The 11 kV network supplied by the Whitianga substation is presently facing an issue with respect to ICP growth. A number of 11kV feeders well exceed our recommended ICP numbers. As a result the SAIDI levels on these 11kV feeders tend to be relatively high (ie customers are exposed to more network outages). The coastal townships to the south of Whitianga (including Hahei and Hot Water Beach) are supplied by two 11kV feeders as follows:

Coroglen Feeder: A rural overhead line feeder that follows a path south from the Whitianga substation to Coroglen and then heads east towards Hahei and Hot Water Beach, a distance of ≈25km. During peak network loading periods (≈2MVA in 2015) a significant portion of the electrical load is at the end of this feeder and it is equipped with a voltage regulator and two pole mounted capacitor banks to elevate delivery voltages. Backfeed capability is now very limited.

Purangi Feeder: Passes through the Whitianga township (via cable and overhead line), crosses the Whitianga harbour (via submarine cable) to supply the Cooks Beach area before heading south-east (via overhead line) to Hahei. The 2015 peak load on the feeder was ≈3MVA. Insufficient capacity is available for backfeed.

The loads on the above two, long 11kV feeders are projected to continue to increase.

Options

Options considered were:

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Whenuakite substation (in and out 66kV configuration).
3. New Whenuakite substation (66kV tee connection).
4. New Whenuakite Substation (66kV switching station)

No feasible non-network options were shortlisted. The underlying issues of high customer count, high growth and feeders with poor reliability cannot be addressed by demand modifying (DG or DSR) non-network approaches. This is evident in the network options also, which propose significant network architecture changes, rather than incremental capacity upgrades.

Preferred Option

The currently preferred option is to build a new Whenuakite substation, supplied via a new 66kV double circuit line that connects into the Tairua – Whitianga circuit using an in-and-out configuration (option 2 above). Installing additional 11kV feeders from Whitianga substation, instead of a new Whenuakite substation, would face considerable consenting and construction challenges and would not address load constraints at Whitianga itself. A tee connection for the proposed Whenuakite substation (Option 3) would exacerbate the existing protection and operational constraints on the 66kV. Obtaining property and consents for both a substation and a switching station (Option 4) would considerably add to costs and project complexity.

A8.2.5 MATARANGI SUBSTATION

MATARANGI SUBSTATION

Constraint

As noted for the Whenuakite constraints above, the 11kV feeders from Whitianga substation are long and heavily loaded, with ICP counts and feeder lengths exceeding our recommended standards. This impacts on reliability as more customers are affected and for a greater number of outages per year. Strong growth has been sustained in the last decade and is predicted to continue due to the area's continued popularity for holiday accommodation. Backfeed capacity on the 11kV is particularly constrained and secure capacity at Whitianga substation is exceeded.

The coastal townships to the north of Whitianga (including Matarangi and Kuaotunu) are supplied by two 11kV feeders as follows:

Owera Rd Feeder: A rural overhead line feeder that follows a path north-east from the Whitianga substation to Matarangi, a distance of ≈15km. During peak network loading periods (≈3.4MVA in 2015) a significant portion of the electrical load is at the end of this feeder and it is equipped with a voltage regulator and two pole mounted capacitor banks to elevate delivery voltages.

Kuaotunu Feeder: Passes through the Whitianga township supplying some urban consumer load before heading north-west to Kuaotunu. The 2015 peak load on the feeder was ≈2.3MVA.

The loads on the above two, long 11kV feeders are projected to continue to increase. The combined peak load of ≈5MVA on the two feeders cannot be supplied by a single feeder (ie during an outage of the other feeder).

Options

Options considered were:

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Matarangi substation supplied via a 66kV spur line.
3. Install an 11/22kV transformer and upgrade the existing 11kV network to 22kV.

In similar manner to Whenuakite substation (refer section A8.2.4), the nature of the underlying issues necessitated options providing a substantial change in network configuration, as opposed to incremental demand adjustments (most non-network options) or capacity upgrades to existing circuits.

Preferred Option

The preferred solution is a new Matarangi substation supplied from a new 66kV line from Whitianga substation (Option 2 above). This option also provides for a staged implementation where the new 66kV line could initially be operated at 11kV and upgraded later when the substation was needed. Upgrading feeders from 11kV to 22kV (Option 3) has been looked at as a coordinated strategy for the Coromandel, but costs remain too high considering the infrastructure (distribution transformers, insulators, lines, cables, tap-changers) that would need to be upgraded or replaced. As for the Whenuakite project, additional 11kv feeders out of Whitianga substation ultimately do not address the constraints on Whitianga substation itself.

A8.2.6 KEREPEHI – PAEROA

KEREPEHI – PAEROA UPGRADE

Constraint

Kerepehi substation supplies a load of ≈10MVA and has a single 66kV supply circuit from Kopu GXP. The 11kV backup supply is small and much of the load is only N secure which falls well short of our security standard. Most of the substation load cannot be supplied when the single 66kV circuit is out of service. Loading is forecast to steadily increase and towards the end of the planning period the substation is projected to exceed secure capacity.

Options

Being an N security substation, the underlying reliability issue cannot be addressed by options which simply alter demand (as most non-network options do) or only increase the capacity of existing circuits. Options which address the actual need are those which provide alternate or backup circuits, preferably at subtransmission voltages.

The following network solutions were shortlisted:

1. Refurbish an existing decommissioned line that runs between Kerepehi and Paeroa in order to provide 33kV backfeed via Paeroa. The 33kV line would need to supply a new/spare 33/11kV transformer that is energised but not supplying load (ie on “hot standby”), as the existing supply to the site is via 66/11kV from a different GXP, and cannot be paralleled.
2. Construct a second (new) dedicated 66kV circuit from Kopu GXP to Kerepehi. The costs would be relatively high and there would be significant consenting and land access issues. The circuit may need to be underground in the worst case.
3. Upgrade the existing 11kV lines/network to provide additional backfeed. The installation of sufficient 11kV backfeed capacity would be costly and difficult with multiple circuits involved over substantial lengths, and operationally complex (multiple automated changeover schemes).

Preferred Option

Considering the issues associated with each option, as outlined above, our present strategy is to further investigate the possible refurbishment of the existing, decommissioned line that runs most of the way between Kerepehi and Paeroa (option 1). This will either see resolution or reach impasse in regard to the considerable uncertainty around property and consenting, and the condition of the existing line. As the results of the line/route negotiations and inspections/design reviews become more evident we will then be able to re-evaluate the potential options. It is possible the final solution may be different to that indicated here.

A8.2.7 WHANGAMATA

WHANGAMATA SECOND 33KV CIRCUIT

Constraint

The existing 33kV network supplying the Whangamata substation has a number of constraints/issues as follows:

1. Whangamata substation is supplied via a single lengthy 33kV overhead line from the Waihi substation. During 2015 the peak demand was ≈10MVA. The 11kV backup is ≈2MVA and in the event of a 33kV line outage most customers cannot be supplied. This falls well short of our security of supply standards, which recommends a security class of AA+ (full restoration in 15 seconds or less).
2. The 11kV backfeed which serves Whangamata is via an 11kV feeder located under the 33kV circuit. Certain contingencies (eg car vs pole) can render both circuits out of service, meaning no 11kV backup is then available.
3. A significant portion of the existing 22km Waihi-Whangamata overhead 33kV line is equipped with small conductor and built to operate at a 50°C conductor temperature (ie summer rating of ≈11MVA). The Whangamata load is summer peaking and during holiday periods the line is both voltage and thermally constrained. 11kV capacitor banks have been installed to manage voltage problems but the substation now operates at a leading power factor worsening line thermal loadings.
4. To avoid outages, maintenance work requires either live line working, or expensive and logistically challenging temporary generation. The restricted outage windows have placed pressure on our ability to keep up with maintenance.
5. The Waihi-Whangamata 33kV line has a history of relatively poor reliability. Between 2002 and 2009 Whangamata experienced 10 line outages greater than 30 minutes, and five of these exceeded four hours. Outages often coincide with peak holiday periods, exacerbating the impact on our customers. Whangamata has a permanent population of ≈4,500 but during holidays this swells to more than 10,000.

Options

Both non-network and network options are being considered to manage or resolve the existing constraint(s).

The following non-network options have been considered:

1. Fossil fuelled generation (ie diesel generation): While not a long term solution to address the entire need, when considered in conjunction with temporary energy storage and a subsequent network upgrade, diesel generation is practical, and is therefore a component of the overall solution as proposed in shortlisted option 3 below.

2. **Renewable generation:** No viable grid scale (~10MW) option has been identified yet that would provide a secure supply. Widely distributed PV is conceptually possible, but would be challenging to coordinate operationally. Renewable sources would need to be combined with energy storage to provide the required availability and address the reliability issues.
3. **Energy storage:** As with diesel generation, we are actively investigating the possibilities for targeted energy storage (eg critical feeders or loads) in conjunction with other options and/or as a means of mitigating outages until a longer term network solution can be implemented.
4. **Fuel switching and demand-side response (DSR):** There are no immediate options for large scale fuel switching. Demand-side response approaches can moderate the existing demand peak, but cannot on their own address the intrinsic reliability issues of the N security 33kV supply. Some DSR options may be possible as part of the interim solution to mitigate outage impacts in the short term.

The following solutions were shortlisted:

1. Construct a second 33kV line from Waikino GXP, via Golden Cross mine and DOC reserve.
2. Install a new 33kV, underground cable from Waihi substation to Whangamata substation predominantly via legal road.
3. Install a new 66kV overhead line that is connected onto the existing Kopu-Tairua 66kV line and supplies a new 66/11kV transformer bank at the Whangamata substation.
4. Re-conductor the existing Waihi-Whangamata 33kV line and install permanent backup diesel generation.
5. Upgrade the 11kV network to provide sufficient backfeed capability.
6. As for network option 1, construct a second 33kV line from Waikino GXP. Until the new line can be commissioned, mitigate outages by installing a limited quantity of Energy Storage and Diesel generation, targeted at critical commercial loads.

Preferred Options

The preferred long-term option is to construct a second circuit to Whangamata via Golden Cross mine. This option is optimal in several ways. It makes use of existing infrastructure through the mine and at Waikino GXP and the solution affords a robust, reliable and operationally elegant solution. We have been working through the complex consenting, access, engineering, construction and design issues. The line route crosses significant DOC estate and therefore requires a DOC concession, as well as RMA consents. The process to gain approval is likely to delay the construction of the second circuit beyond 2023. Therefore, it is proposed to install a hybrid battery storage and diesel generation solution (option 6) which will target critical loads in the commercial centre of the town. This is a temporary solution to minimise the impact of outages on the town's economy until such time as we can construct the second circuit. Once the second circuit is established, the battery storage and diesel generation would be redeployed elsewhere on the network.

Option 1, the 33kV line build alone, cannot be implemented quickly enough due to RMA delays. In the interim, the reliability issues are considered sufficiently severe to require some mitigation. Options 2 and 3 are largely precluded on the basis of cost. Option 5 would also be expensive, due to the long distances and large capacity upgrades involved, and would be operationally undesirable. Option 4 provides a means of improving the reliability of the line, but leaves the substation on single circuit N security indefinitely. As such, both diesel generation and energy storage are viewed more as risk mitigation options. Energy storage, if viable, will be targeted to maintain supply to essential businesses and services in the centre of the town. Our long-term strategy remains to provide appropriate N-1 subtransmission security. We will also continue to give consideration to any practical and economic renewable generation or demand side resources which could complement the diesel / energy storage solution as proposed.

A8.2.8 NORTHERN TAURANGA (OMOKOROA)

NORTHERN TAURANGA (OMOKOROA)

Constraint

The region to the northwest of Tauranga is supplied by a relatively long 33kV subtransmission network, called the Omokoroa Spur. This connects the Omokoroa, Aongatete, Katikati and Kauri Point substations. The spur emanates from the Greerton switchyard, and initially comprises two predominantly overhead circuits, ≈12km long, that run northwest to Omokoroa. The 2015 peak load on these lines was ≈26MVA. There is some network interconnection at 11kV but the transfer capacities are relatively small. The Greerton to Omokoroa 33kV lines have already been thermally uprated to operate at 70°C to address a past constraint.

The four substations supply a mix of both urban and rural land. The rural areas include small-holdings, market gardens, lifestyle blocks and kiwifruit orchards, which are expected to experience significant growth. Residential subdivision expansion has also been identified in the Bay of Plenty's Smart-Growth strategy.

The following constraints/issues exist:

1. The combined peak demand of all four substations is projected to exceed the N-1 ratings of the uprated 33kV overhead lines between Greerton and Omokoroa, again breaching our security standards.
2. During outages of one of the Greerton-Omokoroa circuits the 33kV voltages at Katikati and Kauri Pt substations are low with the result the 33/11kV zone transformer tap-changers exceed their tap range.
3. For the first ≈4km of lines from Greerton, the Omokoroa circuits share poles with the Otumoetai-Bethlehem circuits. Both circuits are configured as rings in normal operation. The circuits are therefore prone to sympathy tripping ie a

fault on one of the rings induces a current in the adjacent one causing a false trip in this also.

Options

Both non-network and network options have been considered to manage or resolve the existing constraints. Generation options are conceptually feasible, but can only address the security issues if implemented at a large scale and use non-renewable energy sources, which is largely inappropriate in this context. Renewable generation, if combined with energy storage, could also address the N-1 capacity limitations, but would be unlikely to keep pace with the high growth which is anticipated. Similarly, demand side responses, already a component of our network strategies, would not provide the magnitude of "capacity" necessary. As such, the following shortlisted options all contemplate major infrastructure upgrade. This included a review of our regional development path, and the consideration of transmission and GXP options.

The following network solutions were shortlisted:

1. Construction of a third Greerton to Omokoroa 33kV overhead line.
2. Construction of a new Greerton to Omokoroa 33kV underground cable circuit.
3. Upgrade of the existing Greerton to Omokoroa 33kV overhead line circuits.
4. Construction of a new 110kV overhead line spur from the Tauranga GXP to Omokoroa, coupled with 110/33kV substation. This option could be staged with the 110kV line operating at 33kV initially.

Preferred Options

Option 2, being a 3rd circuit using underground cable, is preferred because:

- Acquiring and consenting a new overhead line route (option 1) via either public road (including state highway) or private land (intensive horticulture or lifestyle) would be very challenging.
- Further upgrade of the existing lines (Option 3) would require substantially larger conductor, invoking considerable design, property and consenting costs.
- The concept of extending the footprint of the 110kV grid (option 4) was examined in the wider context of possible links right through to the Waikino. The costs for such transmission options, even in the long-term and in addressing a far wider range of constraints, could not ultimately be justified for the relatively small loads at risk.

We will continue to review the possibility of using overhead line construction along sections of the proposed new circuit to reduce the project costs. The project scope already makes use of existing overhead crossings of the Wairoa River.

A8.2.9 PYES PA SUBSTATION

PYES PA SUBSTATION

Constraint

The Pyes Pa and Tauriko areas have a significant amount of land that is zoned for residential, commercial and light industrial development. As the land has developed and sections occupied, the capacity of the existing 11kV network has been eroded. We have already considered the available options and installed 33kV cables (operating at 11kV) from close to the Tauranga GXP to a proposed new substation site, on the basis that the most effective solution will be to install a new 33/11kV substation.

Options

Long term network options to address Pyes Pa and Tauriko subdivisions were considered a decade ago when these extensive and important urban developments were first proposed. At this time, the economics of most non-network options were less viable, but even now the capacity required for such a large greenfields development is beyond that which such options could provide. Even network options, as proposed below, which would substantially augment the 11kV distribution network would be unlikely to provide a satisfactory long term solution, as compared with a dedicated new zone substation within the development.

The following network solutions were considered:

1. Reinforce the existing 11kV network from the Tauranga 11kV GXP. This would result in long, heavily loaded feeders with no back-feed resulting in deteriorating quality well beyond that expected of a high-quality residential development.
2. Install six 11kV express feeders from the Tauranga 11kV GXP to the Pyes Pa area. The GXP would need to be upgraded. The circuit routes from Tauranga 11kV are limited, particularly along Cameron Rd. The 11kV feeders would have high ICP counts, reliability problems and high losses.
3. Construct a new 33/11kV, zone substation at Pyes Pa.

Preferred Options

Earlier analysis confirmed the new Pyes Pa substation (option 3) as the appropriate long-term solution given the size of the new residential and industrial developments proposed. The alternative options 1 and 2, involving varying degrees of 11kV reinforcement, are less cost effective and provide poor quality of supply. In the long term, to provide appropriate reliability, the 11kV options 1 and 2 would have needed substantial retrospective reinforcement, ultimately proving more costly overall.

Timing of the new substation build is a function of section uptake. This has now reached a point where construction is essential to avoid deteriorating reliability, feeder constraints or sub-optimal "work-around" temporary solutions.

A8.2.10 PAPAMOA (WAIRAKEI SUBSTATION)

PAPAMOA PROJECT

Constraint

The Mt Maunganui/Papamoa coastal area has experienced significant residential development, particularly along the coast. Growth has been steady in the past decade, contrasting national and global trends, and has shown signs of a definite pick up in the last two years. The Wairakei area to the south-east of Papamoa is identified in the Bay of Plenty's Smart-Growth strategy and subdivisions are now under construction.

Grid connection is presently from Transpower's 110/33kV GXP at Mt Maunganui. From this GXP, two 33kV circuits feed firstly a new Te Maunga substation and then on to Papamoa substation. Parts are overhead and parts underground.

With the scale of development signalled in the Wairakei and Te Tumu areas, the 33kV network would be totally inadequate in the long-term. Future transmission and GXP constraints are also evident. Hence, our strategy has been to plan for additional transmission capacity into Papamoa and Wairakei.

The following constraints/issues are pertinent:

1. The combined peak demand of the Te Maunga/Papamoa substations (~28MVA) exceeds the N-1 capacity of the existing two 33kV circuits from Mt Maunganui. Back-feed capacity at 11kV is reducing as new development connects and is insufficient to meet our security requirements now.
2. The peak loading on the Papamoa substation has well exceeded firm capacity in the past. Te Maunga substation off-loaded Papamoa, but rapid growth will cause a further breach of our security standards in the near future. Most of the growth is on the south-east of Papamoa (ie Wairakei).
3. We have already installed two 33kV cables to a proposed Wairakei substation site in anticipation of the future load. The 11kV feeders from Papamoa are very highly loaded and we are already using the new 33kV cables at 11kV as an interim measure to alleviate feeder constraints.
4. The peak load on the Mt Maunganui GXP in 2015 was ≈62 MVA. The N-1 capacity of the 110KV lines are 63/77MVA summer/winter. Peak demand is predicted to exceed this in the next decade. The upgrade of the existing overhead transmission lines would be a significant challenge due to public and land owner opposition. The two 110/33kV transformers at Mt Maunganui have an N-1 capacity of 87MVA, providing a further constraint on GXP offtake.
5. In 2028 the unconstrained peak demand on the 33kV cables from Te Maunga to Papamoa would exceed the N-1 rating.

Options

The scale of the proposed urban development along the Papamoa coast required consideration of options that provided substantial network augmentation, including new zone substations, subtransmission and even GXP considerations. The initial proposal was to construct a new GXP, but faced with insurmountable property and consenting issues, the options needed to be reviewed some years ago, and subtransmission development then offered more pragmatic and achievable options. Any practical non-network options would have required close coordination with developers to achieve very high uptake and effectiveness. However, the benefit of non-network options is that less network capacity is then required, but in a greenfields subdivision the incremental cost of additional network capacity is small.

The following solutions have been considered:

1. A new Papamoa 110/33kV GXP supplied via new 110kV circuits connected to the Te Matai-Kaitimako 110kV.
2. A new Papamoa 110/33kV GXP supplied via 110kV underground cables from Te Matai.
3. Upgrade Te Matai GXP and install 33kV overhead lines to a new Wairakei 33/11kV substation.
4. Upgrade Te Matai GXP and install 33kV underground cables to a new Wairakei 33/11kV substation.
5. Same as Option 2 except the 110kV cables are initially operated at 33kV supplying a new Wairakei 33/11kV substation.
6. Installation of a third 33kV underground cable between the Matapihi and Te Maunga substations. A new Wairakei 33/11kV substation supplied from Papamoa substation.

Preferred Options

Option 1 was initially preferred but all reasonable attempts to secure access for new 110kV lines have been effectively exhausted. We have been forced to adapt our strategy and are working towards Option 4, with routes already confirmed for two new high capacity 33kV cables from Te Matai GXP to a new switching station and 33/11kV substation at Wairakei. Reasons for adopting Option 4 are:

1. It has the lowest overall long-term cost while still managing risks and security levels adequately.
2. It is practical and achievable (unlike overhead options), in what is now a tight timeframe as growth picks up again.
3. It improves the supply diversity to all substations. This is due to the fact the Mt Maunganui and the Te Matai GXPs will be linked at 33kV and all the relevant zone substations (Te Maunga, Papamoa and Wairakei) can be supplied via two independent routes.
4. It deals with known technology, in terms of using 33kV underground cables, avoiding risks associated with long 110kV underground circuits laid through rural road reserves with limited control of physical exposure.

