DELIVERING NEW ZEALAND'S ENERGY FUTURE

POWERCO

ELECTRICITY ASSET MANAGEMENT PLAN 2016

NOTE ON COVER PHOTO

The cover shows one of our remote area power supplies (RAPS) installed in the Whanganui region. This unit combines a 1.1kW solar array with battery storage and a generator as backup. The existing 4km long spur line will be decommissioned in 2017, avoiding the need for significant renewal expenditure.

Our RAPS solution is discussed in Chapters 11 and 15 of this AMP.

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CONTENTS

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INTRODUCTION

This section introduces our 2016 electricity AMP and provides an overview of our network.

CONTENTS

Back to contents >

1. EXECUTIVE SUMMARY

1.1 INTRODUCING OUR 2016 ASSET MANAGEMENT PLAN

This Asset Management Plan (AMP) outlines our approach to managing our electricity distribution assets over the period 1 April 2016 to 31 March 2026. It is an essential part of our long-term asset planning and investment framework. Like our previous AMPs, it summarises our asset management approach for our customers and other stakeholders.

Our AMP sets out the investments we plan to make in order to deliver our vision of being a reliable partner, delivering New Zealand's energy future. To achieve this we need to make sure our existing network assets are 'fit for purpose' and continue to deliver a reliable and secure service. We must also ensure that the investments we make now position our network for a more diverse energy future.

We believe that our infrastructure will continue to be the main conduit by which the majority of our customers receive most of their energy, by connecting them to the national grid. At the same time, it will also provide customers with a platform on which they can participate more directly in energy markets, if they choose to do so.

We share the widely held view that having access to an efficient and flexible electricity distribution network will continue to be highly valued by electricity consumers and producers. Furthermore we believe that this value will progressively increase as energy markets evolve and mature over the next decades. We expect our customers to take up new opportunities to generate a proportion of their own energy, share energy at a local level, and access energy from the grid as needed for new electricity applications, such as electric vehicles. Our vision for the future is one where our current electricity distribution network not only provides a safe and reliable link to existing energy sources, but also helps unlock more flexibility, competition, and value.

To deliver this, we are committed to managing our assets prudently over the long-term. This means expanding and developing the network to serve new customers and support additional load from our existing customers, as well as investing to replace assets that are no longer able to deliver the level of service that customers require.

Analysis indicates that annual network investment will need to be significantly increased over the 10-year AMP planning period. Our asset management decision-making is underpinned by matching investment to services that customers value and ensuring that any investment is incurred efficiently. We are acutely aware that the investments we make in our network ultimately flow into the price that homeowners and businesses pay for electricity.

The plans set out in this AMP are considered prudent and have been specifically targeted to balance both near and long-term network needs. However, our planning process is designed to be flexible and our underlying assumptions and analyses, on the case for and timing of investments, are subject to regular review. This is particularly pertinent in light of uncertainties created by emerging technology trends and the anticipated changing use of energy. This approach allows us to flex and reprioritise work as necessary before committing to long-term expenditure.

1.2 PROVIDING A SAFE, RELIABLE AND FLEXIBLE SERVICE TO OUR CUSTOMERS

Our network will continue to play a central role in supplying our customers with electricity for the foreseeable future. It is therefore critical that we invest prudently to ensure the stable and enduring health of our assets. This involves carefully managing the condition of our asset fleets with the aim of stabilising performance and balancing costs and risks through prudent asset renewal.

Safety is never compromised and our planning always factors in safety risks, particularly where our assets are located close to public areas.

Parts of our network, in particular Tauranga and its surrounds, and urban areas such as New Plymouth and Palmerston North, continue to experience significant load growth. Agricultural intensification is also lifting peak load, as dairy farmers, in particular, make the shift to more energy intensive processes. Ensuring we are able to support population and business growth is a critical focus for us.

Positioning ourselves to appropriately respond to these trends and ensure we continue playing our important role effectively in enabling customer energy choice is central to our asset management planning. In particular, our asset management objectives have been put in place to ensure:

- **Our networks are safe** – we have an uncompromising approach to safety. We always take action where we believe there are safety risks. Since publishing our 2013 AMP our focus has been on developing our understanding of the health and criticality of our diverse range of assets. This ensures that our investments are better targeted and clearly linked to network outcomes. As a result of this analysis we are increasing our level of investment in overhead line assets to ensure rates of failure are effectively managed. We will also be progressively replacing a range of switchgear to reduce the potential safety hazards that could arise from the failure of these devices.
- **Our networks are reliable** – a reliable energy supply is important to our customers. We have confirmed this by asking our customers what aspects of our services they value most. In 2015 we surveyed more than 1,000 residential and commercial customers in addition to our usual annual stakeholder engagement. However, we are now seeing rising fault trends on some parts of our network, which is increasing pressure on its reliability performance. Our condition and inspections data indicates that these trends are linked to an increasing proportion of our assets reaching the end of their serviceable lives. The impact of tree encroachment on our lines is also increasing. We are committed to addressing these trends through targeted investment across our network. The AMP sets out how we make these important investment decisions.
- **Our networks are flexible** – our customers' energy needs are diverse and continually changing. We see strong continuing energy growth in business sectors as well as increasing options for our residential customers to adopt technologies such as rooftop solar generation and electric vehicles. It is important to support our customers' energy choices. We are therefore focused on ensuring that we are able to support their capacity and security needs, as well as building sufficient flexibility into our network architecture to accommodate new energy solutions.

Delivering on these areas will help ensure the customers and communities we serve continue to have confidence in our network, their electricity supply, and the safety of assets near their homes and businesses.

1.3 HELPING OUR CUSTOMERS ACCESS EMERGING ENERGY OPTIONS

We live in a period of increasing debate about the future of energy markets. Much of the discussion is led from North America and Europe, where firms and policy makers are seeking new low-carbon energy alternatives. Accordingly, technologies such as solar generation, battery storage, and electric vehicles are becoming mainstream. With sustained research and development in these large economies driving technology development and overall cost reductions, we anticipate that distributed generation, battery storage, and electric vehicles will become increasingly more cost effective.

Since New Zealand already has around 80% of its electricity generated from renewable sources, financial payback is likely to be the main incentive for investment in new distributed generation technologies. As it may be some time before these achieve financial parity with utility scale generation options, we have a window of opportunity to prepare for the impact that new technology may have on our network.

In future, it is likely that new technologies will facilitate competition in the New Zealand energy market and increase the options available to customers to meet their own energy needs. However, unlike many other countries, we can defer these investments in new technologies until they become truly cost effective, and allow our customers to make their own decisions regarding what works for them.

Our future business aspiration is to create an open access network that will provide customers with the flexibility to connect equipment and transact with each other as they see fit, and in doing so secure energy at the lowest possible cost. In effect our business will transition from being a traditional network operator to a distribution system integrator.

This means providing a network that can support users at times taking power from our network and at times feeding power back into it. Not only will our network need to support two-way power flows, it will also need the technology 'smarts' to allow consumers to trade and transfer their energy on an open access network platform. Intelligent technology will play a big part in this future network, which is why we will invest in the needed infrastructure to support these applications.

Technology will also enable us to enhance the level of information available to our customers and ourselves about their energy supply. For example, we are currently investing in systems that will provide improved information on real time network status. Customers tell us that digital means are increasingly important for obtaining information. This extends to how we should provide information to them on their energy use and issues affecting their supply. Others prefer a more personal service and we are committed to ensuring information on our network remains available through traditional channels.

1.4 LIFTING OUR INVESTMENT IN NEW ZEALAND'S ENERGY FUTURE

We currently forecast that we will need to lift investment levels over the planning period from a base of about $175m per year in 2016 to $280m per year by 2026. This is a significant change but is necessary if we are to replace assets reaching end-of-life and ensure that current levels of reliability are maintained. It will also allow us to enhance our network with the necessary communications infrastructure and operational controls to support the flexible future use of our network.

This increase in investment will initially put some upward pressure on prices, but will help reduce price pressure over the long-term as we implement new technology to manage the network at a lower cost.

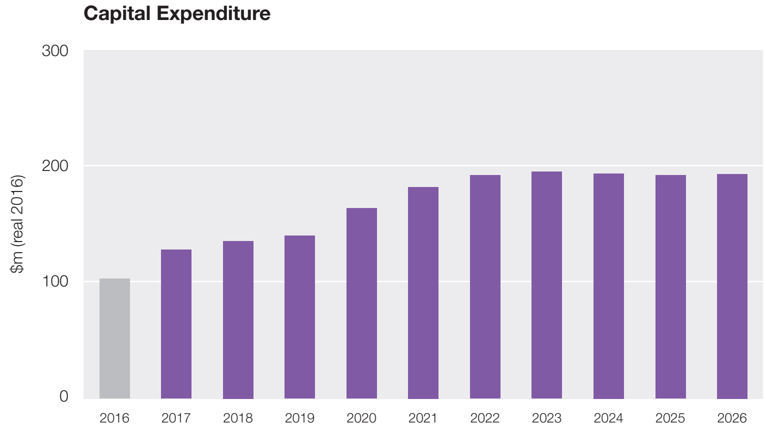
Although currently limited in their impact, beyond the end of our current planning period we foresee that distributed generation, energy storage, electric vehicles and other emerging technologies will have more of an impact on our network operations. The AMP discusses our 'Future Networks Strategy' describing how we plan to respond to the upcoming changes.

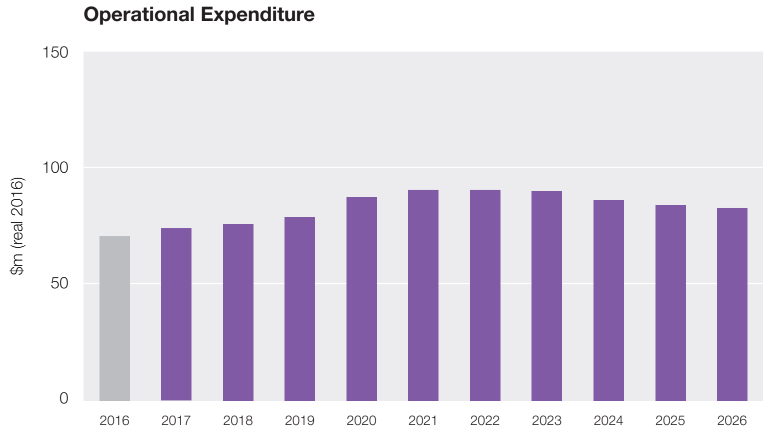
This is the first time we have articulated a long-term technology vision, but we believe it will become an important reference point for future AMPs. Intelligent engineering through appropriate technology will play an important part in limiting future cost increases in the face of increasing investment pressures. It will help keep network performance stable and reliable, while providing open access to our customers. The cost of conducting technology trials, our short-term focus, forms a small part of our overall investment mix. However, the investments have the potential to result in significant customer benefits over the long-term.

Our 10-year expenditure forecast is based on current information and incorporates analysis of asset health, demand growth, and estimates of new technology uptake. We will continue to update our thinking on assumptions, and are open to flexing our plans if improved information becomes available or our current assumptions need to be refined. This is consistent with good asset management practice and the long-term interests of our customers.

Importantly, our short-term Capex forecast is significantly above our current regulatory allowance determined by the Commission under the 2015 default price-quality path (DPP). This means that a proportion of the investment we expect to have to make over the next few years is not currently reflected in our prices. Unless existing features of the regulatory regime (including the incremental rolling incentive scheme (IRIS)) are amended, we will not earn the return on investment that the Commission generally considers reasonable. This is a concerning financial position for us. We will continue to seek ways to defer this expenditure until our revenue allowance can be adjusted (through a customised price-quality path (CPP)) to reflect the investment needs of the network.

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





1.5 LEVERAGING OFF ADVANCED ASSET MANAGEMENT

We are recognised as an effective asset manager. Our costs and performance compare well against the best utilities in New Zealand and Australia. We are proud of this and the way we manage our assets to provide a cost-effective service to our customers.

Continuing to maintain the best balance between performance and cost will only be achieved by ensuring we have a progressive and innovative asset management approach. Our stakeholders rightly expect us to be able to clearly demonstrate that our network is optimally configured, our assets are appropriately utilised, and we operate the business efficiently. This requires us to understand the health of our assets, how they are performing, where future network loadings are likely to arise and the residual risk that it is appropriate for us to manage. Technology will obviously play an important role in our future asset management approach. In summary, our key asset management focus areas include:

- **Leading engineering expertise** – our engineering capability is one of our key strengths. Since the mid-nineties, we have progressively standardised the different assets and management approaches we inherited from previous owners of our networks. Given our history, we have an excellent track record of applying new technologies and integrating enterprise wide systems in a way that reduces the overall cost of our operations. Innovation has been a focus for us recently (for example, our use of 'BasePower' to service remote customers rather than conventional overhead line solutions). This focus will increase over the planning period.
- **Best use of our assets** – we are developing more robust models and processes to ensure we understand the current and expected future performance of our assets and the overall health of our network. A formal programme of physical inspection and testing ensures we are collecting the right data at the right time. Our forecasting techniques enable us to model (with increasing accuracy) the required levels of future investment. Technologies are now available to us, and continue to emerge, which can help us better understand the real time condition of our assets, and enable us to more fully utilise our assets at peak times without increasing risk.
- **Increased network visibility** – we are investing in improved tools and technologies to increase our real-time network visibility. A particular focus is our low voltage network, which connects to the majority of our customers. This will eventually enable us to remotely reconfigure our networks in response to outages or demand peaks. Our control room and automated response systems utilise leading international technology. As the cost of communications and remote sensors falls, it will become increasingly cost effective for us to monitor more of our critical assets in real-time and allow better targeted and informed intervention. These approaches will help us prevent outages and to respond quickly when assets fail.
- **Strong analytical capability** – our asset management initiatives are underpinned by our analytical capability. As we tailor our engineering solutions, maximise asset use, and manage our assets close to their rated limits, there is an increasing need for reliable information and increasing analytical capability. To enable these we plan to increase our investment in analytical skills, key systems and data during the planning period.

We are developing our asset management framework to be consistent with the internationally recognised standard ISO 55000. This is used by many of the best asset managers in the world to guide their operations. Over the last three years we have made good progress towards this as our asset management maturity has improved. We anticipate we will have all the key features of this framework fully embedded within five years, and that this will position us at the leading edge of our sector's asset management practice.

1.6 THE ROLE OF A FUTURE CUSTOMISED PRICE-QUALITY PATH

The amount of revenue that we and other electricity distribution companies can earn from our customers (and by extension, the level of expenditure we are compensated for) is determined by the Commerce Commission. The Commission establishes prices under its DPP mechanism, but a company can make a separate application for a CPP if the revenue allowance under the DPP is inadequate to meet its particular circumstances.

The development of a CPP application involves a substantial amount of time and resource, so is only a viable option if considerable additional investment or operational changes are required.

We are currently in a situation where the DPP does not meet our particular circumstances. Due to our ageing asset base and the need to maintain appropriate service standards for the long-term we must invest more than the amounts provided for under the DPP. Our most recent asset management modelling and forecasting work has been instrumental in helping us quantify the scale of this issue and how best to sequence those investments to maximise value to customers and minimise long-term cost.

We will need to submit a CPP. However, under the current rules for transitioning to a CPP it is not feasible for us to proceed as the process presents unintended risks and costs to network owners. This is a situation we hope will be remedied as part of the input methodologies review being undertaken by the Commission. We are therefore working towards the submission of a CPP application later in the current regulatory period, after the review has been concluded, and on the assumption that the current CPP process issues are addressed.

Our CPP application will reflect the additional investment required to ensure our assets are able to meet customer requirements over the long-term. This increased investment will, by necessity, result in a moderate price increase to our customers, and we will strive to responsibly minimise this. However, the alternative – deteriorating asset health and a network that has not taken advantage of technological improvements – will not meet customers' service quality requirements over the long-term. Ultimately, the costs of energy shortfalls, increasing maintenance, repairs and reactive asset renewal would result in less optimal expenditure and larger future price increases than if we optimise and smooth the investment over time (as we set out in this AMP).

There are uncertainties about when the regulatory regime will be changed to address the shortcomings we see in the current CPP process. However, this AMP assumes these issues will be addressed in the near term and that we will be able to transition to a CPP around April 2019.

The expenditure profile in this AMP represents our best estimate of network needs based on currently available information. However, given the revenue limits we face under our current DPP allowance, we will continue to review options to defer any expenditure that would exceed this allowance, and adjust our overall future expenditure accordingly.

1.7 IN CONCLUSION

This AMP has been developed with a focus on ensuring our network is positioned to meet long-term service expectations of our customers and support their future energy choices.

This means investing to maintain the health of our assets to provide safe and reliable services. We also recognise that our network needs to evolve and become more sophisticated if we are to keep pace with the changing needs of our customers. Balancing the need to achieve these outcomes, while minimising cost to customers, is at the core of our asset management approach.

We believe that good asset management involves challenging assumptions and the status quo. It is essential that we continually improve how we do things if we are to remain at the forefront of effective and efficient asset management, and meet the value expectations of our customers. We are making good progress on our asset management improvement journey as demonstrated by improvements since our last AMP was published in 2013.

Finally, it is important to place our 2016 AMP in the context of the current regulatory environment. Consistent with the asset management focus highlighted above, we have taken a long-term view of network and customer needs rather than constraining our forecasts at current levels or within current regulatory allowances. The indicative expenditure profile set out in this AMP is materially above our current DPP allowance. As such, it is likely that a bespoke allowance, established under a CPP, will be required to appropriately fund these future investments.

We expect the current uncertainty regarding the regulatory rules to be resolved by the Commission as part of the input methodologies review. We expect to remain under DPP expenditure allowances for at least the next two to three years. Operating within this level of allowance is not sustainable over the long-term. Accordingly, during this period of constrained allowance we will focus on immediate, high priority needs. We will also continue refining our future investment forecast so we efficiently develop the network in line with our customers' needs.

2. INTRODUCTION

2.1 CHAPTER OVERVIEW

This chapter provides an overview of our 2016 AMP. It briefly introduces Powerco and our key stakeholders, and sets out how we have structured this AMP.

2.2 PURPOSE OF OUR 2016 AMP

We recognise 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 our regulators.

Our 2016 AMP outlines 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 2016 AMP are to:

- consult 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 performance objectives and how we plan to achieve them
- set out our asset management improvements since our 2013 AMP
- 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 signal a potential CPP.

2.2.2 AMP PLANNING PERIOD

Our AMP relates to a 10-year planning period, from 1 April 2016 to 31 March 2026. 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 17 March 2016.

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 325,000 connected customers. We are the second largest distributor in New Zealand in terms of customer connections.

Our network circuits of over 27,000km 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 effective information to our stakeholders. We use it to explain how we manage our electricity network assets, and aim to provide enough detail to explain our plans and decisions. We also aim to make it a document our customers can readily follow.

To effectively manage complex, long-life assets for a range of stakeholders we balance a range of (sometimes conflicting) interests. When there are conflicting interests, we exercise our best judgment and strive to engage with stakeholders to transparently explain our decisions, including through our AMPs. Our key stakeholders and their main interests are set out 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, we have revised and expanded the content of our 2016 AMP. In addition to streamlining and rewriting previous content we have included a number of new chapters. Two of these new chapters are of particular note:

- **Chapter 6** – outlines our Customer Strategy and how we plan to meet our customers' needs, now and in the future. It explains how we position our customers at the centre of our investment decisions.
- **Chapter 11** – outlines our aim to be a Distribution System Integrator (DSI). This comprehensive new chapter sets out our approach to dealing with an uncertain energy future.

The diagram below sets out the new structure of our 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
Introduces our 2016 AMP and provides an overview of our network.

1 **Executive Summary**
Provides context to stakeholders on key factors that will 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.

ASSET MANAGEMENT FRAMEWORK
Explains our asset management strategy and our approach to investment decision-making.

4 **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.

5 **Governance**
Explains our approach to asset management decision-making and investment planning, project delivery and risk management.

SERVING OUR CUSTOMERS
Explains how we plan to meet our customers' needs, now and in the future.
It also outlines our network targets for assessing our performance.

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

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

NETWORK DEVELOPMENT
Explains our plans to develop our network, including how we will ensure its future readiness.

8 **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.

9 **Customer Connections**
Explains how we connect new customers to our network.

10 **Network Enhancements**
Explains how we invest in automation and communications systems to enhance network performance.

11 **Networks for the Future**
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
Explains our approach to managing our 25 asset fleets.

12 **Approach to Fleet Management**
Introduces our approach to fleet management and explains the interaction between renewals and maintenance work.

13 **Network Opex**
Explains our approach to operations, maintenance and vegetation management.

14 **Overhead Structures**
15 **Overhead Conductors**
16 **Cables**
17 **Zone Substations**
18 **Distribution Transformers**
19 **Distribution Switchgear**
20 **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

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

ASSET MANAGEMENT SUPPORT
Explains how we plan to improve our ICT systems and develop our asset management capability.

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 **Asset Management Capability**
We explain how we intend to improve our asset management capability over the planning period, including the development and expansion of our internal skills base to deal with the challenges of the future.

EXPENDITURE FORECASTS
Summarises our Capex and Opex forecasts.

24 **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. We divide these regions into zones and planning areas. To help provide context to the rest of the AMP, this chapter provides an overview of the locations and network configurations in these regions and zones. Chapter 8 provides detailed information on the 13 planning areas. At the end of this chapter we provide a summary of the assets we own. A more detailed overview of our assets is provided in Chapters 14 to 20.

3.2 OUR NETWORK

Our network supplies electricity to around 325,000 customer connections across two coastal regions of the North Island. Both our supply area and network length are the largest of any single distributor in New Zealand.

3.2.1 NETWORK CONFIGURATION

The operation of the electricity network is analogous to roading. The latter ranges from high capacity and volume national highways to small access roads. Electricity uses high voltage to move large amounts of power over longer distances across the transmission network. As electricity is distributed to less populated areas, the size and voltage of network assets reduce.

Figure 3.1: **Our place in the electricity sector**

GENERATION	TRANSMISSION (national grid)	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.

We have lines and cables operating at 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, a power transformer housed in a zone substation is used. When electrical flow is from a distribution circuit into the LV network, a smaller distribution transformer is used.

3.2.2 TRANSMISSION POINTS OF SUPPLY

Our network connects to the transmission 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's network. The transmission grid conveys electricity from generators throughout New Zealand to distribution networks and large directly connected customers.

GXPs are key points from which local communities are supplied. Large numbers of consumers may lose supply due to a GXP failure or outage so a highly reliable configuration is required. To support this, redundancy is built into GXPs at many locations through duplicated incoming lines, transformers, and sectionalised busbars.

GXP assets are mostly owned by Transpower, although we do own transformers, circuit breakers, and protection and control equipment at some sites. The GXPs supplying our network are discussed in Chapter 8.

3.2.3 OUR 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.

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.

On the following page we provide an overview of these regions, including the zones used to manage our pricing approach. Our 13 planning areas form the basis for our Area Plan Summary document. Further details on these areas can be found in Chapter 8.

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

Figure 3.2: **The regions we cover**

3.3 EASTERN REGION

The eastern network region consists of two zones – Valley and Tauranga. These have differing geographical and economic characteristics, some of which present different asset management challenges.

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

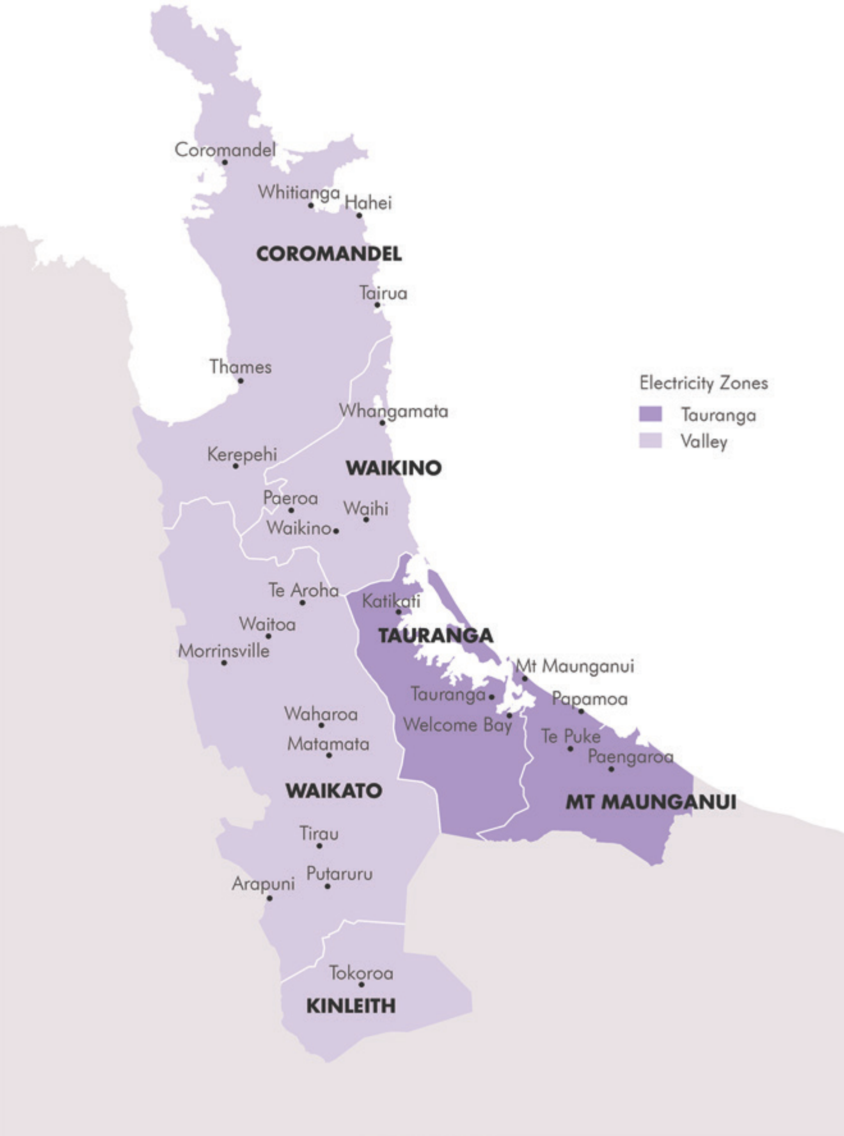
The table below sets out key statistics for the Eastern Region including the number of connected customers and the amount of energy we delivered to them.

Table 3.1: **Key statistics – Eastern Region (2015)**

MEASURE	
Customer connections	150,443
Overhead circuit network length (km)	7,224
Underground circuit network length (km)	3,159
Zone substations	47
Peak demand (MW)	440
Energy throughput (GWh)	2,332

The map below shows the eastern network region and its planning areas.

Figure 3.3: **Eastern network region and planning areas**



3.3.1 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 but by and large the region is rural and predominantly used for dairy farming. It is geographically diverse including the rugged, forested Coromandel area and the predominantly agricultural Waikato.

Detail on the GXPs in this zone including network maps, can be found in Chapter 8.

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, especially on the long circuits up to Whitianga. Despite this, a number of security of supply issues remain to be addressed.

Ensuring a 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.

Waihi substation is the largest substation in the area. Demand on this substation is strongly impacted by a local mine. To manage this, we coordinate our operations with the mine.

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 ideal 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, via an interconnected radial network of 33kV lines. Piako GXP is a new grid connection which addressed high risk constraints at Waihou resulting from recent rapid demand growth.

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, apart from two new dedicated single customer substations at the Inghams and Tatua factories. Upgrades to the 33kV serving Waharoa are needed to address rising demand.

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. Substations at Tower Rd and Browne St supply Matamata via single radial lines but in future will be via a 33kV ring network.

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 and is connected mainly via 11kV switchgear located at the GXP itself. In conjunction with proposals to replace equipment at the GXP we have a programme of works scheduled for the 11kV assets. 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. The security for these urban class substations is the driver for a project to convert to a 33kV ring.

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.

3.3.2 TAURANGA ZONE

The Tauranga zone covers the Western Bay of Plenty area from near Athenree, north of Katikati, south to Otamarakau, 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.

Detail on the GXPs in this zone including network maps can be found in Chapter 8.

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. Kaitimako GXP presently only supplies Welcome Bay substation but our future strategy is to transfer more load to Kaitimako to alleviate loading on Tauranga GXP.

The main urban substations are Hamilton St, Waihi Rd, Otumoetai, Bethlehem, Matua and Welcome Bay. These are designed to accommodate our standard urban substation configuration ultimately with twin 24MVA capacity transformers.

The substations distributed along the northern Tauranga coast are generally smaller capacity serving agricultural loads but otherwise largely rural and lifestyle customers. The subtransmission to these substations is constrained by the capacity of the two 33kV circuits from Greerton which will be a focus of a major upgrade project.

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 generation at a fertiliser manufacturer.

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. The two 33kV circuits to Te Maunga can no longer securely supply both substations and will not be adequate as demand continues to rise. Recent upgrades to the 33kV subtransmission serving Triton and Omanu has given these substations adequate security.

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. Because the two 33kV circuits supplying Te Maunga and Papamoa from Mount Maunganui GXP are already constrained, Wairakei will be supplied via two new, large capacity circuits from Te Matai GXP. This major investment strategy includes upgrades to Te Matai GXP and future substations and subtransmission upgrades expected to be just beyond the AMP period.

The existing network from Te Matai GXP serving Te Puke and Pongakawa is at 33kV. Two overhead lines supply the largest substation, Te Puke. A new Atuaroa substation will help offload Te Puke and will require additional transformer and subtransmission upgrades. The other substations, including the new Paengaroa substation, supply predominantly rural load. They have with small capacities and single circuit constraints.

Further detail on these areas, including network maps can be found in Chapter 8.

3.4 WESTERN REGION

The Western Region includes the four network zones described below. Similar to the Eastern Region, these zones have differing geographical and economic characteristics, some of which present different asset management challenges.

- **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.
- **Masterton** – is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.