A8.2.11 PUTARURU GXP

PUTARURU GXP

Constraint

Six zone substations with a combined demand of ~43MW are supplied from Hinuera GXP, which is supplied by a single 20km long 110kV circuit from Karapiro.

The 33kV network from Hinuera supplies south to Tirau and then Putaruru substations. There is no backfeed, and only a single circuit between Tirau and Putaruru. To the north of Hinuera, a 33kV network serving two substations in Matamata and one in Waharoa, have limited backfeed at 33kV from Piako GXP.

The network supplies a number of industrial consumers which include Fonterra (Waharoa), Fonterra (Tirau), Open Country Cheese (Waharoa), Buttermilk (Putaruru), Icepak (Waharoa), Kiwi Lumber (Putaruru) and Pacific Pine (Putaruru). Over the last decade the Hinuera GXP has experienced steady growth. A significant portion of the load relates to the dairy industry, which means that the electrical demand peaks in spring/summer. Sustained outages, as have occurred too often in the past, have substantial economic impacts on our customers.

A number of constraints therefore apply to this and associated projects:

1. The single 110kV overhead line to Hinuera provides only N security.
2. The peak demand on the Hinuera GXP is ≈43MW, which exceeds the N-1 capacity of the existing transformers.
3. The load to the north of Hinuera (Waharoa, Walton and Browne St substations), has limited back-feed from Piako, and this does not meet our security criteria.
4. Putaruru substation is supplied via a ≈10km, single circuit, 33kV line. There is limited 11kV backup from the adjacent Tirau substation, which falls well short of that required by our security standard.
5. Maintenance on the 110kV line has been restricted due to constraints on outage windows.
6. Customer feedback in regard to the outages has been understandably strong. The South Waikato District Council has expressed concern over the security of supply to Putaruru and Tirau on a number of occasions.

Options

With only N security provided by the single 110kV line to Hinuera, alternate transmission circuits or GXPs are the obvious options, and earlier analysis concluded that a new Putaruru GXP was the preferred solution. Constructing a new Putaruru GXP remains our strategic objective, but insurmountable property issues and grid reconfiguration have both prompted reviews of available options. These reviews have modified the scope of the Putaruru GXP proposal, both in terms of grid interconnection, and in terms of considering high capacity underground circuits to obviate property issues. The only non-network option that could address the scale of the security issue at Hinuera would be a centralised thermal generation unit. Because of its unique commercial and operating characteristics, this option is not included in the shortlist below, but we will continue to investigate its viability and see if any commercial possibilities become evident.

The following grid / network options were shortlisted:

1. Construct a new Putaruru GXP, connected to an existing Arapuni – Kinleith 110kV line.
2. Construct a new Putaruru GXP, connected to the Arapuni power station at 110kV.
3. Construct a new 110kV circuit from Arapuni power station to Hinuera GXP.
4. Construct a second 110kV circuit from Karapiro power station to the Hinuera GXP.
5. Construct a new GXP at Arapuni power station, and supply Putaruru via dual 33kV circuits.

Preferred Option

Option 2 is preferred and involves constructing a new 110kV circuit from Arapuni power station to a new GXP located at Putaruru.

This outcome was confirmed through a collaborative study involving both Powerco and Transpower. This review of options was driven by unexpected changes to the grid configuration, which substantially reduced the benefits of the previously preferred option 1, by introducing constraints on the available offtake capacity from the Arapuni-Kinleith 110kV lines.

Option 2 is now preferred because, in conjunction with upgrades to the 33kV network (refer sections A8.2.12 and A8.2.13), it provides appropriate security to all customers currently supplied from the N security Hinuera GXP. This option also has the lowest estimated cost and is less likely than other options to incur delays or cost escalation due to property or consenting difficulties. Option 2 resolves the limitations on grid offtake capacity imposed by Option 1, and also adopts established grid and network architectures, protection and operating standards, including the ability to parallel both GXPs.

The estimated cost of Option 4 is high, and it also exposes risks of delay or cost escalation by virtue of challenging property and consenting issues. It would also be necessary to upgrade the Karapiro 110kV bus.

Options 3 and 5 had similar order of cost to the preferred Option 2. Option 3 exposes considerable risk around securing property rights and consents for a long overhead line. Option 5 has very similar cost/benefit outcomes to Option 2, but does require voltage management under some contingencies, and has lower limits on the capacity when feeding right through to Hinuera from the new Arapuni GXP.

It is intended to carry out further investigative work in the next 12 months to refine cost estimates and confirm the optimum solution among these remaining options with similar indicative cost / benefit. During this timeframe we can also further investigate the possibilities of possible gas generation options. This will likely be a function of what commercial partnerships are available. This work can be undertaken in parallel with preliminary design/planning for the preferred solution, particularly in regard to aspects of securing access to Arapuni switchyard and crossing the Waikato river.

A8.2.12 KEREONE – WALTON

KEREONE-WALTON UPGRADE

Constraint

As noted in section A8.2.11 (Putaruru GXP), none of the zone substations supplied from Hinuera GXP meet our security standards. This results from a number of constraints, the most serious of which is the single 110kV line from Karapiro to Hinuera, which only provides N security to ~43MVA of demand.

The option to build a new Putaruru GXP, as proposed in section A8.2.11, resolves the constraints in as much as they affect the substations south of Hinuera (Putaruru, Tirau and Lake Rd substations). However, the capacity of the 33kV network is not sufficient to secure the substations north of Hinuera (Browne St and Tower Rd in Matamata and Waharoa). Backfeed to Waharoa and Browne St from Piako GXP is limited by a low capacity 33kV line between Kereone switching point and Walton substation.

Waharoa supplies a number of important industrial customers including Fonterra, Open Country Cheese and Icepak. The peak load at Walton, Waharoa and Browne St substations has been growing recently by over 3% Waharoa has seen particularly rapid expansion and growth is forecast to continue at over 2% pa and this does not include an existing upgrade to accommodate expansion for Open Country Dairy Ltd.

Due to the speed of recent developments at Waharoa, it has been necessary to temporarily split the substation bus and feed half the load from each direction. This means different parts of the load are supplied from different GXPs and subtransmission networks which is operationally undesirable and further degrades reliability.

Options

Non-network options were considered, but only larger scale non-renewable generation could provide the required no break security/availability to the industrial load base and flat demand profile. A Cogen arrangement would be the most likely scenario where this might be viable, but no synergistic commercial opportunities to implement a Cogen solution have yet been identified.

The following network solutions have therefore been considered:

1. Re-conductor the Kereone-Walton 33kV line and thermally upgrade Piako-Kereone 33kV line.
2. Thermally upgrade the Piako-Walton 33kV line only.
3. Replace the Kereone-Walton 33kV line with a 33kV cable and thermally upgrade Piako-Kereone 33kV line.
4. Install a new Kereone-Walton 33kV cable and supply Walton permanently from Waihou GXP.
5. All of the above options include the addition of a 33kV capacitor bank to support network voltages during network contingencies and the thermal upgrade of the Walton-Waharoa 33kV line.

Preferred Option

Option 4 is our preferred option. This makes use of the existing low capacity line to carry the small Walton substation, switching it onto Waihou GXP. The new high capacity cable then feeds Waharoa from Piako GXP, and has sufficient capacity to back-feed Browne St in Matamata, when supply from Hinuera is unavailable. This also allows us to remove the split at Waharoa bus so that all load is sourced from one GXP.

Alternative Options 1 and 2 require costly upgrade work to the existing Kereone-Walton line, and still impose severe capacity limitations on back-feed. Option 3 provides no greater capacity increase than Option 4, but also requires uprating of the existing line. Option 3 is constrained by needing to operate the very low impedance new cable in parallel with the high impedance overhead line. Option 4 circumvents this problem by a reconfiguration, switching Walton substation onto Waihou GXP.

A8.2.13 PUTARURU - TIRAU

PUTARURU – TIRAU UPGRADE

Constraint

Section A8.2.11 (Putaruru GXP) and section A8.2.12 (Kereone – Walton), set out the overall network development strategy to address the N security at Hinuera GXP. Section A8.2.12 details how the Kereone – Walton upgrade will provide adequate support for Browne St substation from Piako GXP**. Section A8.2.11** details how the proposed Putaruru GXP secures substations south of Hinuera. With these projects completed, only Tower Rd substation security remains to be addressed.

We recently installed a new 33kV underground cable from the Hinuera GXP to the Tirau substation to address an overload on the existing overhead line. However, this was also part of a long-term plan to improve support for Tower Rd substation from the new Putaruru GXP. While Tower Rd can be partially back-fed from Putaruru GXP (once constructed) the limited capacity of the overhead line between Putaruru and Tirau will still restrict this to light loads. Voltage constraints would also apply.

Options

Both non-network and network options have been considered to manage or remove the existing constraint(s). The non-network considerations are discussed in Section A8.2.11.

The following options have been considered as part of the development plans:

1. Re-conductor the existing Putaruru-Tirau 33kV line.
2. Install a new 33kV underground cable between the Putaruru and Tirau substations.

Preferred Option

The preferred option is presently (Option 2 above) which involves the installation of a 13km long, 33kV underground cable from Putaruru to Tirau. The new cable would significantly increase the 33kV network capacity between the proposed Putaruru GXP and the existing Hinuera GXP and provide adequate security to the load at Tower Rd substation.

A8.2.14 MOTUROA SUBTRANSMISSION

MOTUROA SUBTRANSMISSION

Constraint

The Taranaki regional loads connect to the 110kV system, with the 220kV being predominantly for through transmission and bulk generation. There are two 220/110kV interconnector transformers, one at Stratford, one at New Plymouth. Transpower’s long-term plans identify some constraints on the 110kV capacity.

The New Plymouth substation was primarily built to accommodate the power station, which has now been permanently decommissioned. Alternative uses for the land have been proposed. Transpower is considering options to partially or fully exit the site. This includes upgraded 220/110kV interconnectors at Stratford, and rationalising the northern Taranaki grid configuration at 110kV only. This would then leave New Plymouth as a small capacity GXP, serving just 20MW of load at our Moturoa substation. The scale of switchgear and plant at the site would vastly exceed that which is optimal for such a small load, and the already disproportionately high maintenance and operating costs are exacerbated by the corrosive coastal environment. Transpower are therefore investigating the economics of disestablishing the whole site, and supplying Moturoa by some alternative means. If this proceeds, it will therefore be necessary to make alternative arrangements to supply Moturoa substation.

Option

The magnitude of the existing load and the security required for this largely preclude non-network options, particularly those such as renewable generation, energy storage or demand side response, which offer only incremental demand adjustments. Only grid scale generation would provide secure supply to Moturoa, but the removal of such generation is the driver behind the need to exit New Plymouth and hence find an alternate supply for Moturoa substation.

The following network solutions have been considered:

1. 2 x 33kV underground cables from Carrington GXP to Moturoa.
2. 1 x 33kV underground cable ring connecting Carrington GXP, Moturoa and City substations.
3. A new 110/33kV GXP at Omata coupled with a 33/11kV substation. Decommission the existing Moturoa substation.
4. A new zone substation in the Spotswood area replacing Moturoa. Supply the new substation via 2 x 33kV circuits from Carrington GXP.

Preferred Option

Option 1 appears the most cost effective, while maintaining the required level of security to the Moturoa substation. This option would involve two new dedicated 33kV cables from Carrington St GXP to our existing Moturoa substation.

Consideration of Options 3 and 4 was prompted by the poor condition and need for imminent replacement of much of the Moturoa equipment. However, the Moturoa site does have space to allow for what would largely be a total rebuild over time. This negates the advantages of a new greenfield substation site. Re-directing 11kV feeders to another site would add to the extra costs. Option 2 was of similar cost but there was insufficient space at City substation for a new 33kV switchboard. Option 3 would be too costly, and was largely eliminated by Transpower’s consideration of grid options.

A8.2.15 PALMERSTON NORTH (FERGUSON SUB)

PALMERSTON NORTH CBD

Constraint

The Palmerston North CBD and commercial / industrial areas are mainly supplied by three zone substations (Pascal St, Main St and Keith St). A number of constraints/issues impact the supply to these important substations:

1. Four 33kV oil filled cables form part of the interconnected network serving these inner city substations. The condition of the cables is difficult to assess, and the incidence of cable leaks is increasing. They have been de-rated to reduce the thermal cycling stress on the cable joints. It also recognises past exposure to thermal cycling and to potentially large circulating currents when paralleling across GXPs. These factors make the continued operation of these cables a very high risk. Maintenance and repair costs are also very high since they are located in dense urban road networks and not easily accessible.
2. During 2015 the Main St substation peak load was ≈28MVA. The two oil filled

33kV cables supplying Main St have a de-rated capacity of ~17MVA, meaning Main St is well below the required no break N-1 (AAA class) security required.

3. During 2014 the peak loads on the Main St and Pascal substations exceeded their respective N-1 firm transformer capacities. Again this means the security to these critical inner city substations is below that required.
4. During 2015 the Main St, Keith St and Kelvin Grove substation load was ≈55MVA and is supplied via a meshed set of three overhead circuits connected to the Transpower Bunnythorpe GXP. The N-1 capacity is exceeded at peak loads. The northern arm of the Tararua Wind Farm can inject up to 34MW, but this does not provide additional security.
5. During 2015 the combined peak load on the Pascal and Kairanga substations was ≈40MVA and has exceeded the N-1 firm capacity of the 33kV network.
6. During 2015 the peak load on the Kairanga substation was ≈17MVA. The substation is supplied via two circuits. One of the circuits includes an oil filled cable that has been de-rated to 12.7MVA. Kairanga substation (also requiring no break class AAA security) does not meet our standards.
7. During 2015 the peak load supplied by the Transpower Bunnythorpe GXP marginally breached the substation's 100MVA transformer firm capacity. Upgrading Bunnythorpe would be difficult and expensive. By contrast the Transpower Linton GXP is moderately loaded.

Options

Analysis of strategic options for the wider region, considering GXP and subtransmission architecture, concluded that reinforcement of the city's supply, particularly for the CBD, should concentrate on utilising the available capacity from Linton GXP. This strategy would necessitate a step change in subtransmission investment to provide new circuits from Linton GXP right into the city. This would be a long term investment, facilitating growth for some time, but would also address the immediate and severe risks exposed by the existing under-rated and poorly performing oil filled cables interconnecting the inner city substations.

Furthermore, in considering the growing risks associated with the exceedance of firm capacity at both Pascal St and Main St substations, together with limitations on the 11kV network from these substations feeding the CBD, the long term development strategy for the city proposed to construct a new zone substation on the south side of the city, with a future northern side equivalent substation constructed in future as and when load growth determined this was necessary.

In this context, the following options were shortlisted:

1. Construct a new substation at Ferguson, install two new 33kV circuits from the Linton GXP to Ferguson substation and two new 33kV circuits from Linton GXP to the Main Street substation.
2. Construct a new substation at Ferguson, install a new 33kV circuit between the Linton GXP and the Ferguson substation, install a new 33kV circuit between Linton GXP and the Main Street substation, install a new 33kV circuit between Main St and Ferguson and divert the second Linton GXP to Pascal Street 33kV circuit to connect to Ferguson substation.
3. Construct a new substation at Ferguson, install two new 33kV circuits between the Linton GXP and the Ferguson substation. Install two new 33kV circuits between Main St and Ferguson, and install a new 33kV circuit between Pascal St and Ferguson.

The deployment of non-network strategies has also been considered in the context of this project:

Fossil fuelled generation or alternate energy sources: Gas is available and feasibility has been investigated, particularly in regard to Cogen. No viable opportunities have yet been identified and environment/consenting would be challenging, especially within the CBD.

Renewable generation: No viable options have been identified at the scale required, especially within the CBD. The 33kV network already has wind generation injected from the northern arm of the Tararua Wind Farm. However, the intermittent availability of this, without storage, precludes any benefit to security.

Storage, efficiency and demand side responses: Widely distributed storage and solar PV, or efficiency programmes could have offered possible demand side resources but the flat daytime load profile of the commercial loads render these less effective. The capacity needed already and the time frame also preclude such options which require complex coordination across multiple parties. In all instances, these options would only serve to mitigate risk until network solutions could be deployed.

Preferred Option

Option 3 will deliver the highest reliability benefits to the Palmerston North CBD. It will alleviate all the existing subtransmission constraints and, with the construction of a new substation at Ferguson, relieve the capacity issues at Main St and Pascal St substations. With this option, all three existing CBD substations will meet our required security levels.

The transfer of Main St onto Linton GXP and the new Ferguson substation being connected to Linton offloads Bunnythorpe and also restores security to the 33kV circuits from Bunnythorpe into Keith St. The oil filled cables are no longer critical to CBD security and can be retired or deployed as emergency backup as appropriate.

Option 1 is not favoured as it is less cost effective, and has less flexibility to staged development. As there are four cables running along the same route, there is an increased risk of the combined failure of the four cables due to a contingent event. A wider corridor required for the four cables will likely result in increased consenting and easement acquisition risks.

Option 2 is not favoured as it will have greater interconnection of the CBD substations, which will require more complex protection coordination systems, and hence a potentially lower reliability.

Due to recent failures and reliability issues with the oil filled cables, it has been necessary to undertake urgent work to restore security to the city's commercial district. This resulted in construction of a temporary overhead line which will later be removed. It was also necessary to bring forward work to effectively retire all four oil filled cable circuits 5-10 years earlier than previously planned. While the urgent work has been necessary to address the immediate and critical supply security risks, it may now be necessary to review the overall long term development strategy for the city, to confirm whether the remaining works and timing are still appropriate given the greater capacity of the replacement circuits and the altered network configuration.

A8.2.16 SANSON – BULLS 33KV

SANSON-BULLS 33KV

Constraint

The northern region of our Manawatu Area is supplied from Bunnythorpe GXP via two 33kV circuits to Feilding substation. From Feilding there is a single 33kV overhead line to Sanson substation, and another long 33kV circuit to Kimbolton substation.

Sanson substation supplies Sanson township, surrounding rural properties and also the Royal New Zealand Air Force (RNZAF) Ohakea air base. Past long-term plans have proposed a 33kV link between Sanson and Bulls (one of the options below) and a 33kV cable operated at 11kV was installed some years ago to supply Ohakea directly from Sanson substation at 11kV. The intention is to upgrade this to 33kV and install a small switching station at Ohakea when the 33kV is extended through to Bulls.

The following constraints presently exist:

1. Sanson is supplied by a single 15km long 33kV overhead line, affording only N security.
2. The 2015 peak demand on the Sanson substation was ≈9MVA. The 11kV back-feed is well below this and maintenance or faults on the 33kV line result in prolonged or widespread outages. This provides security well below the AA+ class prescribed by our standards.
3. The 2015 peak demand on the Bulls substation was ≈6MVA. Bulls is also supplied from a single 33kV line, from Marton GXP. Bulls load can be partially restored (≈3MVA) via switching on the 11kV network, but this also does not meet the required AA security class.
4. The Ohakea base security is sub-optimal considering the critical load supported.
5. The total demand (of Feilding, Sanson and Kimbolton substations) on the Bunnythorpe- Feilding circuits is approaching their N-1 capacity.

Options

The N security resulting from the single Feilding-Sanson 33kV line, means alternate 33kV circuits are the most effective solutions. Similarly, non-network options could not address the intrinsic need for secure subtransmission.

The following network solutions were shortlisted:

1. A new Feilding-Sanson 33kV line.
2. Complete the Sanson-Bulls 33kV link, coupled with a new 33/11kV substation to supply the Ohakea air base, installing an automatic load transfer facility at Sanson substation and thermally upgrading the Bunnythorpe to Feilding 33kV lines.

Preferred Option

Option 2 is currently preferred as it will resolve the security of supply issues at the Sanson and Bulls substations as well as the Ohakea air base. The new 33kV link would involve the use of an existing ≈3.5km 33kV cable (presently operating at 11kV) from Sanson to Ohakea. There would also be the construction of a new 2km overhead line along SH1, followed by ≈2.5km new underground cable across the Rangitikei River and through the Bulls township to the Bulls substation. A new 33/11kV substation would also need to be constructed at Ohakea to supply the existing (and future) air base load.

In Option 2, the Sanson substation can be normally supplied from Bulls via the new 33kV Bull-Ohakea-Sanson line. An automatic load transfer can switch supply back to Feilding when necessary. This would help reduce loading on the Bunnythorpe GXP to Feilding 33kV circuits, and the Bunnythorpe GXP.

The cost of the Sanson-Bulls link (Option 2) is estimated to be lower than a 2nd dedicated circuit from Feilding (Option 1). Option 1 also would not improve security at Bulls, nor assist to offload Feilding circuits or Bunnythorpe GXP..

A8.2.17 INGLEWOOD

INGLEWOOD 6.6KV TO 11KV CONVERSION PROJECT

Constraint

The Inglewood zone substation supplies power to Inglewood township and the surrounding rural areas at 6.6kV. The substation contains two 33/6.6kV supply transformers. Only two substations in Powerco's Western network - Inglewood and Motukawa, operate at 6.6kV.

Disadvantages with operating a 6.6kV network include:

• Voltage drop at the ends of the feeders becomes excessive as the load increases resulting in poor quality supply to customers

• The network is isolated from neighbouring zone substations which all operate at 11kV. This limits the back-feed capacity available to Inglewood substation during a contingent event.

• The 6.6kV voltage is a non-standard Powerco's distribution voltage.

Due to these issues, the Inglewood substation does not presently meet our required security and performance quality levels.

Options

The nature of this project is unique in contemplating a strategic decision to upgrade a small section of 6.6kV distribution to standard 11kV voltage. Typical development options contemplating new circuits, substations or network architecture are not appropriate in this context, and neither are non-network options.

The following network solutions have been considered:

1. Continue to operate the Inglewood network at 6.6kV by upgrading conductors to meet voltage and capacity demands. Over time, all the 115km of feeders would need to be replaced.
2. Install 6.6/11kV step up transformers midway on the feeders, converting the ends of the feeders to 11kV and progressively moving the step up transformers back toward the start of the feeder, eventually carrying out a full conversion to 11kV.
3. Replace the remaining 6.6kV/400V transformers with dual wound transformers and then converting all feeders to 11kV within a 2-3 year timeframe. Changeover would be done on each feeder as a whole, beginning with the one having the worst voltage drop. Once all feeders were changed over the substation would be reconfigured to supply at 11kV..

Preferred Option

The preferred solution is Option 3 which involves replacing all of the remaining 6.6kV/0.4kV distribution transformers in the Inglewood area with dual winding transformers (11/6.6kV-0.4kV) over a 2-3 year period.

Option 1 is not favoured due to the long length of feeder upgrade required, and consequently high cost.

Option 2, which involves using 6.6/11kV step up transformers, is not favoured due to higher capital cost needed for the installation of a voltage regulator and 6.6kV/11kV step up transformer on each feeder

A8.3 MINOR PROJECTS – SUMMARY DESCRIPTIONS

This section provides summary descriptions of the constraints, options and preferred solution for growth and security projects estimated to cost between $1M and $5M and which are scheduled to commence in the next five years.

A8.3.1 WAIHI BEACH TRANSFORMERS

The Waihi Beach substation contains a single transformer. The peak demand has exceeded the transformer's capacity. There is limited 11kV back-feed, and the substation does not meet our security requirements.

Options considered include:

1. **Increased 11kV back-feed:** This would be costly as Waihi Beach is a considerable distance from other substations and is interconnected by a weak 11kV rural distribution network. The manual 11kV switching time would also be too great to allow offload of the transformer in time.
2. **Upgrade existing single transformer: A**ddresses the capacity constraint but does not address the lack of security exposed by having a single transformer.
3. **Upgrade substation to two transformers:** Addresses both capacity and security issues but at additional cost. The substation has adequate space for a second unit.

The proposed solution is to upgrade to a two transformer substation ensuring the capacity and security will provide for the future demand.

A8.3.2 MATAMATA (TOWER – BROWNE 33KV CABLE)

The Browne St and Tower Rd substations are each supplied via a single 33kV line from Hinuera GXP. Together these two substations supply the entire Matamata township, including the CBD. Outages on either of the 33kV lines will cause an immediate loss of supply to the respective substation. The 11kV inter-tie capacity between the substations is not sufficient or sufficiently switchable to meet our security requirements.

Options considered include:

1. **11kV back-feed upgrades:** Increased 11kV back-feed capacity and automated switching could reduce outages. Against this, the more obvious 11kV back-feeds have already been upgraded and multiple automation schemes violates our automation strategy and the principle of simple/safe operational configurations.
2. **2nd 33kV circuit to each substation:** This would involve two new circuits from Hinuera GXP, one to each substation. While this would provide a desirable architecture with ample capacity and security and even support initiatives to backstop Hinuera GXP (refer section A8.1.11), it ultimately proved too expensive.

The proposed solution is to construct a 33kV underground cable circuit between Tower Rd and Browne St substations. This will create a secure 33kV subtransmission ring serving Matamata, without excessive costs and without undesirable operating configurations.

A8.3.3 HINUERA – TOWER ROAD 33KV LINE UPGRADE

The project detailed in section A8.3.2 completes a proposed 33kV ring from Hinuera GXP to Browne St and Tower Rd substations. Both substations will then be afforded N-1 security on the subtransmission, but the combined load will exceed the capacity of the Hinuera to Tower Rd 33kV line.

Alternate options and reasoning considered were:

1. **Second circuit from Hinuera to Tower Rd:** Excessive cost, plus it would require additional switchgear and added complexity of the protection.
2. **Additional 11kV back-feed:** Cannot meet the no-break N-1 requirement required for appropriate security and rejected for the same reasons as detailed in section A8.3.2.
3. **SPS to transfer Browne St to Piako:** Operationally complex with automated switching across GXPs required.

The proposed solution is much cheaper than an additional circuit to Matamata. There are no further practical 11kV back-feed options and the option does not align with our preferred network architecture and security standards. Non-network solutions such as demand side response, load shedding may be possible but only as a risk management strategy to defer the proposed line upgrade.

A8.3.4 MORRINSVILLE SECOND CIRCUIT

The Morrinsville substation is fed by a single 33kV circuit from the Piako GXP and only provides N-security. If there is a fault on this circuit, there will be an immediate loss of supply to all of Morrinsville, including the Fonterra factory adjacent to the substation. Some back-feed from Piako and Tahuna is available, but this does not meet our security criteria.

Options considered include:

1. **Second 33kV circuit Piako to Morrinsville:** A second circuit (mostly underground cable via road reserves) would be constructed from Piako GXP to Morrinsville substation.
2. **33kV ring with Tahuna:** A new 33kV circuit from Morrinsville to Tahuna would allow a 33kV ring to be established.
3. **Increase 11kV backfeed or inter-tie:** This would need at least one high capacity bus tie circuit, and potentially substation upgrades.
4. **Non-network options:** Particularly diesel generation or Cogen.

Options to create a 33kV ring between Morrinsville and Tahuna (also supplied by a single circuit) would provide benefits to both substations, but ultimately proved too expensive considering the long distance to Tahuna substation. Increased 11kV capacity is viable, but is operationally more complex for minimal saving in cost. Non-network options are not well suited to N-security issues. Backup generation could conceivably be deployed under contingencies, but no opportunities have been identified.

The proposed solution is therefore to construct a second 33kV circuit from Piako GXP to Morrinsville substation (Option 1). This is both cost effective and provides adequate capacity and security for Morrinsville now and in the future.

A8.3.5 TOWER RD 2ND TRANSFORMER

Tower Rd substation currently has just one 33/11kV transformer. The 11kV back-feed from Browne St is not sufficient to meet our security standards.

Options considered include:

1. **Install a second transformer:** A matching 33/11kV transformer provides full N-1 security. Tower Rd substation has a programme of upgrades to improve performance and security. The substation has been designed to accommodate a second transformer.
2. **Increased 11kV backfeed:** More complex operationally and potentially higher cost.

Option 1 (a second transformer) is preferred. This provides no break N-1 security appropriate to this urban substation and caters for future growth and development, without introducing unusual operating configurations. Costs are comparable for both options.

A8.3.6 LAKE RD SECOND TRANSFORMER

Lake Rd substation currently has just one 33/11kV transformer. Substations which could provide back-feed are quite remote and existing 11kV capacity is not sufficient to meet our security standards.

Options considered include:

1. **Install a second transformer:** A matching 33/11kV transformer provides full N-1 security in a standard substation configuration.
2. **Increased 11kV backfeed:** More complex operationally. Expected to be higher cost in light of the large distance to the next nearest substations.

The proposed solution is therefore to install a second transformer.

A8.3.7 BAIRD – MARAETAI 33KV RING

The two substations supplying Tokoroa (Baird Rd and Maraetai Rd) are each supplied by a single 33kV circuit with only N security. Any outage of these circuits results in an immediate loss of supply to the respective substation. There is some 11kV back-feed capacity, but this is not sufficient to meet our security criteria, in terms of either capacity or switching time.

Tokoroa is a significant sized town with modest growth. The industrial load supports the mill and surrounding primary agriculture while the commercial load services the town and transit traffic on SH1. The security of the electrical supply considering this load base is not optimal.

The following options have been considered:

1. New 33kV cable between Baird and Maraetai to allow a closed ring, affording N-1 security to both substations.
2. Additional 11kV circuits between the substations.
3. Non-network options.
4. Dedicated 2nd 33kV circuits to each substation.

The most cost effective solution is the ring circuit (option 1). Switchgear extensions can be integrated with planned substation refurbishment. The protection can readily be coordinated to provide full no break N-1 security on the 33kV network. A cable solution is preferred to an overhead solution given the route is through established urban road reserves.

A second dedicated circuit to each substation would have been too expensive and arguably provides no more security. Additional 11kV inter-tie or dedicated bus feeders are conceptually possible, but introduce anomalous and undesirable architectures and operational schemes. No economic non-network solutions could be identified, and non-network options are not well suited to these N security issues.

A7.1.1 WAITARA – MCKEE 33KV

During peak demand periods, if the Waitara West line is not available, the single 33kV Waitara East circuit from Huirangi GXP has insufficient capacity to supply all four substations- Waitara East and West, Pohokura and McKee substations. The tee configuration of the Waitara East/McKee lines also causes protection issues and limits generation injection levels.

Options considered include:

1. **Second circuit from Huirangi to McKee/Waitara Tee:** This allows the tee to be removed and a dedicated circuit provided for each of the McKee circuit and the Waitara East circuit. The new circuit will provide sufficient capacity to resolve the existing constraints for contingencies on the Waitara West circuit.
2. **Upgrade existing 33kV circuit:** This can resolve the capacity issue, but not the protection and architecture issues presented by the tee configuration. Upgrade could still incur costs associated with acquisition of property rights.
3. **Secure generation availability:** No commercially acceptable options have been available and this option does not resolve the protection and configuration issues.

The preferred solution is presently Option 1 – construct a second 33kV circuit from Huirangi GXP to the McKee/Waitara East tee. The cost is slightly higher than other options but it provides a highly secure standard network configuration that resolves all existing operational and protection issues.

A8.3.8 ELTHAM TRANSFORMERS

The Eltham substation supplies Eltham town, the surrounding rural areas, and two significant industrial loads. The substation contains two transformers. The demand has exceeded the secure capacity of the transformers, ie the capacity that can be supplied by one transformer plus available 11kV back-feed.

Options considered include:

1. **Upgrade transformers:** Install two units that will ensure N-1 secure supply meeting the security standards for the future projected load.
2. **Increase 11kV back-feed:** The nearest substations are some distance and their capacity is quite limited, meaning this option is not very effective. Manual switching is still required in this option..

The preferred solution is to replace the existing transformers with two larger units. The Eltham 33kV substation is operated with a split bus and hence the transformers are exposed to higher duty more often, ie whenever there is a subtransmission fault.

A8.3.9 MANAIA SUBTRANSMISSION

Manaia substation is supplied by a short section of single circuit 33kV line. This tees off the Hawera GXP-Manaia-Kapuni 33kV ring. The tee connection and single circuit expose Manaia to reduced N-security and has higher risk of outages. This means the security does not meet our standards.

The capacity of the Hawera-Manaia circuit is also constrained under future peak loading for contingencies where the Hawera-Kapuni line is out of service.

Options considered include:

1. **Change tee to 'In and Out':** This requires a short section of new line from the tee into Manaia substation, and additional switchgear at Manaia.
2. **Increase 11kV backfeed:** While reducing risk of extended non-supply, this cannot meet the security class requirements due to the switched back-feed.
3. **Second circuit from Hawera to Manaia:** A second line from Hawera GXP to Manaia, plus appropriate switchgear and protection would resolve the N security section of line, plus the pending capacity constraint when back-feeding Kapuni.

The preferred solution is Option 1 – to construct a second section of line from the tee into Manaia substation and reconfigure as an in-and out connection. This would allow Hawera-Manaia-Kapuni to operate as a fully secure, closed ring. Option 3 would also resolve the pending capacity constraints but the cost is prohibitive. Relatively low cost thermal upgrades of the existing line may be instead be sufficient, and will be considered when required as part of routine project planning.

A8.3.10 ROBERTS AVE TO PEAT ST 33KV CIRCUIT

The existing 33kV subtransmission network in Whanganui uses a meshed architecture that relies on switched, cross GXP back-feeds to provide security. This results in numerous issues where the subtransmission or substations do not strictly meet our security standards. The issues related to this project can be summarised as follows:

1. Peat St is our most important substation in Whanganui, but only has a single (N-security) 33kV circuit from Brunswick GXP. This cannot provide the no-=break N-1 security (class AAA) which our standards require for a substation serving a load in excess of 20MVA, including parts of the city's CBD.
2. Switched backup 33kV supply is available from substations fed from Whanganui GXP, but the capacity of this is also constrained.
3. Roberts Ave substation is also served by a single N secure 33kV line from Brunswick GXP. It has no alternate 33kV supply, switched or otherwise, and relies heavily on 11kV back-feed from Peat St substation.
4. Kai Iwi substation is fed from Peat St and suffers from the same security issues.
5. Substations fed from Whanganui GXP (Hatricks Wharf, Taupo Quay and Beach Rd) all rely to some degree on capacity from Brunswick GXP to Peat St for certain contingencies on the Whanganui GXP side. Increased capacity into Peat St is required to secure these substations at peak loading.

Note – While the single, hence N security, 220/33kV transformer at Brunswick is a security issue directly impacting Peat St load, the project scope and analysis of options did not consider this issue. It is common to all options and cannot be resolved by subtransmission upgrades on the Brunswick side of the city. The GXP single transformer issue can be, and is in part, addressed by proposals for subtransmission upgrades on the Whanganui side. This is a strategy adopted following earlier higher level (ie GXP and transmission) consideration of regional options, in consultation with Transpower.

The following network options have been considered:

1. Second 33kV circuit from Brunswick GXP to Peat St.
2. Construct a new 33kV circuit between Roberts Ave and Peat St substations and upgrading the existing 33kV circuit between Brunswick GXP and Roberts Ave substation
3. Additional 11kV back-feeds from neighbouring substations.
4. Additional 33kV circuit(s) from Brunswick GXP into Castlecliff substation.

The preferred project is option 2, which involves the construction of a new 33kV circuit between Roberts Ave and Peat St substations and upgrading the existing 33kV circuit between Brunswick GXP and Roberts Ave substation. This option will enable a secure supply to Peat St and Roberts Ave substations, enabling them to meet our security levels.

In conjunction with the Whanganui GXP to Taupo Quay new circuit project (Taupo Quay Second Circuit), Option 2 will ensure all of the key Whanganui city substations, including Taupo Quay, Hatricks Wharf, Peat St as well as Beach Rd, Castlecliff and Roberts Ave substations, will meet our required security levels.

Option 1, which involves the construction of a new circuit between Brunswick GXP and Peat St substation while providing a secure supply to Peat St substation, will not resolve the security of supply issue at Roberts Ave substation. Hence this option was not favoured

Increased 11kV back-feed (Option 3) would not have addressed the systemic network architecture issues, and would have been unlikely to provide sufficient capacity either. The Castlecliff alternative (Option 4) looked promising in light of urban growth in this area, but ultimately the length of new circuit proved too costly.

A8.3.11 TAUPO QUAY SECOND CIRCUIT

This project addresses a number of network constraints, but most particularly:

1. Taupo Quay and Hatricks Wharf are each fed by single 33kV circuits, but the substations are paralleled at the 11kV bus. There is insufficient capacity in either circuit to carry the total peak load following a fault on the other circuit.
2. The 33kV to Taupo Quay also supplies rapidly growing industrial demand at Beach Rd. This 33kV also needs to supply Castlecliff when the normal supply via Brunswick & Peat St is interrupted. The capacity is not sufficient at peak loadings.
3. There are multiple constraints if trying to backfeed Taupo Quay via Brunswick, Peat St, Castlecliff and Beach Rd. If Taupo Quay had full N-1 security from Whanganui GXP, this contingency would not be considered.
4. Peat St is the most critical substation in Whanganui, but if the single 220/33kV GXP transformer at Brunswick is unavailable, Peat St, and all other Brunswick load, must be supplied from Whanganui GXP. Significantly greater capacity is required, especially into Taupo Quay or Hatricks Wharf, to secure all substations under such contingencies.

Due to the highly inter-meshed nature of the network in Whanganui, analysis needs to consider multiple substations, constraints and the matrix of options which can address these. Proposed options below are a result of this wider analysis but are options (or component projects of overall development path options) which are particularly pertinent to the Taupo Quay constraints identified above.

1. **Second Circuit from Whanganui GXP to Taupo Quay:** A second dedicated circuit for Taupo Quay would provide full N-1 security from Whanganui GXP into Taupo Quay. Additional switchgear and protection would also be required. Subject to property negotiations, much of the circuit might need to be underground.
2. **New (second) circuit from Whanganui GXP to Hatricks Wharf:** This would require extensive property and consenting cost, which could necessitate an

underground cable via the existing road reserve, similar to options 1 for most of the route. Additional 33kV switchgear and protection would be needed at Hatricks Wharf, which is highly space-constrained.

The preferred project is Option 1, which involves the construction of a new 33kV circuit between Whanganui GXP and Taupo Quay substation. This option will relieve the capacity constraints between Whanganui GXP and Taupo Quay/Hatricks Wharf substations, including enabling the backup of Castlecliff and Peat St substations during contingencies.

Option 1 will ensure that our required security levels are met at Taupo Quay, Hatricks Wharf, Castlecliff and Peat St substations.

Option 2 involves the construction of a new 33kV circuit between Whanganui GXP and Hatricks Wharf substation. Space limitations at Hatricks Wharf substation mean terminating an additional 33kV circuit there will be difficult. While this option will provide our required security level at Peat St substation, it will not provide the capacity to ensure the required security levels to the Taupo Quay, Beach Rd and Castlecliff substations. Hence this option was not favoured.

A8.3.12 KAIRANGA TRANSFORMERS

The Kairanga substation supplies residential, rural and industrial loads in the southern parts of the Palmerston North area. The substation contains two 15MVA rated transformers. The demand has exceeded the transformer firm capacity. High growth is expected on this substation due to both residential and agricultural developments.

Options considered include:

1. **Increased 11kV back-feed:** This is conceptually possible, but the development of the 11kV network presupposes security standards at the zone substation. A variation to these recognised architectures would not meet our standards and create operational anomalies due to the 11kV automated switching schemes needed. Ultimately, the substantial growth signalled by council planning in and around Kairanga would negate this as a practical long-term solution.
2. **Upgrade transformers:** We have adopted a standard 16/24MVA transformer for large capacity urban substations. Upgrading to this capacity at Kairanga would provide for the immediate demand and growth in the next decade, beyond which an additional substation would be appropriate.
3. **Install a 3rd transformer:** This would be a non-standard substation configuration and quite costly considering expansion of switchyards, transformer bays and the whole substation site.

The proposed solution is to replace the existing transformers with two new 24MVA units. This will provide adequate capacity for future demand with appropriate security, and standard operational and substation configurations.

A8.3.13 SANSON TRANSFORMERS

The Sanson substation supplies Sanson township, Rongotea and Himatangi areas, and the Ohakea Air Base. The substation contains two 7.5MVA rated transformers. Demand has exceeded the firm capacity of the transformers. There is also limited back-feed capability from the 11kV distribution network.

Options considered include:

1. **Increased 11kV back-feed:** Sanson is quite remote from other substations, and due to the N security 33kV subtransmission, most practical 11kV back-feed upgrades have already been exploited.
2. **Upgrade transformers:** Upgrading both transformers would provide adequate security for the substation loads.

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate security for future demand. Options to utilise the existing transformers at another site, or make use of larger ones from another site at Sanson, will be considered at the time.

A8.3.14 KELVIN GROVE TRANSFORMERS

The Kelvin Grove substation supplies commercial, industrial and residential loads in Palmerston North and the rural load to the north of Palmerston North city. The substation contains two transformers rated 15MVA. The demand has exceeded the firm capacity of the transformers.