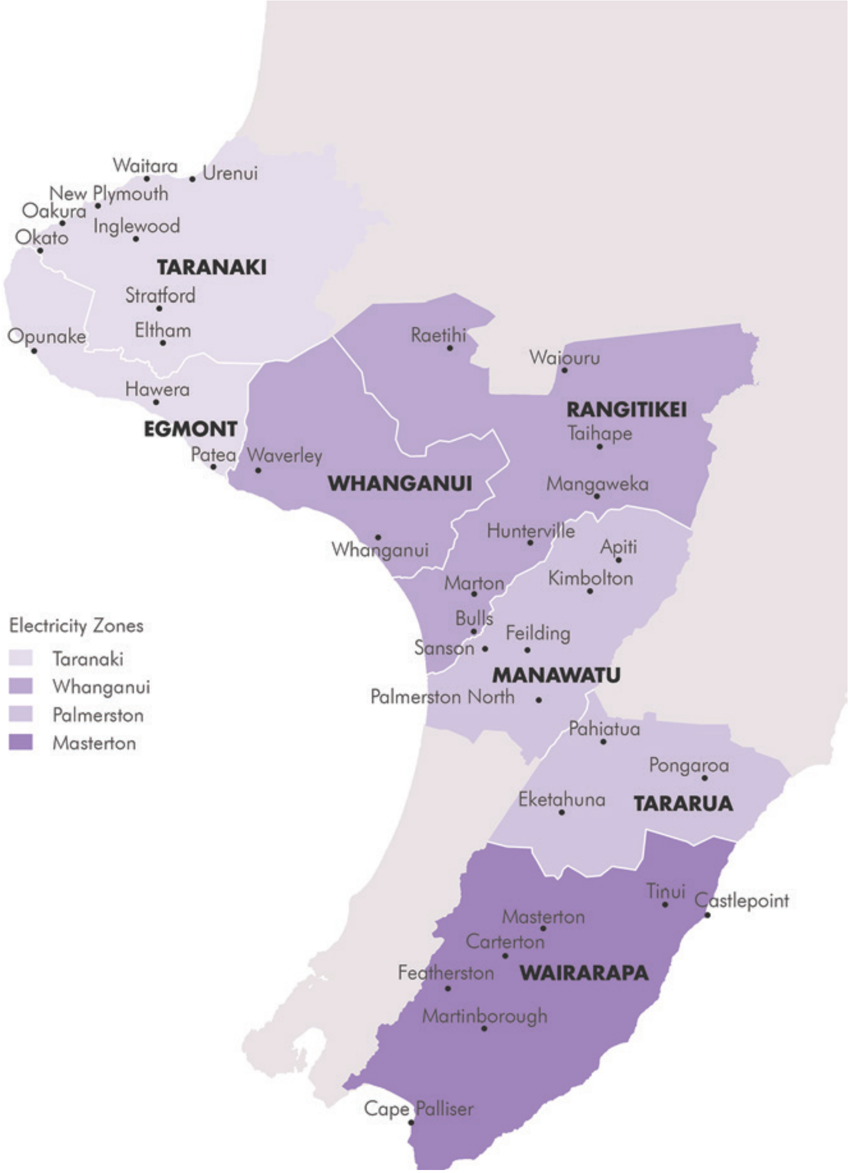
The table below sets out key statistics for the Western Region.

Table 3.2: **Key statistics – Western Region (2015)**

MEASURE	
Customer connections	176,943
Overhead circuit network length (km)	14,571
Underground circuit network length (km)	2,878
Zone substations	68
Peak demand (MW)	412
Energy throughput (GWh)	2,383

The map on the following page shows the western network region footprint by region and planning area.

Figure 3.4: **Western network region and planning areas**



3.4.1 **TARANAKI ZONE**

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

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

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 different GXPs. The largest grid offtake at Carrington St supplies Brooklands substation and the City substation, which serves New Plymouth's CBD. Both 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 supported by our new Katere substation but both are presently fed from two overhead lines from Carrington St GXP. Bell Block will soon be transferred to Huirangi GXP to avoid overloading and will then have two dedicated high capacity overhead circuits from Huirangi.

Huirangi GXP also supplies substations that serve Waitara and major oil and gas sites. 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. The 33kV subtransmission is entirely overhead and is a highly meshed configuration which leads to limitations in security due to protection issues. In particular, Eltham and Cloton Rd require split 33kV busses.

Egmont

Egmont encompasses Hawera and up to Opunake 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 beside, but does not supply, the large Fonterra plant of the same name. The Patea hydro generation also injects into Hawera GXP.

The main development initiatives are to remove a security weakness in the Manaia tee and possible relocation of the Whareroa substation for environmental, renewal and operational reasons.

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 connects to the Maui production station.

Detail on the GXPs in this zone, including network maps, can be found in Chapter 8.

3.4.2 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. Notably, Brunswick only has one 110/33kV supply transformer.

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 Wanganui GXP and have space for just a single transformer each. They operate in a unique parallel configuration using a high capacity 11kV bus tie.

The remaining substations serving the urban area are Roberts Ave and Castlecliff, off Brunswick GXP, and Beach Rd and Whanganui East, off Wanganui 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.

The N security Brunswick GXP, and N security or switched N security configurations on the subtransmission and substations are characteristic of Whanganui's unique network architecture. Where possible we will continue to upgrade and adapt this to more standard network architectures with improved security conformance. Recent upgrades at Peat St, Hatricks Wharf and Beach Rd are part of this. This programme will continue with future plans to add circuits into Taupo Quay and Peat St and upgrade Taupo Quay substation.

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 are both N security and supply the inland networks which have no connection between GXPs. Ohakune is a shared GXP and feeds the 11kV distribution directly.

All the 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 reflecting the relatively low criticality of the load and the security requirements. Low levels of demand growth mean investment in the area is limited to distribution back-feed upgrades.

Detail on the GXPs in this zone, including network maps, can be found in Chapter 8.

3.4.3 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's 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. The capacity of these two GXPs imposes restrictions on further expansion due to high fault levels. Bunnythorpe load is reaching its firm capacity.

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.

The Palmerston North city subtransmission network was formerly owned by Palmerston North Municipal Electricity Department. 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 33kV oil-filled cables from Keith St supply the Main St substation which is close to the CBD. Pascal St substation, on the other side of the CBD, takes supply via 33kV circuits from Linton GXP. Both Main St and Pascal St are above their firm capacity and space restricts us increasing this.

One of our major investment focuses over the AMP period is the security of supply to these substations. We plan to establish a new Ferguson St substation and install high capacity cables from Linton GXP. This will restore appropriate security to the CBD, improve network architecture, alleviate operational constraints and mitigate risks associated with the ageing oil-filled cables.

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. While firm capacity is adequate to all these substations, network architecture, cross GXP switching and generation in-feeds contribute to operational and protection complexities. This sometimes leads to inappropriate 'make before break' switching or protection arrangements.

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 out of 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 and 33kV radial feeders to Sanson and Kimbolton via Feilding. 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. This, and the single circuit to Sanson substation, are another focus of our development plans.

The distribution network in Palmerston North is unique in that it is entirely underground. It was designed in the context of the old electricity industry structure, where two different organisations operated the network within the city and outside the city limits. A radial distribution feeder approach was used with smaller capacity circuits nearer the edge of the city and with no interconnection across the network boundary. Upgrading distribution feeders throughout the city remains a continuing development planning focus.

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.

Detail on the GXPs in this zone, including network maps, can be found in Chapter 8.

3.4.4 MASTERTON ZONE

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.

Masterton zone is connected to the grid through Masterton and Greytown GXPs. The subtransmission networks are 33kV, although there is no interconnection.

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 wind farm via a long radial 33kV line.

Detail on the GXPs in this zone, including network maps, can be found in Chapter 8.

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 conductor
- Underground cable
- Overhead structures
- Zone substations
- Distribution switchgear
- Distribution transformers
- Secondary systems

Our approach to managing our asset fleets is explained in Chapter 12.

3.5.2 ASSET POPULATIONS

Below we set out an overview of our asset populations across our full electricity network. 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 14-20.

Table 3.3: Asset population summary (2015)

ASSET TYPE	POPULATION
Overhead network	
Subtransmission (km)	1,506
Distribution (km)	14,843
LV (km)	5,154
Underground cables	
Subtransmission (km)	147
Distribution (km)	1,945
LV (km)	3,542
Overhead structures	
Poles	266,010
Crossarms	425,213
Zone substations	
Power transformers	188
Indoor switchboards	113
Buildings	158
Distribution assets	
Transformers	33,319
Switchgear	41,295
Secondary systems	
Zone substation protection relays	1,999
Remote terminal units	330

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ASSET MANAGEMENT FRAMEWORK

This section sets out our asset management strategy and explains our approach to investment decision-making.

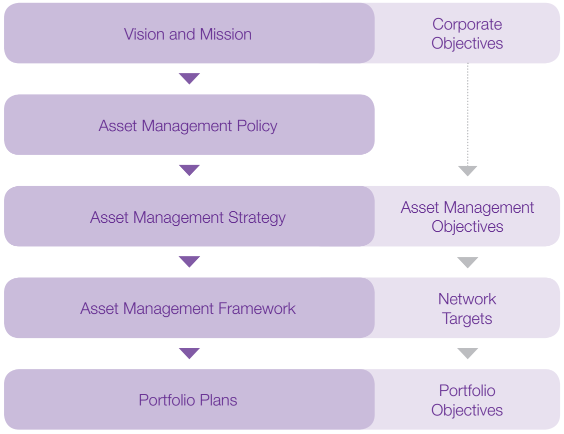
CONTENTS

Back to contents >

4.1 CHAPTER OVERVIEW

This chapter explains our Asset Management Strategy – the thinking and approach that guides our day-to-day asset management activities. 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 4.1: **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.

- **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 strategies and goals. This includes a set of strategic Asset Management Objectives.
- **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 and set our network performance targets.
- **Portfolio plans** – include our investment plans and detailed asset strategies, including fleet specific objectives. These are discussed in Chapters 8-20.

4.2 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. The latter 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.

4.2.1 CORPORATE VISION

Our corporate vision (below) reflects the balance that we, as a modern electricity distributor, seek to strike between continuing to provide a safe, reliable supply to our customers, and ensuring our readiness for a changing future.

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

4.2.2 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**.

4.2.3 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 the following table.

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 4.1: **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.

4.3 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, via structured development over time
- Continually enhancing our asset management capability and skills over time
- Aligning to the best international approach via ISO5500
- 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.

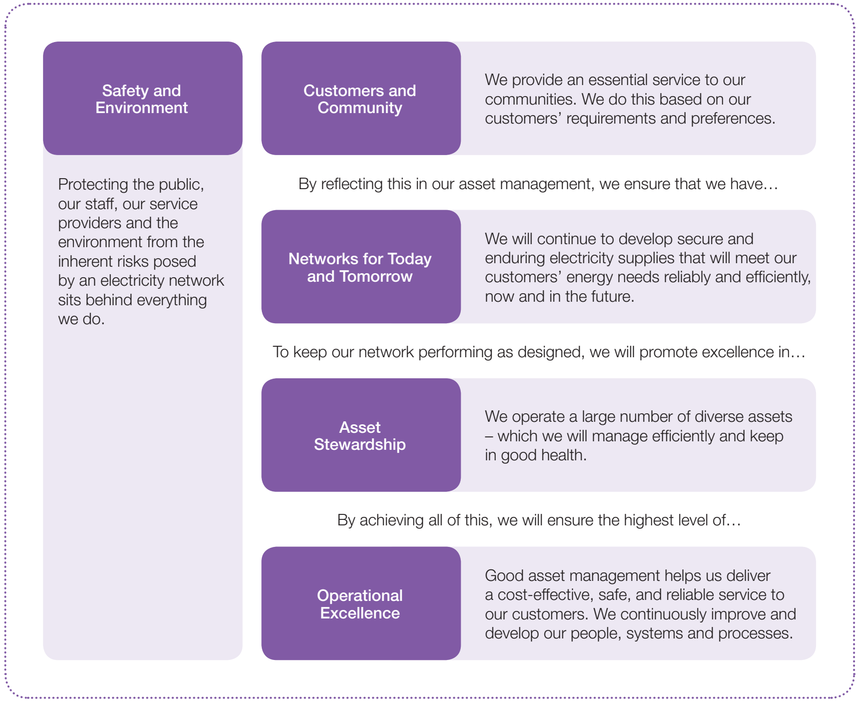
4.4 ASSET MANAGEMENT STRATEGY

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. These 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 the figure below, and are discussed in the sections below.

Figure 4.2: **Our Asset Management Objectives**



4.4.1 SAFETY AND ENVIRONMENT

Our Asset Management Policy reaffirms that 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 that 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 4.2: **Safety goals**

GOAL	SUPPORTING INITIATIVE(S)
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	Ongoing development of safety culture maturity with our service providers.
10% year-on-year reduction in Lost Time Injury Frequency Rate	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.
Full compliance with the new Health and Safety Reform Bill	Training for Board members and staff regarding the requirements of the Health and Safety Reform Bill.

Table 4.3: **Environmental goals**

GOAL	SUPPORTING INITIATIVE(S)
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.

4.4.2 CUSTOMERS AND COMMUNITY

Good customer service is an essential requirement for any successful business. For an electricity lines business this not only covers factors such as delivering a reliable, resilient electricity supply, but also '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, to ensure that 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 the energy choices they wish to make.

Lastly, 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 a set of goals, as set out below. Various initiatives have also been defined, which will help us achieve the goals.

Table 4.4: **Customers and Community goals**

GOAL	SUPPORTING INITIATIVE(S)
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 DSI 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.

4.4.3 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 our customers where they choose to utilise new energy solutions such as rooftop PV, and electric vehicle charging.

Overseas and local studies have shown that effective planning and application of appropriate technologies on our networks is essential to moderate the cost of accommodating new distributed energy solutions. This topic is further discussed in Chapter 11.

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 this objective, we have adopted a set of goals and associated initiatives, as set out in the next table.

Table 4.5: **Networks for Today and Tomorrow goals**

GOAL	SUPPORTING INITIATIVE(S)
At least maintain overall and disaggregated network reliability at historical levels[3] (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, as well as 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.

4.4.4 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 is used in ways that are unsafe or could shorten its life.

[3] 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.

While our network performance has been relatively stable over a long period, there are increasing signs of asset deterioration. This is evidenced by 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 ensure we optimise the timing of asset renewal. This will in turn 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 4.6: **Asset stewardship goals**

GOAL	SUPPORTING INITIATIVE(S)
Our assets perform at their designed capacity over their expected lives	Adopt a 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 operations 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.

4.4.5 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.

We intend to be ISO 55000 certified by 2022. Achieving this will require concerted effort and capability investment in the short-term. In the longer term it will result in optimal delivery against our asset management strategy and objectives. This will support our Operational Excellence goals.

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 4.7: **Operational excellence goals**

GOAL	SUPPORTING INITIATIVE(S)
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 ISO 55 000 certification	Identify and address the necessary steps to achieve (at least) level three maturity on all measures by 2022.

4.4.6 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 will be reported in future AMPs (or AMP updates). These are set out in Chapters 7 and 23.

5. GOVERNANCE

5.1 CHAPTER OVERVIEW

Asset management governance is our term for the system of roles, responsibilities, authorities, and controls that support our asset management decision-making.

This chapter explains our approach to asset management decision-making. It discusses our asset management governance structures and responsibilities. It introduces our approach to life cycle asset management and explains how we plan and deliver our investments. Effective risk management is a core function of good asset management and our risk approach is also set out in this chapter.

5.2 ASSET MANAGEMENT GOVERNANCE

Our approach to asset management has been refined significantly over the past few years. It became apparent that our asset management practices, while fundamentally sound, needed to evolve to manage the future twin challenges of our ageing and deteriorating asset base, and the way technology changes will impact our network and our customers' electricity use.

To meet these challenges, we undertook to improve our overall asset management approach. Underpinning these changes are our governance arrangements and the following objectives that guide them.

- Ensure that our Asset Management Policy and Asset Management Strategy are effectively delivered by our 'frontline' day-to-day activities – helping to ensure 'line-of-sight' between operations and overall objectives.
- Ensure our stakeholders' interests have been considered and reflected in our decision-making.
- Guide and direct our asset management decisions while reflecting the commercial, regulatory and competitive environment in which we operate.
- Ensure all our policies, processes and standards align with our goals as our asset management approaches evolve.
- Ensure we continuously challenge assumptions, analysis and decisions from a wider perspective, before investment.

In 2013, we completed a detailed assessment of our asset management practices against the Commission's Asset Management Maturity Assessment Tool (AMMAT). We scored an average of two and set an ambitious goal of achieving a level three score by 2018. As part of this journey we have overhauled our suite of asset management documentation, conducted a review of how we plan renewal and growth Capex, and updated our approach to forecasting maintenance. These changes are reflected in this AMP and our forecasts.

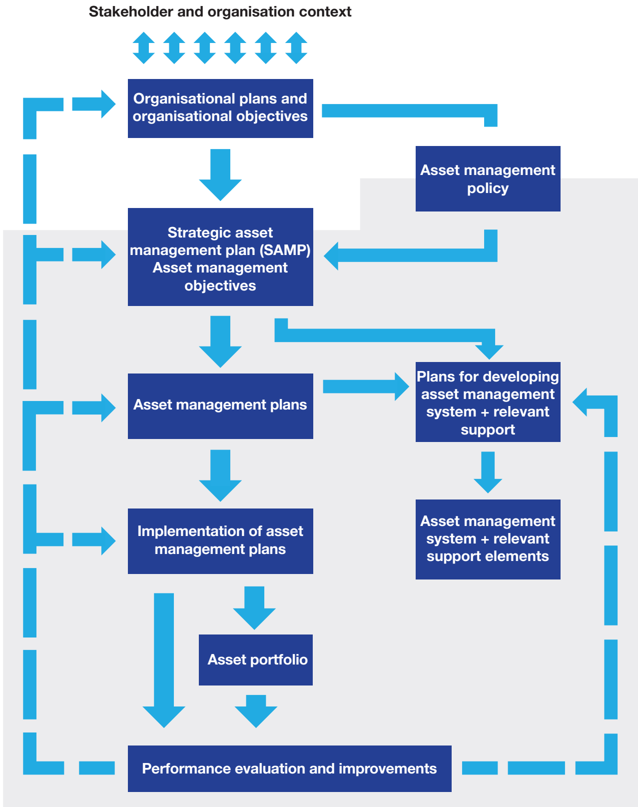
Our updated AMMAT score (discussed in Chapter 23) is now 2.3, which reflects that while we have made improvements, there is still more to be done.

We have also broadened our expectations and set ourselves a target for ISO 55000 compliance by 2022. This will involve continual refinement and improvement of the asset management approaches described in this AMP.

5.3 APPROACH TO ASSET MANAGEMENT

We aim to operate our electricity network and support services in accordance with leading industry practice. Our asset management thinking is aligned with leading practice as described in the ISO 55000 standard. This emphasises the importance of aligning an organisation's corporate objectives with asset management objectives and strategies through to the on-the-ground daily activities.

Figure 5.1: **Our Asset Management System (adopted from ISO 55000)**



The way our Asset Management System is supported by our hierarchy of asset management documentation is shown below. The concept of having a clear 'line-of-sight' between corporate objectives and daily activities is a key feature of effective asset management.

The upper layers are described in Chapter 4. The remaining layers (in grey boxes) explain how we deliver the main activity types that make up our asset management approach. They explain our investment plans over the medium-term and are key parts of this AMP. These documents include our:

- **Area planning summary** – the output of network development plans across our 13 planning areas (discussed in Chapter 8).
- **Fleet Management Plans** – how we manage our 25 asset fleets over their life cycle (seven documents discussed in Chapters 14-20).
- **Maintenance strategy** – our approach to operating and maintaining our overall electricity network (summarised in Chapter 13).
- **Vegetation strategy** – our approach to managing vegetation along our electricity network (summarised in Chapter 13).

Figure 5.2: **Our asset management documentation hierarchy**

5.4 ASSET MANAGEMENT RESPONSIBILITIES

All 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 Objectives and our Asset Management Policy. Below we describe the main governance levels.

5.4.1 OUR BOARD

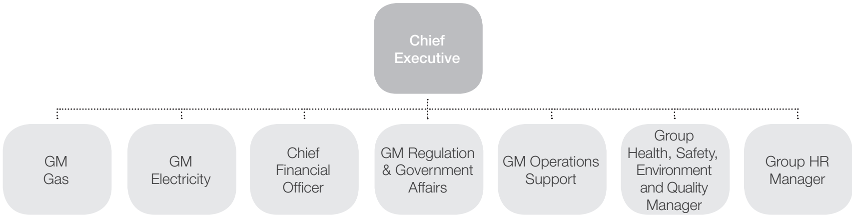
The Powerco Board provides strategic guidance, monitors management's effectiveness and is accountable to shareholders for the company's performance. From an asset management perspective, it does this by endorsing key documentation (including this AMP), establishing our objectives and strategies for achieving those objectives. The main asset management responsibilities of the Board are as follows.

- The Board has overall accountability for maintaining 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 plans. The Board's Regulatory Committee is responsible for ensuring the AMP meets regulatory requirements.
- The Board approves projects or programmes with expenditure greater than $2m.
- The Board reviews monthly performance reports on the status of key work programmes and important network performance metrics. This includes updates on high value and high criticality projects and the status of our top ten risks. 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. It meets on a quarterly basis to review processes and controls. The committee also reviews and discusses issues reported by internal and external auditors.

5.4.1.1 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 below. This structure allows the Electricity Division to focus on core activities and decisions and access specialist skills and advice as required.

Figure 5.3: **Executive team structure.**



The five functional units fulfil a variety of support roles.

The Operations Support unit manages 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.

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, initiating corrective action as required.

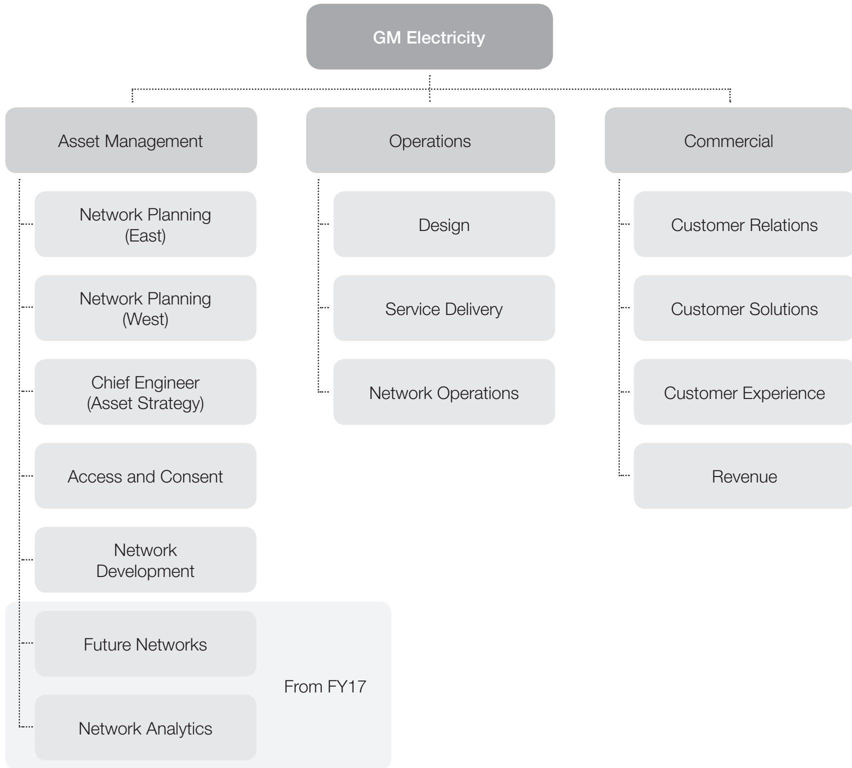
The Regulatory and Government Affairs group manages the interface with our regulators, including making regulatory submissions and disclosures (of which the AMP forms part) and engaging in the rule-setting processes. There is close interaction between this team and the asset management functions to ensure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

The 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.

5.4.2 THE ELECTRICITY DIVISION

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 below.

Figure 5.4: **Electricity Division structure**



5.4.2.1 ASSET MANAGEMENT

The asset management team is broadly responsible for translating the Asset Management Policy into a practical asset management strategy and plan, then managing its delivery.

Network Planning

The Network Planning teams (one team each for the eastern and western parts of the network) execute the asset planning processes, which sit at the heart of our electricity network investment plan (renewal and growth projects). The planning processes culminate in the delivery of asset management documentation, maintenance and Capex plans, concept designs, project briefs (scope and specification of capital projects) and annual work plans.

Access and Consent

This team supports the Planning and Service Delivery teams with the arrangements required for sites or easements for new substations and feeders. This includes landowner liaison, local council liaison, environmental impact assessment and obtaining resource consents and designations.

Chief Engineer (asset strategy)

This team is responsible for network asset strategy, asset risk management guidelines, technical reviews and arbitration, technical support for regulatory submissions, investment policies and design, and the development of standards.

Network Development

This team works closely with the planning teams, and has overall responsibility for long-term network development, including bulk supply planning. The team is also responsible for our overall electricity demand forecasting, determining network architecture, and the setting and review of our network security standards.

Future networks [from FY17]

We are in the process of setting up a Future Networks team. This team will work across the business to implement our Future Networks Strategy (discussed in Chapter 11) by providing the necessary leadership and coordination. It will have responsibility for scenario development and the associated impact assessment, emerging consumer trend analysis, research and development, and proofs of concept for new network applications and non-network solutions.

Network Analytics [from FY17]

We are in the process of setting up a Network Analytics team. This team will be responsible for analysing our asset and network information to assess network performance issues and to provide solution guidance. It will also support others in the electricity team with performance improvement and optimal investment planning.

5.4.2.2 OPERATIONS

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.

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 the contractor competency requirements.

Service Delivery

Our field service operations, including maintenance and construction, are fully outsourced. The Service Delivery group manages the contract with our prime field service provider, as well as with further suppliers that are brought in when needed. The capital projects team, responsible for overseeing project delivery, is also part of the Service Delivery team.

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.

5.4.2.3 COMMERCIAL

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 that 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.

5.5 ASSET MANAGEMENT GOVERNANCE

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

5.5.1 EXPENDITURE GOVERNANCE

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

Each year an Electricity Works Plan (EWP) is approved by our Board. Each project within the EWP is approved based on our delegated financial authority (DFA) policy. A work order is established in our financial system reflecting the associated DFA approval. Any changes to project scope requiring additional expenditure triggers further review and a new approval process is required to agree any changes.

5.5.2 ASSET MANAGEMENT DECISION-MAKING

We have broadly eight levels of asset management decision-making, ranging from strategic decision-making 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.

The table below provides an overview of these governance levels.

Table 5.1: **Asset Management Governance Levels**

LEVEL	PURPOSE	RESPONSIBLE	DOCUMENTATION
Company strategy	Overarching corporate objectives and targets	Board, CEO, Executive	Vision, Mission, Values
Asset Management Policy	Our goals and intentions for the electricity network	Board, CEO, Executive	Asset Management Policy
Asset Management Strategy	Supports policy implementation, sets asset management objectives	GM Electricity, Asset Manager	Asset Management Strategy
Asset Management Plan	Medium and long-term plans to implement the asset management strategy	GM Electricity, Asset Manager	Asset Management Plan
Portfolio management	Fleet and activity specific goals to support our network targets	Asset Manager, Operations Manager, Commercial Manager	Area Plans; Fleet Management Plans Opex strategies
Standards and policies	Detailed technical requirements and procedures	Asset Manager, Design Manager, Chief Engineer	Design standards, maintenance standards
Annual planning	Detailed planning of delivery objectives	Asset Manager, Planning Managers	Electricity works plan
Portfolio budgets	Oversight of expenditure to deliver annual plan	Planning Manager, project managers, Service Delivery Manager	Capital works programme, maintenance works programme

5.5.3 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. This is reviewed annually. 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 relevant DFAs for our Electricity Division are as follows.

Table 5.2: **Delegated Financial Authority limits**

LEVEL	CAPEX LIMIT	OPEX LIMIT
Board	>$2m	>$2m
CEO	$2m	$2m
GM Electricity	$1m	$1m
Senior managers[4]	$600k	$600k
Other managers	$300k	$300k

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

5.5.4 **APPROVAL STAGE GATES**

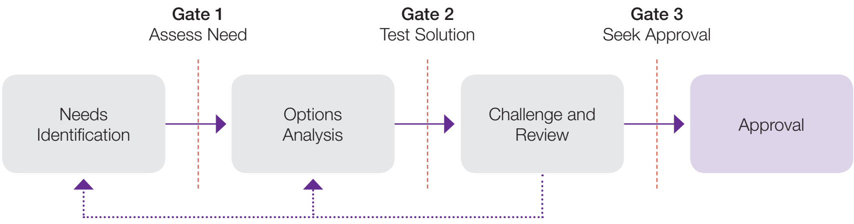
Our decision-making approach for approving network investments uses a stage gated challenge and approval process. This ensures that appropriate governance is applied and that challenges are posed at appropriate stages as investment plans are developed and refined.

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 investments covered in Section 5.9.

Figure 5.5: **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. For information on this process see Section 5.7.4 below. Our investment planning process is described in detail in Section 5.7.

5.5.4.1 **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 provided below.

- **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, 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 the most important. Needs are assessed based on the factors put forward as justification (e.g., 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 (e.g. New Zealand Transport Agency (NZTA)). The need for investment following these requests is assessed by the Commercial team following advice from the Planning 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.

5.5.4.2 **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 provided below:

- **Renewal** – solutions are generally tested by the network planning managers. 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 planning managers. 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, that the solution will meet future demand growth projections and that it represents the least cost technically feasible solution. The degree to which non-network solutions were considered is also tested.

- **Customer connections and 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. Accordingly, the level of challenge is lower. However, projects are still reviewed to check that the chosen solution is safe.
- **Future technology** – Proposals are generally reviewed by the Asset 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, while the remainder go for final approval at a level aligned with our DFA policy (see Section 5.5.3 above).

Project 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 Network Planning team, and are subject to a deliverability review by the Service Delivery team.

5.5.4.3 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. This challenge includes a review of the following considerations:

- Alignment with asset management objectives
- Cost effectiveness
- Deliverability

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 coordination 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).

Once approved, delivery of the project becomes the responsibility of the Service 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.

5.5.5 EXPENDITURE OPTIMISATION

A critical component of asset management governance is investment optimisation. Expenditure rationing often requires deferral of lower priority investments, requiring an understanding of the implications and risks of such deferment decisions.