Options considered include:

1. **Increased 11kV back-feed:** This is conceptually possible, but the development of the 11kV network presupposes security standards at the zone substation. A variation to these recognised architectures would not meet our standards and create operational anomalies due to the 11kV automated switching schemes needed. Ultimately, the strong growth at Kelvin Grove would negate this as a practical long-term solution.
2. **Upgrade transformers:** We have adopted a standard 16/24MVA transformer for large capacity urban substations. Upgrading to this capacity at Kelvin Grove would secure the substation and provide for the anticipated growth.
3. **Install a third transformer:** This would be a non-standard substation configuration and quite costly considering additional switchgear, transformer bays and the necessary space at the substation site.

The proposed solution is to replace the existing transformers with two larger units. This will provide adequate capacity for the future demand with appropriate security.

A8.3.15 FEILDING TRANSFORMERS

The Feilding substation supplies Feilding and the associated commercial, industrial, residential and rural loads in the area. The substation contains two transformers nominally rated at 21MVA each. The demand has exceeded the firm capacity of the transformers. Due to limitations in back-feed capability, the security of supply will not be adequate as load grows.

Options considered include:

1. **Increased 11kV backfeed:** The distance to Feilding from comparably sized secure substations largely precludes this option.
2. **Upgrade transformers:** We have adopted a standard 16/24MVA transformer for large capacity urban substations. Upgrading to this capacity at Kelvin Grove is viable, but notably does not provide a particularly large increase in firm capacity. Growth would erode this relatively quickly. 30MVA units are also feasible, but will again create a non-standard configuration and mean that fault levels can be hard to manage.
3. **Install a third transformer:** This would be a non-standard substation configuration, which we would prefer to avoid because of the additional protection complexity.
4. **New Zone Substation:** A new zone substation for Feilding is a viable long-term strategy, but incurs a very high cost (>$10m compared with $2m for the transformer upgrade only). Consideration of such a high cost major project is more in the scope of high level analysis associated with the Feilding subtransmission (also close to N-1 capacity), and the long-term growth patterns in the region and Feilding itself.

The proposed solution is to replace the existing transformers with two larger units. This solution is likely to be reviewed closer to the expected upgrade date. In particular, we will attempt to firm up the longer term development path and determine whether another zone substation in Feilding is a more appropriate long-term strategy.

A8.3.16 PIAKO SUBSTATION NEW 11KV FEEDER

The Piako substation supplies the rural area surrounding Morrinsville, some of the outlying suburban areas of Morrinsville and one major industrial load. The substation contains two supply transformers.

There are a total of seven 11kV feeders supplied from the Piako zone substation. The Kereone 11kV feeder is 114km in length with three other rural 11kV feeders over 40km in length. During peak periods, the loads at the end of the feeders can experience low voltages. These feeders experience voltages outside the regulatory requirements that Powerco must comply to.

Moreover, the Kereone area is experiencing steady growth, so the voltage performance of these feeders will deteriorate over time.

The proposed solution is to split the existing Kereone feeder into two feeders; one of the new feeders will be created to serve the area to the south including Te Miro, and the other feeder will essentially be the remaining section of the existing Kereone feeder, which will serve the Kereone area only. The southern section of the existing Kereone feeder will be offloaded to the neighbouring Lake Rd feeder.

This solution will also provide sufficient capacity for future growth in this area.

Alternative solutions such as voltage support and upgrading the conductor are not favoured as they will only provide limited improvements in capacity and short term benefits, and will not improve reliability due to the long feeder lengths.

A8.3.17 WAIHI BEACH 33KV TEE SUPPLY

The Waihi Beach supply is via a spur teed off one of the Waikino GXP-Waihi 33kV overhead circuits.

Supply for Waihi Beach is lost if a fault anywhere on the overhead Waikino-Waihi Beach-Waihi 33kV circuit occurs. Conversely, a fault on the 33kV spur line to Waihi Beach will result in Waihi substation running on N (single redundancy) security.

Furthermore, the loss of the Waihi Beach spur may cause the parallel Waikino-Waihi 33kV circuit to overload at high loads, resulting in the need to shed Waihi Gold Mine load at Waihi to resolve the overloading.

The following shortlisted solutions were considered:

1. Extend 33 kV outdoor bus to accommodate new bay for the Waihi Beach circuit. Install new 33 kV cable from Waihi to the Waihi Beach tee-off to create dedicated Waihi-Waihi Beach circuit. Install a sectionaliser (normally open) at the tee to allow remote reconfiguration of the network in the event of a cable fault or cable maintenance. This option requires an extension to the site.
2. Install a new 33 kV indoor switchboard in a separate switchroom located next to the existing 11 kV switchroom. Remove existing outdoor 33 kV buswork. Install a new 33 kV cable from Waihi to the Waihi Beach tee-off to create a dedicated Waihi-Waihi Beach circuit. Install a sectionaliser (normally open) at the tee to allow remote reconfiguration of the network in the event of a cable fault or cable maintenance.

The preferred solution is to build a new 33kV indoor switchroom at Waihi. This will consolidate all existing outdoor switchgear into a modern indoor equivalent which will free up space on the existing site and enhance safety. To give Waihi Beach a dedicated supply, a new 33kV cable will be laid from the new switchboard to the existing tee-off to create a new Waihi-Waihi Beach 33kV circuit. This option is the lowest cost option and has considerable safety and operational benefits compared to the option of extending the outdoor bus work.

A8.3.18 KATIKATI SUBSTATION SECOND SUBTRANSMISSION CIRCUIT

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings.

The substation is supplied via a single 33kV overhead line from Aongatete substation.

The size and nature of the load connected to the Katikati substation at risk from non-supply in the event of a 33kV line outage is significant. Some load can be back fed from neighbouring substations, such as Aongatete and Kauri Point substations, but it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance is limited to low load times.

The following shortlisted options were considered:

1. Increase the 11kV back-feed capability to Katikati substation.
2. Install a second 33kV circuit to Katikati substation.

The preferred solution is to install a second 33kV circuit to the Katikati substation by laying a cable from the Katikati substation and connecting onto the Aongatete – Kauri Point overhead line, creating a hard tee to Kauri Point. This means that for an outage on one subtransmission circuit, supply can be maintained at the Katikati substation (n-1 security). With this solution, the Katikati substation will meet our required security level.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required back-feeding capacity are not favoured due to the higher overall cost and the complexity of upgrading the mix of conductors on some of the lines. The switching required on the 11kV network can also take a considerable amount of time for a substation outage.

A8.3.19 KATIKATI SUBSTATION SECOND TRANSFORMER

The Katikati substation supplies Katikati township, as well as the surrounding horticultural and lifestyle dwellings. The substation is a single supply transformer bank substation.

The size and nature of the load connected to the Katikati substation, at risk from non-supply in the event of a transformer outage, is significant. Some load can be back-fed from neighbouring substations, such as Aongatete and Kauri Point substations. But it requires complex switching and is insufficient to support the entire Katikati load. Programmed maintenance has to be limited to low load times, for which appropriate windows are increasingly difficult to achieve.

The following shortlisted options were considered:

1. Increase the 11kV back-feed capability to Katikati substation.
2. Install a second transformer at Katikati substation.

The preferred solution is to install a matching second 33/11kV supply transformer (Option 2). This option will provide full (no break) N-1 security to the Katikati substation (together with the Katikati second circuit, refer to section 16.5.3). This option will cater for future growth and development without introducing unusual operating configurations.

Alternatives such as increasing the capacity of the 11kV feeders to provide the required back-feeding capacity are not favoured due to the complexity of upgrading the mix of conductors on some of the lines. The switching required on the 11kV network can also take a considerable amount of time to restore supply after a substation outage.

A8.3.20 PAPAMOA SUBSTATION NEW 33KV SWITCHBOARD

The Papamoa substation supplies the growing residential and lifestyle load of South East Mt Maunganui. Strong growth has meant that both the firm transformer capacity and sub-transmission capacity has been exceeded by the peak demand at this substation. The drivers for this project are the same as for the Papamoa Reinforcement project and are discussed in Section A8.2.10 above.

The solution involves the construction of a new 33kV indoor switch room at Papamoa, and transferring the Papamoa (and Te Maunga) substation loads to the Te Matai GXP (following the completion of the Papamoa and Wairakei substation projects).

This option is associated with Papamoa Region Reinforcement project and assumes:

- the Wairakei substation project will be completed in FY2019
- the Papamoa and Te Maunga substation are reconnected, such that Papamoa is normally supplied from Wairakei substation (in turn from Te Matai GXP) via two new 33kV circuits.

A8.3.21 HINUERA ODID

The Hinuera GXP supplies the area around Matamata, Tirau and Putaruru. The network comprises three single radial feeds:

- Hinuera-Lake Rd-Browne St supplies Browne St, half of Waharoa substations
- Hinuera-Lake Rd-Tower Rd supplies Lake Rd, and Tower Rd substations
- Hinuera-Tirau supplies Tirau and Putaruru substations.

Constraints in the area include a single circuit breaker supplying both Lake Rd and Tower Rd substations; a single circuit breaker supplying both circuits to Tirau substation (one cable and one overhead line), and that the existing protection system is designed to operate with Hinuera GXP as a source. Following the commissioning of the Putaruru GXP, and with the scenario of an outage of Hinuera GXP, the Hinuera area sub-transmission network including Tirau, Lake Rd and Tower Rd substations will have slower tripping times due to the lower fault levels when Putaruru becomes a fault source.

Due to these constraints, the required security levels at Lake Rd, Tower Rd, Tirau and Putaruru substations are not met.

The solution is to construct a partial outdoor-to-indoor 33kV conversion at Hinuera. Adding at least three more feeders will accommodate the recently installed Hinuera to Tirau cable and separate out the Lake Rd circuit from the Tower Rd circuit. These upgrades will improve the reliability to all three substations; Lake Rd, Tower Rd, and Tirau.

A9.1 APPENDIX OVERVIEW

This appendix details upcoming or in progress significant renewal projects. Only zone substation and subtransmission projects are included, that also have costs expected to exceed $500k.

Section A9.2 below outlines projects that are in progress during our FY18 financial year. Section A9.3 provides a summary of projects planned for execution during FY19-22.

A9.2 SIGNIFICANT RENEWAL PROJECTS 2018

A9.2.1 MOKOIA SUBSTATION (EX-WHAREROA SUBSTATION)

Whareroa substation was constructed in 1973 to supply the then named Kiwi Dairies Plant (now Fonterra) and surrounding rural community. Fonterra no longer takes supply from this substation. There are serious issues with access, environmental issues and maintenance at Whareroa substation. As the site no longer has any relevance to Fonterra, they want us to relocate our assets off their land.

The outdoor 33 kV switchgear and associated structures and buswork date back to when the site was established and are in poor condition. Parts of the indoor 11 kV switchboard have failed and are not economically repairable, and the switchboard does not meet current safety requirements. The location is also problematic as it is distant from the load it supplies, raising voltage regulation issues.

In considering major refurbishment and renewal it was decided to construct a new substation at Mokoia, nearer the load centre. The project was found to be cost effective and will enable improved future maintenance and operation. The new transformer will be higher rated at 7.5 MVA/ 10 MVA to allow for existing demand and future growth.

MOKOIA SUBSTATION (EX-WHAREROA SUBSTATION, $000, 2016 REAL)	
Estimated Total Project Cost	$5,328
Expected Project Timing	2017-2018

A9.2.2 MOTUKAWA – T27 POWER TRANSFORMER REPLACEMENT

Motukawa is a single transformer zone substation, supplying the immediate Tarata rural area with some dairy industry loads. There are approximately 562 ICPs supplied by this substation. The transformer is rated for 2.5MVA, 33/6.6 kV and was manufactured by Ferranti in 1958. It is currently leaking oil and previous attempts to repair the leaks have been unsuccessful. The transformer's latest DP test result is approximately 400 which indicates that the transformer paper is in poor condition. A transformer failure would result in loss of supply and restoration would require some time before load could be switched to backup supplies. Backup supplies are not rated for the morning and evening peak times.

The project is to replace the existing transformer, with a spare 33/11/6.6 kV, 5/6.25 MVA transformer, and associated equipment such as cables and protection relays.

MOTUKAWA - T27 POWER TRANSFORMER REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$662
Expected Project Timing	2017-2018

A9.2.3 CHAPEL SUBSTATION 33 KV SWITCHGEAR REPLACEMENT

Chapel substation is located in the Masterton CBD. The three 33 kV outdoor circuit breakers and buswork are aging (45-50 years old). Spare parts are not available for the circuit breakers, and the equipment is difficult to maintain. In addition there are safety concerns in relation to operating an exposed 33 kV bus in a CBD area with significant foot and vehicle traffic. An adjacent block wall in close proximity to the buswork is a further risk, as it could collapse into live equipment during a seismic event.

The project will involve replacing the three outdoor 33 kV CBs with a five panel indoor switchboard in a new building. The building will be located on the Western side of the site, removing any risk of collapse of existing buildings onto the new switchroom.

CHAPEL SUBSTATION 33 KV SWITCHGEAR REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$1,493
Expected Project Timing	2018-2019

A9.2.4 KINLEITH LOAD CONTROL PLANT REPLACEMENT

The existing ripple injection plant was commissioned in 1976 and uses technology that is now extremely difficult to service, with spares and technical support difficult, if not impossible, to obtain. The risk of failure of this equipment is high. The manufacturers of the existing plant ceased trading in New Zealand in the 1980s. Load control is still required in the region, to allow peak load reduction thereby deferring network capacity upgrades.

This project is to replace the existing 33 kV ripple injection plant with new plant housed inside a Portacom-type building within the perimeter of the existing Kinleith Ripple switchyard. The 33 kV outdoor switchyard equipment will need to be reconfigured for the new connections to the new plant.

KINLEITH LOAD CONTROL PLANT REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$853
Expected Project Timing	2017-2018

A9.2.5 GREERTON INDOOR 33 KV SWITCHBOARD

Greerton switching station is located in the Tauranga region and is critical to the supply of the Tauranga region.

The site contains a large number of outdoor 33 kV oil circuit breakers which are aged and in poor condition. In addition, the site is at risk of damage from a slip from a nearby hill which would likely damage a large portion of the outdoor switchyard.

We plan to replace the outdoor 33 kV switchgear with an indoor switchboard and undertake civil works to reduce the risk of slips. The conversion will also improve the reliability of the site and provide switchgear that is far safer to work on. While conversion to an indoor switchboard has a higher capital cost, it is cost effective over the lifetime of the assets due to the associated reliability, maintenance and safety benefits.

GREERTON INDOOR 33 KV SWITCHBOARD ($000, 2016 REAL)	
Estimated Total Project Cost	$3,519
Expected Project Timing	2018-2020

A9.2.6 MOBILE SUBSTATION

Many of our rural zone substations have only a single power transformer supply (ie N security), typically rated between 5 and 10 MVA. Any maintenance or planned replacement work at these substations often requires an outage and recently it has become increasingly difficult to arrange the required shutdowns due to diminishing backfeed capability. A mobile substation will be used as a temporary bypass and eliminate the need for extended outages to carry out scheduled maintenance or replacement work.

The project will include procurement of the mobile substation and installation of permanent connection points at key sites to allow straightforward connection. Investigations are currently underway to determine the best configuration of the mobile substation. Transformer capacity is not expected to exceed 8 MVA. The switchboard will likely include three outgoing 11 kV feeders, and the unit will be self-contained for communications and SCADA.

MOBILE SUBSTATION ($000, 2016 REAL)	
Estimated Total Project Cost	$2,666
Expected Project Timing	2017-2019

A9.2.7 LIVINGSTONE SUBSTATION 33 KV SWITCHYARD REBUILD

The 33 kV outdoor structure at Livingstone is in poor condition and represents a safety risk. Concrete structure poles have spalled and the connecting steel is beyond remedial work. A severe corrosion problem with externally mounted CTs and VTs means that parts of these are in imminent risk of failure, with some CTs having already failed due to corrosion causing oil leaks.

The project is to rebuild the outdoor 33 kV switchyard at Livingstone zone substation, replacing the 33 kV circuit breakers, CTs, VTs and line isolators. The project also includes replacing the last remaining oil 11 kV circuit breaker with an equivalent vacuum circuit breaker.

LIVINGSTONE SUBSTATION 33 KV SWITCHYARD REBUILD ($000, 2016 REAL)	
Estimated Total Project Cost	$677
Expected Project Timing	2018

A9.2.8 HAWERA GXP – INJECTION PLANT REPLACEMENT

The load control plant at Hawera is the last remaining plant on our network using a static frequency converter manufactured by OMI. The frequency converter was commissioned in 1982. The equipment is obsolete, there is a high risk of failure, and spares and technical support is very difficult to obtain (if it can be obtained at all). The plant is also operating on a frequency that is subject to attenuation. Load control is still required in the region, to allow peak load reduction thereby deferring network capacity upgrades.

The project involves replacing the injection plant and migrating to a lower, industry preferred frequency which will ensure that signal levels throughout the network will be sufficient for the foreseeable future. The new frequency will match that at Opunake, making any future migration of load between the GXPs seamless to the load control system.

HAWERA GXP – INJECTION PLANT REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$853
Expected Project Timing	2018

A9.2.9 KIMBOLTON 33 KV/11 KV SUB-TRANSMISSION LINE REBUILD

The Kimbolton subtransmission line supplies Kimbolton zone substation, which in turn supplies approximately 1,488 ICPs. Installation of the conductor occurred between 1958 and 1977, meaning that some has now been in service for 60 years. The line has a type of two-piece insulator which are known to fail. Replacement is warranted to ensure that an acceptable level of reliability and safety is maintained.

The existing line is underbuilt with an 11 kV line, making maintenance of both lines difficult. Parts of the 11 kV line require reconductoring which would require both lines to be de-energised and earthed; supply would need to be maintained by local generation during the period of work. Options analysis has been carried out, and the best option is to relocate the 33 kV circuit to the opposite side of the road, as an underground cable (as it was a similar cost to an overhead line). This approach allows supply to be maintained while working on the 11 kV line, which will shortly require reconductoring. An underground cable also has safety benefits compared to an overhead line when placed near a road.

KIMBOLTON 33/11 KV SUBTRANSMISSION LINES REBUILD ($000, 2016 REAL)	
Estimated Total Project Cost	$1,066
Expected Project Timing	2018

A9.2.10 TAUPO QUAY SUBSTATION 11 KV SWITCHBOARD REPLACEMENT

Hatricks Wharf and Taupo Quay are planned to secure each other's load. The Hatricks Wharf transformer has been upgraded; the Taupo Quay transformer must now be upgraded to match it.

However, Taupo Quay's existing 11 kV switchboard was manufactured in 1988 and some of the assets on the switchboard will be underrated for the new transformer.

The project involves installing a new 11 kV switchboard in preparation for the planned power transformer upgrade.

TAUPO QUAY SUBSTATION 11 KV SWITCHBOARD REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$640
Expected Project Timing	2018

A9.2.11 PAEROA SUBSTATION – TRANSFORMER REPLACEMENT

The Paeroa substation supplies the Paeroa township & surrounding farming area. The transformers at Paeroa substation are the oldest in service in the Eastern region. Obtaining spares is difficult and the transformer foundations have been found to be inadequate and do not comply with current seismic codes. There is no bunding or oil containment.

We plan to replace the transformers at Paeroa substation with refurbished units in order to improve substation capacity and backfeed capability. We also have projects planned to upgrade other equipment at Paeroa including the 11kV switchboard and building (discussed below), 33 kV circuit breakers and feeder cables.

PAEROA SUBSTATION – TRANSFORMER REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$661
Expected Project Timing	2018-2019

A9.2.12 PAEROA SUBSTATION – 11 KV SWITCHBOARD REPLACEMENT

The Paeroa substation was constructed around 1964. The 11 kV fault level at the substation is high due to the two transformer configuration and the switchboard arc flash level is beyond acceptable limits. In addition the switchroom at Paeroa substation has a seismic grade well below our current standard.

The project involves replacing the 11 kV switchboard, and either seismic strengthening of the existing building or a new switchroom. The new switchboard will be fitted with modern arc flash protection.

PAEROA SUBSTATION – 11 KV SWITCHBOARD REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$853
Expected Project Timing	2018-2019

A9.2.13 MOTUROA SUBSTATION BUILDING, TRANSFORMER, 11 KV AND 33 KV SWITCHGEAR

Moturoa substation supplies several important loads including Taranaki Port, Base Hospital, the Moturoa commercial hub and a large number of urban residential consumers. It supplies approximately 8,881 ICPs.

We acquired Moturoa Substation from Transpower in 2010. It was constructed in 1971 and none of its equipment has been renewed since then. The coastal environment has badly impacted its building, 11 kV switchboard, two power transformers and other equipment. The transformers have no bunding or oil containment. The 11 kV switchboard and related equipment are old and obsolete and the switchboard has no arc flash containment. The seismic strength of the building housing the 11 kV switchboard is well below our current standard.

This project is to renovate Moturoa Zone Substation by constructing a new building to house a 13-panel 11 kV switchboard and to replace the existing transformers with two new higher rated 33/11 kV transformers. This was found to be the least cost, long term economically sustainable solution to bring the aging assets up to standard and achieve Moturoa's required security of supply criteria.

MOTUROA SUBSTATION BUILDING, TRANSFORMER, 11 KV AND 33 KV SWITCHGEAR REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$6,569
Expected Project Timing	2017-2020

A9.3 SIGNIFICANT RENEWAL PROJECTS 2019-2022 ($000, 2016 REAL)

PROJECT NAME	DESCRIPTION	PLANNING AREA	2019	2020	2021	2022
Akura - 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Wairarapa	-	-	958	-
Akura - T1 and T2 Power Transformer Replacement	Poor asset health, inadequate oil bunding and oil containment. This project includes the replacement of two transformers, installing oil containment, bunding, firewalls and new power cables.	Wairarapa	-	-	-	2,776
Alfredton - T1 Power Transformer Replacement	Poor asset health, unit is a non-standard autotransformer, and the oil bunding and oil containment is inadequate. This project will replace the power transformer and upgrade the associated oil bunding and containment.	Tararua	1,107	-	-	-
Bunnythorpe – Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Manawatu	-	-	-	811
City - 11kV Switchboard Replacement	Oil type switchgear with high arc flash incident energy. This project will replace the existing switchgear and install new power cable tails.	Taranaki	-	-	-	1,110
Feilding - 11kV Switchboard Replacement	Poor asset health, oil type switchgear and high arc flash incident energy. This project will replace the existing switchgear.	Manawatu	-	987	-	-
Feilding - Outdoor to Indoor Conversion	Poor outdoor switchgear asset health and is located in an urban area. This project will convert the existing outdoor switchgear and associated structures into an indoor 33kV switchboard including a new building, power cables and associated secondary systems.	Manawatu	-	1,877	-	-
Kaponga - 4708T and 4709T Power Transformer Replacement	Poor asset health, inadequate oil bunding and oil containment. This project includes the replacement of two transformers, installing oil containment, bunding, firewalls and new power cables.	Taranaki	-	2,212	-	-
Kapuni - 11kV Switchboard Replacement	This switchgear is a known type issue and has high arc flash incident energy. This project will replace the existing switchgear and install new power cable tails.	Egmont	-	-	-	763
Linton - Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Manawatu	-	-	810	-
Livingstone - T1 and T2 Power Transformer Replacement	Poor asset health. This project will replace the existing transformers, install new firewall and reuse existing feeder cables.	Egmont	-	-	1,703	-

PROJECT NAME	DESCRIPTION	PLANNING AREA	2019	2020	2021	2022
Mangamaire – Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Tararua	-	-	-	811
Mangamutu 33kV Aged ACSR Renewal	The Mangamutu circuit has been found to have significant levels of corrosion to the internal strands of steel and aluminium in its Coyote ACSR conductor. This is indicative of historical ACSR conductor which has inconsistencies of grease application, which are now showing evidence of accelerated corrosion and shortened lives. The conductor is to be replaced with Neon AAAC as to improve the capacity of the line.	Tararua	683	-	-	-
Mataroa - Load Control Plant Replacement	Existing load control equipment is old and spare parts together with knowledgeable maintenance staff are becoming scarce. This will be replaced with a modern ripple plant.	Rangitikei	-	-	810	-
Milson - 11kV Switchboard Replacement	Existing switchgear is an oil type switchgear and has the highest arc flash incident energy on our network. This project will replace the existing switchgear, replace existing incomers and install new cable tails.	Manawatu	-	-	-	918
Milson – Outdoor to Indoor Conversion	Outdoor 33kV circuit breakers are bulk oil (with associated risks of explosive failure), and their condition is beginning to degrade. As the zone substation is in a residential area, the project will replace the outdoor switchgear with a modern indoor 33kV switchboard, reducing public safety risks and visual impact.	Manawatu	-	-	-	1,560
Papamoa - 11kV Switchboard Replacement	Existing switchgear is an oil type switchgear and has high arc flash incident energy. This project will replace the existing switchboard.	Mt Maunganui	-	-	952	-
Pongakawa – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and install new power cable tails. Arc flash levels will also be reduced.	Mt Maunganui	537	-	-	-
Putaruru – 11kV Switchboard Replacement	Oil switchgear in poor asset health. The project will replace the existing switchgear and building, and install new power cable tails. Arc flash levels will also be reduced. Project timing aligned to Putaruru GXP major growth project.	Waikato	-	1,619	-	-
Sanson - 11kV Switchboard Replacement	Existing switchgear is an oil type switchgear and has high arc flash incident energy. This project will replace the existing switchgear, replace existing incomers and install new cable tails.	Manawatu	-	-	847	-
Stratford 33kV Aged Copper Renewal	The subtransmission network in Stratford is a mixture of 16mm2 and 40mm2 copper, which is heavily aged and in poor condition – in recent years there have been a significant number of conductor failures. This project is a continuation of the renewal projects in this area which includes the completed Douglas section and the FY17 Kaponga and Cardiff sections.	Taranaki	-	411	445	632

PROJECT NAME	DESCRIPTION	PLANNING AREA	2019	2020	2021	2022
Tatua - T1 Power Transformer Replacement	Poor asset health. This project will replace the existing unit on the existing bunded area.	Waikato	-	-	1,150	-
Thames - 11kV Switchboard Replacement	The existing switchgear is old and has high arc flash incident energy. The project will replace the existing switchboard including installing new power cable tails.	Coromandel	-	-	-	891
Triton – Outdoor to Indoor Conversion and 11kV Switchboard Replacement	The existing outdoor 33kV and indoor 11kV switchgear is in poor condition. The existing outdoor switchyard is currently constrained in terms of space. This project will convert the existing outdoor switchgear to indoors as well as replacing the existing 11 kV switchgear, new building and install the associated power cables and secondary systems.	Mt Maunganui	-	-	3,053	-
Waharoa - T1 Power Transformer Replacement	Poor asset health. This project will replace the existing unit as well as installing a new firewall and 11kV feeder cables.	Waikato	-	-	-	1,293
Waihapa - 4714T Power Transformer Replacement	Poor switchgear and transformer asset health and the existing bund will need to be sized for the new transformer. This project will replace the existing structure, switchgear, transformer, oil containment and associated power cables.	Taranaki	-	-	1,461	-
Walton – 11kV Switchboard Replacement	The existing switchgear is very old and is an oil type switchgear. This project will replace the existing switchboard as well as install new power cable tails.	Waikato	-	522	-	-

A10.1 APPENDIX OVERVIEW

This appendix sets out forecast scheduled maintenance expenditure ($000, real 2016) by asset category over the planning period.

ASSET CATEGORY	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Zone Substations											
Routine scheduled maintenance and inspection	2,999	3,452	3,685	3,916	3,639	4,036	4,285	4,031	3,772	3,858	3,664
Subtransmission Lines and Cables											
Routine scheduled maintenance and inspection	327	377	779	821	840	287	301	279	319	337	295
Distribution and LV Lines											
Routine scheduled maintenance and inspection	932	1,073	3,308	3,377	3,562	3,252	3,117	3,262	3,358	3,496	3,329
Distribution Transformers											
Routine scheduled maintenance and inspection	844	971	796	859	932	819	771	842	818	928	821
Distribution Switchgear											
Routine scheduled maintenance and inspection	1,761	2,027	1,957	2,429	2,680	2,228	2,074	2,173	1,909	2,183	2,080
Other Network Assets											
Routine scheduled maintenance and inspection	431	496	736	731	755	786	780	801	823	835	852
General Maintenance											
Other corrective work	7,768	7,651	6,435	6,468	6,479	6,042	5,605	5,638	5,672	5,705	5,739
Defects	3,437	3,437	5,260	6,460	6,460	5,962	5,962	4,462	3,477	3,477	3,477
Third party damage repair	891	891	891	891	891	891	891	891	891	891	891
Reactive maintenance	6,733	7,081	7,214	7,311	7,409	7,348	7,288	7,333	7,379	7,425	7,471
Total Maintenance Expenditure	**26,123**	**27,456**	**31,060**	**33,263**	**33,647**	**31,650**	**31,073**	**29,712**	**28,418**	**29,135**	**28,619**

A11.1 APPENDIX OVERVIEW

This appendix discusses the performance of our poorer performing feeders. For the worst few of these feeders we explain the reasons and any planned remedial works.

The analysis uses FIDI, which is the average number of minutes that a customer on a feeder experiences without supply. The analysis period is the 2016 calendar year.

The analysis is broken down by feeder class[124]. Each distribution feeder is assigned a class that best encompasses the types of consumers connected to the feeder.

A11.2 FEEDER CLASS F1

Te Puke Quarry Rd, Tauranga – A total of seven outages occurred with five planned shutdowns accounting for 43% FIDI minutes and one from defective equipment accounting for 53% of the FIDI minutes recorded against the feeder. This feeder has a F1/F4 security rating with most faults occurring on the F4 section. Further 11kV conductor renewals are planned.

McCabe Rd, Valley – A total of 20 outages occurred with 11 planned shutdowns accounting for 66% FIDI minutes and five from defective equipment accounting for 21% of the FIDI minutes recorded against the feeder. This feeder has a F1/F4 security rating with most faults occurring on the F4 section.

Kawakawa, Manawatu – Three planned outages accounted for 97% FIDI minutes. The planned outages were for crossarm replacement on the feeder. One unplanned outage was due to a cable strike from a post-hole borer.

Mangatoki, Taranaki – Is classed as a F1/F4 feeder. Eleven unplanned outages account for the FIDI minutes listed against the feeder. All outages occurred beyond the recloser, which is on the F4 section of the feeder.

Bryce St, Whanganui – An unplanned outage caused by a truck hitting a pole accounted for 90% of the FIDI KPI. An unknown fault accounts for 10% of FIDI minutes. No work has been planned on this feeder.

Te Puke North, Tauranga - A total of 7 outages occurred with one from defective equipment accounting for 53% FIDI minutes and five from planned shutdowns accounting for 43% of the FIDI minutes recorded against the feeder. This feeder now has a F2 security rating.

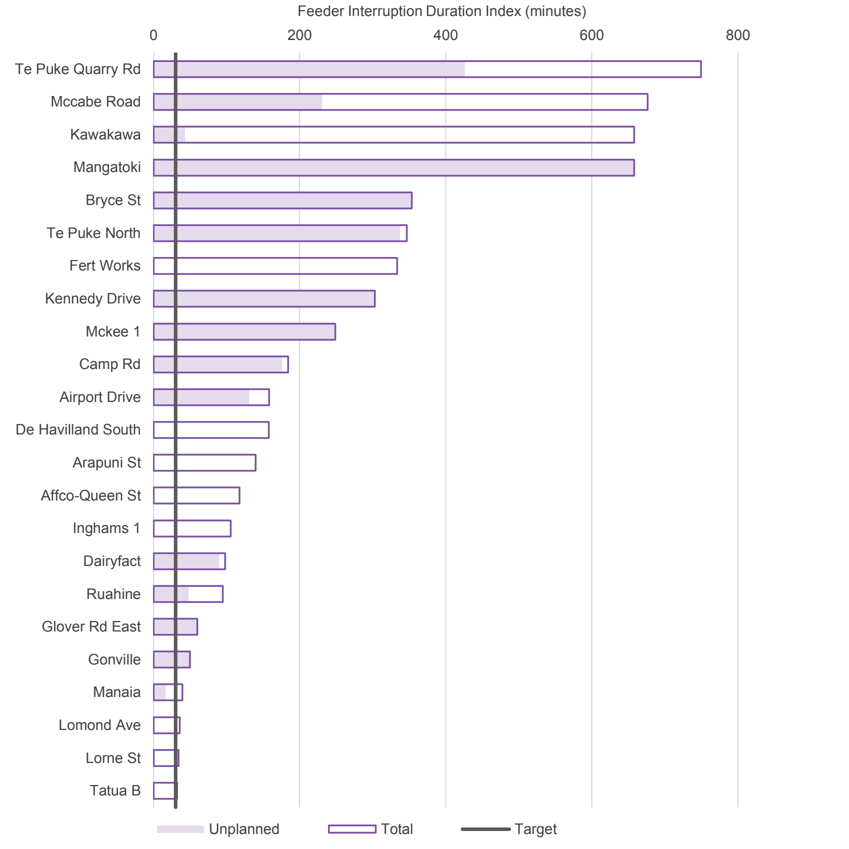
FERT Works, Tauranga – One planned outage occurred against the feeder. The major customer is to be moved to a newer cable to increase reliability**.**

Kennedy Drive, Valley - A total of two outages occurred with one from a cable fault accounting for 65% FIDI minutes and one from foreign interference accounting for 35% of the FIDI minutes recorded against the feeder. This feeder will be reclassified to a F2/F3 security rating due to recent configuration changes. Additional automation is to be added.

McKee 1, Taranaki – Two unplanned outages account for the FIDI minutes listed against the feeder. Both outages were on the same day. One outage listed cause as unknown and a broken binder found on the second outage. Full repairs were made and no further work is planned for the feeder.

Camp Rd, Whanganui – One unplanned outage has accounted for 96% of the FIDI KPI that has been listed against the feeder. The major customer has generation therefore the impact of the outage was minor for the customer. No further work has been planned for the feeder.

Feeder Class F1 FIDI



[124] We note that some of the feeders may contain multiple feeder classes and in this analysis the total FIDI contribution from all the feeder classes will be compared against the highest class target. Please refer to Chapter 7 for more details.

A11.3 FEEDER CLASS F2

Gilberd St, Whanganui - A lightning strike on the line caused over 99% of the FIDI minutes listed against the feeder.

Aramoho Inland, Whanganui – Four unplanned outages have been listed against the feeder. Some 62% of the FIDI minutes listed against the feeder are due to earthquake activity. With the other outages listed against adverse weather and defective equipment.

Waterworks Rd, Whanganui – The feeder is classed as a F2/F5 feeder. The F2 section is at the beginning of the feeder which has a circuit length of only 2.4 km. The feeder has had a total of 28 unplanned outages listed against it. Only one outage has been recorded on the F2 section of the feeder.

18th Ave, Tauranga. A total of three outages occurred with two from foreign interference accounting for 98% FIDI minutes recorded against the feeder. This feeder has a recloser and remote tie point installed, and has 1,071 ICPs.

Kopu, Valley - A total of four outages occurred with one planned shutdown accounting for 33% FIDI minutes and one from vegetation accounting for 61% of the FIDI minutes recorded against the feeder. This feeder has a F2/F4 security rating with most faults occurring on the F4 section.

Pahiatua 1, Manawatu – The feeder has had 12 planned and unplanned outages listed. Planned outages account for 98% of FIDI minutes listed against the feeder. The planned outages were for pole and crossarm replacement. No further work is planned for the feeder.

Whanganui East, Whanganui – Two unplanned outages account for the FIDI KPI. The feeder was opened at the request of the NZ Fire Service attending a reported fire on a pole. The second unplanned outage has been recorded as an ‘unknown.’

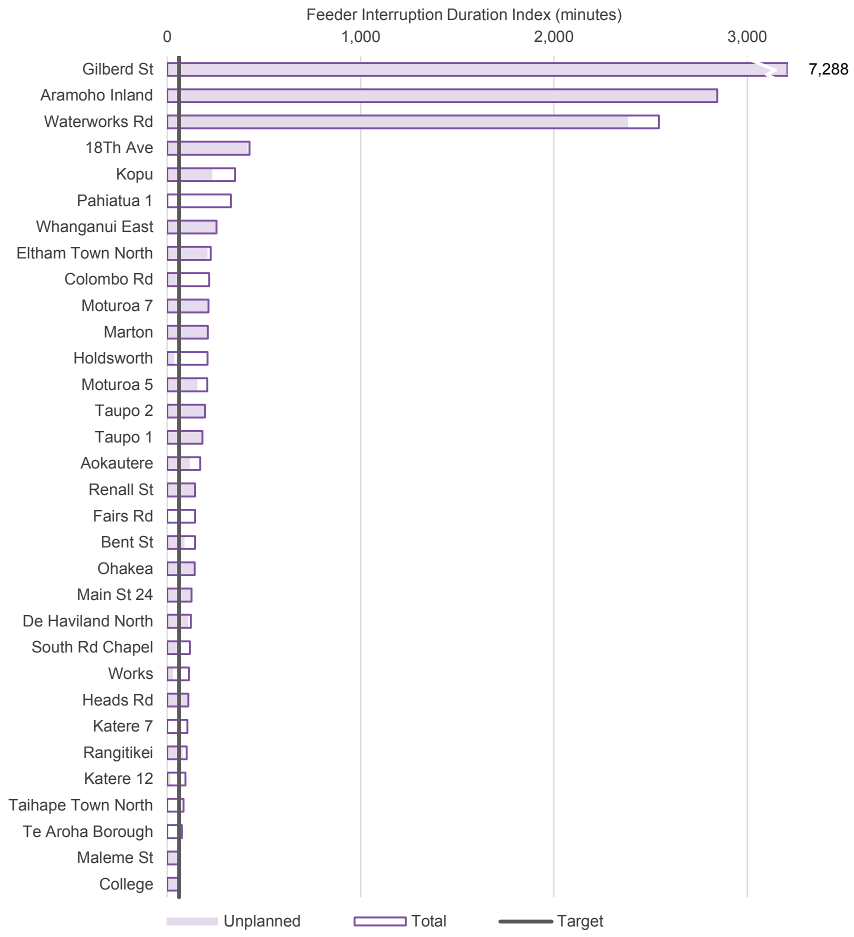
Eltham Town North, Taranaki – A total of seven outages occurred on the feeder during the reporting year. Two outages accounted for 82% of the FIDI KPI listed against the feeder. The MOC classifications were unknown (38%) and adverse environment (44%). No further work is planned for the 2018 year

Colombo Rd, Masterton – Planned outages have accounted for 69% of the FIDI KPI. Work included pole and insulator replacement. Two unplanned outages with a car hitting a pole and a bird strike on the overhead line account for the remaining FIDI recorded against the feeder. No further work on the feeder is planned in the 2018 year.

Moturoa 7, Taranaki – One unplanned outage during adverse weather was the cause of the FIDI KPI listed against the feeder. No further work is planned for the feeder.

Marton, Whanganui – Two unplanned outages account for the FIDI listed against the feeder. One outage was due to a high voltage ground-mounted switch failing. In the second outage the feeder was patrolled with nothing obvious found and was classified as ‘unknown’. No further work is planned for the feeder.

Feeder Class F2 FIDI



A11.4 FEEDER CLASS F3

Revans, Wairarapa – The feeder is classed F3/F4. Planned outages for pole replacement account for 52% of the FIDI KPI listed against the feeder. A subtransmission fault has been listed against the feeder which has increased the feeders FIDI KPI. All other unplanned outages were beyond recloser C634 which is the F4 section of the feeder.

Opoutere, Valley. A total of 24 outages occurred with three from foreign interference accounting for 54% FIDI minutes and four from vegetation accounting for 34% of the FIDI minutes recorded against the feeder. This feeder has a F3/F4 security rating with most faults occurring in the F4 section. Five SCADA devices are installed on the feeder with two more to be installed, and has 1,258 ICPs.

Waite St, Wairarapa – The feeder is classed F3/F4. Planned outages for pole and crossarm replacement account for 68% of the FIDI KPI listed against the feeder. A subtransmission fault has been listed against the feeder which has increased the feeders FIDI KPI. No further work is planned for the feeder.

Eketahuna, Wairarapa – Vegetation and an unknown outage account for 72% of the FIDI KPI. Planned outages for pole replacement account for 23% of FIDI against the feeder. No further work is planned for the feeder for the 2018 works plan.

Puriri St, Whanganui – 74% of the FIDI KPI listed against the feeder was due to foreign interference unplanned outages. The two outages were due to car versus poles. No further work is planned on the feeder.

Shaw Ave, Valley. A total of four outages occurred with one from foreign interference accounting for 75% FIDI minutes recorded against the feeder. This feeder has only 323 ICPs.