To finalise the EWP each year, individual investment decisions at a project level are prioritised through a formal optimisation process, using our Coin tool. This ensures that the investments selected most effectively meet the needs of stakeholders and that the risks of deferment are appropriately considered and well understood. Optimisation-based deferral of safety-critical projects is inappropriate, so these projects are afforded highest priority in the optimisation process.

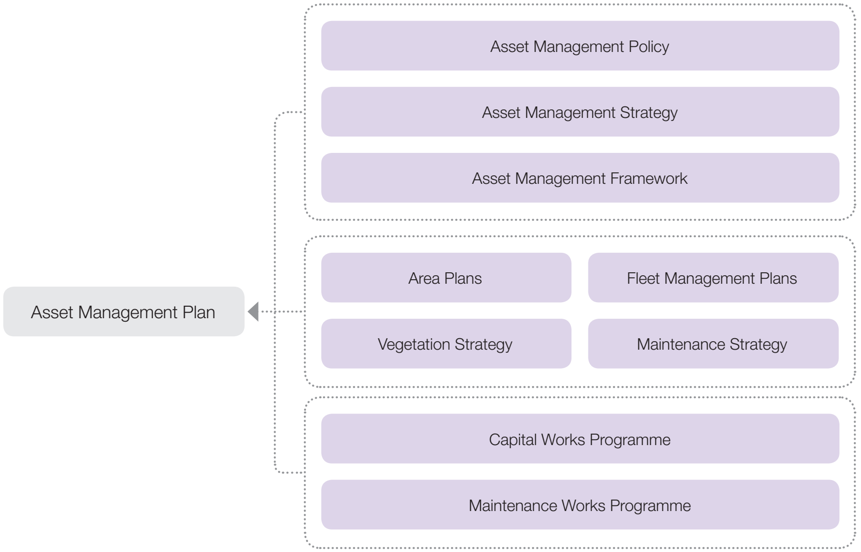
In addition, our forecast expenditure is tested against funding arrangements prior to budget commitment. This includes comparisons to revenue allowed under the DPP.

5.5.6 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, and aims to meet our Information Disclosure obligations.

It summarises our internal asset management documentation as depicted below.

Figure 5.6: **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 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.

5.5.7 ANNUAL ELECTRICITY WORKS PLAN APPROVAL

Responsibility for preparing the draft EWP lies with our Planning and Service Delivery teams. The former owns the plan, while the latter provides advice on deliverability, outage planning and resource availability.

The draft plan is prepared by our planning managers in consultation with the Asset Strategy and Service Delivery teams. 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 CEO.

The annual electricity budgets are based on the EWP. This budget is subject to challenge by the Board, which ultimately approves it.

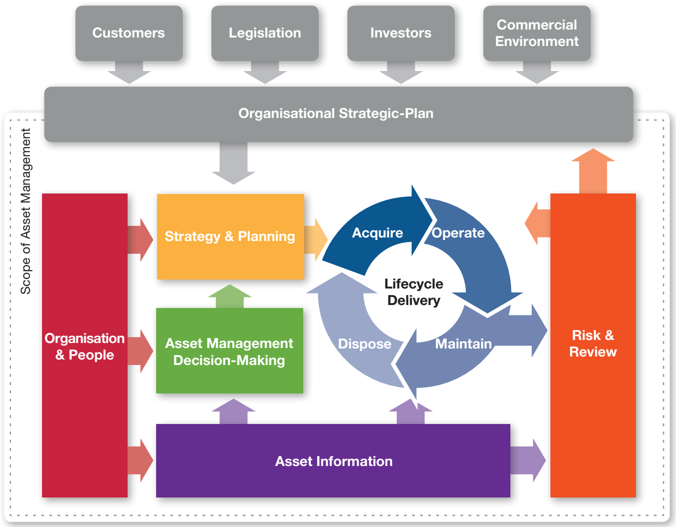
5.6 LIFE CYCLE APPROACH TO ASSET MANAGEMENT

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.

5.6.1 GENERALISED LIFE CYCLE APPROACH

The figure below depicts a generalised asset life cycle shown in the context of the larger asset management model.

Figure 5.7: **Asset management life cycle in the larger asset management context**[5]



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There are a number of key life cycle based considerations when undertaking asset management activities. Below we list some of the aspects considered as part of our decision-making.

- Decisions made at the concept and planning stages of an asset's life will have a major bearing on its practical and safe operation.
- The value of an asset is 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 involves 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.
- Complex decommissioning and removal of assets can burden future asset managers if this has not been considered and prepared for from the outset.

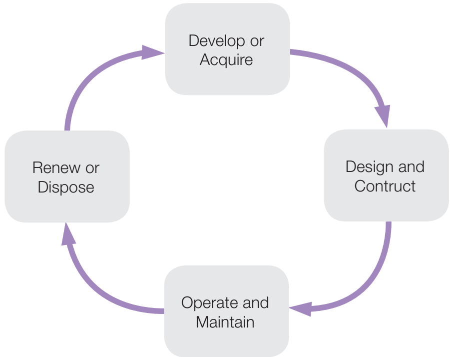
The remainder of this section discusses the importance of effective asset management governance throughout the full life cycle.

[5] Source: The Institute of Asset Management, "An Anatomy of Asset Management", July 2014.

5.6.2 OUR INTERPRETATION OF THE ASSET LIFE CYCLE

While our lifecycle stages are broadly consistent with the above model, we have adjusted them to better suit an EDB. Our interpretation of the life cycle is shown below.

Figure 5.8: **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. Our interpretation of the asset life cycle is discussed further in Chapters 8 and 12.

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 Service Delivery teams. New assets are mainly constructed to address:

- Network growth and security (discussed in Chapter 8)
- Network enhancements (discussed in Chapter 10)
- New customer connections (discussed in Chapter 9), and relocations of existing assets (addressed in Chapter 21)
- Future network needs (discussed in Chapter 11)

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 12 and 14-20.

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 13.

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 12 and 14-20.

5.6.3 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 our asset strategies

- Developing our asset strategy 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.
- We have to consider the evolving nature of the electricity industry, what future networks may look like and the associated network services and asset solutions. Again these new developments require a long-term view across the asset life cycle.

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 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.
- Assessing the impact of maintenance standards is a core design function and can only be effective if done in close consultation with the Service Delivery team. These standards have a major impact on the operational costs of assets and the performance of assets over their lives.

Construction

- 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.

Performance analysis

- 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.

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 that 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 that 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.

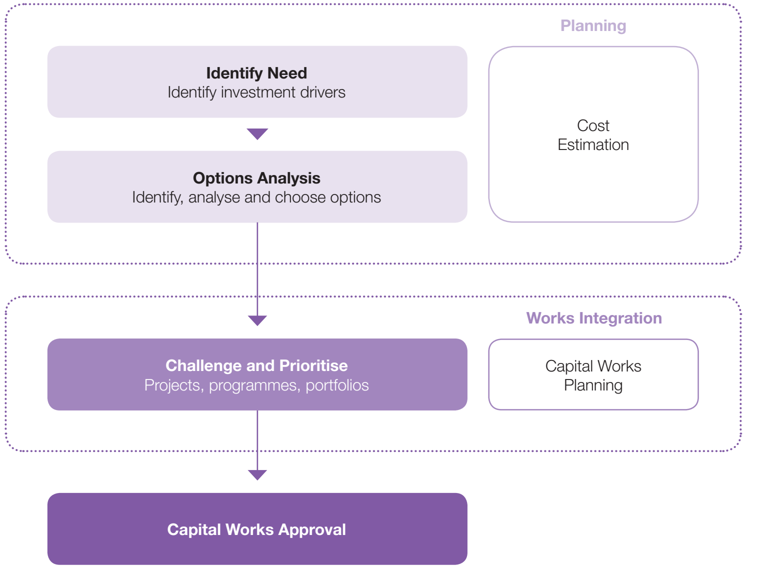
5.7 INVESTMENT PLANNING

In this section we describe our approach to planning capital investments on our network. It sets out the activities and processes we employ to ensure that our investments prudently support our asset management objectives.

5.7.1 ELECTRICITY WORKS PLANNING

The overall planning approach is referred to as our electricity works planning process. The approach includes needs identification, options analysis, approvals, and how we deliver these in an integrated manner. The process is depicted in the next figure.

Figure 5.9: Electricity works planning process



These activities primarily occur during the Develop or Acquire phase, although they are often used as part of our renewal decision-making process.

5.7.1.1 PROCESS STAGES

The main stages of this process are set out below.

- **Needs Identification** – we undertake Capex investments in response to a number of drivers, including asset condition, network demand, obsolescence, and the need to minimise safety risks.
- **Options analysis** – following identification of a need we consider potential solutions to address the underlying driver.
- **Works integration** – Capex works are prioritised within and across fleet management portfolios based on factors such as relative asset criticality and the impact on asset health.
- **Approvals** – a robust final approval process is undertaken before handover to delivery.

Below we provide further detail on these processes and how they are implemented.

5.7.1.2 SUPPORTING PROCESSES

There are a number of supporting processes that underpin the above processes. These include our overall governance discussed in Section 5.5.

To ensure we are making prudent choices and delivering value for our customers it is important that we effectively estimate the likely cost of planned investments. To support this, we have developed a cost estimation process that provides consistent and robust cost estimates when evaluating possible solutions and forecasting future expenditure needs. These estimates are also used to inform our tendering processes. Our approach to cost estimation is described in more detail in Chapter 24.

5.7.2 CAPITAL INVESTMENT CATEGORIES

To be consistent with Information Disclosure requirements, we use a set of categories to report our capital investments. Below we explain the main ones relevant to this planning period.

- **System growth** – capital investments in new or upgraded assets that provide additional capacity and/or network security. This is discussed in Chapter 8.
- **Asset replacement and renewal** – capital investments renew our fleets by replacing assets or through refurbishments that extend the life of existing assets. These investments are discussed in Chapters 14-20, which summarise our Fleet Management Plans.
- **Reliability, safety and environment** – capital investments are managed as part of our fleet management processes but are separately identified to reflect their particular drivers. These investments are also discussed in Chapters 14 20. This includes our automation programme, discussed in Chapter 10.
- **Asset relocations** – investments generally facilitate works by third parties, particularly road-related projects. The majority of these costs are met by the customer making the request. These investments are discussed in Chapter 21.
- **Customer connections** – investments meet requirements specified by a customer. A portion of these costs are met by the customer making the request. These investments are discussed in Chapter 9.

5.7.3 INVESTMENT DRIVERS

Our network Capex needs result from a range of investment drivers. The extent to which individual drivers or needs are directly relevant to specific Capex investments will vary. In many cases, multiple drivers may be relevant to a particular investment. In such cases we associate the investment with the primary driver. Also, certain needs are more likely to drive specific Capex categories, for example, the risk of asset failure is generally linked to asset replacement and renewals.

The main investment drivers for network Capex over the planning period are set out below.

- Safety
- Asset health
- Service performance (including demand growth)
- Third party requests
- Future networks

The extent to which these drivers are considered will vary, with no driver in isolation providing a definitive indication of when investments may be required. Below we explain these in further detail and provide relevant examples.

Safety

Safety is our fundamental organisational value and will be a key driver for 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 the last remaining oil-filled switchgear, which could pose an arc flash risk.

Asset health

For a number of our fleets we have developed asset health indices (AHI) to better reflect likelihood of asset failure. These are used to estimate remaining life on a consistent basis across fleets. AHI is used to inform levels of investment within portfolios and between portfolios. AHI is estimated using a number of factors including:

- The condition of the asset
- Survivor curves
- Its age relative to typical life expectancy
- Known defects or 'type issues'
- Factors that affect the rate of degradation, such as location

Asset health is the main driver behind our asset replacement and renewal investments.

Assets in poor condition are at increased risk of failure, leading to additional reliability and safety risks. We categorise poor condition assets as defects, which are scheduled for renewal through defects management processes. We also use asset condition to forecast our investments based on the expected remaining life of an asset.

One of our largest Capex programmes in the next planning period will undertake required pole renewals. The timing and scale of these investments is based on known defects and AHI informed by survivor curves.

Service performance

Consistent with our "Networks for Today and Tomorrow" objectives we are committed to providing services to our customers that meet their expectations. In terms of investment drivers, there are three key aspects impacting our forecast expenditure during the planning period:

- **Demand growth** – investments ensure our assets can reliably meet forecast increases in customer demand over the planning period. These investments are informed by our demand forecasting process discussed in Chapter 8.
- **Security standards** – inform investments that manage the overall security and resilience of our network. These investments impact the level of redundancy on our network and are based on the standards described in Chapter 8.
- **Reliability** – investments seek to manage aggregate network reliability levels as measured by SAIDI and SAIFI. In addition, they are triggered by specific issues on the network, including addressing worst performing feeders. These investments are mainly discussed in Chapter 10.

Examples of service performance-driven expenditure include the upgrade of overhead lines in the Coromandel region and reinforcements of the Palmerston North CBD. In addition, some of our renewal works take into account historical outage rates caused by equipment failure, e.g. crossarm replacements.

Third party requests

Bulk connections (residential and small commercial) are processed by our Commercial team. Forecast connection expenditure is based on expected population growth prepared by local councils, also influenced by demographic and economic factors supplemented by knowledge of particular developments and subdivisions.

Relocations are often requested by NZTA, Kiwirail and local councils. We work with these authorities to relocate electricity assets as required.

Future networks

In Chapter 11, we discuss the implications of changing customer requirements and new technologies on the future electricity network. Investments in future-proofing our network, such as establishing network-wide communications links, or proving concepts for new network solutions, are an integral part of our investment during the planning period.

5.7.4 NEEDS IDENTIFICATION

Identification of necessary capital investments is an ongoing process across our business. Timely identification and analysis of these needs is a key asset management discipline. We identify network Capex needs through a number of activities, including asset condition monitoring, network studies, technology assessments and safety reviews.

We place a large emphasis on potential safety-related investments to help manage this key risk area. These are identified using various information sources, including field inspections, review of health and safety incidents, and the experiences of peer utilities.

5.7.5 OPTIONS ANALYSIS

Once Capex needs are identified we begin to consider potential solutions to the need. The number and type of solutions (or options) that are considered will vary depending on the type of investment: for example, whether the Capex is driven by security constraints or asset failure risk.

We describe the process used to assess alternative options and choose a preferred solution as 'options analysis'. Options analysis follows the same generic process though there are differences between approaches for certain investments. However, it generally includes technical studies, economic assessments and risk analysis. The process may also include stakeholder consultation.

Below we discuss the approaches used for our two main categories during the planning period, asset replacement and renewal (ARR) and network development.

Asset replacement and renewal

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 AHI, our analysis includes estimating the future health of assets based on various 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, e.g. failure risk, is addressed by each option, including a status quo or 'do nothing' option.

Network development

The options analysis approach for network development is commensurate with the size and complexity of the project. To guide this process and to ensure works receive an appropriate level of analysis we have defined three categories based on the scale and complexity of the work.

- Major – Individual projects over $5m
- Minor – Individual projects between $1m and $5m
- Routine – Smaller, usually recurring works with an individual value below $1m

For major projects, options analysis will include developing a long list of all potential options. The long list of options generally includes a mix of the following.

- Non-network solutions such as demand response or generation[6]
- Enhancements to existing assets
- Creation of new assets
- Operational solutions such as special protection schemes

The list of options is reduced to a short-list by applying specific criteria. These include whether an option addresses the identified need, is feasible (commercially and technically), and can be reliably and safely implemented in sufficient time to meet the need.

Having developed a short-list, we confirm the suitability of each option to fully meet the need, including operational and maintenance requirements and construction feasibility and timeframes. We also complete a high level scope for each option to determine a cost comparison.

For minor projects we apply the same principles, but modify the level of analysis according to the size of the investment. Where appropriate, routine works are considered as a programme for the purposes of options analysis.

5.7.6 WORKS INTEGRATION

Following the selection of preferred solutions we then prioritise these within fleets, and across expenditure categories. This works integration is done using a range of techniques to assign relative priorities to the individual projects.

The proposed set of projects in a portfolio are reviewed, challenged and approved by the relevant portfolio owner who has specific asset management knowledge and expertise in their portfolio. The methods used to prioritise projects will vary by fleet and expenditure type and are discussed in the relevant expenditure chapter.

Works integration is a continual process that ensures we reflect changing priorities, including any changes in key investment drivers and resource availability. This is also required to address changes to the asset base (including asset failures) and to allow us to effectively respond to unforeseen events such as needing to replace equipment damaged in storms.

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 noted below.

[6] Where these can be cost-effectively and reliably introduced as an alternative to a conventional network investment.

- **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.

5.7.7 APPROVALS

As projects move through the approval process they are subject to our governance processes. The confirmation of individual projects is undertaken using a staged approval process (see Section 5.5.4). Each of these stages culminates in an effective ‘go/no-go’ decision that determines whether a project will proceed to the next stage. These decisions are based on factors such as project cost, risk, and feasibility. As discussed above they are decided at an appropriate management level based on the expected expenditure and complexity of the project.

Our Capex forecasts for the planning period have been built on a ‘bottom up’ basis where identified projects have been aggregated before being challenged and approved. This ensures that forecasts have been derived in a systematic and rigorous manner, and have undergone appropriate scrutiny.

5.8 WORKS DELIVERY

Our asset management objectives require us to design and construct a safe, reliable, efficient, and serviceable network. To achieve this, we have adopted a model that focuses on good industry practice. The Design and Construct phase of the asset life cycle involves in-house engineers and designers, NOC staff, and approved contractors who carry out the physical work on the network.

We have developed a number of design and construction objectives and initiatives that flow from our asset management objectives. These are detailed and discussed below.

- **Safety-in-design** – supports our Safety and Environment objective.
- **Competency** – reflects our commitment to safety, we and our contractors work within a suite of industry recognised competency standards and qualifications.
- **Field delivery partnership** – we rely on a strong relationship with our field operations contractors. This interaction contributes to the delivery of projects on time and within budget. There will be a need for more contractor resources as the scale of our investment grows.
- **Approved equipment lists** – simplify the design and construction process. It streamlines the purchasing process and contributes to our Asset Stewardship objective. This is discussed further in Chapter 12.

- **Post commissioning feedback** – is used to gain valuable insights as to whether our design and construction methods could be improved.
- **ISO 55000 Certification** – to be achieved by 2022.

We continually refine our design and construction process to be as efficient and effective as possible. In the past few years this has included changing from an ‘alliance’ outsource model to a fully contestable model and bringing more design work in-house.

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.

5.8.1 OVERVIEW OF PROCESS

The delivery process is managed by our Service Delivery team, which specialises in procurement and project management of external service providers. The process includes the following key activities.

- **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.

These processes are described in more detail below.

5.8.1.1 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.

5.8.2 DETAILED DESIGN

Detailed design builds on the high level design work undertaken during cost estimation and options analysis. The output of this process is a completed detailed design for the works, budget breakdown, and tender documentation.

Analysis during detailed design extends to areas such as safety, constructability, operability and planned outage requirements. This includes identifying and addressing construction risks.

For minor and routine works, the design is straightforward, so is completed by the selected service provider after the tender process. For other works, detailed design occurs before the tender is awarded because it is needed for tendering.

5.8.3 TENDERING WORK

Our construction process is an outsourced activity. We operate a long-term contract model for faults, maintenance and minor capital works, and a more traditional principal contractor model for major capital works, which are tendered job by job. This means that about 80% of our capital work programme has been subject to some form of market testing.

Outsourcing has the major benefit of keeping downward pressure on costs through commercial tension. We recognise that to maximise this tension in contracts, we must adopt a model that facilitate service provider viability. We have also become more sophisticated in the incentives and controls we put in place to manage our service providers.

Major contracts and some minor works are delivered to the secondary market. Minor works help secondary service providers maintain a high utilisation rate, which in turn helps maintain competitive pricing.

We run a closed tender process, offering work to only those contractors that are pre-approved. We use a FIDIC[7] template for the tender process, and a standard evaluation form is used to assess each tender. The evaluation form varies across work types, although several key criteria such as safety performance are consistent.

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. Once the bids are received, we negotiate the main terms of the contract with the preferred bidder. If none of the bids are satisfactory we reissue the tender.

5.8.3.1 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.

5.8.3.2 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, and at the individual level to ensure they are competent to complete the tasks and work on the network as safely as possible.

Project 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 Service Delivery team is tasked with delivery of the works programme, and its staff are competent and experienced at the management in 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.

Materials procurement

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.

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 commissioning process is controlled by NOC, with the support of the Service 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, confirming that 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.

5.8.4 ENSURING DELIVERABILITY

Deliverability in this document refers to all areas that impact our ability to implement our investment programme. This includes our planning and project management functions, field resource availability, managing the network safely, and minimising the impact of our programme on our customers.

Our network investment over the planning period will increase in a number of areas, particularly renewals. While this is a significant change, we are confident that our governance and planning processes will ensure we can deliver our works programme in a safe and cost-effective manner.

[7] Based on material from the International Federation of Consulting Engineers.

5.9 INVESTMENT GOVERNANCE FOR NON-NETWORK ASSETS

We use separate but similar processes to govern our non-network investments. These include assets that support the operations 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.

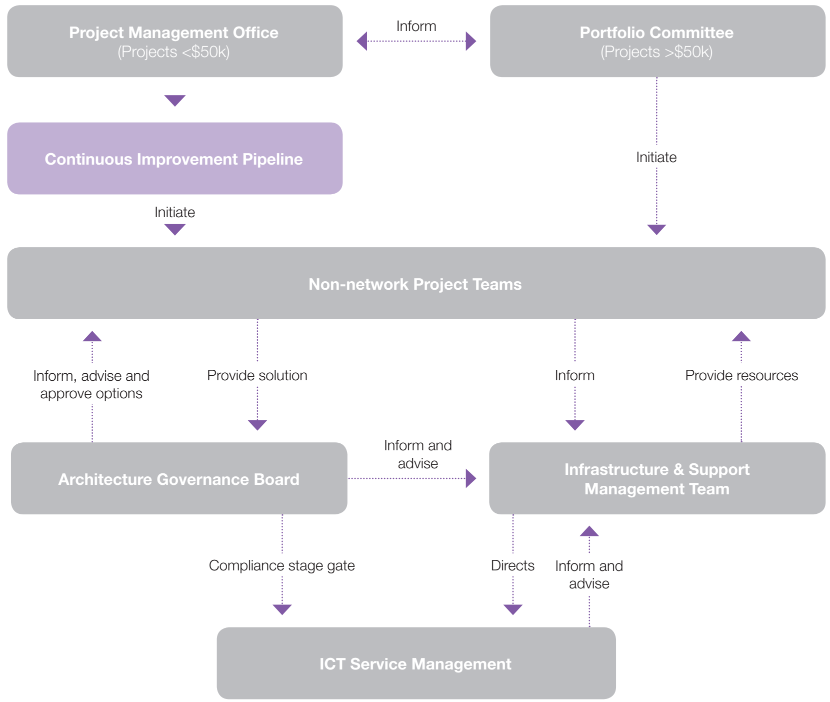
- Which initiatives complement our strategic direction?
- What are the right programmes/projects to do?
- How much change can the organisation absorb?
- Which initiatives are the most beneficial?
- What can the organisation resource?
- What can we afford?
- What are the risks and impacts?

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

5.9.1 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 is summarised in the diagram below. Their roles are explained in the remainder of this section.

Figure 5.10: **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.

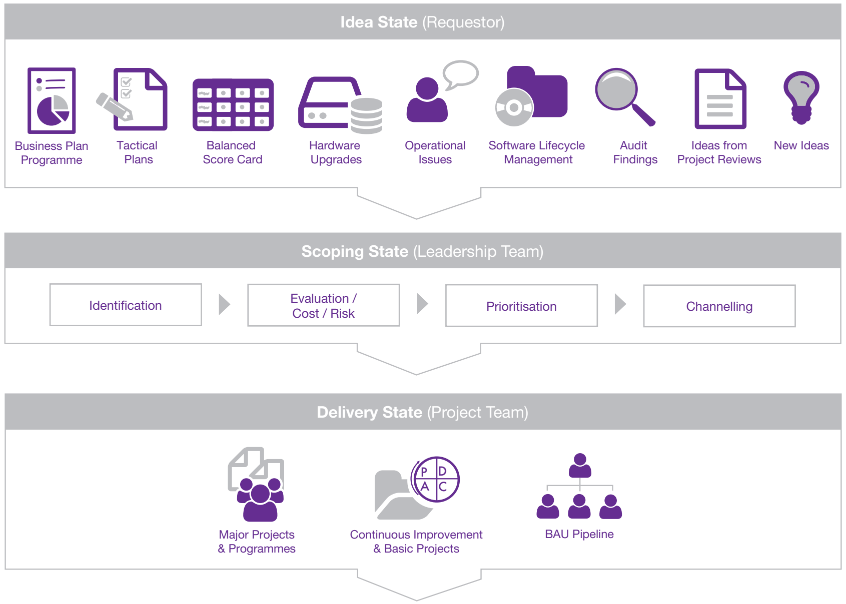
In addition, the Architecture Governance Board assesses the impact of technology change against the following criteria:

- 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

5.9.2 MANAGING CHANGE INITIATIVES

The diagram below provides an overview of catalysts for change initiatives, the phases they progress through, and how they are delivered into the organisation.

Figure 5.11: **Overview of catalysts for change**

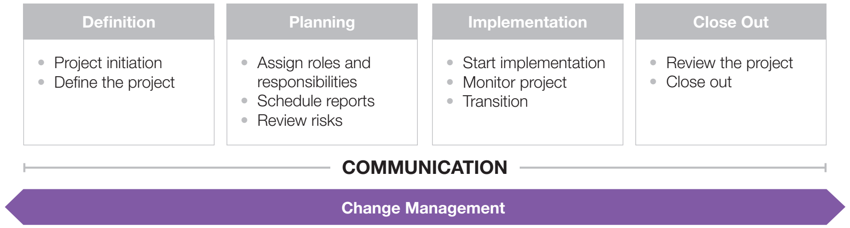


These are a number of possible change sources that need to be monitored as part of the 'idea state'. These are then assessed through the 'scoping state' where they are subjected to a staged review process by relevant staff and managers. Finally, chosen change initiatives are delivered through our project teams and overseen by our PMO.

5.9.3 PROJECT LIFE CYCLE

The following diagram illustrates a generalised project life cycle used in developing non-network solutions and assets. It includes the key activities undertaken during each phase. It highlights the importance of communications and effective change management throughout the process.

Figure 5.12: **Phases of project life cycle**



Further description of these processes and how they are implemented can be found in Chapter 22.

5.10 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, or managing procurement and delivery to ensure financial prudency. Managing these requires sound governance processes to direct effective procedures and controls.

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 to relevant standards.[8]

5.10.1 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.

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

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

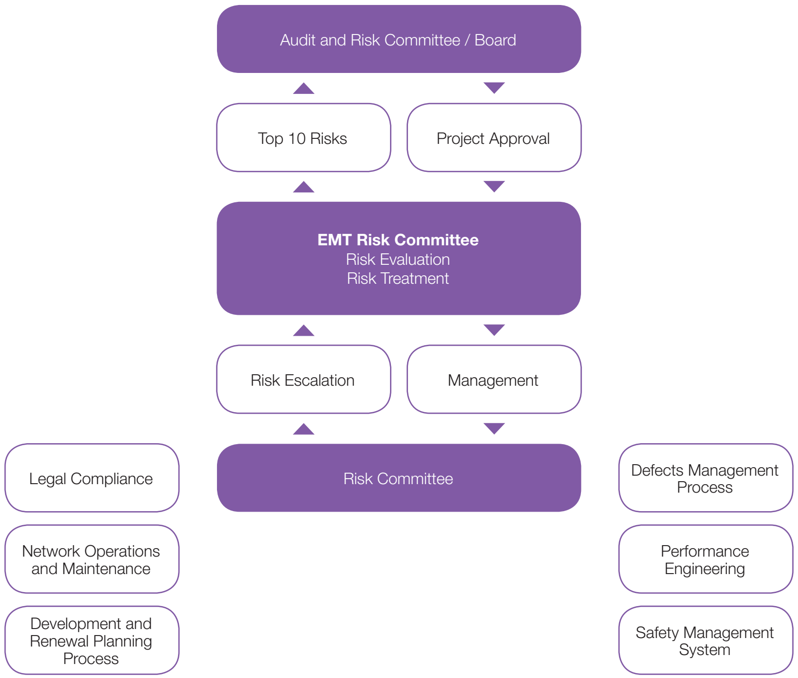
The framework we apply to identify, assess, treat, monitor and review risks is consistent throughout the business. The risk management process includes the following activities:

- **Identification** – of risks throughout the business takes place via workshops in which a variety of techniques are used e.g. 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, their 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 that 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 managements 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 the next figure.

Figure 5.13: **Our risk management process**



5.10.2 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 achieve the following outcomes:

- Ensure that 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 as at 1 March 2016 has been included in Appendix 6.

5.10.3 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 – from network architecture planning, 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.

- **Security standards assessment** – our works development process includes formal evaluation of our networks against our security criteria
- **Capacity assessment** – our demand forecasting processes review our networks against anticipated demand, given anticipated future loads
- **Poor condition/non-standard equipment** – our planning processes seek out critical items of equipment that are at higher risk of failure or are non-standard
- **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 to ensure key residual risks arising from our planning process are visible and signed off at an appropriate level

5.10.4 HIGH IMPACT LOW PROBABILITY (HILP) EVENTS

While we consider our network to be generally resilient to HILP events, there are certain scenarios that would escalate into this category if careful and selective risk management is not applied. Our network and processes have been designed to be resilient to HILP events that are outside our control, such as natural disasters.

The following aspects of our network and our asset management approach limit the consequences should these events occur.

- **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 resilience** – our facilities have been progressively upgraded to ensure resilience to earthquakes.
- **Multiple control options** – we have alternative control and emergency management capability available in the event that the New Plymouth facility is disabled.
- **Response plans** – we have well tested response plans and demonstrated capability to manage significant natural events and widespread damage to our networks.
- **Scenario testing** – we have completed a range of studies to understand the vulnerability of our network, including modelling the impact of a volcanic eruption and understanding the susceptibility of essential assets (such as our depots) to liquefaction.
- **Business continuity plans** – we have structured business continuity plans in place to ensure that the functional support aspects of our business are resilient and can support ongoing operations.