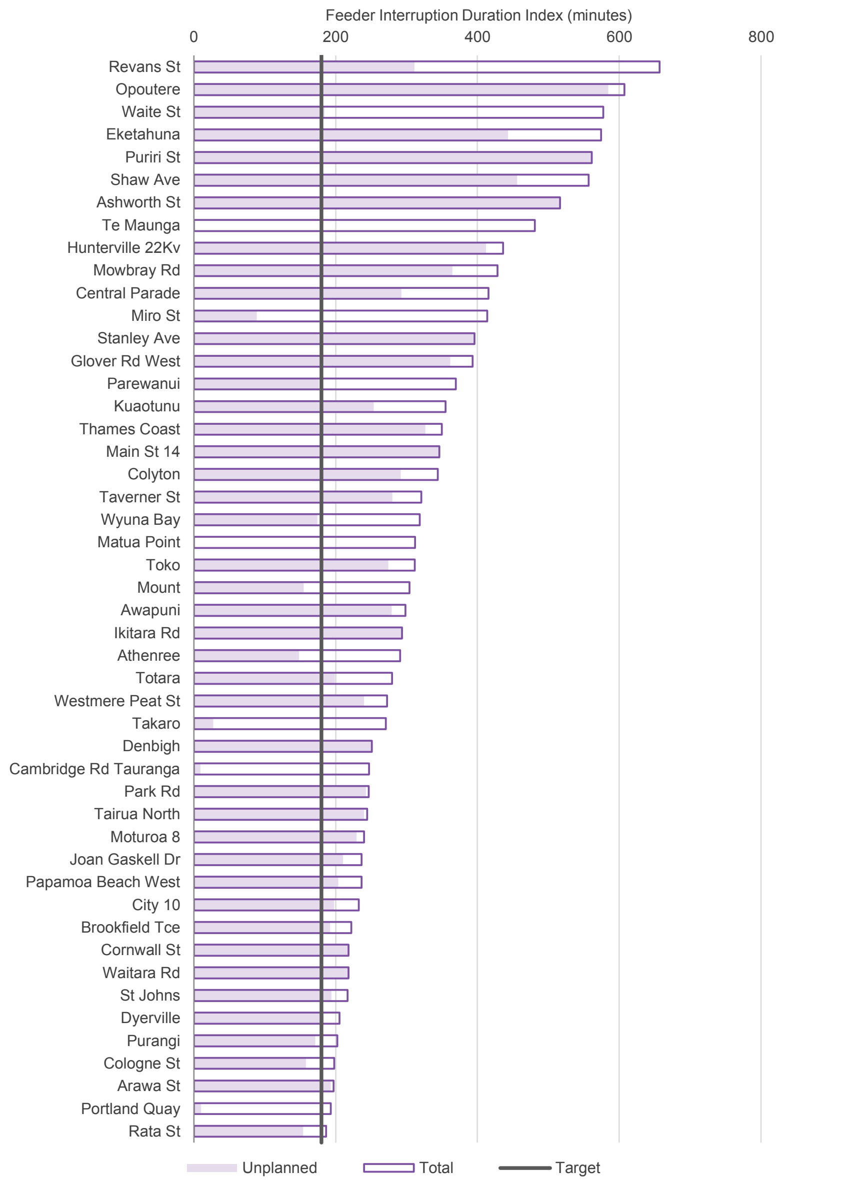
Ashworth St - A total of 5 outages occurred with 3 from defective equipment accounting for 99% FIDI minutes. Faults primarily past recloser or from a cable fault. This feeder has a F3/F4 security rating. Additional automation and new section of cable is to be added.

Te Maunga - A total of five outages occurred with four planned shutdowns accounting for 99% FIDI minutes. No further work is planned on the feeder

Hunterville 22kV Whanganui – The feeder is classed a F3/F4. The feeder has had eight planned and 25 unplanned outages recorded during the reporting year. The planned outages were for line reconstruction with the replacement of poles and crossarms. Only one unplanned outage caused a loss of supply to the F3 section of the feeder. Tree trimming has been planned to be carried out on the feeder.

Mowbray Rd- A total of 41 outages occurred with 33 outages from planned shutdowns, foreign interference accounted for 58% of the FIDI minutes recorded against the feeder. This feeder will be reclassified to a F3/F4 security rating. No further work is planned on the feeder.

Feeder Class F3 FIDI



A11.5 FEEDER CLASS F4

Tarata, Taranaki - Unplanned outages caused by vegetation line strikes have caused 68% of the KPI FIDI listed against the feeder. Defective equipment has accounted for a further 27% of KPI FIDI. The feeder has had the main circuit breaker replaced due to faulty operation. The feeder has also been is targeted for tree trimming in the 2017 year.

Kohete Rd, Taranaki – The feeder has nine outages listed against it, one planned and 8 unplanned, with five with the MOC classification as unknown. Faulty insulators have been replaced which is most likely the cause of the 'unknown' listed unplanned outages. No further work is planned for the feeder in the 2019 year.

Ngaere, Taranaki – The feeder has had 19 unplanned outages recorded during the reporting year. MOC classifications of the outages are: unknown 8 (42% FIDI) and defective equipment 9 (54% FIDI). The feeder requires a line condition patrol to be carried out and defect work carried out in the 2018 year.

Riverlea, Taranaki - The feeder has had 12 unplanned outages recorded during the reporting year. MOC classifications of the outages are: Adverse weather (40% FIDI) and defective equipment (22% FIDI). The feeder requires a line condition patrol to be carried out and defect work carried out in the 2018 year.

Manutahi, Taranaki - The feeder has had 12 unplanned outages recorded during the reporting year. The feeder will be reconfigured once the new Mokoia zone substation is commissioned. The feeder requires a line condition patrol to be carried out and defect work carried out in the 2018 year.

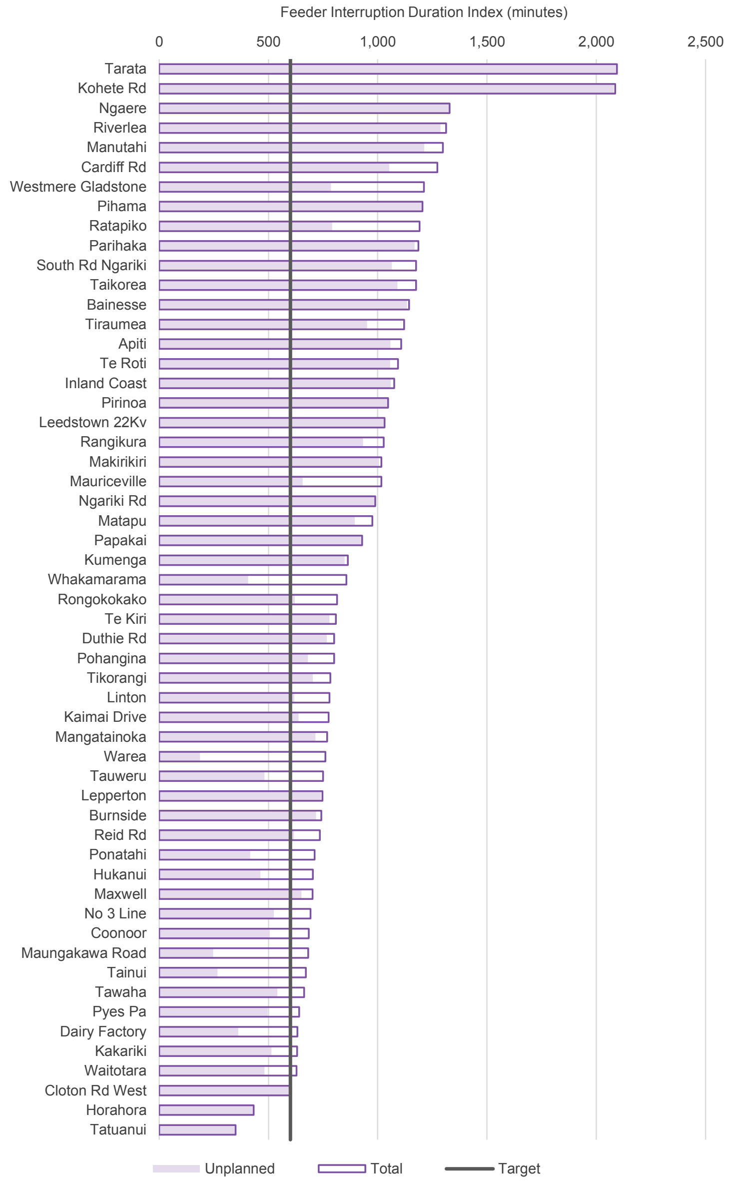
Cardiff Rd, Taranaki – The FIDI KPI can be broken down to unknown (57%), planned shutdowns (17%), defective equipment (16%) and vegetation (8%). One of the sections of the feeder supply up the mountain to the skifield through DOC reserve land. There is a project to underground this section of feeder. Once the project is completed the feeder's performance should improve.

Westmere Gladstone, Masterton - The feeder has had 15 planned and 11 unplanned outages recorded during the reporting year. The planned outages were for line reconstruction with the replacement of poles and crossarms .Further reconstruction work is planned for the 2018 year.

Pihama, Taranaki - Defective equipment has caused 86% of the FIDI minutes recorded against the feeder in the reporting year. Transformer and air break switches have been replaced during the year. Further work is planned to be carried out in the 2019 year which will include conductor replacement.

Ratapiko, Taranaki – Unknown and defective equipment unplanned outages account for 66% of the KPI FIDI listed against the feeder. Planned outages account for 34% of FIDI listed against the feeder. The planned works included pole, crossarm and conductor replacement. No further work is planned for the feeder in the 2018 year.

Feeder Class F4 FIDI



A11.6 FEEDER CLASS F5

Horoweka, Manawatu– Defective equipment has caused 62% of the FDI minutes recorded against the feeder and planned outages accounting for 33% of the FIDI KPI. Pole replacement and tree trimming have been carried out on the feeder. No further reconstruction work is planned for the 2018 year.

Annedale, Wairarapa – The feeder has had 14 unplanned outages with vegetation accounting for 8 faults or 62% of the FIDI KPI. The feeder is been targeted for tree trimming.

Strathmore, Taranaki - Vegetation has been the main cause for the unplanned outages on the feeder. The feeder has been targeted for tree trimming work in the 2017 and 2018 years.

Rawhitiroa, Taranaki – The feeder has had 14 unplanned outages listed against the feeder. Thirteen unplanned outages were on small sections of the feeder. One unplanned outage and foreign interference accounted for 78% of the FIDI KPI recorded in the reporting year. No further work is planned for the feeder in the 2018 year.

Castlehill, Manawatu – The feeder has had extensive reconstruction work carried out during the reporting year. Some 95% of the FIDI KPI recorded against the feeder was due to planned outages. No further work is planned for the feeder.

Huiroa, Taranaki – Two unplanned outages with long duration times have accounted for 92% of the FIDI KPI listed against the feeder. Adverse weather and access to the network to carry out repairs were the reasons for the long duration time. No further work is planned in the 2018 year.

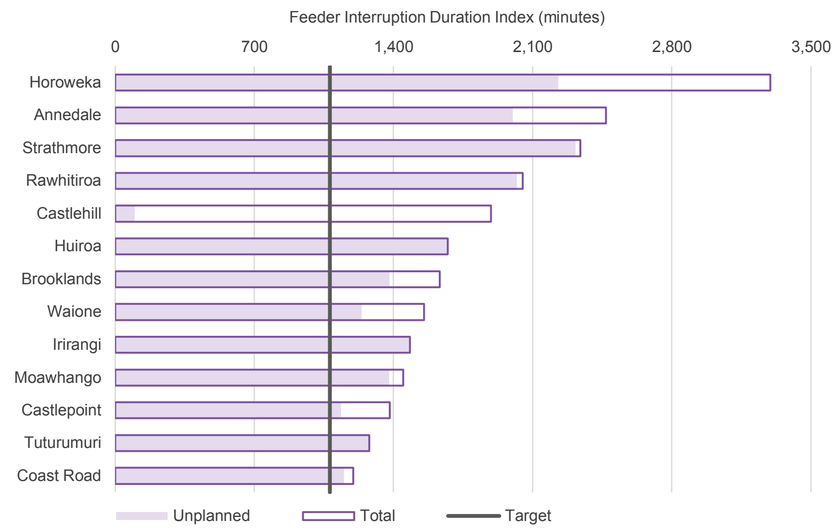
Brooklands, Palmerston - Reconstruction work has been carried out on the feeder during the 2017 year.

Waione, Manawatu - The FIDI KPI can be broken down to Unknown 7%, Planned shutdowns 20%, Defective equipment 36%, Adverse weather 23% and Vegetation 13%. Planned works have included pole and transformer replacements. No further work is planned to be carried out in the 2018 year.

Irirangi, Whanganui - The FIDI KPI can be broken down to Unknown 19%, Planned shutdowns 1%, Defective equipment 44%, Foreign interference 25% and Vegetation 11%. The feeder requires a line condition patrol to be carried out and defect work carried out in the 2018 year.

Moawhango, Whanganui - Adverse weather has accounted for 76% of the FIDI KPI listed against the feeder. Reconstruction work has been carried out in the 2017 year and there is more planned reconstruction work for the 2018 year.

Feeder Class F5 FIDI



A12.1 APPENDIX OVERVIEW

This appendix provides further information on the non-network assets that support our electricity business.

A12.2 SYSTEMS USED TO MANAGE ASSET DATA

We use the following information systems when managing our assets:

- ESRI Geographical Information System
- JD Edwards (JDE) Maintenance, Work Management and Financial System
- Service Provider Application (SPA) web application and field data entry system
- SCADA master stations, SCADA corporate viewer and PI system
- OMS Outage Management System
- Connections Works Management System (CWMS) electricity Improvement Register database and Coin optimisation tool
- Hard copy records and Engineering Drawing Management System (EDMS)
- Stationware
- Customer Complaints Management System
- Safety Manager
- Billing System
- Ancillary databases

These systems are described in the following sections.

A12.2.1 GEOGRAPHICAL INFORMATION SYSTEM (GIS)

We use a GIS to capture, store, manage and visualise our network assets. The GIS is built on top of a set of ESRI and Telvent applications (ArcGIS, ArcFM) that deliver data in web, desktop and service-based solutions. The system contains data about the lines, cables, devices, structures and installations of our electricity distribution network. Future work includes identifying key connections between our electricity and gas network and mapping them on the GIS.

GIS is the master system for current assets in the network, but it also distributes and informs other systems about the current assets via a middleware system interface (Biztalk server).

The primary consumer of this data is the enterprise system (JDE), which acts as the works management and financial system that operates as a slave system off the GIS data. The asset spatial information is also a key input into maintenance scheduling where geographical and network hierarchy factors are considered in the planning, monitoring and improvement of the asset base.

A12.2.2 MAINTENANCE, WORKS MANAGEMENT AND FINANCIAL SYSTEM

We operate a JDE system, which provides asset management and reporting capability, including financial tracking, works management, procurement and maintenance management. We have centralised asset condition and maintenance programming in JDE. As the master for all maintenance and condition information, JDE drives asset renewal programmes centrally. Within JDE, we have implemented system and process improvements for defects management.

A12.2.3 SERVICE PROVIDER APPLICATION (SPA)

We have a mobile platform that delivers applications to field services PCs and mobile devices. This application enables field capture of asset condition, maintenance activity results and defects. Reporting on the data generated by the SPA application is delivered via a suite of reports out of both JDE and Business Objects. The defect and condition data can also be viewed spatially from the GIS.

SPA helps ensure that asset management data provided by service providers is complete and to standard. This is key if we are to retain core asset knowledge in-house.

A12.2.4 SCADA MASTER STATIONS, SCADA CORPORATE VIEWER, AND OSISOFT PI SYSTEM

We operate OSI Monarch SCADA in both our regions. The master stations to control and monitor our network are highly available and are located in each of our datacentres. In the event of a failure the SCADA support team is able to fail over the system from one location to another.

Monarch Lite provides real-time access to users outside of NOC via Citrix. This application provides users with access to real-time network information for use in planning and network management.

The PI system specialises in the collection, processing, storage and display of time-series data. We use PI to store the SCADA tag values from analogue SCADA points.

A12.2.5 OUTAGE MANAGEMENT SYSTEM (OMS)

The OMS is a business-critical application designed for 24/7 operations within our business. OMS is used as a Fault Management System for all LV faults reported by consumers and retailers. OMS uses information provided by the OSI SCADA system from customers who inform their retailer of faults, and who enter the information directly into the OMS system or via a B2B interface. Complex algorithms are used within the OMS system to calculate the possible fault location on the network and the affected number of ICPs. This information is then provided to service providers so they can dispatch a service provider to resolve the fault.

OMS is also used as the fault database to produce external reports for the Commerce Commission and Ministry of Economic Development, and internal reports for our management and engineers to improve network performance. It is an ongoing record of electrical interruptions in our network, with data collected by fault staff in the field and control room.

Daily automated interruption reports from OMS are circulated internally. Key outages and SAIDI and SAIFI totals are reported monthly. An annual network reliability report is prepared for information disclosure purposes.

A12.2.6 CONNECTIONS WORKS MANAGEMENT SYSTEM (CWMS) ELECTRICITY

This is an online workflow management system, which facilitates and tracks the processes associated with connection applications, approvals, and works completion. Application, review and input work steps are available to our approved contractors via the internet. The primary function of the system is to manage the flow of customer initiated work requests through our formal process, from initial request through to establishment of the ICP in billing and reference systems. The workflow ensures that the latest business rules are applied to all categories of connection work.

Work requests from new or existing customers are covered by our Customer Initiated Works process. This process places importance on providing new and existing consumers with a choice of prequalified contractors that they can engage to carry out work at their connection point(s). The business rules of the process ensure that the integrity of the overall local network and the quality of supply to adjacent consumers is retained, while making the customer initiated work contestable.

A12.2.7 ENGINEERING DRAWING MANAGEMENT SYSTEM

The drawing management system is based on BlueCielo Meridian, and works in conjunction with AutoCad drawing software. It is a database of all engineering drawings, including substation schematics, structure drawings, wiring diagrams, regulator stations, and metering stations. In addition, there is a separate vault that contains legal documents relating primarily to line routes over private property.

A12.2.8 STATIONWARE

This application provides us with a protection database to manage settings in our protection relays.

A12.2.9 CUSTOMER COMPLAINTS MANAGEMENT SYSTEM

This is a workflow management system that maintains an auditable record of the life cycle of a customer complaint. The application is designed to work within the Electricity and Gas Complaints Commission rules regarding complaints, and automatically generates the key reports required.

Another feature of the application is the integration with the GIS and ICP data sources, to provide spatial representation and network connectivity details of complaints and power quality issues. This provides valuable information to the planning teams.

A12.2.10 SAFETY MANAGER

Safety Manager is one of the systems that support our operational risk model and workflow. As the central repository for incidents, hazards and identified risks, it acts as a platform to manage these across internal and external stakeholders at both an operational and strategic level. In addition, it supports the Health, Safety Environment and Quality team in supporting the management of PPE and H&S competencies for all our employees.

A12.2.11 BILLING SYSTEM

Powerco receives consumption data from retailers and customers. Bills are calculated using the Junifer billing engine and invoiced from JDE.

A12.2.12 OTHER RECORD SYSTEMS

In addition to the electronic systems, several other recording systems are maintained, including:

- Standard construction drawings
- Equipment operating and service manuals
- Manual maintenance records
- Network operating information (system capacity information and operating policy)
- Policy documentation
- HV and LV schematic drawings

A12.3 CONTROLS OF SYSTEMS AND LEVEL OF INTEGRATION

A12.3.1 CONTROLS

Extensive effort is made to protect the integrity of asset information held in our information systems. The system architecture deployed by us has security controls in place to restrict access, a change management process to control system changes, and is fully backed up on and off-site. Process and controls to limit human error are applied to user interfaces to reduce inputting error and reconciliation of data occurs, where possible, to identify cases of potential data error.

A12.3.2 INTEGRATION

Asset management information systems support us in our asset management processes. Over the past seven years we have implemented new enterprise systems and are working through a replacement programme for our ageing systems.

We are constrained by some of our current systems’ inability to share information, and with limited integration options. We attempt to manage information-sharing via the data warehouse and business intelligence tools. Microsoft BizTalk provides integration between some of our systems, although ageing systems are not always able to use modern integration tools due to their proprietary nature.

We strive to implement open platform, fit-for-purpose systems that allow us to manage our asset management information so that data and information is readily accessible to internal and external parties.

A12.3.3 LIMITATIONS OF DATA AND INITIATIVES TO IMPROVE DATA

Obtaining high-quality information to support asset management carries an expense. We are continually assessing where new investments should be made to improve the data available. We have a wide range of projects that focus on making better use of data we already collect. We also have a Continuous Improvement Team to deliver incremental improvements to systems, data and processes.

We are continually working to improve the asset data we maintain in our enterprise systems.

Planned IT asset management business improvement programmes to address data and information are listed in Chapter 10.4.

A13.1 APPENDIX OVERVIEW

This appendix provides further details on the future network initiatives discussed in Chapter 13.

A13.2 NEW NETWORK TECHNOLOGIES AND APPLICATIONS

A13.2.1 LOW VOLTAGE MONITORING AND METERING

As with many other distribution networks, our visibility of power flows and power quality on our low voltage networks is very limited. This is in line with traditional practice. Since the average consumption per household and the consumption trends were remarkably stable over many decades, it was practical and cost-effective to build one-size-fits all low voltage networks and then afterwards pay minimal attention to these (other than maintain them in a safe condition).

However, the traditional environment is changing:

- The distribution edge – where the major changes in demand patterns, including two-way power flows, are occurring – is mainly at the low voltage level.
- Customer load patterns are increasingly diverging, with implications for low voltage network design and utilisation.

Our intention is to install meters and monitors at key positions on the low voltage network (ubiquitous metering is in our opinion not essential, especially as smart meter data is readily available). These positions will be selected to ensure that maximum information on overall low voltage demand patterns and power quality is gathered. Our intent is to use the information gathered to:

- Better optimise our existing low voltage network design standards to fit the consumer types they serve.
- Obtain early identification of network overloading or power quality issues.
- Improve understanding of transformer and network loading to support LV interconnection and self-healing networks.
- Improve fault location through ‘last gasp’ communications on power failure.
- Improve understanding and modelling of the impact of distributed generation, especially PV and EV clustering effects on LV power quality.
- Obtain improved data to calibrate HV feeder load flow models for planning purposes.
- Form an accurate view of the impact of low voltage outages on the overall network reliability experienced by customers[125].

[125] Under current regulatory settings, reliability is measured on higher voltage networks only.

A13.2.2 EXPAND BASEPOWER APPLICATIONS

We developed the BasePower unit as a combined generation/storage electricity solution for application especially in remote areas where power supply quality is below desired standards. It is intended for use where the cost to upgrade the existing electricity network and to improve quality of supply is prohibitively expensive.

We are currently trialling its application in a number of settings. We intend to incorporate the findings from these trials and then work with remote communities or customers to roll out more of these applications where required.

A13.2.3 AUTOMATIC FAULT DETECTION AND LOCATIONS

We have already trialled the so-called FLISR (automatic fault location, isolation and service restoration) application on our network. This activity is an expansion of the initial work.

As noted earlier, we have extensive rural networks which are more susceptible to external interference than urban networks. We plan to improve the experience of customers in rural areas by improving our capability for fault detection and location. This will reduce the time required for our control centre to become aware of outages and for fault crews to locate faults and respond to these. Various applications to achieve this will be tested on the network.

In future these schemes will also, where the opportunity exists, be expanded to include automatic fault isolation and restoration.

A13.2.4 BATTERY STORAGE

Effective battery storage has major potential to enhance network performance in the future. Network applications can include:

- Peak lopping, thereby allowing network reinforcement to be deferred.
- Reducing the variability in output from renewable generation sources – ‘riding through’ fluctuating generation output as sunlight and wind levels change.
- Reducing the impact of voltage rises by absorbing excess generation capacity from distributed generation sources.

While our focus is on network applications, we also see potential value from non-network applications for battery systems, including:

- Offering capacity into a fast or instantaneous reserves market.
- Providing other ancillary services.
- Buying electricity at times of low pricing, and providing this to customers during high peak price periods.

- Supporting environmental programmes by improving the use of renewable generation sources (overcoming some of the issues with supply intermittency, and the mismatch between peak generation and peak consumption times).

While battery storage is currently, in the large majority of cases, not directly competitive with conventional network supply, there are a number of applications where it may prove economically viable. These numbers are expected to grow in future as the price for battery installations continue to decrease and the value of non-network benefits are better realised.

We intend to investigate the application of bulk battery storage systems (typically 500 kWh to 1 MWh) on our network. In particular, we are keen to develop a transportable solution that can be used to defer reinforcement on different parts of our network in subsequent applications. [126]

While we do not currently intend to become actively involved with small scale battery units (on the customer side of the meter), we will continue to monitor the developments in this field. We may want to work with customer groups in future to adopt battery-based solutions as part of demand management incentives.

A13.2.5 REAL TIME ASSET RATINGS

Asset ratings are currently applied in accordance with passive capacity ratings. For example, we understand the capacity of a power cable and will ensure in our network design and operating practices that this capacity is not exceeded. This conservative approach is perfectly sound in an environment where the actual performance and behaviour of assets is not monitored in real time, and running assets to failure is not an option.

However, by having a real time view on the actual performance of an asset, it may be possible to safely increase its utilisation. For example, the limiting factor on a power cable is the temperature at which it is operating[127]. So if we can monitor the temperature in real time and ensure that safe levels are not breached, it may be possible to safely increase the current throughput – even if for limited times only.

We intend to conduct several proofs of concept of real time rating applications on our network, using different technologies and applied to different asset types.

A13.2.6 STATE ESTIMATION AND NETWORK AUTOMATION

State estimation is a key element of building a real-time network model. It refers to the continuous, semi-real time assessment of various parameters on the network, including power flows, network status and configuration, voltage levels, and asset temperature.

[126] At current price levels, permanent battery storage installations are generally not economical as network reinforcement solutions.

[127] Cable temperature is of course proportional to the current it carries, but several factors can influence the actual level.

This can be used to provide a near real-time view of the loading and available capacity on various parts of the network. In turn, this provides the basic information required to make decisions on rerouting power flows at various times of the day to deal with peak demand – and in so doing offers potential to significantly increase network utilisation (deferring reinforcement).

It can also be used to support other applications such as the monitoring of asset condition, for supporting self-healing networks, or for allowing temporary network islanding.

We intend to investigate the application of state estimation to our network, along with the applications that it is intended to support.

A13.2.7 SELF-HEALING NETWORKS

Self-healing networks can be viewed as an extension of the fault location, isolate, repair concept discussed above. However, it can be applied at a far more granular level in dense, meshed networks. The end goal is for a network to be able to automatically detect an outage, to isolate the fault, and progressively restore the network until all customers are reconnected, or only the minimum possible customers remain without power (those in the direct vicinity of the original fault).

We intend to investigate the application of self-healing options, especially in our urban networks. This will be extended to those parts of our rural network where the opportunity exists.

A13.2.8 VOLTAGE SUPPORT APPLICATIONS

One of the problems with large numbers of renewable distributed generators feeding back into the network relates to voltage regulation. This can arise for two reasons – (a) widely fluctuating voltage levels as a result of the variable output of renewable generation, and (b) when generators export to lightly loaded parts of the network, leading to voltage rises.

Various options exist for managing voltage regulation to within acceptable limits (including customer side solutions, such as using ‘smart’ inverters). We intend to test some of these approaches under various generation scenarios, with the goal of having approved solutions should the problem arise on our network.

A13.2.9 DISTRIBUTED CONTROL AND AUTOMATION

We currently run a very centralised network control model. All network information is conveyed to our NOC (with the exception of protection systems which operate by themselves). Operating decisions are made here, and instructions for operations issued – resulting in automatic actions, or manual intervention.

In future, much of the intelligent network functionality may replicate this centralised control model – with data centrally collected and analysed, and control signals issued based on the results. However, it may in many instances be more efficient, and more economical, to collect and process information on site, issuing local control signals (communicating after the event with the central control system, if necessary). This may be especially valuable at the more remote ends of our network where communication means are often limited and slow.

We intend to further investigate the use of distributed control systems and network applications in both our rural and urban networks.

A13.2.10 INTEGRATING COMMUNITY ENERGY SCHEMES

While not yet common in New Zealand, we have observed overseas trends for communities to create collective energy schemes. These can involve local generation or special power purchasing arrangements. The communities include groups of residents in part of a neighbourhood, large industrial complexes and campus environments.

At times of excess generation, these communities wish to export power to the grid, whereas at other times they may import. Depending on the size of such communities, this behaviour may cause instability problems on the network. It also potentially gives rise to very poor asset utilisation.

Conventional network solutions to address these problems would be inefficient and expensive. Recovering the cost for such expensive investments would run the risk of pushing the communities to disconnect from the grid, which is generally not what they, or network companies, desire. However, connection to the grid remains valuable as it provides more supply resilience than local generation and also makes up for generation capacity shortfalls.

It is therefore important to find innovative, cost-effective ways of integrating community schemes into normal network operation. We intend to investigate this and develop effective solutions to be ready if such schemes arise on our network.

A13.2.11 ELECTRIC VEHICLE CHARGING CONTROL SYSTEMS

While the increased uptake of EVs would offer material environmental, economic and utility benefits to users, they could pose some challenges for electricity distribution networks.

If substantial numbers of EV users in close proximity should charge their vehicles at the same time (for example, in the late afternoon/early evening after arriving back from work), this could overload parts of our low voltage and distribution networks. This problem will be particularly acute if fast charging stations are used.[128]

We will investigate various means of smoothing charging loads to avoid the need for network reinforcement. This will require close cooperation with the EV owners and could involve technical solutions such as rotating charging periods between several users over the off-peak period[129], or incentive schemes whereby financial rewards are offered (or additional costs avoided) for off-peak charging.

While EV charging loads are not currently an issue, the intent is that we will have fully functional solutions available for when this becomes necessary. This may include technical and non-technical solutions.

A13.2.12 DATA AND CONTROL SHARING WITH TRANSPOWER

With increasing reliance on variable renewable energy sources in future, it is likely that the proportion of traditional generation will further diminish. With that, we are likely to see a reduction in system inertia, as we rely more on generation connected through power electronics, and with highly variable outputs. This may mean in future it will become more problematic to maintain stable frequency levels on the transmission grid and hence distribution networks. This is an industry-wide problem as much of the generation on which we are likely to rely will be connected through distribution networks, which cannot be managed by the System Operator (currently Transpower) alone.

While this is currently not an issue, it is important as an industry we fully understand the potential for instability issues to arise and agree on arrangements to forestall this. It will likely involve the System Operator requiring far greater levels of visibility on power generation and flows in distribution networks, including an understanding of the extent, location and nature of distributed generation connected and major new load such as EV clusters. It may also require a greater degree of shared load control than is currently available.

We intend to work with industry bodies such as the Electricity Networks Association Smart Technology Working Group and the System Operator on this issue. If necessary, we will develop data and control sharing protocols with the System Operator.

A13.2.13 FREQUENCY KEEPING SUPPORT

As a next step on from collaborating with the System Operator to maintain grid stability, as discussed above, it may become necessary to actively manage frequency stability on the distribution network.

This is not foreseen to be necessary in the near future, but we believe it is important we understand the options that exist for a distribution utility to provide this support. In coming years we will investigate this further, and potentially conduct some trials on our network.

[128] Slow charging is when an EV is connected to a normal (or dedicated) wall socket. This adds an additional load that is equivalent to a large domestic device, such as a hot water cylinder. Fast chargers vary in size, depending on the charging rate, but would need a dedicated, reinforced power outlet and could typically represent an additional load equivalent to a full normal household peak demand (or more, for larger installations).

[129] This will still ensure that vehicles are fully charged the next morning, but will shift the additional demand to periods when sufficient network capacity already exists.

A13.3 NON-NETWORK SOLUTIONS

A13.3.1 DEMAND MANAGEMENT

As noted before, we have an extensive hot water load control system in place, which we use to reduce peak load on the network from time to time. In future it is foreseen that this capability can be much extended as more controllable devices are used. We intend to investigate alternative means of demand management solutions – including potentially new techniques to replace existing ripple-type systems.

Since we generally do not intend to become involved with installations on the customer side of the meter, our involvement in customer demand-side management, other than potentially extending the life of our hot water control systems, is likely to rely on incentive schemes rather than on installing equipment. On the residential side, these incentives will mainly be achieved through pricing.

We also intend to investigate the option for demand-side management through commercial arrangements with larger commercial and industrial consumers. It may be possible to defer network reinforcement through entering into load-shedding arrangements, or obtaining rights to have standby generators operate for limited periods.

A13.3.2 SMART METER DATA ANALYSIS

On many parts of our network, there is now a relatively high penetration of smart meters. These can provide through the retailers that manage them valuable information about demand patterns and power quality at individual ICPs or (when aggregated) at feeder level. We intend to work with retailers to obtain information that will allow us to improve our understanding of customer demand patterns, typical customer categories (and clusters), and the power quality they experience. This in turn will help us to:

- Identify emerging load trends to ensure that our networks are ready for this.
- Refine our network design standards, particularly for low voltage networks, to better reflect actual customer demand patterns.
- Address issues with voltage regulation and power quality.
- Identify potential safety concerns eg if excessive voltage swings are noticed.
- Improve our low voltage network models through analysing data trends.

A13.3.3 GAS-FUELLED GENERATORS/FUEL CELLS

On many parts of our network footprint, there are gas distribution networks owned by us and others. We intend to investigate the feasibility and economics of using gas-driven generation at constrained locations on our electricity networks, for electricity generation at peak demand times.

While combined heat and power generation (CHP) plants are commonly used at large industrial installations, we wish to pursue opportunities to apply this at a smaller scale.

More recently, there have been substantial advances in gas-driven fuel cell technology. This is successfully applied at commercial scale, but the application of residential sized fuel cells is also expanding. This is existing technology that offers very high energy efficiency, and we intend to investigate the application of these units on our networks, where they could provide an economic alternative to electricity network reinforcement.

A13.4 ENABLING OR PARALLEL TECHNOLOGIES AND SYSTEMS

In this section we describe our plans to develop enabling technologies or systems. These are necessary to support the electricity network of the future, but are not strictly part of the network, or by themselves do not provide network solutions.

We also include a discussion on some parallel technologies that we intend to investigate further. These are not directly intended to provide network benefits.

A13.4.1 ENHANCED ASSET AND NETWORK DATA ANALYTICS

Access to comprehensive and accurate data will be fundamental to the network of the future, including enhancing the management of our existing assets.

We intend to put significant focus on the expansion of our data collection, data management and data analytics capabilities in the near future. Focusing on our existing assets, we plan to provide our asset managers and operations teams with an accurate, easy-to access knowledge base and an efficient set of tools. This will allow them to analyse asset and network information, and improve their decision-making. Looking into future applications, we will create data management systems that can be easily integrated into the new applications that we roll out in the future.

Part of the work will also include a programme to improve the breadth and accuracy of the data we collect in the field, and establish effective data quality audit procedures.

A13.4.2 MOBILE SUBSTATIONS

An option we are planning is the use of a mobile substation (Powerco doesn't currently own one). This would be used to reduce outages on N security substations, particularly in the Western Region. It would enable routine maintenance to be carried out on tap changers and transformers without prolonged outages. We will also review the implications to our security standards and development planning.

A13.4.3 COMMUNICATIONS NETWORKS

It was noted before that an effective communications network is a key enabler for the network of the future. We therefore intend to greatly expand the communications network in the next five years as described in Chapter 10.

A13.4.4 ENHANCED INFORMATION SYSTEM SOLUTIONS

As with communications networks, the network of the future will rely heavily on information systems to make it function successfully. In Chapter 22 of the AMP we describe our intended plans for developing our IS capabilities over the next 10 years. Some of the network directed improvements we intend to adopt include:

- An enterprise asset management system (which may be a part of a larger enterprise resource platform). This is to enhance our asset data management capabilities and support advanced asset management applications.
- An enhanced OMS. This will expand on our existing OMS, to include functionality like field force mobility[130], improved outage planning and improved updating of asset records and as-built plans.
- A distribution management system. This will be the platform for our real time network model, and will further expand the functionality of our OMS, for outage management, network management and SCADA management. It will integrate with the planned state estimation capability we intend to develop.

A13.4.5 SMART CITY PROGRAMMES

Around the world, there is much interest from progressive cities in the so-called smart city concept. In essence, this involves taking a holistic view of how the operation of cities can be improved to become more friendly and accessible to its residents, support healthier lifestyles and be more environmentally sustainable. This is achieved through improved planning, streamlining operations and processes, applying new urban solutions including new technology where useful, maximising energy efficiency and broadly paying more heed to residents' quality-of-life requirements.

Electricity networks play an important part in smart cities, in various ways that include:

- Improving energy efficiency through more efficient use not only of electricity, but also through a holistic approach to energy management including more efficient heating and cooling systems, transport, public lighting, demand management schemes, etc.
- Expanding the use of communications networks already in place for controlling electricity networks for use by local authorities and others to achieve smarter solutions.

130 Allowing our field force remote access to our up-to-date network data, fault location, job descriptions, and the ability to update records directly after completing jobs.

- Supporting energy efficient housing and commercial buildings, through innovative power supply arrangements including dedicated pricing arrangements.
- Encouraging the efficient use of distributed generation, through facilitating easy connection to networks and effective open access arrangements.
- Allowing the effective integration of community energy schemes into the larger network.

We intend to work closely with interested councils on our footprint to support their drive towards achieving smart cities.

A13.4.6 COST OF SERVICE TARIFFS

We believe that electricity pricing will be a key component of the network of the future. Simple volume-based tariff schemes do not provide a cost reflective signal of the actual use of distribution network assets and therefore the cost to supply service. They will increasingly not be suitable for the network of the future:

- Even if nothing else changes in the way networks are built and used, it is well understood that these are built to deliver to peak demand. The important usage parameter that reflects the true cost of electricity distribution services is therefore a customer's maximum demand, in particular that portion that coincides with the general network demand peak.
- Many of the proposed future network solutions discussed above will rely on providing effective incentive signals. For the bulk of our customers this can only be done through tariffs, which will have to be flexible enough to accommodate the required pricing signals.
- It is anticipated that many different types of customer devices, including distributed generation, will be connected to the network in future, and we intend to encourage this. However, this could stress networks in various ways, which we will have to address. Economic efficiency principles suggest that the additional cost thus incurred should not be socialised to all consumers (when the benefits accrue to a smaller number), and it will therefore become necessary to adapt tariffs to reflect the impact of individual behaviour.

With the roll out of smart meters across New Zealand, the ability to develop smarter tariff schemes is greatly enhanced. However, this development will still require significant research and analysis, which will be a key focus for us in coming years.

Importantly, it should also be recognised that changing pricing structures will have a major impact on customers – there are bound to be winners and losers from each change.

We will therefore have to carefully consider the implication of proposed changes on customers, and develop means to lessen the potential negative impact. This will be particularly important for the less well-to-do sections of our community, who generally have less opportunity to implement energy behaviour changes or to participate in distributed generation or energy storage.

This table provides a look-up reference for each of the Commerce Commission's information disclosure requirements. The reference numbers are consistent with the clause numbers in the electricity distribution information disclosure determination (2012).

2.6	ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
	Disclosure relating to asset management plans and forecast information	
2.6.1	Subject to clause 2.6.3 below, before the start of each disclosure year commencing with the disclosure year 2014, every EDB must complete and publicly disclose an AMP that: (1) Relates to the electricity distribution services supplied by the EDB (2) Meets the purposes of AMP disclosure set out in clause 2.6.2 (3) Has been prepared in accordance with Attachment A to this determination (4) Contain the completed tables required in clause 2.6.5 (5) Contains the Report on Asset Management Maturity set out in Schedule 13	(1) The AMP relates to electricity distribution services, as stated in Chapter 1. (2) Compliance with 2.6.2 is outlined in the box below. (3) Compliance with Attachment A is outlined in Appendix 15 below. (4) The tables required by clause 2.6.1(5) are in Appendix 2 and the MS Excel schedules have been supplied to the Commission. (5) Schedule 13 is provided in Appendix 2 and is also discussed in Chapter 10.5.
2.6.2	The purposes of AMP disclosure referred to in clause 2.6.1(2) are that the AMP: (1) Must provide sufficient information for an interested person to assess whether (a) Assets are being managed for the long-term (b) The required level of performance is being delivered (c) Costs are efficient and performance efficiencies are being achieved (2) Must be capable of being understood by an interested person with a reasonable understanding of the management of infrastructure assets (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks	(1) & (2): An overview of the AMP is provided in Chapter 2.5. Chapters 5 to 9 describe how we manage our assets. A glossary is provided in Appendix 1 to assist understanding; and (3): Risk is discussed in Chapter 6.9 and Appendix 6. High Impact Low Probability (HILP) events are specifically addressed in Chapter 6.9.4.