5.10.5 CONTINGENCY PLANNING

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 that 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, i.e. events that fall outside of the ordinary operation of the network.

The table below provides an overview of the main plans and procedures that support the effective operation of the electricity network in emergency situations.

Table 5.3: **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, e.g. 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 civil defence 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.

5.10.5.1 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

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.

SERVING OUR CUSTOMERS

This section explains how we plan to meet our customers' needs, now and in the future. It also sets out network targets for assessing our performance.

CONTENTS

6.1 CHAPTER OVERVIEW

This chapter provides an overview of our customers[9] and our strategies for meeting their needs. We exist to serve the needs of our customers, and so their opinion matters to us.

This chapter explains who our customers are and what they care about. It explains how we actively engage with them to understand what they value. It sets out what they believe we do well, and where they are seeking improvement.

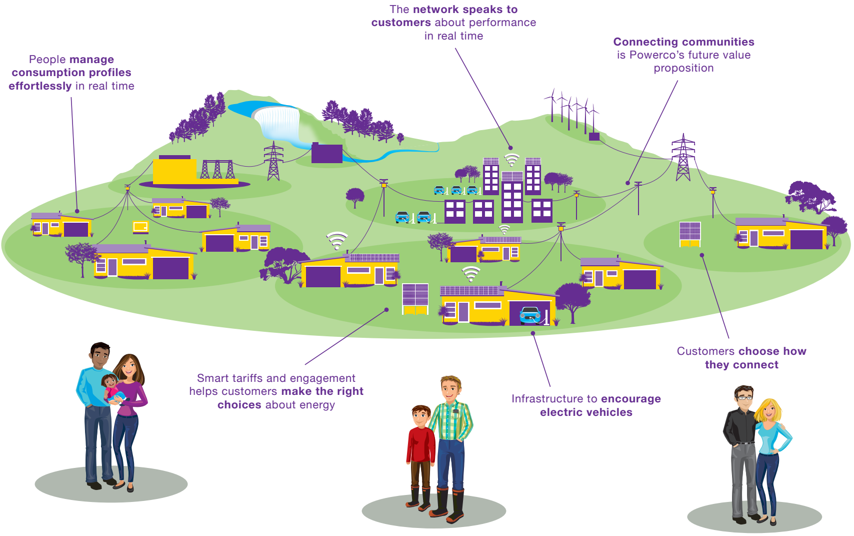
We have used the insights received from customers to inform and test our objectives and investment plans for the planning period. Throughout this chapter we explain the links between what our customers tell us and our objectives.

Finally, the chapter describes our strategy to redesign how we interact with our customers. Through this we can develop better insight into their expectations and requirements in a rapidly changing energy market.

6.2 OUR CUSTOMERS

Electricity is an indispensable part of modern economic and social life. As use and dependence on electricity has grown, so too has our customers' expectation of the availability and quality of their supply.

Figure 6.1: **Changing customer expectations**



[9] 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.

In addition to excellent customer service, customers increasingly expect high quality, timely information on their service. If we are to continue meeting these requirements, it is crucial we fully understand the services our customers require and what value they place on these, now and in the future.

6.2.1 CUSTOMER OVERVIEW

We are proud to serve over 600,000 New Zealanders, supplying power to over 325,000 installation control points (ICP). 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
- 326,941 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.

Table 6.1: **Number of customers (ICPs) and electricity delivered (2015)**

CUSTOMER TYPE	ICPS	% OF TOTAL ICPS	ELECTRICITY DELIVERED (GWH)	% OF TOTAL ELECTRICITY DELIVERED
Mass market	325,122	99.4	2,574	66.1
Commercial	1,238	0.4	1,084	6.0
Large commercial / industrial	581	0.2	1,084	27.9
Total	326,941	100%	3,891	100%

Our customers are distributed relatively evenly across our network. 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.

6.2.2 MASS MARKET CUSTOMERS

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. Mass market customers typically want a bundled energy supply service, and sometimes do not fully understand the structure of the electricity industry, or our role within it. However, they are clear on the level of service they require.

From our engagement, we've found that residential customers' reliability expectations vary. It can depend on where the customer lives (rural or urban) or their recent experiences of reliability. We find that most customers accept occasional power cuts, and our ability to keep them informed when these events occur is most important. Ensuring good customer service and reliable, effective information flow is therefore a priority.

Growth in our mass market consumer base is closely tied to population and is regionally diverse. Tauranga has been our strongest growth area, supported by inward migration alongside increasing economic prosperity.

Over the past three years, growth in customer numbers 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 9.

We use a number of techniques to effectively engage with our mass market customers. These are discussed in Section 6.3 below.

6.2.3 COMMERCIAL AND INDUSTRIAL CUSTOMERS

We have over 1,200 medium-sized commercial customers. A further 581 customers have demand greater than 300 kVA. These latter customers are classed as large commercial and industrial due to their demand. Together these customers only account for 0.6% of our ICPs, yet consume 34% of the electricity we deliver.

These customers range from medium-sized retail and dairy producers through to food processing, ports, and large manufacturing. Growth in these sectors is closely tied to general economic growth (indicated by GDP), and growing exports from these industries. As an example the kiwifruit sector has grown strongly as the industry recovers post-PSA.[10] This also creates growth in secondary processing and support sectors.

Depending on the timing and degree of notice provided service interruptions can have significant operational and financial impacts on our commercial and industrial customers. We aim to provide earlier notice, with increased engagement on preferred timing, to these customers.

Given the size and complexity of their operations, our larger customers often have more specific service requirements than the mass market. We prioritise open dialogue with our large customers to ensure we understand their businesses and drivers so we can better meet their specific supply requirements. We engage directly with them on their future investment and production plans, as increases in their capacity needs can have implications for our growth and security investments. A number of investments during the planning period have been informed by such discussions, and are further discussed in Chapter 8.

Given the importance of these customers our regional account managers work closely with them. We have a key customer manager who works with our largest 30 customers. More information on our large customers is provided in Appendix 4.

6.2.4 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 Energy 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 ensures they can provide a quality bundled service to customers and seamlessly resolve any supply issues on their behalf. Working with retailers to ensure a simple and effective energy supply for customers is a key part of what we do.

[10] PSA is a bacterial disease which affects kiwifruit vines.

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.

6.2.5 ELECTRICITY GENERATION

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 1,400 distributed generation installations of less than 1MW capacity connected to our network. The combined capacity of these smaller generators is just over 8MW. 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. We understand that customers planning to use SSDG would prefer immediate connections. However, such installations need to be processed in a robust and auditable process.[11]

Distributed generation has the potential to introduce congestion where generated output approaches distribution transformer capacity. This requires formal engineering investigations at some sites to ensure network stability and public safety. As prices of PV and inverter technologies drop and more providers enter the market, we will see connections and service expectations rise. We are committed to future-proofing our network and streamlining our processes to meet this demand.

6.2.6 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 in Chapters 9 and 21.

6.3 WHAT OUR CUSTOMERS VALUE

As discussed earlier, we have a diverse customer base, with residential, commercial, and industrial customers across a large area of the North Island. This diversity means that what customers value will differ from group to group.

To better understand what our customer groups value, we actively engage with them to capture their preferences. We then use this information to inform our asset management decision-making.

6.3.1 OUR CURRENT APPROACH TO ENGAGEMENT

Although we are interposed with retailers, we engage with customers across a number of channels as a means of gaining insight into their preferences and understanding what they value. The channels range from face-to-face discussions to targeted and self-selected surveying techniques. A summary of our engagement approaches are listed below.

Agricultural field days, expos and trade shows – each year we have stands at the Mystery Creek and Central Districts agricultural field days. We also attend various expos and trade shows across our network area. Attending these events provides customers with an opportunity to have face-to-face discussions with our staff. This allows for a highly constructive exchange of information.

Commercial and account management interactions – we employ a team to maintain regular dialogue with our larger commercial and industrial customers so we remain well informed of their needs, plans, and expectations.

Surveys – we survey customers face-to-face, online and by post about the quality and price of their electricity supply. Each year we survey around 5,000-6,000 customers.

Stakeholder meetings and focus groups – we regularly meet with key stakeholders and customer-representative groups. These include Federated Farmers, Chambers of Commerce, and territorial local authorities. We also hold focus groups, which provide us with valuable insights on different customer demographics.

Website and phone – our website and free phone number – www.powerco.co.nz and 0800 POWERCO (0800 769 3726) – allow customers to easily contact us and provide feedback.

Consultation documents – we produce documents, like this AMP, to keep stakeholders and customers informed and to generate discussion.

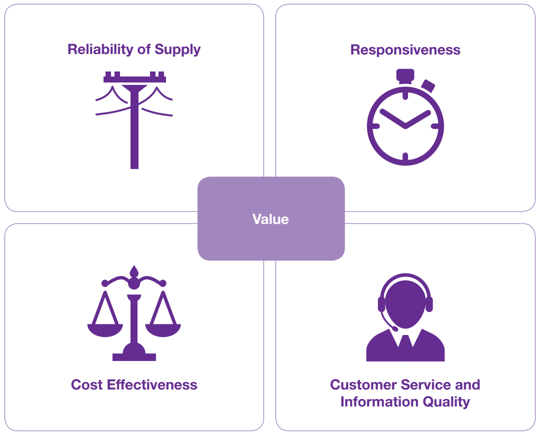
[11] Including requirements set out in Part 6 of the Electricity Industry Participation Code.

Community-wide consultation – to address specific regional issues. Their purpose is to seek feedback on specific major projects or for regional, medium and long-term network development plans. Campaigns involve a mixture of the above engagement methods, in addition to media advertising and information kiosks.

Consultation videos – we have developed a set of short educational videos and published them on YouTube to help customers understand our industry and facilitate more meaningful feedback.

Through the results of these engagements, we have developed a picture of what customers generally value most. The four key themes are shown below.

Figure 6.2: **What our customers value**



We have developed performance targets that reflect these aspects of our service. These targets are discussed in Chapter 7.

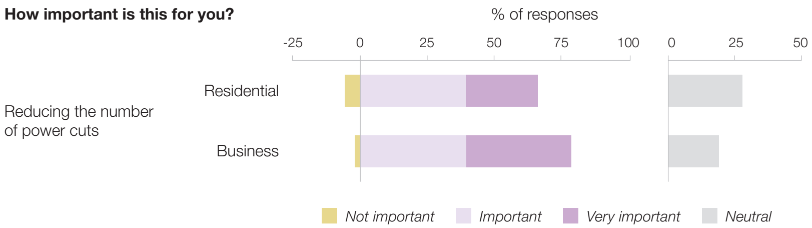
6.3.2 RELIABILITY OF SUPPLY

Delivering electricity safely and reliably is our business. We know how important both of these aspects are to our customers. As safety is paramount in everything we do, we treat it separately from these other aspects of value.

Reliable supply is hugely important to electricity consumers, a fact underlined by the importance of SAIDI and SAIFI in the DPP regime.[12] We know from customers (see next chart) that this is especially true for certain groups such as businesses.

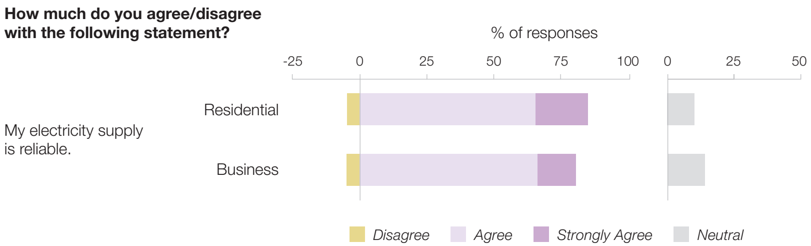
[12] SAIDI and SAIFI are explained in Section 7.4.1.

Figure 6.3: **Customer feedback – reducing outages**



We continually focus on ensuring 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, as shown in the chart below.

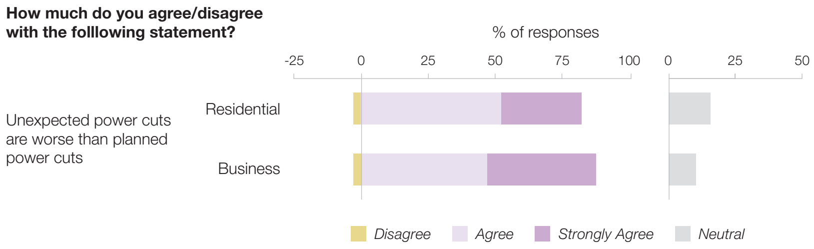
Figure 6.4: **Customer feedback – reliability of supply**



Reliability is maintained by our teams of skilled engineers who study our network and its assets looking for potential issues. Once these are identified we consider options to ensure they do not impact our customers. As discussed in Chapter 5 we then make decisions on how to prudently intervene such as upgrading or replacing assets. While this is a complex and often labour intensive activity, it is essential if we are to meet our customers' reliability needs. Over the planning period, we will lift capability in this space (discussed further in Chapters 11 and 23).

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. To avoid multiple planned outages in an area we optimise our resources and adjust the timing of work to ensure we can undertake multiple jobs in parallel.

Figure 6.5: **Customer feedback – planned versus unplanned outages**



In our latest survey, we found that 81% of residential respondents and 87% of business respondents felt that unexpected outages were worse than planned outages. This reflects the importance of addressing asset issues (such as defects) before they result in a failure, even if the work involves a planned shutdown. Our investments over the planning period seek to avoid such asset failures and ensure unplanned interruptions do not increase.

How this informs our asset management objectives

Networks for Today and Tomorrow: We will manage unplanned interruptions by prioritising network reinforcements and renewal investments with greater reliability benefits.

6.3.3 RESPONSIVENESS

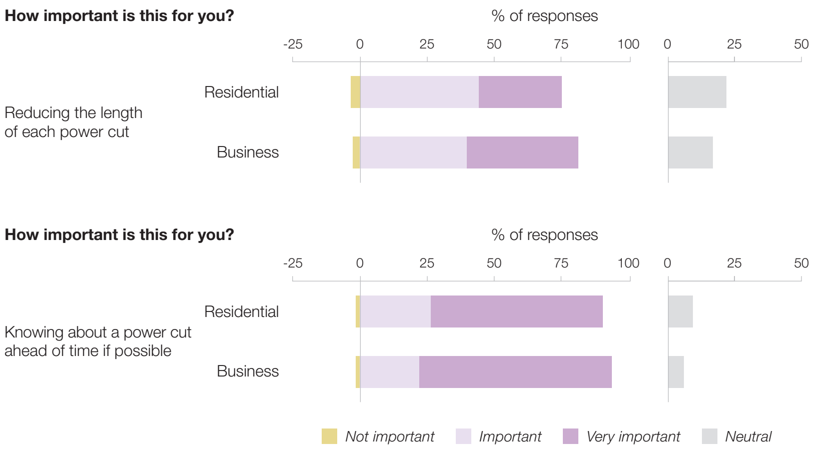
Responding quickly to issues on our network is key to reducing their impact and lessening potential safety and reliability risks. This is achieved through coordinated activity by our operations teams and our service providers.

Our NOC is staffed 24 hours a day, seven days a week, 365 days a year. If supply is interrupted unexpectedly, we respond by restoring it as quickly and safely as possible. Our NOC operators are in constant contact with field staff when supply needs to be restored. We collect information to help us reduce the risk of future outages. This includes recording what caused the power cut, what areas were affected, and for how long.

Unplanned outages occur for a variety of reasons. Some of these 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 within our control are easier to foresee and prevent, and we do everything we reasonably can to eliminate them. We are also focused on implementing strategies to minimise affected areas and repair times in the event of an outage.

The following figure highlights relevant customer feedback from our latest survey.

Figure 6.6: **Customer feedback – responsiveness**



Below we discuss how we plan to respond to some of the main interruption causes within our control.

- **Asset failure** – equipment failure accounts for a significant number of outages each year. Over the planning period we plan to invest significantly in renewing assets in poor condition that have elevated risks of failure.
- **Vegetation** – tree contacts are responsible for an increasing number of outages. As discussed in Chapter 13, over the planning period we will expand our tree trimming activities and improve how we interact with tree owners.

Understanding the nature of these events, their causes and how to prevent them will be a key focus for us during the planning period. However, when failures occur our main focus will be to restore supply as quickly and safely as possible.

How this informs our asset management objectives

Customers and Community: We will reduce the impact of outages by improving our fault response capability so that supply is restored quickly and safely.

Customers and Community: We will provide better, more timely information on planned and unplanned outages by adopting new communications channels.

6.3.4 COST EFFECTIVENESS

The electricity industry is structured in a way that means customers often do not make the association between their monthly bill and the cost of providing a safe and reliable distribution service. On average, about a third of every dollar in consumers' electricity bills goes towards the costs of distributing it.

Through engagement, mostly via surveying, we have found customers recognise the importance of investing in the network to ensure safety and reliability. Our discussions suggest customers expect us to invest appropriately to maintain reliability as well as focusing on defective equipment to prevent further outages. We will do so by renewing assets in poor condition that have elevated risks of failure.

The graphs below highlight relevant customer feedback from our latest survey.

Figure 6.7: **Customer feedback – price of electricity and line charges**

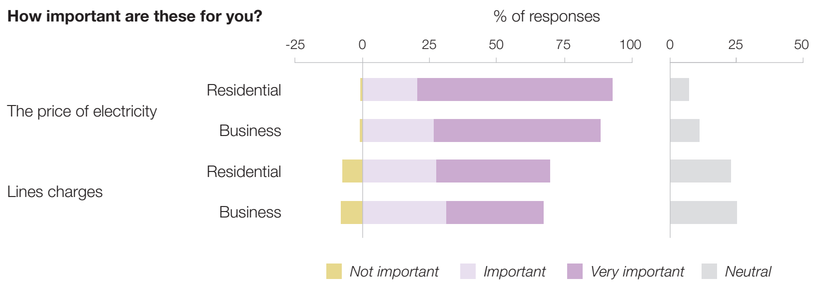
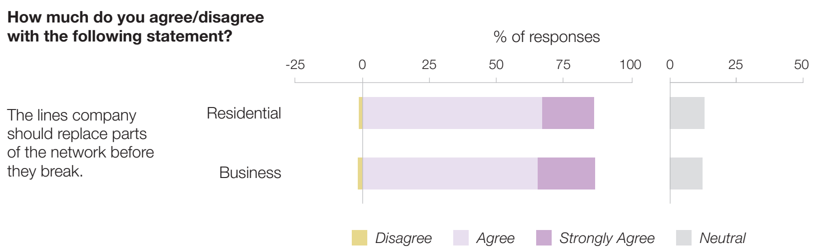


Figure 6.8: **Customer feedback – asset replacement**



Customers expect that our investments are prudent and appropriate to meet their performance expectations. They expect us to carefully evaluate our decisions so we optimise our investments and their underlying costs. As discussed in Chapter 5, we have a comprehensive set of governance arrangements that support our asset investment decisions. In essence, these make sure we do the right project, at the right time, for the right price.

How this informs our asset management objectives

Operational Excellence: Using our improved governance processes we will ensure our investments are prudent and benefit customers over the medium to long-term.

Asset Stewardship: Well targeted asset renewals will reduce asset failures and help ensure safe and reliable performance of our network.

6.3.5 CUSTOMER SERVICE AND INFORMATION QUALITY

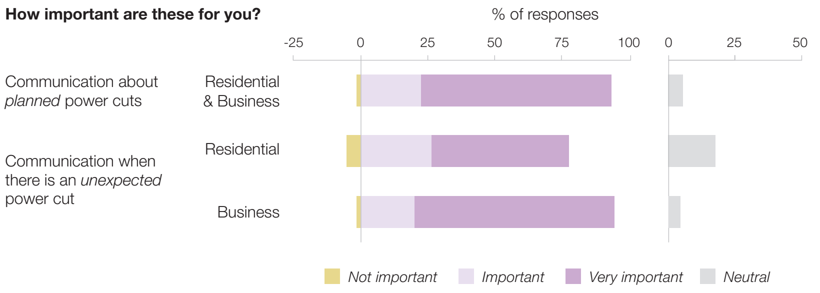
Our customers value timely and accurate information about their electricity supply. Society is increasingly dependent on data and information to make decisions about how to plan their lives and their businesses. This has been brought on, in part, by advances in mobile technology and social media. These have created an expectation that information should be readily available through a number of channels.

The way we interact with our customers is a key focus for us. The quality of our service during customer interactions will impact the perceived value of our service. These interactions include:

- Providing information on reasons for and likely duration of an outage
- Providing sufficient notice and information on planned shutdowns
- Connecting customers to the network
- Responding to queries or information requests
- Capturing feedback and timely complaint management

These more qualitative aspects of service are often very important to customers, as was evident in our latest survey (see next page). The most important aspects for residential customers was communication around power cuts. Information on upcoming planned power cuts was important to 90% of residential respondents. Information around unexpected power cuts was also highly valued by 78% of respondents. The results were similar for business customers who placed even greater value on each of these aspects.

Figure 6.9: **Customer feedback – communication about power cuts**



These results show that communication about power cuts is very important to our customers. From research, we have found the preferred channels of communication for planned outages are email, letters or texts. For unplanned outages texts, phone calls, and emails are the most valued channels. With advances in social media and digital interactions, we plan to adopt a wider number of communication channels.

Providing new and upgraded connections for customers is important to the communities we serve. Providing timely and cost-effective connections supports local businesses and residential development. Currently we connect around 3,500 new customers each year and make a similar number of changes to our network on behalf of customers and other stakeholders. These activities are discussed further in Chapters 9 and 21, respectively.

How this informs our asset management objectives

Customers and Community: We will provide better, more timely information on planned and unplanned outages by adopting new communications channels.

6.4 RESHAPING OUR CUSTOMER APPROACH

The electricity market is changing. As with other sectors, technology is making it possible for customers to access a more personalised experience when buying services and products. This, combined with new products entering the market, is driving consumers to seek out providers who personalise their experience to reflect the aspects they value, and can accommodate the choices they wish to make in the way they manage their energy.

We recognise the need to develop our approach alongside changing consumer expectations and allow these changes to guide us . We share a widely held view that energy markets will continue to evolve, and that our network will play a critical role in this change. We expect our customers to take up new opportunities to generate a proportion of their own electricity, share it at a local level, and access it from the grid as needed for new applications, for example for electric vehicles.

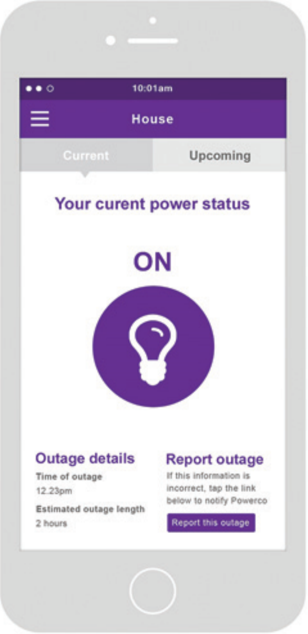
Our vision for the future is one where our network not only provides a safe and reliable link to existing electricity sources, but also helps our customers unlock more flexibility, competition, and value at a household level. Delivering this vision involves a much closer and detailed discussion with our customers. It is not appropriate for us to tell our customers how to manage their energy or limit their options. We must find a way to understand our customers and enable their needs. To reflect this, we use the terms *increasing insight,* and *building agility*.

6.4.1 EVOLVING CUSTOMER NEEDS

Customers will continue to value a reliable electricity supply. However, their broader needs around service interactions are expanding to include new areas.

While these changes are likely to stem from a number of areas, we believe that the following aspects will be most relevant to our customers during the planning period.

- **Access to information** – residential consumers' demand for near-instantaneous access to information and services in other industries, most particularly media and entertainment, is driving higher expectations.
- **New technologies** – will change the services that consumers require. Increased adoption of products such as micro generation, battery storage and electric vehicles is expected as their costs become more affordable.
- **Personalised pricing** – consumers expect to only pay for the services they receive and value the ability to respond to pricing through behaviours and activity. This will become increasingly important as new markets form around tailored energy needs and use of the grid to exchange energy.



- **Changing usage patterns** – changes in how we consume electricity (e.g. energy efficiency initiatives) mean that traditional tariff structures may no longer suit particular consumers.
- **Increasing reliability needs** – due to increasing commercial reliance on electricity consumers expect higher standards of reliability.
- **Small scale distributed generation** – the price of solutions such as PV continues to reduce increasing their viability for mass market consumers. These technologies may change how our customers use our services, and we will need to be flexible in our response.
- **Affordability** – is becoming an increasingly important issue particularly for vulnerable groups. The electricity industry has not seen the cost reductions available to other industries through advances in technology. To ensure long-term viability, EDBs will need to deliver the above innovations cost effectively, often against a background of ageing networks requiring increased renewal investment.

It is crucial we understand the services that households and businesses require and the value they place on these. We must then integrate their views into our investment planning process. Doing so will support our Customer and Community and Networks for Today and Tomorrow asset management objectives.

6.4.2 VISION AND APPROACH

The changing needs of our customers means it is vital to put them at the centre of our business. We intend to interact with them more often and more directly to ensure our investments meet their needs, and that we remain relevant to them. We plan to do so by increasing our insight into their preferences, and increasing our agility to respond to their preferences.

What we mean by insight and agility:

Insight: Intelligence about our customers that enables us to understand their preferences and inform our asset management and commercial activity.

Agility: Capability within our organisation to translate customer preferences into strategies to deliver new service offerings.

In combination, these two strategies will raise our relevance to our customers through increased value and improved service offerings.

6.4.3 INCREASING INSIGHT INTO OUR CUSTOMERS

Customer expectations around distribution services are evolving. While service interruptions remain a key service quality measure, customers now want to have access to more information, more options and greater flexibility. Our approach will be to learn about their preferences in a structured way and communicate them across our organisation. This will help us continue to make appropriate long-term investments and position ourselves to respond to customer needs.

We plan to increase our levels of insight by collecting information from customers about preference and needs, combining it with network information as well as other sources of data and then using it to inform other activities around the business.

We will do this by providing value through our interactions and by learning from customer feedback. This will be used to further refine existing interactions and explore new ones. We will target all our customer groups and provide a tailored service to each to ensure optimal value is achieved.

6.4.3.1 OUR PLAN TO GAIN NEW INSIGHTS

As other customer marketplaces evolve to provide a more tailored experience, we will need to consider the unique experiences and preferences of our customers when operating and developing the network. Our current approach does not differentiate individual customers but uses general groupings, such as residential, commercial, rural or urban. We then associate general characteristic to those groups. This limits our ability to target our offerings to specific needs.

To gain improved insight into our customers, we will need to develop our business across a number of areas.

- **Create a mechanism to personalise relationships:** A current barrier to developing insight into our customers is the interposed nature (via retailers) of our relationship with them. We will develop a customer facing “Powerco Hub” which will allow us to directly interact with customers on all distribution service interactions such as planned and unplanned outages, customer-initiated works, complaints and enquiries.

  The Powerco Hub will provide person-to-person interactions and use a number of digital channels such as mobile apps, social media and tailored web applications. This will enable our customers to engage with us through whatever medium best suits them. It will extend beyond the mass market consumer to our commercial and industrial customers where we will use both digital and personal interfaces to ensure we provide timely, accurate and personalised information. This will ensure our engagements are relevant and useful.
- **Develop new sources for insight into customer behaviour and preference:** We currently have limited understanding of how the mass market consumer uses the network. This is in part due to limited information available about energy usage in a customer’s home or business. Our future direction is to integrate new sources of operational data (such as smart meter and LV monitoring data) into our customer records to enrich our understanding. As new customer technologies such as smart appliances, electric vehicles and distributed generation/storage solutions become more popular, these too can be included in this data set to provide an even greater understanding and help us personalise our service offering.

- **Develop an understating of our customers and make it available across the business:** We are presently limited by a lack of individual customer records and identify the majority of our customers solely by their ICP number. We will centralise our customer information into a customer relationship management system. This will allow us to collect and manage a wide variety of customer information enabling us to tailor our services to them. Holding more detailed information on our customers will also allow more in-depth customer analysis.

  In tandem, these approaches will ensure that our customers value the interactions they have with us and provide us insight into their preferences to further improve our service offering.

How this informs our asset management objectives

Customers and Community: We will build a deep understanding of our customers' requirements and preferences, to improve the customer service, choice, and quality of service we offer.

6.4.4 THE NEED FOR AGILITY

The mass uptake of new technologies will change how customers use our network. They are increasingly expecting a more personalised and updated service offering. This poses a unique challenge and we will need to integrate our traditional network investments with the required agility to meet rapidly changing consumer expectations. The resulting 'store front' of offerings must be well integrated to existing systems and processes that naturally evolve at a slower pace.

6.4.4.1 HOW WE WILL INCREASE OUR AGILITY

We recognise that new energy technologies are entering the market at an increasing rate. Our network must enable customers to use these technologies to expand and diversify their energy use, and by extension expand their use of the distribution network.

To increase our agility, we will need to develop our business across a number of areas.

- **Trialling new distribution technologies that enable customers to use the network to meet their needs** – our network needs to be flexible so it can meet the future needs of our customers. This will involve understanding how the grid can be used to support various market models, such as solar sharing and peer-to-peer energy communities. In parallel, we will trial a number of distribution solutions to enable these markets to work. These smart network designs and solutions are further explored in Chapter 11.

  This will also involve expanding the design and application of our remote area power supply (RAPS) system. This solution enables customers in remote rural locations to receive reliability associated with living in an urban centre, reducing susceptibility to adverse weather and unplanned outages occasionally experienced in remote rural areas. RAPS is explained further in Chapter 11.

  As the number of smart devices increase on the network and in customers' homes, a richer exchange of information with these technologies will be required. This is beyond our current communications capabilities, which will need to be developed on certain parts of our network.

- **Creating pricing options that enable retailers and customers to personalise their service offering** – pricing that provides consumers with choice and incentives to positively change their consumption behaviour is important to ensure agility in our business. We are looking to provide stronger peak and off-peak pricing signals to help customers understand how their energy use relates to the investment needed on the network. In addition to this, we are developing new smart tariffs to cater specifically to new technologies. These new tariffs, combined with more specific demand signals, will provide customers with options to reduce their costs while helping us to optimise asset utilisation and defer network investment.

- **Understanding how new distribution edge technologies change energy use patterns** – as a first step, we need to understand how new edge technologies will change what is required from our network. These include products such as PV, electric vehicles, home automation, and energy storage. These products may change the pattern of peak demand and generate more two-way electricity flows within our network. We will collaborate with our customers to integrate this.

  We will also expand channel partner relationships with retailers, service providers and technology vendors to better understand how these new demand side technologies will evolve and interact with our network.

How this informs our asset management objectives

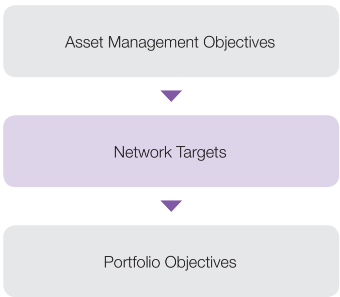
Customers and Community: our insight into our customers' requirements and preferences will be reflected in the excellent customer service, choice, and quality of service we offer.

7.1 CHAPTER OVERVIEW

This chapter sets out our network targets for the planning period. We use these to gauge our asset management performance, including how we are tracking against the asset management objectives discussed in Chapter 4.

We have revised and updated our targets to align them with our priorities for the period. While some of these may prove challenging, we are now building the capacity and capability to ensure they can be achieved. In particular, achieving our reliability targets will require significant investment during the planning period.

Figure 7.1: **Alignment of network targets**



The targets described below are categorised according to our asset management objectives – Safety and Environment, Customers and Community, Networks for Today and Tomorrow, and Asset Stewardship. This ensures our targets are aligned with our overall Asset Management System. Operational Excellence targets are set out in Chapter 23.

7.2 SAFETY AND ENVIRONMENT

As described in Chapter 4, protecting the public, our staff, our service providers and the environment from the inherent risks posed by our network is core to our business. The two overall objectives below guide our activities in this area.

Safety and Environment objectives

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

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

Under these objectives, we describe network targets under three categories – safety, environmental responsibility, and legislative compliance. Targets for these categories along with current performance are discussed in the following sections.

7.2.1 SAFETY

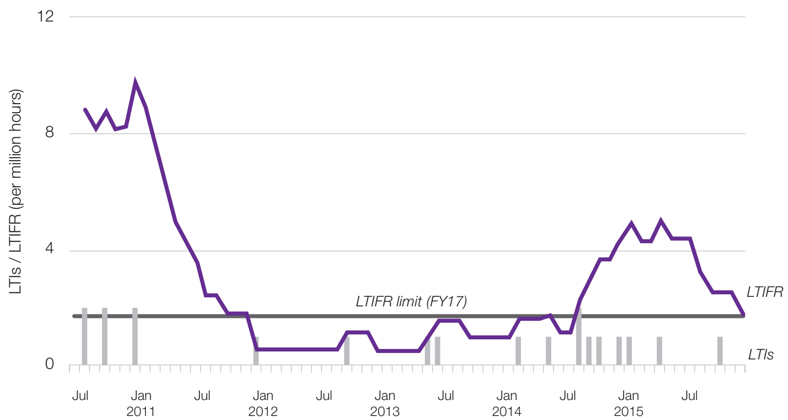
Our most important requirement is that our network assets are safe. Electrical equipment is inherently hazardous and is capable of causing serious harm, particularly if incorrectly managed. We are committed to preventing harm to the public, our staff and service providers. We are committed to continually improving the level of safety management applied to our network over the planning period.

Over the past decade we have ensured that safety is the primary consideration for everything we do. Initially we focused on improving the performance of our staff and the service providers who support us in building and maintaining our network. In recent years we have increased our focus on asset safety and public safety.

7.2.1.1 SAFETY PERFORMANCE

Our primary measure of safety performance is Lost Time Injury Frequency Rate (LTIFR).[13] Shown in the figure below is our LTIFR for the past four years, along with the associated lost time injuries (LTIs).

Figure 7.2: **LTIFR historical performance[14]**



Our LTIFR has reduced significantly from five years ago, reflecting our progress in improving safety performance and preventing harm to our staff and service providers. During 2014 we experienced several LTIs causing our LTIFR to temporarily increase above target levels. The number of LTIs has reduced over the past 12 months because of continued efforts by our staff and service providers to seek zero harm outcomes. As a result, our LTIFR has returned to target levels.

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

[14] 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.

Our target reflects the belief that we can operate in a way that prevents harm to our staff and to the public. We believe we are on track to deliver this outcome reliably, and that our safety culture supports this. Our focus is now shifting to ensuring we have the systems and tools necessary to improve this outcome over time.

We are planning on further refining our measurement of safety performance, for example by including measures with an increased focus on injury severity.

7.2.1.2 SAFETY TARGETS

Current safety improvement targets comprise a mix of lagging and leading measures as well as programme completion. All reported safety incidents are recorded, assessed and managed. The targets include a focus on safety programme completion.

Table 7.1: Safety targets

INDICATOR	TYPE	TARGET
LTIFR	Lagging	<1.76 FY17, reducing 10% p.a. Aspiring for *zero* LTIs
High Potential Incidents (HPIs) reported in a timely manner and investigated using full ICAM within 28 working days	Leading	100%
Safety programme delivery	Leading	Programme delivered as planned

In line with our overall Safety and Environment objective of an injury free workplace, we strive to have zero lost time injuries for those who work on or around our network. We strongly believe this is achievable. To measure our progress against this objective we will reduce our LTIFR target every year to ensure we continuously improve our safety performance.

We also use a more detailed set of internal safety targets, which include safety interactions, public safety campaigns and major public safety incidents.

7.2.1.3 SAFETY INITIATIVES

We are implementing the following initiatives to support our safety objectives and performance targets.

- **Phasing out unsafe assets** – we will phase out assets that no longer meet modern safety standards, or are no longer deemed sufficiently safe to operate or maintain. This is described in more detail in our fleet management Chapters (14-20).
- **Service provider relationships** – we are careful to select only those service providers who can achieve the highest levels of safety for their staff and the public. We will continue to work with our delivery partners to ensure the best possible safety outcomes are achieved over time.
- **Critical risk assessment** – of our assets from a public and worker safety perspective to ensure the optimal condition of safety-critical assets. This includes developing effective plans to manage critical risk areas and reviewing the effectiveness of these on a regular basis.
- **Safety governance** – to support compliance with the new Health and Safety Reform Act, including training on the new requirements for directors and all levels of the organisation. We will continue to undertake regular safety engagements with staff and service providers.
- **Continually improve measurement and reporting of safety issues** – to encourage a culture where all safety-related incidents and near misses are freely reported, analysed, and widely disseminated across the company. This will include sharing with our service providers and the wider industry. Learnings will be embedded into our processes.
- **Public safety communication** – by engaging in regular communication with our customers and communities to reinforce awareness of the risks associated with electricity networks.
- **Fully embedding safety-in-design processes** – by adopting best practice standards and processes into all our planning and design activities. Health and safety factors will be reviewed during construction, commissioning and maintenance. Feedback is provided to planning and design teams.

7.2.2 ENVIRONMENTAL RESPONSIBILITY

We are committed to managing our assets in a manner which minimises pollution or any other adverse impacts on the surrounding environment.

We support the New Zealand Energy Strategy and the New Zealand Energy Efficiency and Conservation Strategy and are committed to developing more sustainable energy outcomes.

We are also committed to pursuing continual improvement and recognise that sound environmental management is consistent with and complementary to our Customers and Community objectives.

7.2.2.1 ENVIRONMENTAL PERFORMANCE

Managing our oil-filled assets

The majority of environmental risks on our network relate to potential oil leaks, mainly from our transformer and cable assets. We manage this risk primarily through asset inspections, after which necessary defects are raised to ensure the appropriate actions are taken. We investigate larger oil leaks using an Incident Cause Analysis Method (ICAM) investigation methodology.

Where significant leaks are found, we ensure any contaminated soil is removed from the site and soil tests are completed to ensure proper remediation.

Sulphur hexafluoride

We have recently passed the threshold for being classed a major user of SF_6. We have set up an account with the Emissions Trading Scheme (ETS) and are firming up the processes needed to manage the reporting and audit requirements associated with being a major user.

The SF_6 leak rates for 2014 and 2015 were 0.32% and 0.33% of total stock respectively. These are both well below the legislative compliance level of 2%. We continue to pay close attention to this area to ensure our environmental impact is as low as practical.

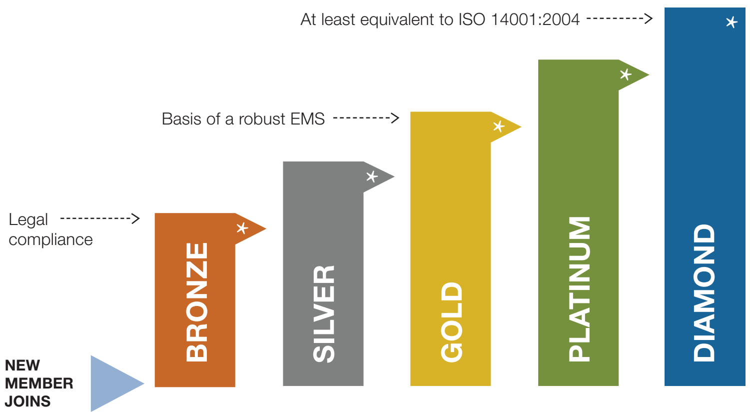
Enviro-Mark

We are a member of the Enviro-Mark Programme (see www.enviro-mark.co.nz) and have annual external compliance audits of our Environmental Management System (EMS) against international best practice criteria.

We have achieved Enviro-Mark Gold level, a significant improvement compared to our 2013 AMP where the majority of our sites were certified as Bronze Level. This involved establishing environmental hazard processes, communicating our environmental policy statement and testing our environmental emergency plan.

Further levels of certification exist (see the figure below), and we aim to reach Diamond level by FY17. This requires us to continuously monitor our environmental performance, ensure staff receive EMS training, and ensure continuous improvement and internal auditing of our EMS.

Figure 7.3: **Enviro-Mark levels of certification**



* Independent verification and then Landcare Research certification at each step

7.2.2.2 ENVIRONMENTAL TARGETS

Current environmental performance measures are mainly leading measures. All reported environmental incidents are recorded, assessed and managed. The targets focus on environmental programme completion.

Table 7.2: **Environmental targets**

INDICATOR	TARGET
Medium or higher consequence environmental incidents investigated using ICAM	100%
Enviro-Mark certification	Achieving Diamond status during FY17
Environmental programme delivery	Programme delivered as planned
SF_6 leak rate	<2% of stock

7.2.2.3 ENVIRONMENTAL INITIATIVES

We are implementing the following initiatives to support our environmental objectives and performance targets.

- **Continually improving measurement and reporting of environmentally related issues** – to encourage a culture where all environmental incidents and near misses are accurately reported, analysed, discussed, and widely disseminated. Learnings are then taken and embedded into our processes.
- **SF_6 management** – including improved reporting processes for our SF_6 holdings and leak rates. Vacuum switchgear alternatives are considered.
- **Best practice EMS** – we are continuing with the Enviro-Mark programme and external audits with the aim of achieving Enviro-Mark Diamond level. We will meet all statutory environmental requirements and other relevant standards and codes. The EMS provides a framework for setting and reviewing environmental objectives and targets.
- **Power transformer oil containment** – we now install oil containment and separator systems for power transformers which do not have these systems. This limits the risk of a major oil spill in our zone substations. More information is provided in Chapter 17.

7.2.3 LEGISLATIVE COMPLIANCE

Full legislative compliance is our target. It relates to all areas of our asset management activities. We have included it under our Safety and Environment objectives to reflect its close link with these aims.

Compliance is reviewed at 12 monthly intervals throughout the organisation. There are numerous pieces of applicable legislation, with the following being directly relevant to our safety and environmental performance:

- Electricity Act and pursuant Electricity (Safety) Regulations 2010 – applicable to multiple process reviews
- Health and Safety in Employment Act 1992 – training and competency management, hazard identification and communication
- Health and Safety at Work Act 2015 – applicable to internal and contractor processes
- NZECP34 – alignment of maintenance and design requirements for overhead lines and switchgear
- Electricity Industry Participation Code – particularly applicable to distributed generation and protection relays
- Building Act 2004 – strength of buildings and seismic stability

7.3 CUSTOMERS AND COMMUNITY

As described in Chapter 4, our network provides an essential service to our communities. As key stakeholders, the needs of our customers and communities dictate how we manage our network assets. We have set ourselves an overall objective that guides our activities in this area.

Customer 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.

Under this objective, we have developed targets in three categories: customer service and engagement, fault response, and power quality. Targets for these three categories along with our current performance are discussed in the following sections.

7.3.1 CUSTOMER SERVICE AND ENGAGEMENT

As set out in Chapter 6, we use a variety of techniques to engage with customers, such as preference surveys, stands at field days, stakeholder meetings and focus groups. Field days provide a good opportunity to regularly survey customers and the results of these surveys inform our customer service and engagement targets.

7.3.1.1 CUSTOMER SERVICE AND ENGAGEMENT PERFORMANCE

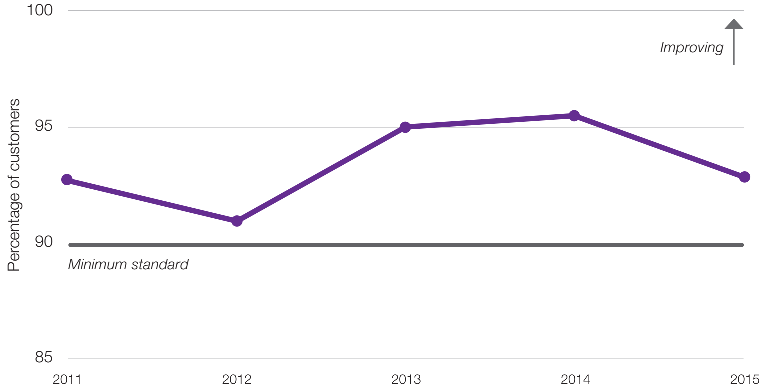
Over the past five years we have surveyed our customers at field days to better understand their electricity supply preferences, perceived reliability, and value.

Two key questions we use in these surveys relate to electricity reliability and quality.

- When considering frequency and duration of power cuts, describe the reliability of the electricity supply you currently receive (from very unreliable through to very reliable).
- Overall "quality" includes reliability, power quality/voltage and customer service (response to power cuts and service requests etc.). Does the overall "quality" of your current electricity supply meet your expectations?

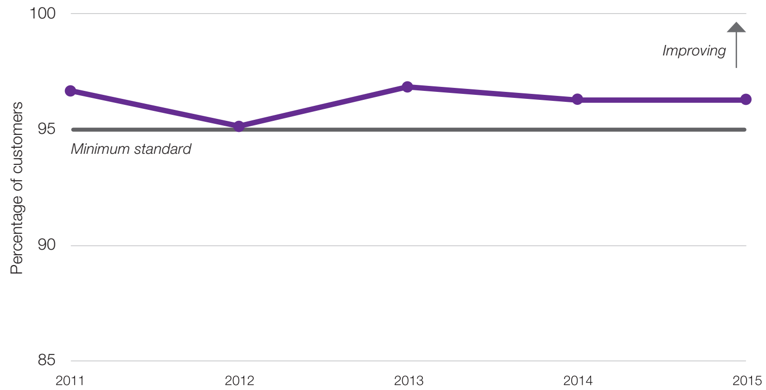
The figures below show the summarised responses to these questions.

Figure 7.4: **Percentage 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 7.5: **Percentage 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.

7.3.1.2 CUSTOMER SERVICE AND ENGAGEMENT TARGETS

In the table below are our targets for field days survey results. We have consistently achieved our targeted levels and are striving for further improvements.

Table 7.3: **Customer service and engagement targets**

INDICATOR	TARGET
% of customers that consider their electricity supply reliability is acceptable or better	>90%
% of customers that consider their overall electricity supply quality meets expectations	>95%

As these results are collected during field days, they are not fully representative of our full customer base. We plan to transition to targets based on broader customer surveys, completed on an annual basis.

7.3.1.3 CUSTOMER SERVICE AND ENGAGEMENT INITIATIVES

Initiatives we have planned or are underway include the following.

- **Customer strategy initiatives** – we are currently redesigning how we interact with our customers and how we use engagement and insight to improve our service offering. These initiatives are described in Chapter 6.
- **Worst performing feeders' improvement** – we will prioritise renewal and maintenance work to improve performance on poor performing feeders. Examples of this analysis are in Appendix 11.

7.3.2 FAULT RESPONSE

Effective fault response limits the consequences of unplanned outages. We measure our fault response performance by looking at both response times (for faults and emergencies) and resolution times. To recognise the diverse range of customers we serve we use feeder type[15] (which reflects the type of connected load) to specify different response times for different customers.

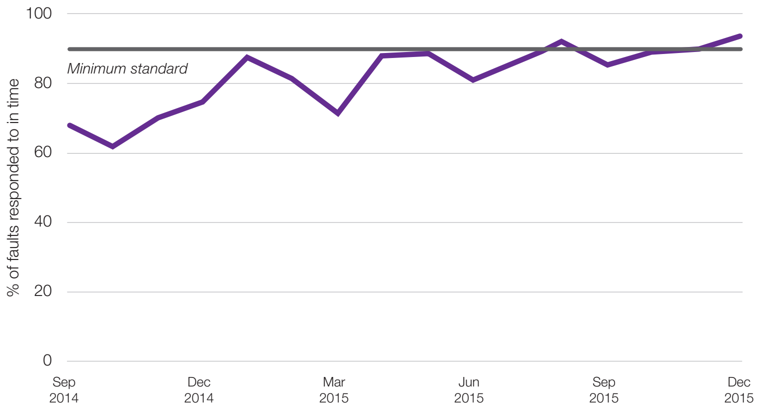
Fault response performance is also critical from a public safety perspective. When assets fail they can create safety hazards that must be controlled. Fault response also relates to our Safety and Environment objective of Section 7.2.

7.3.2.1 FAULT RESPONSE PERFORMANCE

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.

[15] More information on feeder types is included in the feeder reliability section later in this chapter.

Figure 7.6: **Percentage of faults responded to within target response time**



Fault response performance has improved over the period, with recent performance close to or at target levels. However, there is still room for improvement.

Fault Resolution Performance

Fault resolution performance on our HV assets (both urban and rural) has been below target since EFSA was put in place. This is a focus area for us and emerging trends indicate performance is now improving. Performance on our LV network is better, with monthly performance typically above target levels.

Closely monitoring our performance when dealing with faults is important to help manage levels of unplanned SAIDI. SAIDI performance is influenced in part by our ability to respond to faults. As SAIDI levels have often been at or above target levels, we need to improve our fault response performance. SAIDI is explained in Section 7.4.1.

7.3.2.2 FAULT RESPONSE TARGETS

Performance measures for expected response and supply restoration are included in our field service agreements. Response times vary based on the feeder type. Our targets are defined in terms of:

- **Response time** – measured as the time taken to be on-site from when the outage is notified, for both standard and emergency faults.
- **Fault resolution** – measured as the time taken to restore supply from when the outage is notified.

The performance targets are set out in the following tables.

Table 7.4: **Fault and emergency response targets**

FEEDER TYPE	FAULT RESPONSE TIME (MINS)	EMERGENCY RESPONSE TIME (MINS)	PASS THRESHOLD
F1, F2	60	30	>90%
F3	90	45	
F4	135	67	
F5	180	90	

Table 7.5: **Fault resolution targets**

FEEDER TYPE	RESOLUTION TIME (MINS)	PASS THRESHOLD
F1, F2, F3	180	>85%
F4, F5	360	>95%

7.3.2.3 FAULT RESPONSE INITIATIVES

Initiatives we have planned or are underway include the following.

- **Service level agreements** – our service provider contracts contain financial incentives for fault response performance.
- **OMS improvements** – we plan to extend the functionality of our OMS with features such as distribution management, storm management and automated switching. These improvements will improve both fault response performance.
- **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.

7.3.3 POWER QUALITY

Power quality covers various aspects of a customer's supply. This includes continuous concerns like flicker, harmonics, phase balance and voltage, and discrete perturbations like voltage sags and swells, and frequency excursions.

The power quality landscape is changing and this is affecting tolerance levels.

- Power quality has been defined according to legislation. While voltage regulation is still set by statute (as +/-6% of nominal supply voltage of 230V at the customer's point of connection), recent changes to the Electricity Supply Regulations and the withdrawal of many of the Codes of Practice have altered many of the power quality requirements. These are now encompassed within a new industry Guide.
- Changes of the status of electricity from a "Service" to a "Good" under the Consumer Guarantees Act may have implications on the supply quality objectives. Classification as a "Good" defines quality as what a reasonable customer would expect. Understanding customers' needs is therefore an essential part of understanding the supply quality objectives. This implies a need for continued investigation.
- Increasing use of electronic devices, particularly variable speed drives, is resulting in a progressive deterioration of the waveform quality of electricity.
- Increasing use of distributed generation within customer installations brings about bi-directional power flows and wider voltage variations.

Performance outside tolerance has usually been indicated by notification from the customer, but some tariff meters are now capable of providing real time voltage measurement and historical logging of a variety of different power quality measures.

7.3.3.1 POWER QUALITY PERFORMANCE

Customers' power quality concerns are tracked through our systems. Some of these are not immediately obvious, are intermittent, or require special investigations. Most can be resolved quickly through a fault call out.

Table 7.6: **Power quality issues**

ISSUE	CHARACTERISATION	IMPACT TO CUSTOMER
Flicker	Frequency of less than 35Hz	Visual flicker with lighting
Harmonics and inter-harmonics	3rd, 5th and 7th harmonics most common on distribution level	Radio interference, electronic appliances mal-operating, transformer/motors overheating, induction motors contacts tripping
Phase voltages unbalance	One or two phases with voltage <95%, negative sequence voltages	Damages rotating machines, a fuse on one phase continually blows
Longer term brownouts	Voltage drop below 0.9pu > 1 min	Burns out motors
Longer term over-voltages	Greater than 1.1pu > 1min	Light bulbs blowing, 3-phase motor heating
Auto Reclosure (< 1min, > 2 sec)	Power goes off then comes back on	Reset electronic equipment, clocks,
Short-term fluctuations, dips & sags, flicker	Lights flicker	Visual flicker, clocks running faster
Voltage spikes	Short-term <1min	Damages equipment
Frequency excursions < 1 sec	Deviation from 50Hz	
Frequency excursions > 1 sec	Deviation from 50Hz	Clocks running faster/slower

As at the end of November 2015, we had 42 power quality complaints that we are monitoring, pending resolution, or are awaiting customer acceptance. We take all complaints seriously, and have processes in place to ensure we understand their root cause, and how they relate to the way we manage our network.

7.3.3.2 POWER QUALITY TARGETS

Of the power quality issues listed in the previous section, three are defined by legislation and have their own targets. We aim for 100% compliance with these targets. These are listed in the next table.

Table 7.7: **Power quality targets – voltage and harmonics**

INDICATOR	TARGET	HOW MONITORED
Longer term brownouts	**Voltage within 6% of nominal**	Customer complaints
Longer term over-voltages	**Voltage within 6% of nominal**	Customer complaints
Harmonics & inter-harmonics	**Total harmonic voltage < 5% at Point of Common Coupling**	PQ meters at the substation, site monitoring using portable data-logger

We also measure our power quality performance by how we respond when notified of a potential issue. We aim to respond to power quality concerns within 24 hours of notification.

Table 7.8: **Power quality targets – customer complaint response**

INDICATOR	TARGET
Power quality customer complaints responded to and logged within 24 hours	>90%

7.3.3.3 POWER QUALITY INITIATIVES

The key initiative we have underway for power quality performance is our network insight programme. This deploys monitoring devices on the LV side of key distribution transformers. This enables greater visibility of the LV network, allowing us to identify and respond to power quality issues before they worsen. More information on this programme is provided in Chapter 11.

7.4 NETWORKS FOR TODAY AND TOMORROW

As described in Chapter 4, we will continue to provide a secure and enduring electricity service to meet our customers' needs. We have set ourselves an overall objective that guides our activities in this area.

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.

Under this objective, we describe network targets under three categories – overall network reliability, feeder reliability, and networks for the future. Targets for these categories along with our current performance are discussed below.

7.4.1 OVERALL NETWORK RELIABILITY

Electricity network reliability is based on the continuity of supply to customers. Reliability is part of the Commission's DPP regime. We set reliability targets at an overall network level (discussed in this section) and at feeder level (discussed in the following section).

Our overall network reliability targets are informed by a number of factors including the following.

- Customer feedback on their needs and preferences
- The make-up of the DPP quality threshold
- What is practical to achieve given economic and technical constraints.

They are measured using indices of interruption duration (SAIDI) and frequency of interruption (SAIFI) and variants of these, and assume normal weather conditions. Our SAIDI and SAIFI is disclosed annually.

SAIDI and SAIFI

Consistent with other EDBs we use SAIDI and SAIFI to measure and track the overall reliability provided to our customers.

- **SAIFI:** represents the average number of times (frequency) an average customer has an interruption. It is measured in interruptions per year.
- **SAIDI:** represents the average interruption duration for an average consumer. It is measured in units of time, usually minutes over a year.

These are aggregate measures of reliability and do not reflect individual customer experience.

SAIDI is the more common measure. A SAIDI of 120 minutes means that the average consumer on the network did not have supply for two hours during the year. A SAIFI of two means that the average consumer on the network had two interruptions that year.

Maintaining appropriate levels of reliability requires consistent focus across our business. Some of our investment directly targets improved reliability (e.g. automation discussed in Chapter 10) while our renewal of poor condition assets will eventually lead to a lower level of asset faults.

Our OMS is used for reporting network performance and recording faults. This data is then used for internal reporting and preparing public information disclosures relating to faults and SAIDI / SAIFI performance.

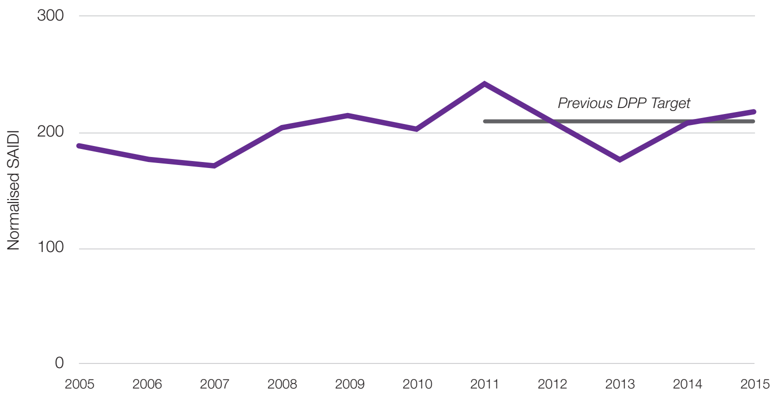
7.4.1.1 NETWORK RELIABILITY PERFORMANCE

Our normalised[16] historical SAIDI and SAIFI performance is discussed below.

Historical SAIDI performance

Over the past 10 years SAIDI has been variable between years primarily due to the influence of weather cycles. It also has a slight upward trend mainly due to increasing fault numbers caused by asset failures and tree contacts. Previous DPP target levels were breached in 2011 and 2015, which was also our target level from the 2013 AMP. This is shown in the figure below.

Figure 7.7: **Historical normalised SAIDI**



Unplanned SAIDI makes up approximately 80% of our historical SAIDI. In our 2013 AMP we targeted an unplanned level of SAIDI of less than 170 minutes. This was comfortably met in 2013, but was exceeded in 2014 and 2015 though by less than two minutes on both occasions.

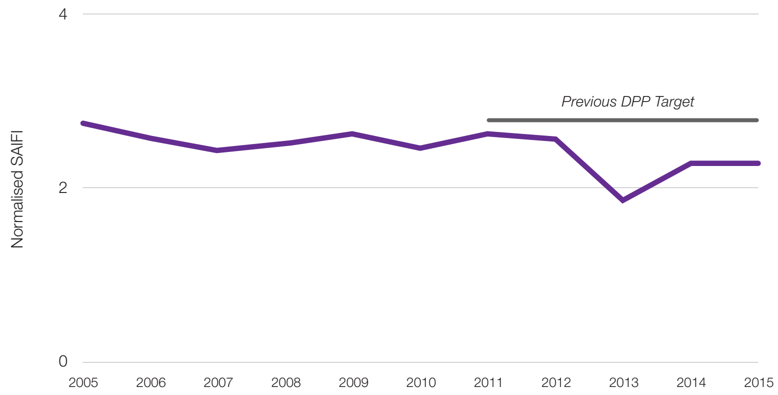
Both our performance against DPP and AMP 2013 targets reflect that managing our SAIDI performance is becoming more difficult, due in particular to unplanned outages. This is one of the drivers for our increasing investment in asset renewal and security upgrades which is discussed in later sections of this AMP.

[16] Normalisation of SAIDI and SAIFI involves capping the total amount of SAIDI and SAIFI that can be accrued in a single day to a boundary value (set by the Commission). When the boundary value is exceeded the day is referred to as a “major event day”. This is done to reduce the impact of significant weather events on long term SAIDI and SAIFI trends.

Historical SAIFI performance

There has been a general trend of reducing SAIFI even though the numbers of faults and interruptions have been increasing. This trend is mainly due to our successful deployment of distribution automation. In addition, we have optimised our protection settings and increased the self-sectionalising ability within our network. SAIFI levels were well under the previous DPP target during the 2011-2015 period.

Figure 7.8: **Historical normalised SAIFI**



7.4.1.2 NETWORK RELIABILITY TARGETS

We are aware that as our network assets continue ageing, the incidence of faults is likely to continue increasing, putting pressure on our reliability performance. However, our customers expect network performance to remain at historical or better reliability levels.

We have set ourselves the target of maintaining SAIDI and SAIFI in line with the DPP target levels up until 2019.