2.6	ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
2.6.5	Every EDB must (1) Before the start of each disclosure year, complete each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports: The Report on Forecast Capital Expenditure in Schedule 11a The Report on Forecast Operational Expenditure in Schedule 11b The Report on Asset Condition in Schedule 12a The Report on Forecast Capacity in Schedule 12b The Report on Forecast Network Demand in Schedule 12c The Report on Forecast Interruptions and Duration in Schedule 12d (2) If the EDB has sub-networks, complete each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB in relation to each sub-network for the disclosure years provided for in the Report on Forecast Interruptions and Duration set out in Schedule 12d (3) Include, in the AMP or AMP update as applicable, the information contained in each of the reports described in subclause 2.6.5(1) and 2.6.5(2) (4) Within five working days after publicly disclosing the AMP or AMP update as applicable, disclose the reports described in subclause 2.6.5(1) and 2.6.5(2) to the Commission (5) Within five months after the start of the disclosure year, publicly disclose the reports described in subclause 2.6.5(1) and 2.6.5(2)	(1): These reports are provided in Appendix 2. (2): We have two sub-networks (the Eastern and Western regions). Three copies of Schedule 12d are provided in Appendix 2. (3): These reports are provided in Appendix 2. (4): The AMP, including appendices, will be published at www.powerco.co.nz and be sent to the Commission. (5): These reports will form part of our annual information disclosure to the Commission, published by 31 August 2017.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
AMP Design	
1. The core elements of asset management: 1.1. A focus on measuring network performance and managing the assets to achieve service targets 1.2. Monitoring and continuously improving asset management practices 1.3. Close alignment with corporate vision and strategy 1.4. That asset management is driven by clearly defined strategies, business objectives and service level targets 1.5. That responsibilities and accountabilities for asset management are clearly assigned 1.6. An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets 1.7. An emphasis on optimising asset utilisation and performance 1.8. That a total life cycle approach should be taken to asset management 1.9. That the use of non-network solutions and demand management techniques as alternatives to asset acquisition is considered.	1.1: Chapter 9 outlines service objectives and measuring network performance. 1.2: Chapter 10 outlines AMMAT results and improvement plan. 1.3: Chapters 5 and 6 describes the alignment. 1.4: Chapters 5 and 6 describe the strategies while Chapter 9 describes network targets. 1.5: Chapter 6 describes accountabilities across all levels of the organisation. 1.6: Chapter 3 provides a high-level overview of our assets. Chapters 15 to 21 and Schedule 12a (Appendix 2) provide details on location and condition information for each asset class. 1.7: Chapter 9.5 discusses asset utilisation and asset performance. 1.8: This is outlined in Chapter 6.4, further detail is provided in chapters 7 and 8. Additionally, Chapter 14 outlines our approach to asset management life cycle and fleet management. 1.9: Chapters 7.2.9, 13.3, 13.4 and Appendix 13 discuss non-network solutions. Appendix 8 provides descriptions of non-network solutions considered for various projects.
2. The disclosure requirements are designed to produce AMPs that: 2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1 above 2.2 Are clearly documented and made available to all stakeholders 2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets 2.4 Specifically support the achievement of disclosed service level targets 2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment 2.6 Consider the mechanics of delivery including resourcing 2.7 Consider the organisational structure and capability necessary to deliver the AMP 2.8 Consider the organisational and contractor competencies and any training requirements 2.9 Consider the systems, integration and information management necessary to deliver the plans 2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs 2.11 Promote continual improvements to asset management practices Disclosing an AMP does not constrain an EDB from managing its assets in a way that differs from the AMP if its circumstances change after preparing the plan or if the EDB adopts improved asset management practices.	2.1: This is discussed throughout the AMP. 2.2: This AMP is widely distributed to our stakeholders and is available on our website www.powerco.co.nz. A summary AMP will also be provided for people with more limited asset management knowledge. 2.3: Our self-assessment against the AMMAT is provided in Chapter 10.5. 2.4: Our new service objectives are discussed in Chapter 9. 2.5: Chapter 6.9 discusses overall risk while Chapters 11 and 12 detail how we address growth and security risks and reliability risks respectively. Chapters 15 to 21 and Schedule 12a (Appendix 2) provide details on condition information for each asset. 2.6: Chapters 7.5 and 8.4 detail approach to Capex and Opex delivery respectively. Chapter 10 outlines how we will enhance delivery capability. 2.7: Is discussed in Chapters 6 and 10. 2.8: Is discussed in Chapters 10.2 and 10.3. 2.9: Chapters 12 and 13 provide an overview of the network and service offerings we are planning for. Chapter 22 provides commentary on our systems, IT capabilities and plans. Chapter 10.4 outlines our information approach and initiatives. 2.10: We have used terminology in line with this Appendix, and also provided a glossary in Appendix 1. 2.11: Chapter 6 outlines how we manage our network, while Chapter 9 details the networks targets we aim to achieve. Chapters 10.3 to 10.5 provide improvement initiatives for our asset management capability.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
Contents of the AMP	
3. The AMP must include the following:	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Chapter 1 is an Executive Summary and provides a brief overview and the key messages and themes in the AMP. Chapter 2.5 provides information on the structure of the AMP
3.2 Details of the background and objectives of the EDB's asset management and planning processes	The background to our asset management and planning process is provided in Chapters 2 to 6. This describes the context in which we operate. The objectives of our asset management and planning process are provided in Chapter 5.
3.3 A purpose statement which: 3.3.1 Makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes 3.3.2 States the corporate mission or vision as it relates to asset management 3.3.3 Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB 3.3.4 States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management 3.3.5 Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest	3.3.1: The purpose statement is in Chapter 2.2. 3.3.2: Our corporate vision, mission and values and their relationship with the AM process is discussed in Chapter 5.2. 3.3.3: See Chapters 6.1, 6.5, 6.6 and 6.7. 3.3.4: See Chapters 2.2, 5 and 6.5. 3.3.5: This is described in Chapters 2.2, 5 and 6.5. .
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the AMP. The asset management planning information for the second five years of the AMP planning period need not be presented in the same detail as the first five years.	Our AMP planning period is from 1 April 2017 to 31 March 2027, as described in Chapter 2.2.2.
3.5 The date that it was approved by the directors	The AMP was approved on 9 June 2017 (refer to Appendix 15).
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates: 3.6.1 How the interests of stakeholders are identified 3.6.2 What these interests are 3.6.3 How these interests are accommodated in asset management practices 3.6.4 How conflicting interests are managed	An overview of our stakeholders is in Chapters 2.4 and 4. A more detailed description of each main stakeholder's interests, how these are identified and accommodated in the asset management plan is in Appendix 3.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including: 3.7.1 Governance - a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors 3.7.2 Executive - an indication of how the in-house asset management and planning organisation is structured 3.7.3 Field operations - an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	3.7.1: Refer to Chapter 6.2.2. 3.7.2: Refer to Chapter 6.3. 3.7.2: Chapters 7.5 and 8.4 discuss field operations in detail.
3.8 All significant assumptions: 3.8.1 Quantified where possible 3.8.2 Clearly identified in a manner that makes their significance understandable to interested persons, including 3.8.3 A description of changes proposed where the information is not based on the EDB's existing business 3.8.4 The sources of uncertainty and the potential effect of the uncertainty on the prospective information 3.8.5 The price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b	3.8.1, 3.8.2, 3,8.4: Chapter 26 provides key assumptions and uncertainty in the development of the AMP. 3.8.3: Chapter 13 and Appendix 13. 3.8.5: Chapter 26.3.2 describes how we developed the escalators we used to inflate our forecasts into nominal New Zealand dollars in schedules 11a and 11b (refer to Appendix 2).
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures.	This is discussed in Chapter 26.4.
3.10 An overview of asset management strategy and delivery To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify: • How the asset management strategy is consistent with the EDB's other strategy and policies • How the asset strategy takes into account the life cycle of the assets • The link between the asset management strategy and the AMP • Processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented	Chapter 5 explains how corporate vision is translated into Asset Management investment and operational decisions. Chapter 6 explains our approach to asset management decision-making. It discusses the asset management governance structures and responsibilities. It introduces our approach to life cycle asset management. An explanation of how we plan, deliver and monitor investments is detailed in Chapters 7, 8 and 9.
3.11 An overview of systems and information management data To support the AMMAT disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe: • The processes used to identify asset management data requirements that cover the whole of life cycle of the assets • The systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets • The systems and controls to ensure the quality and accuracy of asset management information • The extent to which these systems, processes and controls are integrated	The processes used to identify data requirements are discussed in Chapter 10.4 whereas the systems used to manage asset information are detailed in Chapter 22.4 and Appendix 12. Integration of the core systems is shown in Chapters 22.4 and 22.5 (refer to Figures 22.2 and Figures 22.3) and Appendix 12 (A12.3)

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data. Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.	Asset data and system limitations and improvement initiatives are detailed in Chapters 10.4 (refer to Tables 10.3 and 10.4), 10.5, 22.4.3, 22.5 and Appendix 12.
3.13 A description of the processes used within the EDB for: 3.13.1 Managing routine asset inspections and network maintenance 3.13.2 Planning and implementing network development projects 3.13.3 Measuring network performance.	3.13.1: Refer Chapters 8 and 23. 3.13.2: Refer Chapter 7.2 3.13.3: Refer Chapter 9.7.
3.14 An overview of asset management documentation, controls and review processes. To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should: (i) Identify the documentation that describes the key components of the asset management system and the links between the key components (ii) Describe the processes developed around documentation, control and review of key components of the asset management system (iii) Where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy (iv) Where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house (v) Audit or review procedures undertaken in respect of the asset management system	Chapter 6 provides commentary on documentation, process and systems.
3.15 An overview of communication and participation processes To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should - (i) Communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants (ii) Demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements	This is discussed in Chapters 2.4, 5 and 10.
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	Figures are reported in constant 2016 or 2017 dollars, as agreed with the Commerce Commission and to be consistent with our CPP submission. Refer to each chart axis throughout the AMP and Chapter 26.1
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	We have refined this AMP to be easier to follow and for an interested person to understand. This includes a flow which better covers the dynamic long-term management of assets, efficient delivery of services and reaching an appropriate performance level. Chapter 2.5 provides information on the AMP structure.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
Assets covered	
4. The AMP must provide details of the assets covered, including:-	
4.1 A high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including 4.1.1 The region(s) covered 4.1.2 Identification of large consumers that have a significant impact on network operations or asset management priorities. 4.1.3 Description of the load characteristics for different parts of the network 4.1.4 Peak demand and total energy delivered in the previous year, broken down by sub-network, if any	4.1.1: A high level description of sub-regions is in Chapters 3.2 to 3.4. The extent to which these are interlinked is in Chapter 3.2. 4.1.2: Large consumers are described in Appendix 4. 4.1.3: Load characteristics for our two network regions are described in Chapter 3, and for each of our planning areas throughout Chapter 11. Detailed demand forecasts are included in Appendix 7. 4.1.4: This is provided in Table 3.1 (Chapter 3).
4.2 A description of the network configuration, including:- 4.2.1 Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point 4.2.2 A description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings 4.2.3 A description of the distribution system, including the extent to which it is underground 4.2.4 A brief description of the network's distribution substation arrangements 4.2.5 A description of the low voltage network including the extent to which it is underground 4.2.6 An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems. To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.	4.2.1: Bulk supply points are described in Chapters 3.2.2 and 11, specifically 11.5 and the maps throughout, and Tables 11.28 and 11.29. 4.2.2: The subtransmission system is referred to in Chapters 3.2 to 3.4 and maps and tables are provided throughout Chapter 11. The information required on zone substation capacity is provided in Schedule 12b of Appendix 2. 4.2.3: The distribution system is described at a high level in Chapter 3, along with the extent to which it is underground. Chapters 11 and 15 to 21 describe the distribution system in more detail. 4.2.4: Refer Chapter 19. 4.2.5: The low voltage system is described at a high level in Chapter 3, along with the extent to which it is underground. Chapters 15 to 21 describe the low voltage system in more detail. 4.2.6: Refer Chapter 21. Single line diagrams of the subtransmission network are available to interested parties on request.
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network.	We have two sub-networks: the Eastern and Western regions. The maps in Chapter 3 denote if a GXP is in the Eastern or Western region (Figures 3.3 and 3.4).
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category: 4.4.1 Voltage levels 4.4.2 Description and quantity of assets 4.4.3 Age profiles 4.4.4 A discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	An asset summary is provided in Chapter 3.5. The fleet categories and a Portfolio to Asset Fleet mapping are provided in Chapter 7.3.2 . Chapter 14 provides an introduction to our fleet management plans which are provided by each asset category (7 broad portfolios) in Chapters 15 to 21.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
	4.5 The asset categories discussed in subclause 4.4 above should include at least the following: 4.5.1 Sub transmission 4.5.2 Zone substations 4.5.3 Distribution and LV lines 4.5.4 Distribution and LV cables 4.5.5 Distribution substations and transformers 4.5.6 Distribution switchgear 4.5.7 Other system fixed assets 4.5.8 Other assets 4.5.9 assets owned by the EDB but installed at bulk electricity supply points owned by others 4.5.10 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand 4.5.11 Other generation plant owned by the EDB.	4.5.1- 4.5.8: Refer to Chapters 15 to 21 4.5.9: GXP meters are discussed in Chapters 11.5 and 21.6 4.5.10: Refer to Appendix 13, specifically A13.2.2 and A13.4.2 4.5.11: The only generation plants owned by us are a small number of BasePower units on the network. These are modular combinations of micro-hydro, solar PV and diesel generation as a stand-alone power supply to replicate grid supply, along with conversion of heating to LPG. For further information see Chapters 13.4.1 and 16.4.6
Service Levels		
5.	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Chapter 9 details the AMP performance objectives and how they are consistent with the business strategies and asset management objectives. This includes targets over the planning period (refer to figures).
6.	Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next five disclosure years.	Chapter 9.7 and Schedule 12d in Appendix 2 provides this information.
7.	Performance indicators for which targets have been defined in clause 5 above should also include: 7.1 Consumer orientated indicators that preferably differentiate between different consumer types 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation	This is discussed in Chapter 9. 7.1: Chapters 9.7 and 9.8 provide customer-orientated indicators. Indicators that show different consumer types are given in Tables 9.3 and 9.4. 7.2: Chapter 9 discusses our network targets, for example, Chapter 9.5 describes our asset health and utilisation targets. Chapter 9.3 provides a summary of the basis of our targets in each Asset Management objective area.
8.	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	This is discussed in Chapter 9.
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	The figures throughout Chapter 9 provide historical performance for new targets.
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	This is discussed in Chapters 9.3 and 26.

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Network Development Planning		
11.	AMPs must provide a detailed description of network development plans, including:	Network development planning is discussed in Chapter 11.
	11.1 A description of the planning criteria and assumptions for network development	The criteria are discussed in Chapters 7.2.
	11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described	This is discussed in Chapter 7.2.
	11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs	The use of standard designs and standardised assets is discussed throughout Chapters 7 and 15 to 21. Asset obsolescence and standardised replacements are specifically dealt with in Chapter 7.3.3. Standard designs are specifically covered in Chapter 7.5.3. Materials and equipment standards are specifically covered in Chapter 7.5.4
	11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss: 11.4.1 The categories of assets and designs that are standardised 11.4.2 The approach used to identify standard designs	Detailed in Chapters 15 to 21 which are disaggregated to individual asset categorises. The approach used for standard designs is in Chapter 7.5.3, the approach for standardised assets to address obsolescence is in Chapter 7.3.3 and the asset specification purchase strategy is in Chapter 7.5.4.
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network. The energy efficient operation of the network could be promoted, for example, though network design strategies, demand-side management strategies and asset purchasing strategies.	Our strategy for future electricity network is discussed in Chapter 13.5 and our current initiatives are in Chapter 13.4. Appendix 13 provides further information.
	11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network. The criteria described should relate to the EDB's philosophy in managing planning risks.	This is discussed in Chapter 7.2.4.
	11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	Chapters 6.3, 6.5, 7.2 and 7.4.1 provide detail on how network development is prioritised and Chapter 5 provides alignment with corporate visions and goals.
	11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand: 11.8.1 Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates 11.8.2 Provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts 11.8.3 Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period 11.8.4 Discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives	Demand forecasts and network constraints are in Chapters 7.2.3.1, 11.4 (specifically Tables 11.2 to 11.27) and Appendix 7. 11.8.1: The methodology is provided in Chapter 7.2.3. 11.8.2: Forecasts at zone substation level, constraints and the impact of distributed generation are provided in Chapter 11.4 (refer to Tables) and Appendix 7.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including: 11.9.1 The reasons for choosing a selected option for projects where decisions have been made 11.9.2 The alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described 11.9.3 Consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment	Chapter 11.4 summarises our Area Plans and describes all significant network developments. Appendix 8 discusses all network and non-network options considered for major projects. 11.9.3: Chapters 10, 11.4 and 13.4 illustrate our current innovation program. Chapter 13.5 discusses our future strategy.
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include: 11.10.1 A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months 11.10.2 A summary description of the programmes and projects planned for the following four years (where known) 11.10.3 An overview of the material projects being considered for the remainder of the AMP planning period For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.	Chapter 11.4 summarises our Area Plans and describes all significant network developments. Appendix 8 discusses all network and non-network options considered for major projects.
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	Chapter 7.2.3 describes how we treat distributed generation in our demand forecasts which informs network development plans. Our policies for connecting distributed generation are described in Chapter 7.2.11 and are available on our website www.powerco.co.nz
11.12 A description of the EDB's policies on non-network solutions, including: 11.12.1 Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation 11.12.2 The potential for non-network solutions to address network problems or constraints	Refer to Chapters 7.2.9, 13 and Appendix 13
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12. The AMP must provide a detailed description of the lifecycle asset management processes, including:	
12.1 The key drivers for maintenance planning and assumptions	The drivers and key challenges are in Chapter 8.2.

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	12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 12.2.1 The approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done 12.2.2 Any systemic problems identified with any particular asset types and the proposed actions to address these problems 12.2.3 Budgets for maintenance activities broken down by asset category for the AMP planning period	Our maintenance strategy is discussed in Chapters 23.2 to 23.4 and forecasts in Appendix 9. 12.2.1 & 12.2.2: Each asset class fleet plan in Chapters 15 to 21 contains known issues and programmes of replacement. 12.2.3: Described in Appendix 10.
	12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 12.3.1 The processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets 12.3.2 A description of innovations made that have deferred asset replacement 12.3.3 A description of the projects currently underway or planned for the next 12 months 12.3.4 A summary of the projects planned for the following four years (where known) 12.3.5 An overview of other work being considered for the remainder of the AMP planning period	12.3.1-12.3.5 (excluding 12.3.2): Chapters 15 to 21 and Appendix 9 covers our renewal strategy which documents all asset replacement and renewal policies and programmes. 12.3.2: Examples are documented in Chapters 11,13, 23.3.3, 23.4.3, 23.5.3, and 23.7.4.
	12.4 The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	The fleet categories and a Portfolio to Asset Fleet mapping are provided in Chapter 7.3.2. Chapter 14 provides an introduction to our fleet management plans which are provided by each asset category (seven broad portfolios) in Chapters 15 to 21.
Non-Network Development, Maintenance and Renewal		
13.	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including:	
	13.1 A description of non-network assets	13.1: Chapter 22 and Appendix 12 describe non-network assets.
	13.2 Development, maintenance and renewal policies that cover them	Maintenance and renewal strategy are discussed in Chapter 22.
	13.3 A description of material capital expenditure projects (where known) planned for the next five years	Refer to Chapter 22.5 and 22.7.
	13.4 A description of material maintenance and renewal projects (where known) planned for the next five years	The major projects are described in Chapter 22, with expenditure forecasts included in Chapter 26.
Risk management		
14.	AMPs must provide details of risk policies, assessment, and mitigation, including:	Chapter 6.9 provides an overview of risk management, including details of our policies and processes for assessment and mitigation.
	14.1 Methods, details and conclusions of risk analysis	14.1: Methods are discussed in Chapter 6.9. The details of risks are provided in Appendix 8.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
	14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events.	14.2: This is discussed in Chapter 6.9.4.
	14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 16.2.	14.3: This is discussed in Chapter 6.9
	14.4 Details of emergency response and contingency plans. Asset risk management forms a component of an EDB’s overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset-related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.	14.4: This is discussed in Chapter 6.9.5 and Appendix 8 (risks 3 and 7)
Evaluation of performance		
15.	AMPs must provide details of performance measurement, evaluation, and improvement, including:	
	15.1 A review of progress against plan, both physical and financial. i) Referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances ii) Commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced iii) Commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted	This AMP contains objectives, targets, and the rationale for these targets is in Chapter 9. 15.1: Project and expenditures variances are described in Appendix 5. Additional material is provided throughout Chapters 15 to 21.
	15.2 An evaluation and comparison of actual service level performance against targeted performance: (1) In particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances	Chapter 9 provides an evaluation of performance against historic targets.
	15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB’s asset management and planning processes.	15.3: Refer to Chapters 10.5 and Schedule 13 of Appendix 2.
	15.4 An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Chapter 9 describes our initiatives for each category of network targets and Chapter 10 for delivery initiatives. Refer specifically to Chapters 9.4.3, 9.5.4, 9.6.4, 9.7.6, 9.8.4 and Tables10.1 to 10.5.
Capability to deliver		
16.	AMPs must describe the processes used by the EDB to ensure that:	
	16.1 The AMP is realistic and the objectives set out in the plan can be achieved.	Chapters 5 and 6 describe how we ensure the AMP is realistic and objectives can be achieved.
	16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Chapter 6 describes the processes and organisational structure we use for implementing the AMP.

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

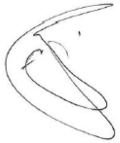
Pursuant to clause 2.9.1 of Section 2.9

We, John Loughlin and Paul Callow, being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

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



Director

Director

12 June 2017

Date

12 June 2017

Date

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POWERCO