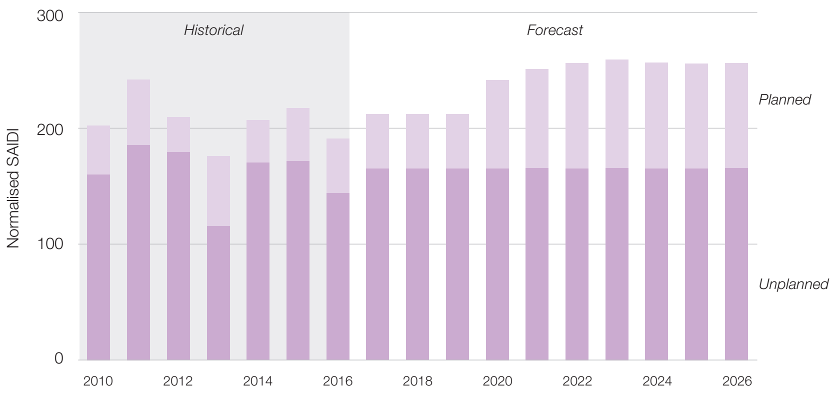
Table 7.9: **DPP reliability targets**[17]

	SAIFI	SAIDI
DPP target (normalised)	2.3406	188.8628
DPP cap (normalised)	2.5197	210.6290
DPP collar (normalised)	2.1615	167.0966
Unplanned boundary value	0.0640	11.2140

As we transition to a CPP in FY20, planned SAIDI and SAIFI levels will need to increase in order to deliver increasing work volumes. This is particularly the case for asset renewals which generally require a planned shutdown.

The figures below show our forecast reliability performance[18] for both SAIDI and SAIFI over the planning period. These forecasts reflect the expected increase in planned work from FY20 onwards. We continue to target maintaining at least today's level of unplanned SAIDI and SAIFI, in line with our customers' expectations.

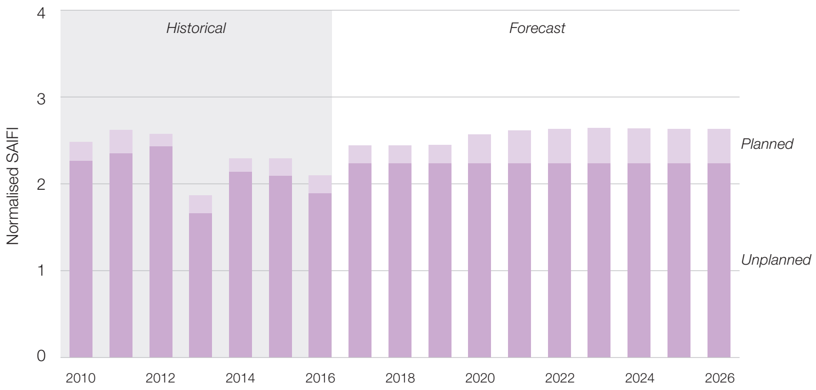
Figure 7.9: **Forecast SAIDI for the planning period**



[17] The DPP quality standard includes normalised SAIDI and SAIFI targets, each with a cap and collar within which financial incentives apply. The current targets weigh planned shutdowns at 50% of the actual SAIFI or SAIDI value. An annual breach occurs if the DPP cap is exceeded.

[18] The figures show forecast SAIDI and SAIFI, with planned and unplanned interruptions equally weighted. This is consistent with historical figures and better reflects overall performance. The DPP weights planned outages at 50% resulting in differences between the DPP target value and our forecast reliability for 2017-2019.

Figure 7.10: **Forecast SAIFI for the planning period**



Forecast SAIDI and SAIFI with planned reliability weighted at 50% are shown in the table below.

Table 7.10: **Reliability forecast for the planning period**

	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
SAIDI	188.9	188.9	188.9	203.3	208.1	210.8	212.2	211.1	210.7	210.8
SAIFI	2.34	2.34	2.34	2.40	2.42	2.44	2.44	2.44	2.43	2.43

7.4.1.3 NETWORK RELIABILITY INITIATIVES

Reliability initiatives we have planned or are underway include the following.

- **Renewal programmes** – investment is targeted at assets with increased risk of failure. This will reduce the likelihood of faults and help manage unplanned SAIDI and SAIFI. More information on these programmes is included in Chapters 14-20.
- **Vegetation management** – we have developed a new vegetation management strategy aimed at addressing increasing tree-related faults.
- **Network automation** – allows us to improve reliability performance by providing remote or automated operation of distribution switchgear. It also provides improved visibility of fault location and network state. This allows us to respond faster to events. More information is contained in Chapter 10.

7.4.2 **FEEDER RELIABILITY**

Measuring feeder reliability (rather than just overall network reliability) is important. Although overall network performance may be acceptable, individual customers will experience varying degrees of reliability, and sometimes at levels below their expectations. Focusing on feeder reliability helps us prioritise our investments to ensure reliability better meets customer expectations.

Over time we expect to do more analysis at a customer level (rather than feeder level). Although feeder-based analysis provides a more granular view of network performance than overall SAIDI, customers on a single feeder can still have varying levels of service due to their location on the feeder and the level of automation and switching devices.

7.4.2.1 **FEEDER RELIABILITY PERFORMANCE**

Feeder-based planning analysis is undertaken using feeder class (see Chapter 8). Each distribution feeder is assigned a feeder class that best reflects the types of consumers connected to the feeder.

Table 7.11: **Feeder classes**

FEEDER CLASS	TYPICAL CUSTOMER TYPE
F1	Large industrial
F2	Commercial/CBD
F3	Urban residential
F4	Rural (intensive)
F5	Remote rural

The table below shows our reliability standards for each feeder class. We analyse feeder performance using a Feeder Interruption Duration Index (FIDI). FIDI represents the average number of minutes per year that a customer is without supply on a particular feeder.

Table 7.12: **Reliability performance standards by feeder (consumer type)**[19]

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

Large industrial customers (F1) may have tailored reliability and voltage stability needs based on their supply agreements.

Meetings with the public have been held regarding specific customer reliability concerns at which customers can discuss the reliability of their supply. Feedback on reliability tends to be mixed but generally supports the feeder targets above.

Below we summarise our 2015 FIDI performance.

Table 7.13: **Feeder reliability performance in 2015 (FIDI)**

MEASURE	LARGE INDUSTRIAL F1	COMMERCIAL F2	URBAN F3	RURAL F4	REMOTE RURAL F5
FIDI limit (minutes)	30	60	180	600	1080
Feeders above limit	34	35	63	63	4
Total feeders	67	115	206	200	20
% compliant	49%	70%	69%	69%	80%

FIDI compliance was generally low in 2015, and worst for our F1 feeder class. 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.

[19] The reliability performance in the table is for distribution feeders only, and excludes the performance of the network upstream of the feeder.

F2, F3 and F4 feeders are performing close to our target level of 70%, but targeted renewals will still be required to ensure performance is maintained. F5 performance was good in 2015, though five feeders were close to the FIDI limit again reinforcing the need to continue with targeted renewals on these feeders.

Further analysis on our worst performing feeders is included in Appendix 11.

7.4.2.2 FEEDER RELIABILITY TARGETS

Our feeder reliability target is listed in the table below. We are aiming to ensure that greater than 70% of our feeders meet our FIDI reliability standard, improving this to 85% by the end of the planning period.

Table 7.14: **Feeder reliability target for the planning period**

INDICATOR	TARGET
% of feeders compliant with FIDI standard	>70%, improving to 85% by 2026

In the future we expect to supplement this target with more customer-specific measures.

7.4.2.3 FEEDER RELIABILITY INITIATIVES

Our feeder reliability initiatives are the same as those for network reliability (see previous section). Feeder and customer reliability analysis will drive where we will focus these to ensure improvements are prioritised towards feeders where performance is an issue.

7.4.3 NETWORKS FOR THE FUTURE

As discussed in Chapter 11, we are embarking on a future networks programme in order to ready ourselves for major changes in the electricity industry. It is essential that we measure ourselves in this area, to ensure we make the progress we expect.

The first milestone of this programme is to develop a detailed future technology strategy with an associated 10-year roadmap. Achieving this milestone during FY17 is our primary target in this area. The strategy will include relevant targets to measure our progress. These will be included in future AMPs.

We will also continue to track the progress of our current innovation programme, which is discussed in more detail in Chapter 11. We achieved our 2013 AMP target of five new technology work programmes per year.

7.5 ASSET STEWARDSHIP

As described in Chapter 4, we operate a large number of diverse assets which we aim to manage efficiently and prudently. Reflecting this aim we have set an overall objective to guide our asset stewardship activities.

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.

Under this objective, we describe network targets under two categories – asset utilisation and asset failure rates. Targets for these categories along with our current performance are discussed in the following sections.

7.5.1 ASSET UTILISATION

Asset utilisation is an important measure for us. It involves balancing investment levels, network performance, and the risk of long-term outages. Higher levels of asset utilisation tend to indicate more prudent use of capital. Conversely, higher levels of asset utilisation can lead to performance risk if there is limited asset redundancy available to cater for asset failures or shutdowns.

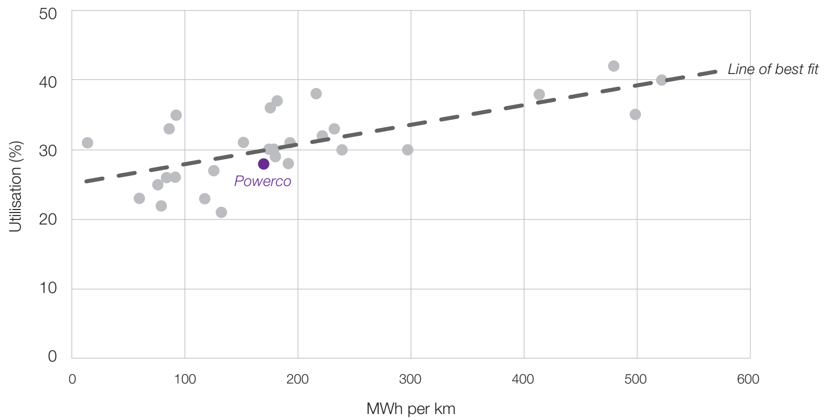
Closely associated with utilisation is the management of asset capacity to meet future demand. This forms an integral part of our planning process as load to capacity ratios drive the need to invest in new or larger assets. The network must be capable of meeting demand until any necessary reinforcements or additions can be brought into service.

7.5.1.1 ASSET UTILISATION PERFORMANCE

Distribution transformer utilisation

The figure below compares our average distribution transformer utilisation with other EDBs. It suggests a positive relationship between utilisation and energy density, likely because higher density networks can use higher diversity factors in their transformer loadings.

Figure 7.11: **Comparison of NZ EDB distribution transformer utilisation and network load density**



Our transformer utilisation is close to the line of best fit. We use this relationship to inform our distribution transformer utilisation target of 30%, based on the energy density of our network. It should be noted that measuring distribution transformer utilisation is subject to the nature of diverse customer loads. For example, a small transformer supplying a single customer can be expected to have a lower utilisation than a large transformer supplying many customers, even though both sizes reflect good design.

Zone substation transformer utilisation

Our current zone transformer utilisation is 55.3%. 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.

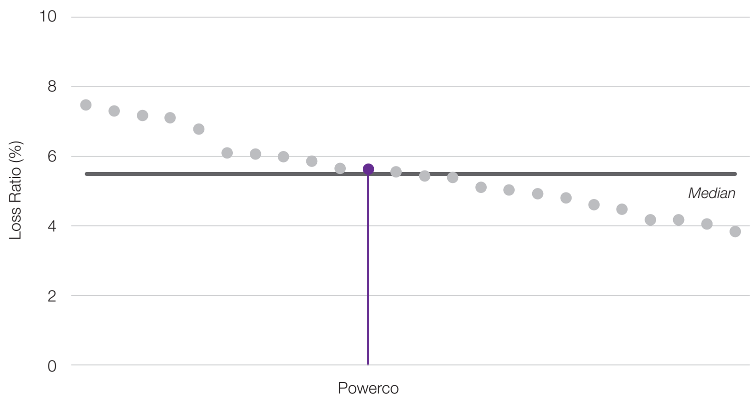
Network losses

A similar measure to asset utilisation is the magnitude of a network's energy losses. Network losses arise from electrical resistance in conductors, transformer magnetisation, and other losses (non-metered loads, metering errors and timing inconsistency of meter readings). Technical losses can be optimised through good design but not eliminated entirely. High network losses may reflect inefficient design whereas low losses may reflect an 'over-designed' network.

Measurement of technical losses involves determining the difference between energy flowing into the network (GXP and distributed generation) and energy flowing out of the network (customer load demand).[20]

Our aim for network losses is a loss ratio[21] of 6%. The figure below shows our network loss ratio compared to other EDBs.

Figure 7.12: **Benchmarking of average network loss ratio (2013-2015)**



We use the median (i.e., the middle data point in an ordered set) as a benchmarking reference, due to its reduced sensitivity to outliers. Our loss ratio is close to the median value across all EDBs, which suggests an appropriate level of network losses.

7.5.1.2 ASSET UTILISATION TARGETS

We use three asset utilisation targets to reflect our diverse assets, and that a single measure is unlikely to fairly represent overall utilisation. Our three measures of asset utilisation are listed in the table below.

[20] In practice, the measurement of losses is problematic because of inconsistent information, for example meter readings from different retailers may have different timings.
[21] Loss ratio is measured as total network losses divided by energy entering our network.

Table 7.15: **Asset utilisation targets**

INDICATOR	TARGET	CURRENT (2015)
Average distribution transformer utilisation	30%	28.5%
Average zone transformer utilisation	50%	55.3%
Network energy losses	6%	5.1%

7.5.1.3 ASSET UTILISATION INITIATIVES

Asset utilisation can be optimised by improving the load factor of demand through load diversity, demand side management techniques, and better management of asset capacity risks through dynamic cable rating. Asset utilisation initiatives include the following.

- **Network development** – when asset loads exceed rated levels, they are typically upgraded with a new asset that is sized for future expected load growth. More information is in Chapter 8.
- **Future network initiatives** – will improve utilisation of our network using technologies such as LV monitoring, battery storage, real time asset ratings, and state estimation. More information is in Chapter 11.
- **Developing and implementing an energy efficiency campaign** – providing advice to our customers on the efficient use of electricity to help optimise asset utilisation in areas where network capacity is constrained.

7.5.2 ASSET FAILURE RATES

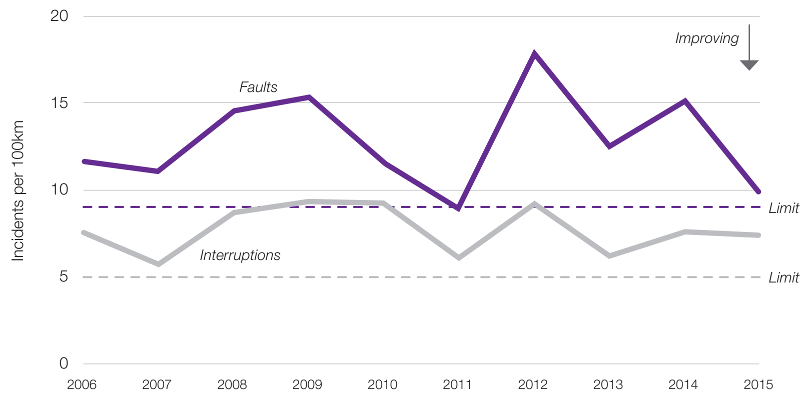
Our aim is to ensure our assets reliably and safely meet our customers' expectations. Line and cable assets typically have a low failure rate throughout most of their life followed by periods of worsening reliability as their condition deteriorates. For these assets, we typically undertake condition-based renewals. These are informed by asset inspections and renewals modelling.

7.5.2.1 ASSET FAILURE RATE PERFORMANCE

Analysis of network fault rates between 2006 and 2015 show that distribution and subtransmission overhead lines have been performing poorly against our targets. This strongly indicates the need to increase overhead line renewal investment and improve vegetation management in order to improve performance.

Historical subtransmission overhead faults and interruptions are shown in the figure below. Year-on-year performance is highly variable, but is consistently worse than (i.e. above) our targets.

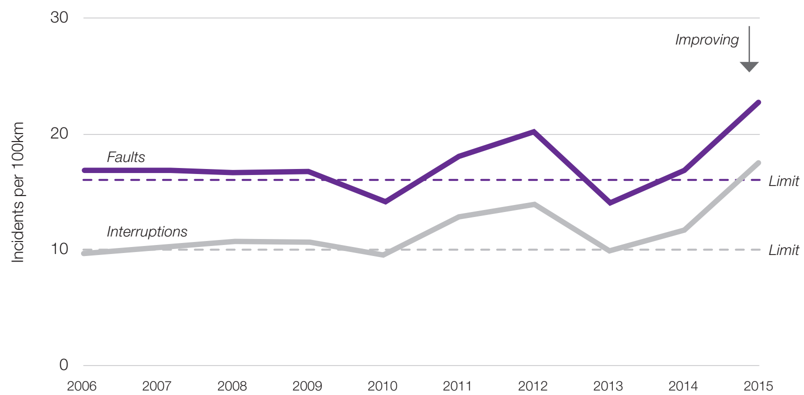
Figure 7.13: **Subtransmission overhead faults and interruptions per 100km**



The difference between the number of faults and interruptions reflects the impact of redundancy within our network. In an N-1 situation, a failed asset will not always lead to an interruption.

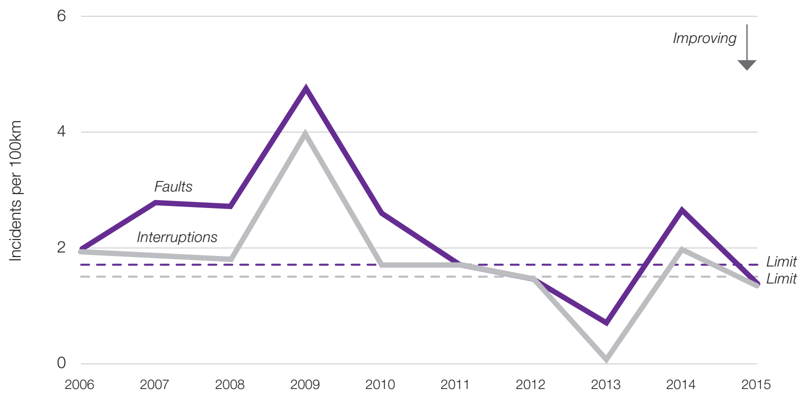
The figure below shows our historical distribution overhead faults and interruptions. Following a period of relative stability, total numbers of faults and interruptions, and associated variability appear to be rising.

Figure 7.14: **Distribution overhead faults and interruptions per 100km**



As shown below an improving fault trend can be seen on our subtransmission underground network.

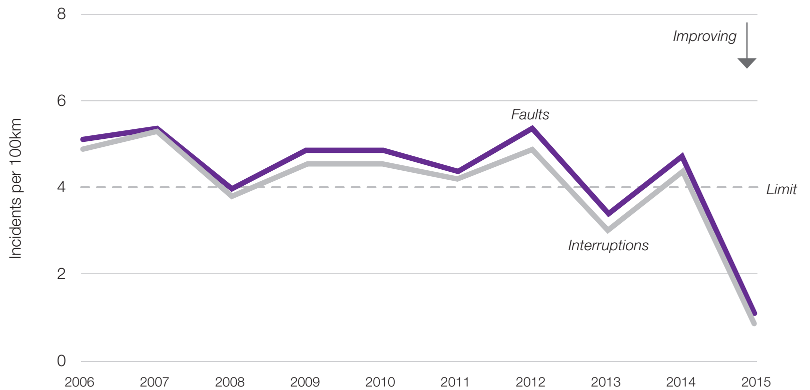
Figure 7.15: **Subtransmission underground faults and interruptions per 100km**



The fault rate on these circuits has largely been at target during the last five years. This shows improvement from earlier in the period.

As shown below our distribution underground network, apart from FY15 which had exceptional performance, has had fault and interruption rates above our targeted levels.

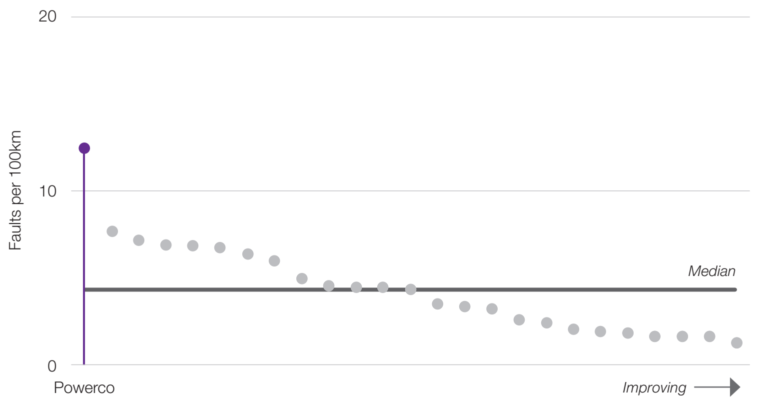
Figure 7.16: **Distribution underground faults and interruptions per 100km**



7.5.2.2 BENCHMARKING WITH EDBS

We use benchmarking to understand our performance compared with other EDBs. The figure below shows our subtransmission overhead fault rate compared to other EDBs.

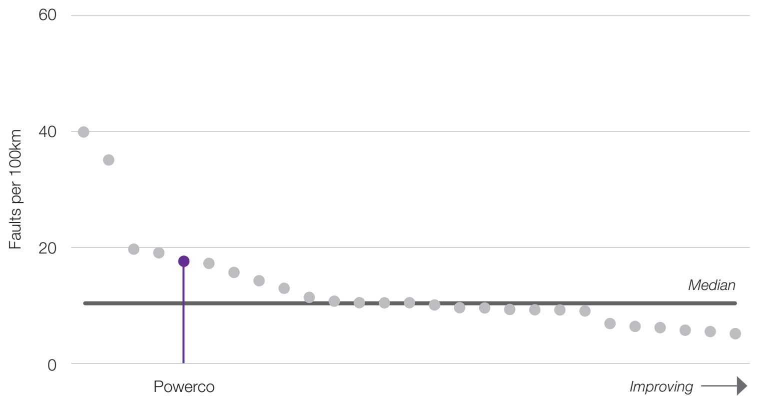
Figure 7.17: **Subtransmission overhead line benchmarking (2013-2015 average)**



Averaged across the past three years, our subtransmission overhead fault rate is the worst of the comparison group. As seen in the previous section, our subtransmission overhead faults have been steady over the past 10-year period, further emphasising that our performance in this area has been poor for some time.

Below our distribution overhead line fault rate is compared to other EDBs.

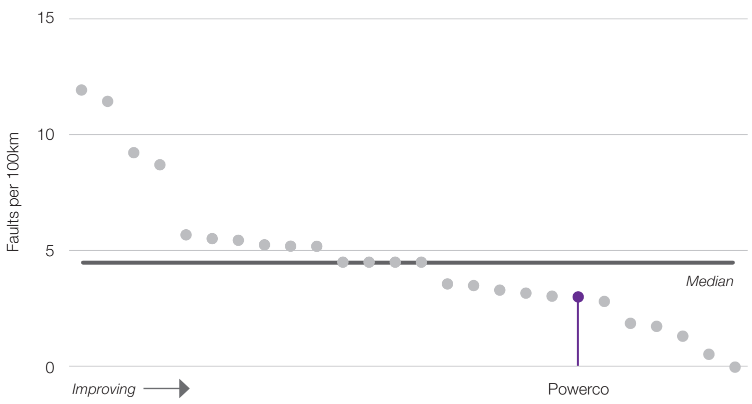
Figure 7.18: **Distribution overhead line benchmarking (2013-2015 average)**



Our performance is significantly above the median performance of other EDBs. This analysis indicates scope for more proactive management of vegetation and overhead distribution line renewal.

Our relative distribution cable performance is shown on the next page.

Figure 7.19: **Distribution cable benchmarking (2013-2015 average)**



Unlike overhead lines, our relative cable asset performance is good compared with our peers, and below our current target.

Subtransmission cable fault rates have not been included in this benchmarking analysis due to the small population of New Zealand EDBs operating subtransmission cables.

Objectives deduced from our failure rate performance focus on reversing the worsening trend of overhead distribution and subtransmission faults and maintaining the improving trends on our distribution cable networks.

7.5.2.3 ASSET FAILURE RATE TARGETS

Our asset failure target rates have been compiled using a combination of the benchmark interruption rates in the EEA's security of supply guide and our historical performance. These targets aim to optimise asset performance by balancing reliability expectations and the size of investments needed to achieve them.

Table 7.16: **Asset failure rate targets**

ASSET TYPE	FAULT RATE TARGET	INTERRUPTION RATE TARGET
6.6, 11, 22 kV overhead line	<16 per 100 km	<10 per 100 km
6.6, 11, 22 kV underground cables	<4 per 100 km	<4 per 100 km
33, 66 kV overhead line	<9 per 100 km	<5 per 100 km
33, 66 kV underground cables	<1.7 per 100 km	<1.5 per 100 km

7.5.2.4 ASSET FAILURE RATE INITIATIVES

Initiatives we have planned or are underway include the following.

- **Overhead conductor renewal** – the poor performance of our overhead distribution lines is in part due to issues we face with our conductor population. Renewal of worst performing conductor will increase during the planning period, as discussed in Chapter 15.
- **Vegetation management** – vegetation encroachment is responsible for a significant proportion of our overhead line faults. Our improved approach to vegetation management is described in Chapter 13.

7.6 COMPARISON TO 2013 TARGETS

Our 2013 AMP included network targets in the same focus areas as this 2016 AMP (safety, network performance, asset management capability,[22] asset utilisation and networks of the future). The sections above include reference to our 2013 targets where relevant, and discuss our performance against those.

In the 2013 AMP we set ourselves the target of market testing more than 80% of our field work. Since then, we have established the EFSA for faults, maintenance and minor capital works. Major contracts and some minor works are run through tender processes. We are now confident more than 80% of our works are market tested, and we have elected not to retain a target for this area within our 2016 AMP. For more information on works delivery refer to Chapter 5.

[22] Asset Management capability targets are described in Chapter 23.

7.7 TARGET SUMMARY

The tables below summarise our network targets for the planning period.

Table 7.17: Safety and environment targets

INDICATOR	UNITS	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Safety												
LTIFR	LTIs per million hours worked	2.20	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	% reported and investigated						100%					
Safety programme delivery							To plan					
Environmental responsibility												
Medium or higher consequence environmental incidents investigated using ICAM	% investigated						100%					
Enviro-Mark certification	Enviro-Mark standard	Gold	Diamond									
Environmental programme delivery							To plan					
SF_6 leak rate	% of stock						<2%					
Legislative compliance												
Legislative compliance							Full					

Table 7.18: Customers and Community targets

INDICATOR	UNITS	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Customer engagement												
% of customers that consider their supply reliability is acceptable or better	% of customers						>90%					
% of customers that consider their overall electricity supply quality meets expectations	% of customers						>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%					

Table 7.19: Networks for today and tomorrow targets

INDICATOR	UNITS	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Overall network reliability												
SAIDI	Normalised SAIDI with planned valued at 50%	167.6	188.9	188.9	188.9	203.3	208.1	210.8	212.2	211.1	210.7	210.8
SAIFI	Normalised SAIFI with planned valued at 50%	1.99	2.34	2.34	2.34	2.40	2.42	2.44	2.44	2.44	2.43	2.43
Feeder reliability												
% of Feeders compliant with FIDI standard	% compliance	70%	70%	70%	71%	73%	75%	77%	79%	81%	83%	85%
Networks of the future												
Complete Future Technology strategy and 10-year roadmap			Complete									

Table 7.20: Asset stewardship targets

INDICATOR	UNITS	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Asset utilisation												
Distribution transformer utilisation	% utilisation						30%					
Zone transformer utilisation (zone substation peak demand divided by zone substation total capacity)	% utilisation						50%					
Network energy losses versus energy entering network	%						6%					
Asset failure rates												
6.6, 11, 22 kV overhead line faults / interruptions	Faults / interruptions per 100 km						<16 faults <10 interruptions					
6.6, 11, 22 kV underground cable faults / interruptions	Faults / interruptions per 100 km						<4 faults <4 interruptions					
33, 66 kV overhead line faults / interruptions	Faults / interruptions per 100 km						<9 faults <5 interruptions					
33, 66 kV underground cable faults / interruptions	Faults / interruptions per 100 km						<1.7 faults <1.5 interruptions					

NETWORK DEVELOPMENT

This section explains how we plan to develop our network, including how we will ensure its future readiness.

CONTENTS

Back to contents >

8. GROWTH AND SECURITY

8.1 CHAPTER OVERVIEW

This chapter introduces our approach to developing our network. It provides a brief explanation of what we mean by network development, before focusing on our growth and security investments.

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.

8.2 NETWORK DEVELOPMENT

We use the term network development to describe capital investments that increase the capacity, functionality, or size of our network. These include the following four main types of investments.

- **Growth and security** – investments to ensure we can meet demand on our network at appropriate supply security levels, discussed in this chapter.
- **Customer connections** – expenditure to facilitate the connection of new customers to our network, discussed in Chapter 9.
- **Network enhancements** – to improve the reliability performance of the network and to ensure adequate communications capabilities, discussed in Chapter 10.
- **Future networks** – focused investments including proof-of-concept trials to ensure our network can meet future customer needs, discussed in Chapter 11.

8.2.1 NETWORK DEVELOPMENT STRATEGY AND OBJECTIVES

To guide our strategy for network development we have defined a set of objectives, as listed in the next table. They are linked with our overall asset management objectives in Chapter 4.

Table 8.1: Network development 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.
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.

The remainder of the chapter focuses on our Growth and Security portfolio and our expected forecasts for the period.

8.3 GROWTH AND SECURITY

Growth and security works 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. It is a significant area of investment over the planning period.

We broadly classify our growth and security investments according to the following types of project:

- **Major projects** – over $5m, generally involving subtransmission or GXP works.
- **Minor projects** – between $1m and $5m that typically involve zone substation works and small subtransmission projects.
- **Routine projects** – repetitive 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.

This chapter outlines the process we use to determine our growth and security related investments, and then considers the specific projects we anticipate are required over the planning period.

- **Investment planning** – is the process we use to plan for new investments and the relationship with customer service levels, security standards, demand forecasting methods and options analysis.
- **Area plans** – provide a geographical overview of the future growth and security investment needs across our 13 planning areas.
- **Forecast expenditure** – sets out our forecast Capex on growth and security during the planning period.

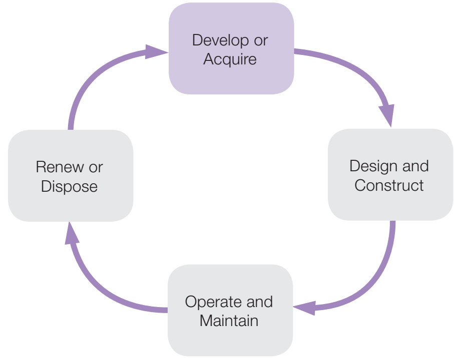
Further information on our planned growth and security investments can be found in Appendix 8.

8.4 INVESTMENT PLANNING

Planning for growth and security investments requires that 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 (e.g. renewal plans), such that investments are optimised across all business objectives and constraints. As such, we manage our assets using an asset life cycle approach. The figure below depicts the four life cycle stages that make up our Asset Management System. Growth and security planning is located within the 'develop or acquire' stage.

Figure 8.1: **Asset management life cycle**



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 the following:

- 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

Establishing and applying appropriate security of supply criteria is a key area. Security drives the larger investments related to the subtransmission system and zone substations, which directly impact reliability to large numbers of customers. Recently we have been reviewing these criteria and their application, and this is discussed further in Section 8.4.4.

8.4.1 DEMAND FORECASTING

Growth and security planning is essentially a comparison of asset capacity against demand. Demand is a function of time, both in terms of the reasonably predictable and repeatable patterns of daily and seasonal profiles, and also longer term trends in population, economic activity and customer behaviours.

Because of the long lead time for major projects that reinforce large capacity assets, such as subtransmission circuits, it is essential to forecast the expected demand on all parts of the network several years ahead to identify potential security issues before they occur.

The section below describes our demand forecasting approach in more detail.

8.4.1.1 OVERVIEW OF FORECASTING APPROACH

Our demand forecasting approach has recently been reviewed to improve consistency and robustness. This review also introduced more systematic correlation to externally validated economic and demographic trends.

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

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

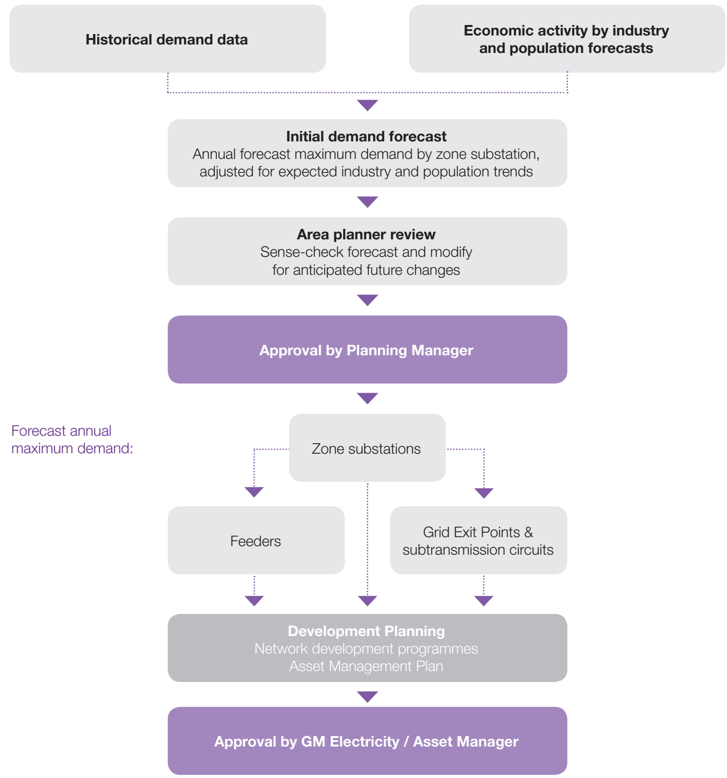
These forecasts are primarily based on the zone substation forecast. At this level of network aggregation, demand data is robust and still provides enough resolution for planning purposes. Forecasts at a per feeder level are more prone to the uncertainty and higher variability introduced by single events or factors.

The growth rates of the underlying zone substations are used to determine our subtransmission or GXP growth rate forecasts. This is done through a weighting factor that represents the proportion of maximum demand at each substation and the diversity[23] between them. This allows more rigour than directly trending GXP data only.

The diagram below shows the key elements of our current demand forecasting approach.

[23] Diversity is the ratio of the total coincident demand of multiple loads divided by the sum of the individual anytime peak demands of each individual load.

Figure 8.2: **Demand forecasting approach**



Zone substation forecasting is at the heart of our demand forecasts, and we have developed a purpose built tool to assist with this. The tool allows us to identify the underlying trend in demand by removing:

- Temporary load transfers for operational switching, which can set false peaks
- Permanent load transfers for network reconfiguration, which cause step interruptions in the historical trend

The tool also acts as a permanent archive of historical data as each year's new data is introduced and analysed. It records the decisions relating to filtering or econometric weightings. This improves consistency and transparency.

The forecast tool also assists planners in assessing the existing maximum demand. This is not always straightforward as historical peaks need to be reviewed to account for the effects associated with load transfers.

One of the recent improvements to our forecasting has been to introduce weighted econometric parameters sourced from New Zealand Institute of Economic Research (NZIER). These provide a range of sector based economic and demographic trends that we then map to our planning areas by industry sector (using installation connection numbers and types).

We record significant changes in forecast demand. These are almost always from customer developments, which in most cases cannot be confirmed until close to the date when financial commitments are made. As such, a number of potential load developments are included in our base forecast. Options analysis helps ensure we optimise our growth and security expenditure based on customer growth, taking into account these uncertainties. As a final safeguard, no commitment for customer investments is made until formal customer agreements are concluded.

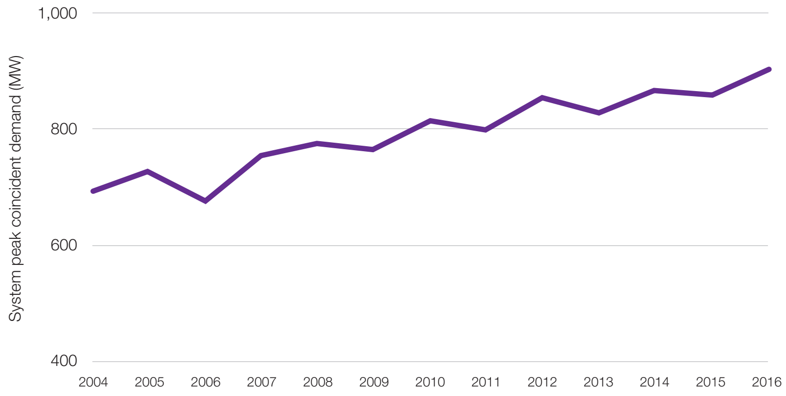
Historical demand data includes the impact of ripple control and embedded generation. Embedded generation is still expected to be below the threshold of significance over the planning period, with a few exceptions that can be adjusted for. The use of ripple control (to control hot water storage heaters) does have the potential to distort the peak network loads that are recorded, particularly as the reasons and methods for using ripple control can change over time. In many cases the true unconstrained peak loads on our network (i.e. no ripple use) would be significantly higher than those that have been recorded. The future use of our ripple controlled load is under consideration. Managing the impact that ripple control has on our demand forecast remains something we will incorporate in future improvements to our forecasting process.

At present we treat PV growth as a negative load, with no material impact on underlying demand growth. In future, when the impact becomes material, we propose to consider separate forecasting and even separate planning processes to accommodate distributed generation. Chapter 11 discusses future PV uptake.

8.4.1.2 DISCUSSION ON OBSERVED TRENDS

In the past decade, at a national and local grid level, many sources in New Zealand have reported flat or reducing peak demand. In contrast, our network has continued to experience steady and sustained growth. The chart below shows the historical demand trend for our network.

Figure 8.3: **Historical system load demand trend**



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 below indicate annual historical growth rates by planning area for the western and eastern regions.

Figure 8.4: **Historical demand growth in western planning areas**

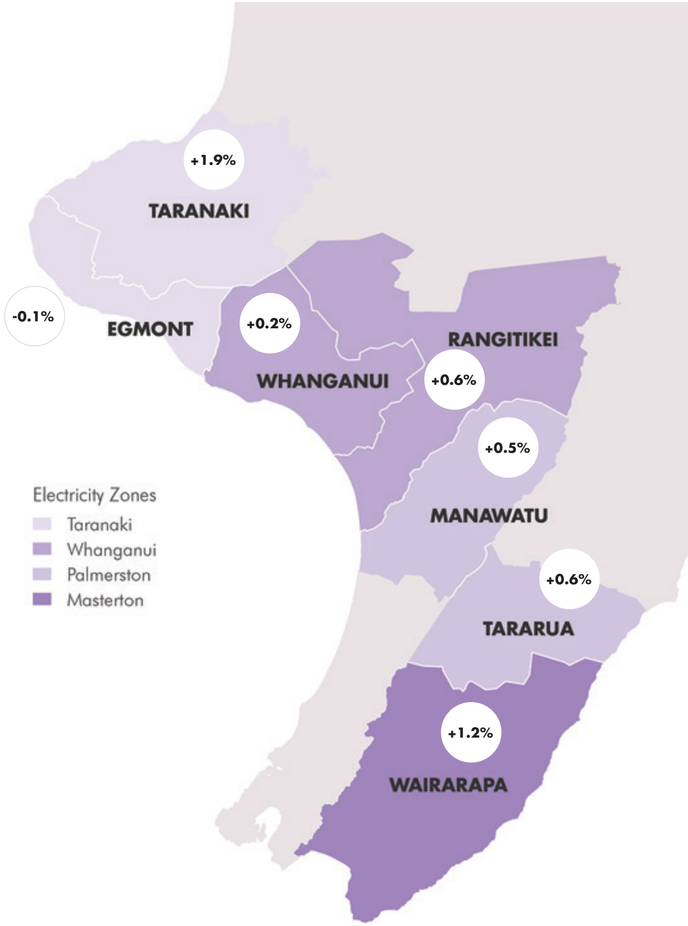
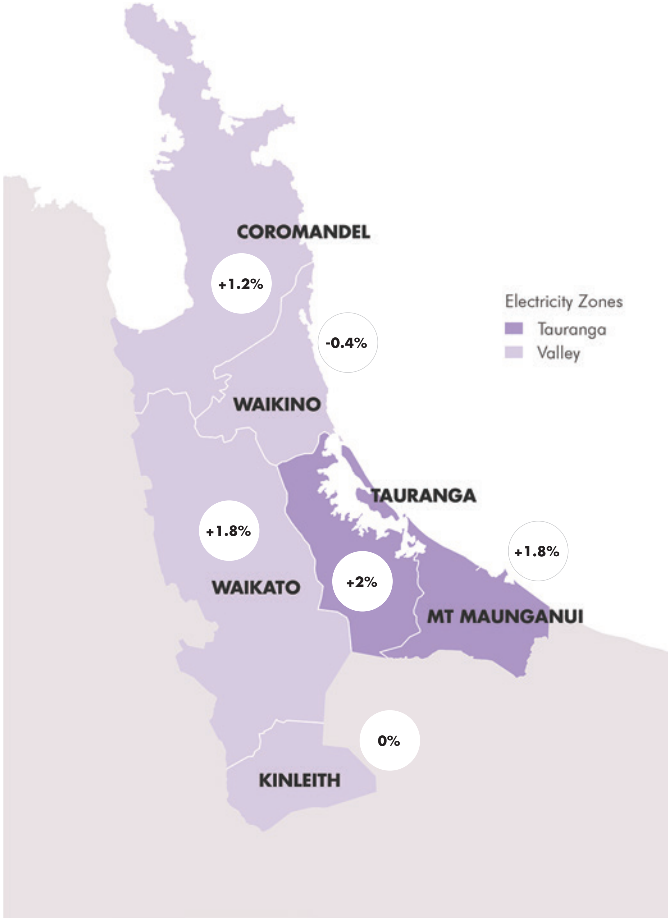


Figure 8.5: **Historical demand growth in eastern planning areas**



Higher growth is evident in areas such as:

- Tauranga and Mt Maunganui – population increase driving residential subdivisions and commercial/industrial developments.
- Waikato – dairy and associated food processing industries.
- Taranaki – industrial, often associated with oil and gas.

Embedded generation

Wind generation development on our network has been very infrequent. 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 tend to be connected directly to the transmission grid and do not impact our growth and security planning directly.

Small scale solar PV uptake continues to grow, but to date there has been little interest in utility scale PV.

8.4.2 ASSET RATINGS

The ratings (i.e. 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 that load profiles and fault occurrences are also statistical distributions, the management of load against capacity requires statistical risk assessment.

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** – 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** – standard assigns a nominal continuous rating that is used to systematically identify potential future overloads. Short-term ratings (i.e. 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.

8.4.3 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 (e.g. 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.

8.4.4 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 high demand times without extended loss of supply to customers. At the levels of load encountered at most of our zone substations, N-1 is the optimal consideration (i.e. 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 failed. Three of our five security classes are qualified by the allowable switching time before all load can be restored.

Lastly, 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 interpret their feedback on the price/quality trade-off, and also consider the results from other benchmarks, trends or comparisons.

8.4.4.1 REVIEW OF OUR SECURITY STANDARDS

We have begun a review of our security criteria and network architecture as we plan for possible technological shifts in future networks. As part of this we have recently commissioned a review to provide a comparison with other distributors in New Zealand and overseas.

We have however been cautious not to introduce new criteria until our review is complete and we understand the full implications of changing energy trends and requirements. This is especially important since our network is an amalgamation of several historically separate networks that have had diverse approaches to security.

We have also sought to align 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.

8.4.4.2 A TWO-STAGE APPROACH TO SECURITY STANDARDS

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 standard is essentially a deterministic approach. It is used to provide a consistent and systematic review 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 the constraints adopts a more probabilistic, reliability based analysis.

We chose this two-stage approach since the 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 probabilistic criteria can 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 (i.e. the consequence or cost) of an outage if it occurs at peak demand, but not the probability (i.e. likelihood or frequency of outages). However, they are easy and accurate to apply from a planning or operational perspective.

With the two-step approach we have applied, all potential needs are detected during the initial systematic review of the entire network against the deterministic security criteria. These are then assessed further through options analysis, taking into account demand profiles and the impact of outages. This helps determine the optimum cost effective solutions.

In cases where there is 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.

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. The zone substation security classes are then determined from the following matrix, which is a function of both 11kV feeder type and amount of load involved.

Table 8.2: **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

Further details are set out in our security of supply standard. The feeder types are defined in Table 8.4.

The table above yields a desired security class for each zone substation. These classes are shown in demand forecast tables throughout this AMP.

The restoration targets assigned to each of the security classes are set out below.

Table 8.3: **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 relate to restoration time allowed.

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.

8.4.5 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.

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.

8.4.6 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 (i.e. dual circuit). We currently do not use duplexing.

A further option we are investigating is the development of a mobile substation. 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. If this mobile substation proves viable we will also review the implications to our security standards and development planning.

Option analysis uses a 20-year period for cost assessments. A life cycle approach involves consideration of all appropriate cost elements, including Capex, maintenance and network losses. The analysis includes reliability, where this reflects the cost of unserved energy to customers in the event that supply cannot be maintained. The analysis identifies the most cost effective, long-term solution.

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

8.4.7 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 or water storage are also being developed. 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.
- **Demand side management** – technology offers emerging possibilities ranging from simple variable thermostats through to smart appliances and home energy management systems.
- **Power flow management** – 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. However, ripple control systems are not well suited to localised network constraint management. Furthermore, past distribution price structures and instantaneous gas hot water options have eroded the base of switchable load.

8.4.8 DISTRIBUTION PLANNING

Distribution planning ensures that 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 customer, served by that feeder. This load type is a proxy for the economic impact of lost supply, and therefore the target reliability standards for each feeder type differ to show the significance of reliable supply.

Table 8.4: **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 often triggers the need to increase back-feed capacity. For more information on our reliability and automation plans, see Chapter 10.

There are a number of other drivers for investing in distribution feeders, which are listed below.

- 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 (i.e. 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 types of 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 (i.e. regulators or capacitor banks)

8.4.9 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 (e.g. 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.[24]

[24] http://www.powerco.co.nz/Get-Connected/Distributed-Generation/

8.5 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.

8.5.1 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 $49.1m, the second largest spend of all our areas.

8.5.1.1 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.

8.5.1.2 DEMAND FORECASTS

Demand forecasts for the Coromandel zone substations are shown below, with further detail provided in Appendix 7.

Table 8.5: Coromandel zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Coromandel	AA	0.0	4.6	4.9	5.1	5.4
Kerepehi	A1	3.0	9.7	10.4	11.1	12.0
Matatoki	AA+	3.0	4.7	5.2	5.7	6.2
Tairua	AA	8.5	8.4	9.0	9.6	10.2
Thames T1&T2	AA	6.1	11.8	12.2	12.8	13.6
Thames T3	AA	6.9	3.3	3.5	3.8	4.0
Whitianga	AA	1.5	16.4	17.6	18.9	20.4

Growth is forecast to be steady, especially on those substations that supply popular holiday towns. This is 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 2015. 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.

8.5.1.3 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 8.6: 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 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, and Kopu-Kauaeranga
Kerepehi substation	Single circuit – insufficient 11kV back-feed to meet security criteria.	Kerepehi-Paeroa upgrade
Coromandel substation	Single 66kV circuit with minimal 11kV back-feed.	Kaimarama-Whitianga circuit
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

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, potentially using transformers from other sites.

8.5.1.4 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):	$8.8m
Expected project timing:	2019-2023

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 a 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. Because of the high cost the options will be subject to further review and the proposed project scope could be refined in the future.

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):	$6.5m
Expected project timing:	2020-2022

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 a separate project to install capacitor banks at Whitianga and Tairua.

NEW KOPU–KAUAERANGA LINE

Estimated cost (consenting):	$7.5m
Expected project timing:	2017-2020

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 Thames, Coromandel and Whitianga substations on the 66kV ring during an outage of the Kopu-Tairua 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.

WHENUAKITE SUBSTATION

Estimated cost (concept):	$8.2m
Expected project timing:	2021-2023

The two 11kV feeders supplying the coastal area south of Whitianga, including the holiday townships of 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.

Options considered are detailed in Appendix 8. This analysis needs to be considered in conjunction with a proposed Matarangi substation.

The proposed solution is to construct a new Whenuakite zone substation. It is proposed to supply this substation from the existing 66kV ring 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):	$11.3m
Expected project timing:	2023-2025

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.

Options considered are detailed in Appendix 8. This analysis needs to be considered in conjunction with that for the possible Whenuakite substation (see previous project).

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 earlier.

KEREPEHI-PAEROA UPGRADE

Estimated cost (concept):	$6.8m
Expected project timing:	2017-2021

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 upgrade an existing 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.

8.5.1.5 OTHER DEVELOPMENTS

We are planning to install capacitor banks at Tairua and Whitianga to address the immediate 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.

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.

8.5.2 WAIKINO

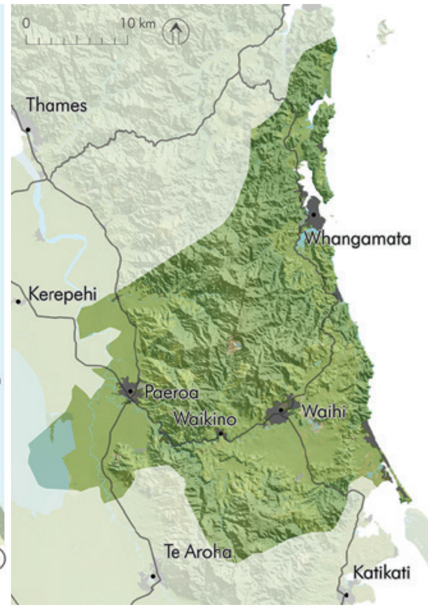
The Waikino area includes the popular holiday town of Whangamata, which is supplied by a single 33kV circuit from Waihi. The main growth and security project in this area is to add a second 33kV line from the Waikino substation to Whangamata. Major and minor project spend related to security over the next 10 years is $9.7m.

8.5.2.1 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 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.

8.5.2.2 DEMAND FORECASTS

Demand forecasts for the Waikino zone substations are shown below, with further detail provided in Appendix 7.

Table 8.7: **Waikino zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Paeroa	AA	7.8	8.0	8.5	9.0	9.6
Waihi	AA	12.0	18.7	20.3	21.8	23.4
Waihi Beach	A1	2.0	5.4	5.8	6.1	6.5
Whangamata	AA	2.0	9.5	10.1	10.8	11.4

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.

8.5.2.3 EXISTING AND FORESEEN CONSTRAINTS

Major constraints affecting the Waikino area are shown below.

Table 8.8: **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.	Note 3
Waihi substation	Demand exceeds secure capacity of the two transformers.	Note 4
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 5
Paeroa substation	Expected end-of-life of transformers (x2).	Note 5

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. A project is included in the Works Plan to construct a new section of line from Waihi substation to the tee, and install a dedicated circuit breaker off the Waihi bus.
4. 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.
5. 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.

8.5.2.4 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):	$8.4m
Expected project timing:	2017-2021

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 solution we propose is to install 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.

WAIHI BEACH SUBSTATION SUPPLY TRANSFORMERS

Estimated cost (concept):	$1.3m
Expected project timing:	2021-2023

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.

8.5.2.5 OTHER DEVELOPMENTS

A new section of line is under construction from Waihi substation to the tee for the Waihi Beach circuit. This allows supply to be maintained to Waihi Beach even if the Waikino to Waihi circuit is out of service.

8.5.3 TAURANGA

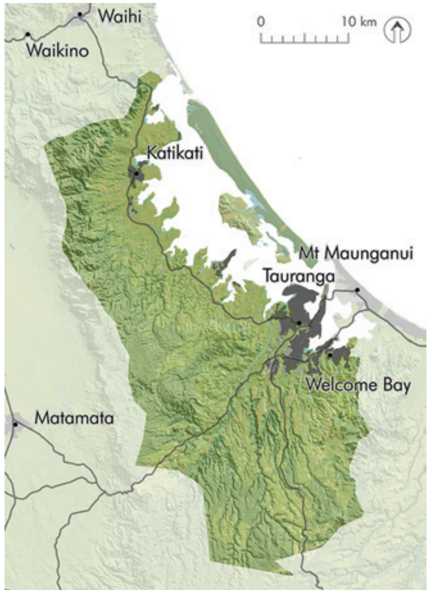
The Tauranga region has historically had high demand growth driven by population growth, and we are expecting this to continue.

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 $16.1m.

8.5.3.1 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 and Otumoetai, with a single 33kV radial circuit from Otumoetai to 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.

8.5.3.2 DEMAND FORECASTS

Demand forecasts for the Tauranga zone substations are shown below, with further detail provided in Appendix 7.

Table 8.9: **Tauranga zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Aongatete	A1	5.0	6.2	6.7	7.2	7.8
Bethlehem	AA	8.9	8.2	9.0	9.7	10.5
Hamilton St	AAA	26.2	16.0	17.4	19.1	21.3
Katikati	AA+	4.0	7.7	8.2	8.8	9.4
Kauri Pt	A1	2.0	2.7	2.9	3.1	3.3
Matua	AA	3.5	10.5	11.4	12.1	12.9
Omokoroa	AA	12.1	11.6	12.6	13.6	14.7
Otumoetai	AA	13.6	8.7	9.3	9.9	10.5
Tauranga 11	AAA	30.0	28.4	30.5	34.1	38.1
Waihi Rd	AAA	26.1	21.4	23.4	25.7	28.1
Welcome Bay	AA	22.2	22.0	24.9	27.4	29.7

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.

8.5.3.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tauranga area are shown below.

Table 8.10: 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 insufficient 11kV back-feed to secure all load at Matua. The 33kV line shares poles with the 11kV feeder used to back-feed.	Note 4
Otumoetai and Bethlehem substations	An outage on one of the 33kV circuits from Greerton feeding the Otumoetai-Bethlehem ring can cause overloading on the remaining circuit.	Otumoetai-Bethlehem
Matua substation	An outage on one of the two Greerton-Otumoetai 33kV circuits can cause low voltages at Matua substation.	Otumoetai-Bethlehem
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.	Note 7
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. Matua has a lot of 11kV inter-tie capacity and although this can't nominally meet security standards, the risk can be managed operationally for now. The longer term plan is to construct a second 33kV circuit.
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. A routine size project is in the works plan to upgrade the transformers at Matua.
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.

8.5.3.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major projects planned for the Tauranga area.

OTUMOETAI-BETHLEHEM

Estimated cost (design):	$2.7m
Expected project timing:	2015-2018

The 33kV ring from Greerton to Otumoetai and Bethlehem does not have sufficient capacity to secure all loads (including Matua, which is fed off Otumoetai) in the future. Low voltage is also experienced when one circuit is out of service. The need to replace both the Otumoetai and Greerton 33kV switchboards was also considered alongside these growth and security constraints.

Options considered included additional circuits, both overhead and underground, upgrades to existing circuits, and possible network reconfigurations. Underground circuits are more viable through a heavily built up urban environment. Options to mesh the Bethlehem-Otumoetai ring with the northern Tauranga 33kV (Omokoroa) were considered but did not provide sufficient benefit for the complexity and cost.

The preferred solution, which is now in the design phase, is to install a new 33kV cable from Greerton to Otumoetai, with a new switchboard at Otumoetai to provide a fully secure back-feed to Bethlehem via the existing ring circuit.

NORTHERN TAURANGA REINFORCEMENT (OMOKOROA ADDITIONAL 33KV CIRCUITS)

Estimated cost (concept):	$8.3m
Expected project timing:	2017-2024

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):	$5.1m
Expected project timing:	2017-2019

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.

8.5.3.5 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.

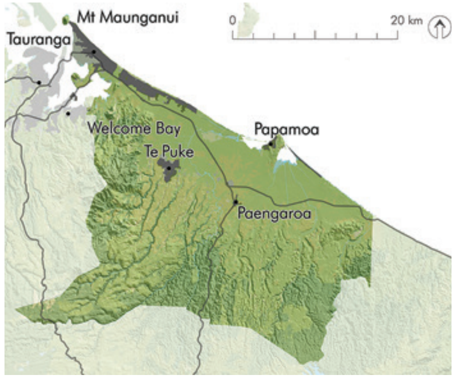
In the long-term, Sulphur Pt is an additional substation that is planned. This would be dedicated to the port and timing is largely related to the port's development plans. The new substation is not expected to be needed until the early 2020s. A 33kV cable is in place to a nominated substation site, 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.

8.5.4 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 $21.7m.



8.5.4.1 OVERVIEW

The Mt Maunganui area covers the urban parts of Mt Maunganui as well as the developing Papamoa and Wairakei coastal strip.

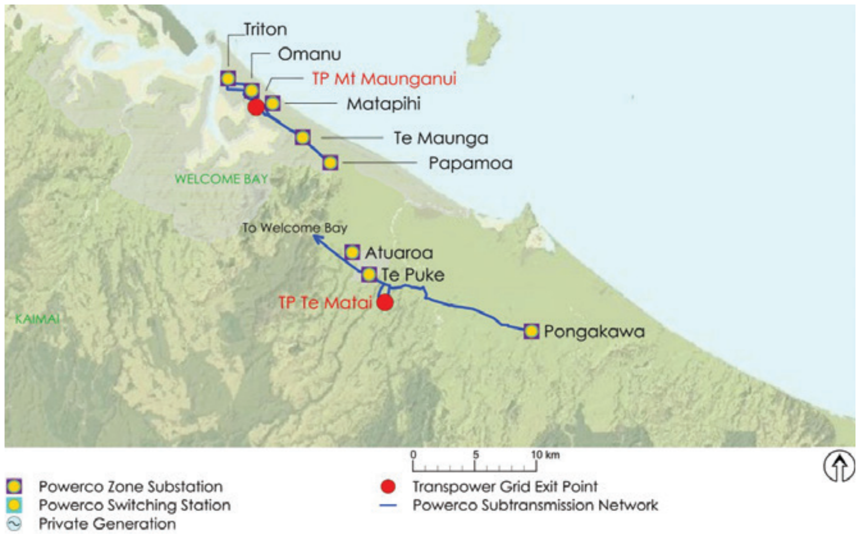
Our Mt Maunganui area also encompasses Te Puke and surrounding rural areas down to Pongakawa and the inland foothills. This is because the planned developments will link the Mt Maunganui and Te Puke electricity supplies and it is easier to consolidate the planning in one area.

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.

8.5.4.2 DEMAND FORECASTS

Demand forecasts for the Mt Maunganui zone stations are shown below, with further detail provided in Appendix 7.

Table 8.11: **Mt Maunganui zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Matapihi	AAA	26.2	11.9	12.7	13.6	14.6
Omanu	AAA	26.2	14.4	15.6	16.9	18.3
Papamoa	AAA	22.6	22.2	24.3	26.4	28.5
Te Maunga	AA	7.0	6.5	7.0	7.7	8.3
Triton	AAA	22.9	20.6	22.7	25.0	27.6
Atuaroa	AA+	5.0	7.8	8.4	9.2	10.0
Paengaroa	A1	6.5	6.5	7.2	7.9	8.7
Pongakawa	A1	3.2	4.8	5.5	6.3	7.2
Te Puke	AAA	22.9	15.6	17.4	19.2	21.1

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.

8.5.4.3 EXISTING AND FORESEEN CONSTRAINTS

Major constraints affecting the Mt Maunganui area are shown below.

Table 8.12: **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
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. New sections of cable through the airport will address immediate capacity constraints.
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.
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.

8.5.4.4 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):	$20.8m
Expected project timing:	2016-2019

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.

8.5.4.5 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.

8.5.5 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 $36.4m.

8.5.5.1 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.

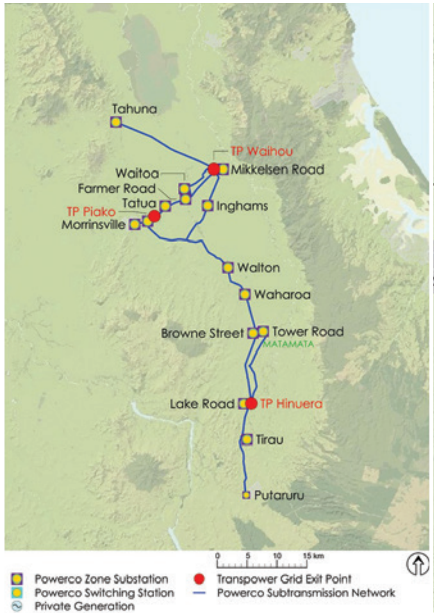
The environment is generally favourable to network construction, maintenance and operations. Peat lowland areas can provide challenges to structural foundations and thermal rating of cables.

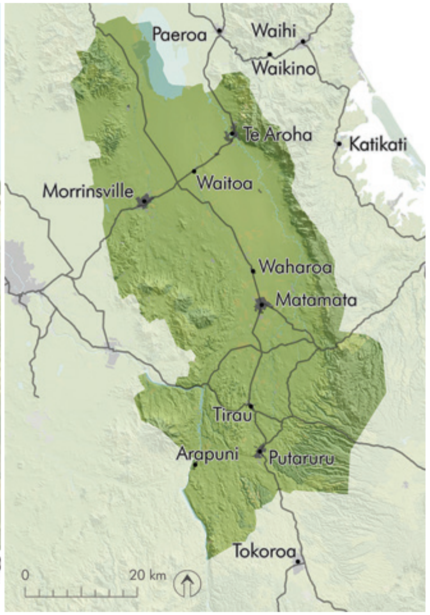
The climate is typical of the Waikato region with mild winters and warm humid summers. Being inland the region is relatively sheltered from extreme weather and coastal influence.

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.

[25] At present the supply to Waharoa substation is shared between two GXPs, Piako and Hinuera.

8.5.5.2 DEMAND FORECASTS

Demand forecasts for the Waikato zone substations are shown in the table below, with further detail provided in Appendix 7.

Table 8.13: **Waikato zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Farmer Rd	AA	6.4	5.7	6.6	7.4	8.2
Inghams	AA	5.0	3.8	4.0	4.2	4.5
Mikkelsen Rd	AA	20.7	15.0	15.8	17.0	18.4
Morrinsville	AA	3.0	9.8	10.2	10.7	11.4
Piako	AA	21.8	13.5	14.5	15.6	16.9
Tahuna	A2	3.0	5.7	6.0	6.3	6.8
Tatua	AA	5.0	3.9	4.1	4.4	4.7
Waitoa	AAA	20.0	14.7	15.5	16.3	17.1
Walton	A1	3.5	6.2	6.8	7.5	8.2
Browne St	AA+	12.8	9.3	10.1	11.0	12.0
Lake Rd	A1	2.4	5.8	6.4	7.0	7.6
Putaruru	AA	3.5	11.2	12.0	12.9	13.9
Tirau	AA+	2.8	9.4	10.0	10.6	11.1
Tower Rd	AA	3.0	9.0	9.8	10.6	11.5
Waharoa	AA	3.0	9.2	11.7	12.5	13.4

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.

8.5.5.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikato area are shown below.

Table 8.14: **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.	Piako GXP
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
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.	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.	Note 4
Inghams substation	Single transformer does not meet security standards.	Note 5

Notes:

1. Putaruru GXP is the main project to address Hinuera's lack of security (i.e. 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.
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.

8.5.5.4 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):	$9.3m
Expected project timing:	2016-2019

Hinuera GXP is supplied by a single 110kV circuit (25km) from Karapiro. Less than 10MW of the existing 43MW of Hinuera demand can be back-fed from Piako through 33kV tie lines. 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 build a new Putaruru GXP (110/33kV substation), which will connect to the grid through a new switching station on the 110kV Arapuni-Kinleith B line. A new 110kV cable will connect the switching station to the new 110/33kV substation, which will have just a single transformer. 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.

Advice from the system operator indicates that potential changes to North Island thermal generation in 2018 would place constraints on the available future capacity from Putaruru, which would require a review of the project's viability.

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.

PIAKO GXP (SECOND 110/33KV TRANSFORMER)

Estimated cost:	$1.6m
Expected project timing:	2016-2019

The Piako GXP was built three years ago to offload Waihou GXP which, at the time, was exceeding N capacity and was a very high risk.

Piako GXP is a two-transformer 110/33kV substation. As well as housing the original 40MVA transformer, a new 60MVA transformer was installed in 2015. The 40MVA is intended to be used at Putaruru GXP, once built, which means a second 60MVA unit will be bought for Piako. This is therefore linked to the timing of the Putaruru GXP project.

MATAMATA SUBTRANSMISSION (TOWER-BROWN 33KV CABLE)

Estimated cost (concept):	$1.4m
Expected project timing:	2019-2021

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):	$1.4m
Expected project timing:	2018-2019

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.

KEREONE-WALTON UPGRADE

Estimated cost (concept):	$6.9m
Expected project timing:	2018-2021

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.

MORRINSVILLE SECOND CIRCUIT

Estimated cost (concept):	$1.2m
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. 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):	$1.5m
Expected project timing:	2019-2021

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):	$1.6m
Expected project timing:	2021-2023

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. 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:	$1.3m
Expected project timing:	2020-2022

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.

PUTARURU-TIRAU UPGRADE

Estimated cost (concept):	$9.0m
Expected project timing:	2021-2023

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.

8.5.5.5 OTHER DEVELOPMENTS

A number of smaller subtransmission projects are associated with the larger projects identified previously, particularly securing the load from Hinuera GXP. These include:

- Upgrade the 33/11kV transformers at Putaruru substation and install a new indoor 33kV switchboard
- New 33kV switchboard at Hinuera GXP
- Thermal upgrade of Hinuera-Browne St 33kV line
- An upgrade of the single bank transformer at Tirau

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.

After these projects are completed there are still two significant constraints:

- 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
- The Tarukenga-Kinleith-Putaruru – Arapuni 110kV line's limit power flows on the interconnected grid, which in turn limits capacity and security at our GXPs and requires system splits or SPS

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 Arapuni-Putaruru-Kinleith 110kV line will require a significant level of investment to increase the capacity. The line is classified as 'interconnected grid' and will require a rigorous project plan and assessment of the economic cost of the load at risk. The lead time for this type of project is expected to be considerable.

8.5.6 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. Minor project spend related to growth and security over the next 10 years is $2.6m.

8.5.6.1 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.

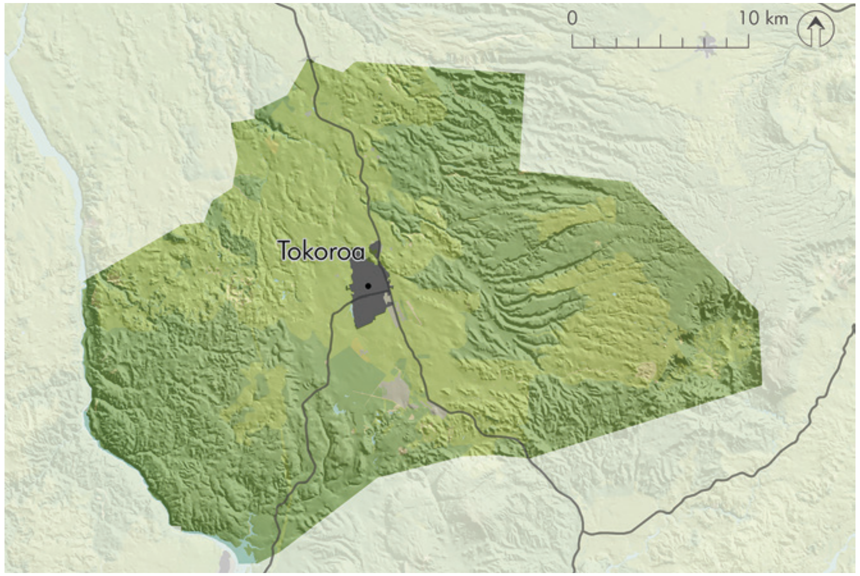
The area includes the large pulp and paper mill at Kinleith, which has a significant influence on the local economy, industry and employment. Other keys to the district's economy are primary production (dairy farming) and forestry.

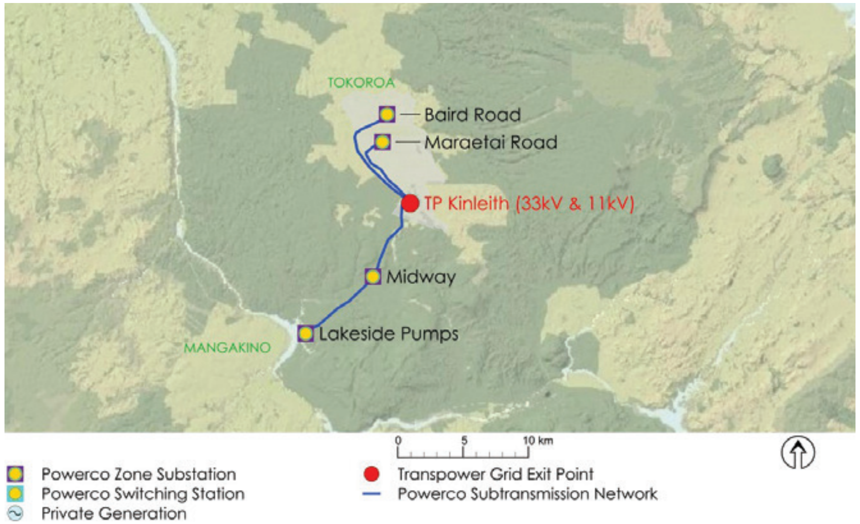
The terrain varies from rolling pasture land around Tokoroa to large expanses of pine forests around the Kinleith mill. The climate is similar to other parts of the Waikato, although it is slightly cooler as the area is on the fringes of the central North Island plateau.

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.

8.5.6.2 DEMAND FORECASTS

Demand forecasts for the Kinleith zone substations are shown below, with further detail provided in Appendix 7.

Table 8.15: **Kinleith zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Baird Rd	AA+	5.0	9.0	9.5	10.1	10.7
Maraetai Rd	AA+	4.0	11.7	12.8	13.8	14.7
Midway / Lakeside	A2	0.0	4.1	4.2	4.3	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 plan 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.

8.5.6.3 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 8.16: **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.

8.5.6.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Kinleith area.

BAIRD-MARAETAI 33KV CABLE RING	
Estimated cost: (design)	$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.

8.5.6.5 OTHER DEVELOPMENTS

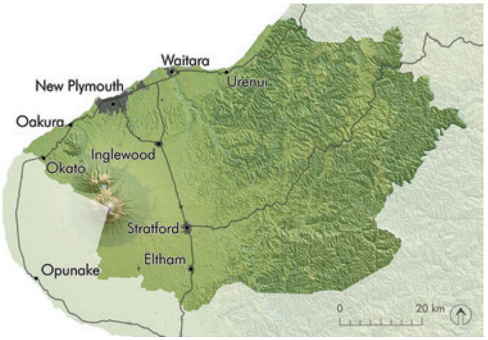
Transpower are working on detailed designs for a major refurbishment of the Kinleith GXP. As part of this, the 11kV feeders to the mill will need to be re-routed to new switchgear. Protection upgrades will be carried out at the same time. This work will be coordinated with the customer.

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. For further details, refer to the other developments section of the Waikato area (Section 8.5.5).

8.5.7 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. There are three minor projects to improve security with a total growth and security expenditure of $15.4m over the next 10 years.



8.5.7.1 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.

8.5.7.2 DEMAND FORECASTS

Demand forecasts for the Taranaki zone substations are shown below, with further detail provided in Appendix 7.

Table 8.17: **Taranaki zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Bell Block	AAA	22.9	17.6	19.1	21.1	23.2
Brooklands	AAA	27.0	21.1	24.4	27.7	31.0
Cardiff	A1	1.4	1.7	1.8	2.0	2.1
City	AAA	22.9	20.3	22.1	24.1	26.2
Cloton Rd	AA+	14.6	10.8	11.9	12.9	13.9
Douglas	A1	1.5	1.9	2.0	2.1	2.3
Eltham	AA+	11.3	10.2	10.8	11.5	12.4
Inglewood	AA	6.0	5.2	5.5	5.7	6.0
Kaponga	A1	3.0	3.4	3.6	3.9	4.3
Katere	AAA	24.3	11.8	13.7	15.4	17.1
Mckee	AA	1.5	1.3	1.4	1.5	1.6
Motukawa	A1	1.1	1.2	1.2	1.3	1.4
Moturoa	AAA	22.9	21.3	22.3	23.2	24.2
Oakura	AA	3.0	3.1	3.4	3.8	4.1
Pohokura	AA	10.0	7.2	7.3	7.6	8.0
Waihapa	AA	0.6	1.2	1.2	1.3	1.3
Waitara East	AA	10.1	6.5	6.6	6.8	6.9
Waitara West	AA	9.0	8.1	9.1	9.9	10.7

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.

8.5.7.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Taranaki area are shown in the following table.

Table 8.18: **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 220/110kV interconnection capability. This has implications on our subtransmission for the Moturoa substation.	Moturoa subtransmission
Stratford GXP	N-1 capacity exceeded - metering equipment.	Note 1
Carrington St GXP	N-1 capacity exceeded - secondary assets.	Note 2
Huirangi GXP	Transformer's firm capacity will be exceeded.	Note 3
Bell Block and Katere substations	The N-1 capacity of the two circuits feeding Bell Block and Katere substations is exceeded.	Huirangi-Bell Block upgrade
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 4
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 5
Kaponga substation	Demand exceeds secure capacity of the two transformers. Transformers are scheduled for replacement.	Note 5
McKee substation	Transformer is scheduled for replacement.	Note 6
Motukawa substation	The single transformer does not provide sufficient security and is scheduled for replacement.	Note 5
Waihapa substation	Transformer is scheduled for replacement.	Note 6
Oakura substation	Transformer does not provide sufficient security.	Note 4
Douglas substation	Transformer does not provide sufficient security.	Note 5
Waitara West substation	Demand exceeds secure capacity of the two transformers.	Note 5

Notes:

1. Two new 40MVA transformers were installed recently. These will provide N-1 capacity but metering equipment constrains this at present. The cost to fix this is minor and will be addressed as demand requires.
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 (i.e. via load transfer).
4. Oakura is a new N security substation. A project in 2016 will reinforce 11kV back-feeds and reduce the switching time of load transfer in order to improve security.
5. Risk is low because of the small load, the low probability of a transformer failure, and the availability of some 11kV back-feed. These issues will be managed operationally. Where renewal is required, the capacity of the replacement unit will also be designed to address the long-term development.
6. Capacity of the replacement units will take into account future development requirements.

8.5.7.4 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	$7.7m
Expected project timing:	2020-2021

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 need 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 have identified further economic benefit if they 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.

HUIRANGI-BELL BLOCK UPGRADE

Estimated cost: (construction)	$4.2m
Expected project timing:	2014-2016

The Bell Block and Katere substations are fed by two 33kV circuits from Carrington St GXP. The N-1 capacity of these two circuits has been exceeded. An alternative low capacity 33kV supply from Huirangi GXP can feed part of Bell Block's load, but this does not meet our security criteria for these two important substations feeding the growing industrial and residential developments.

To restore adequate security to Bell Block and Katere substations, Bell Block will be permanently transferred on to the Huirangi GXP and supplied through a new high capacity dual circuit line. This work is expected to be completed within the next year. Transpower have upgraded the Huirangi GXP transformers and 33kV switchgear in readiness for the new 33kV feeders.

WAITARA TO MCKEE 33KV LINE

Estimated cost (concept):	$1.5m
Expected project timing:	2020-2021

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:	$2.0m
Expected project timing:	2020-2022

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 (i.e. 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.

8.5.7.5 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.

The Inglewood and Motukawa area still uses a 6.6kV distribution voltage. Because growth is low, there is minimal pressure to consider upgrading, but it would be more economic from a spares and standards perspective. We will continue to replace assets in readiness for a future changeover to 11kV.

8.5.8 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 $2.4m.

8.5.8.1 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.

8.5.8.2 DEMAND FORECASTS

Demand forecasts for the Egmont zone substations are shown below.

Table 8.19: **Egmont zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Cambria	AAA	19.1	14.5	14.7	15.2	15.8
Kapuni	AA+	7.1	9.9	10.5	11.4	12.6
Livingstone	A1	2.9	3.4	3.5	3.7	3.9
Manaia	AA	5.5	8.2	8.8	9.4	10.1
Ngariki	A1	3.0	4.0	4.3	4.7	5.1
Pungarehu	A1	4.5	4.7	5.0	5.3	5.6
Tasman	AA+	6.1	6.8	7.1	7.4	7.8
Whareroa	A1	3.8	6.6	6.8	7.0	7.3

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.

8.5.8.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Egmont area are shown below.

Table 8.20: **Egmont constraints and needs**

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Hawera GXP	A 110kV outage causes low voltage at Hawera. The transformer firm capacity is exceeded.	Note 1
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 2
Pungarehu substation	Demand exceeds secure capacity of the two transformers. Transformer is scheduled for replacement in 2022.	Note 2
Tasman substation	Transformer firm capacity has been exceeded. Transformer is scheduled for replacement in 2023.	Note 2
Livingstone substation	Transformer firm capacity has been exceeded. Transformer scheduled for replacement in 2018.	Note 2
Ngariki substation	Single transformer. The 11kV back-feed does not meet security criteria.	Note 2
Whareroa substation	Single transformer. The 11kV back-feed does not meet security criteria. Transformer is scheduled for replacement in 2018.	Note 3

Notes:
1. Risk is low as the voltage constraint only applies with no generation. Transformer capacity is only limited by a bus section and can be managed operationally by using an adjoining Kupe transformer.
2. 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.
3. A substation at Mokoia is planned to replace the Whareroa substation during which the existing security issues will be considered.

8.5.8.4 MAJOR GROWTH AND SECURITY PROJECTS

Below are summaries of the major growth and security projects planned for the Egmont area.

MANAIA SUBTRANSMISSION

Estimated cost (concept):	$2.4m
Expected project timing:	2019-2021

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 (i.e. If the Hawera-Kapuni circuit is out of service).

Options considered are detailed in Appendix 8.

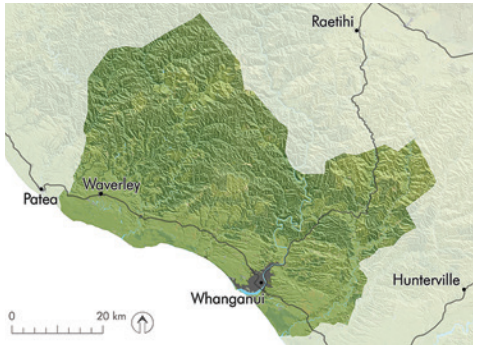
The proposed solution is a direct circuit between Manaia and Kapuni using a second circuit from Manaia to the tee and reconfiguring as a full ring connection.

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.

8.5.9 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 $6.7m.

8.5.9.1 OVERVIEW

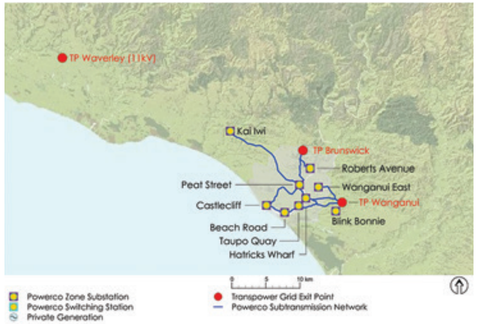


The Whanganui area covers the city of Whanganui and its surrounding settlements, which form the Whanganui district.

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. Wanganui 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 Wanganui East) are supplied from the Wanganui GXP, and four (Peat Street, Roberts Avenue, Kai Iwi, Castlecliff) from the Brunswick GXP. Waverley GXP directly supplies the Waverley township and surrounding areas via 11kV distribution feeders.

Whanganui has a relatively 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.

8.5.9.2 DEMAND FORECASTS

Demand forecasts for the Whanganui zone substations are shown below, with further detail provided in Appendix 7.

Table 8.21: **Whanganui zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Beach Rd	AA+	6.0	14.7	18.3	20.0	21.5
Blink Bonnie	A1	2.7	4.7	5.2	5.5	5.8
Castlecliff	AA+	9.2	10.9	11.4	11.8	12.2
Hatricks Wharf	AA+	9.2	12.4	13.0	13.6	14.4
Kai Iwi	A1	1.5	2.4	2.6	2.7	2.9
Peat St	AAA	21.8	17.1	17.3	17.6	18.1
Roberts Ave	AA	4.5	10.6	11.2	11.6	12.0
Taupo Quay	AA+	8.0	10.9	11.3	11.9	12.6
Wanganui East	AA	5.9	7.9	8.3	8.7	9.0

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.

[26] Springvale Structure Plan, Whanganui District Council, April 2012.

8.5.9.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Whanganui area are shown below.

Table 8.22: **Whanganui constraints and needs**

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Wanganui 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.	Note 2
Waverley GXP	Single 110/11kV transformer – no N-1 security.	Note 3
Taupo Quay, Beach Rd and Castlecliff substations	Wanganui GXP to Taupo Quay 33kV circuit: Insufficient capacity to supply all three substations during an outage of Brunswick-Peat St-Castlecliff circuits.	Taupo Quay second circuit
Hatricks Wharf and Taupo Quay substations	Insufficient capacity to supply both substations when the Hatricks Wharf 33kV circuit is not available.	
Peat St and Hatricks Wharf substations	Wanganui GXP to Hatricks Wharf 33kV circuit: Insufficient capacity to supply both substations when normal supply to Peat St via Brunswick is unavailable.	Peat St second circuit
Hatricks Wharf and Taupo Quay substation	Insufficient capacity to supply both substations when the Taupo Quay 33kV circuit is unavailable.	Taupo Quay second circuit
Beach Rd and Castlecliff substations	Taupo Quay to Beach Rd 33kV circuit: Insufficient capacity to supply both substations for an outage on Brunswick-Peat St-Castlecliff circuits.	Note 4
Peat St and Kai Iwi substations	Hatricks to Peat St 33kV circuit: Insufficient capacity to supply both substations when Brunswick GXP to Peat St circuit is unavailable.	Peat St second circuit
Castlecliff, Beach Rd and Taupo Quay substations	Peat St to Castlecliff 33kV circuit: Insufficient capacity to supply all three substations when the Taupo Quay 33kV circuit is unavailable.	Taupo Quay second circuit
Beach Rd and Taupo Quay substations	Beach Rd to Castlecliff 33kV circuit: Insufficient capacity to supply both substations when the Taupo Quay 33kV circuit is unavailable.	Taupo Quay second circuit
Peat St, Castlecliff, Beach Rd and Taupo Quay substations	Brunswick GXP to Peat St 33kV circuit: Insufficient capacity to supply all four substations when Wanganui GXP to Taupo Quay circuit is unavailable.	Taupo Quay second circuit
Roberts Ave substation	Single 33kV circuit from Brunswick GXP to Roberts Ave. The 11kV back-feed does not meet security standard.	Note 5
Wanganui East substation	Single 33kV circuit from Wanganui GXP to Wanganui East. The 11kV back-feed does not meet security standard.	Note 6
Kai Iwi substation	Long single 33kV circuit from Peat St to Kai Iwi. The 11kV back-feed does not meet security standard.	Note 7
Roberts Ave substation	Single transformer.	Note 8
Hatricks Wharf substation	Single transformer.	Note 8
Taupo Quay substation	Single transformer.	Note 8
Wanganui East substation	Single transformer.	Note 8
Kai Iwi substation	Single transformer. Renewal, scheduled for 2022.	Note 9
Beach Rd substation	Demand exceeds secure capacity of the two transformers.	Note 10
Blink Bonnie substation	Single transformer. Renewal - transformer replacement.	Note 9

Notes:

1. The replacement units will be sized appropriately for the forecast demand and required security. In the interim, the constraint is managed operationally by transferring load to Brunswick GXP if necessary.
2. We have investigated a second transformer at Brunswick during options analysis of the wider set of issues with the GXPs and subtransmission. The cost of a second GXP transformer is very high. The preferred development strategy is to provide greater inter-GXP transfer capacity through our 33kV subtransmission, which is inherent in the options considered to address subtransmission constraints. Both 33kV upgrades proposed for Whanganui help to significantly lower the risk associated with a single transformer at Brunswick. Risk is also mitigated through a non-contracted on-site spare, and the low probability of failure of such units.
3. We and Transpower have previously assessed that a second transformer at Waverley GXP is not economic. Full N-1 cannot be justified for such a small load. We will consider further options to improve 11kV inter-tie capacity to other GXPs.
4. Beach Rd is sub-fed from Taupo Quay through a single 33kV circuit. When normal supply to Castlecliff is interrupted, this circuit must carry both Castlecliff and Beach Rd. While the total demand exceeds the capacity, the margin is not great and only exposes a small risk of lost supply at peak loading and if a fault occurs at the same time. There is also 11kV load that can be transferred away, although not strictly in the time required by the security classes. As such, we will continue to manage this constraint operationally. It is possible that the proposed new second circuit from Wanganui GXP to Taupo Quay may be more appropriate to terminate at Beach Rd, in which case this constraint will also be alleviated.
5. Options to secure Roberts Ave, possibly through a 33kV ring with Peat St, were considered. The preferred option was a second circuit to Peat St. To improve Roberts Ave reliability we will look at improving the already strong 11kV inter-tie with Peat St.
6. A second circuit to Wanganui East was considered during options analysis but was not cost effective. Instead we will look at opportunities to further reinforce the 11kV inter-tie capacity.
7. 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.
8. Consideration has been given to installing second transformers at each of these substations. The single transformer configuration, while not strictly complying with our security criteria, is highly cost effective and mitigated by the strong 11kV inter-tie capability in the Whanganui network architecture. Some substations are physically too small to enable second banks to be installed. Hatricks Wharf and Taupo Quay are already configured in a pseudo N-1 configuration by paralleling the two 11kV busses.
9. 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.
10. A second transformer was recently added to provide security. Customer load increases will drive further upgrades.

8.5.9.4 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. The two most significant growth and security projects 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):	$3.8m
Expected project timing:	2021-2023

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 Wanganui 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.

BRUNSWICK GXP TO PEAT ST SECOND CIRCUIT	
Estimated cost (concept):	$2.9m
Expected project timing:	2017-2021

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 proposed solution is to build a second circuit from Brunswick GXP to Peat St. This will operate in parallel with the existing circuit and ensure Peat St is fully secure in regard to subtransmission contingencies. Security will also be improved for Roberts Ave, Castlecliff and Kai Iwi.

The security issue with the single 220/33kV transformer at Brunswick GXP is not resolved by this project to build a second circuit to Peat St. However, the Taupo Quay second circuit does mitigate the risk by providing sufficient emergency back-feed for what would be a very rare (high impact, low probability) event such as the failure of the Brunswick transformer.

The proposed solution also does not directly resolve the Roberts Ave security. It is intended that additional 11kV transfer capacity, already quite substantial, should ensure adequate reliability for Roberts Ave customers even if it does not strictly comply with the security standard.

8.5.9.5 OTHER DEVELOPMENTS

Transpower are replacing the 33kV switchboard at Wanganui GXP and have 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.

8.5.10 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. As such there are no major or minor growth and security projects planned for the next 10 years.

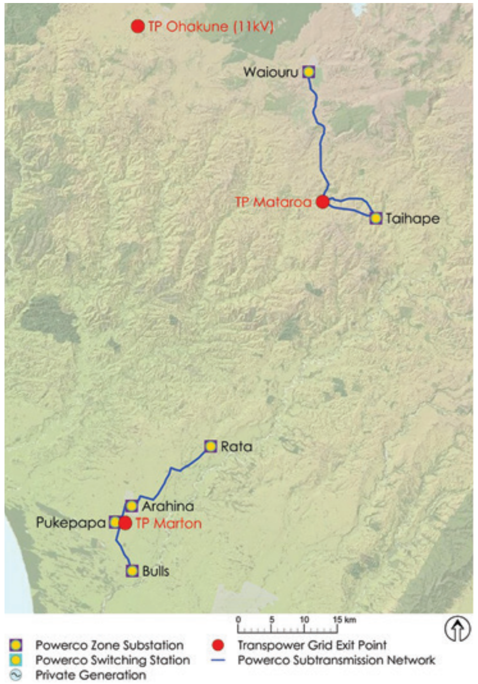
8.5.10.1 OVERVIEW

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.

8.5.10.2 DEMAND FORECASTS

Demand forecasts for the Rangitikei zone substations are shown below, with further detail provided in Appendix 7.

Table 8.23: **Rangitikei zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Taihape	A1	3.0	5.3	5.5	5.6	5.8
Waiouru	A1	2.6	2.6	2.6	2.7	2.7
Arahina	AA	7.4	9.1	9.2	9.5	9.8
Bulls	AA	3.6	6.0	6.5	6.9	7.4
Pukepapa	A1	4.0	9.1	10.0	10.9	11.8
Rata	A1	2.0	2.5	2.7	2.9	3.1

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.

8.5.10.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Rangitikei area are shown in the following table.

Table 8.24: **Rangitikei constraints and needs**

LOAD AFFECTED	MAJOR ISSUES	GROWTH & SECURITY PROJECTS
Mataroa GXP	Single 110/33kV transformer provides no security.	Note 1
Ohakune GXP	Single 110/11kV transformer provides no security.	Note 1
Waiouru substation	Single Waiouru 33kV circuit does not provide security.	Note 2
Waiouru substation	Single 33/11kV transformer does not provide security.	Note 2
Taihape substation	Mataroa GXP to Taihape 33kV circuits: Old manually operated switchgear prevents parallel operation so security to substation is not fully met.	Note 3
Taihape substation	Single 33/11kV transformer does not provide security.	Note 2
Marton GXP	Firm capacity for 110/33kV supply transformers is exceeded.	Note 4
Arahina and Rata substations	Single circuit to Arahina. Security to both subs is restricted.	Note 2
Arahina substation	Single 33/11kV transformer does not provide security.	Note 2
Rata substation	Single Arahina to Rata 33kV circuit does not provide security.	Note 2
Rata substation	Single 33/11kV transformer does not provide security.	Note 2
Bulls substation	Single Bulls 33kV circuit does not provide security.	Note 5
Bulls substation	Single 33/11kV transformer does not provide security. Transformer replacement is scheduled for 2023.	Note 2
Pukepapa substation	The single supply transformer does not provide sufficient security to the substation.	Note 2

Notes:
1. Previous analysis and public consultation have assessed that the cost of a second unit is not justified. Transpower have a mobile substation that can mitigate the impact of outages.
2. Provision of N-1 for 33kV circuits or zone transformers is not economic for small low criticality loads. Options to improve 11kV back-feed will be considered under routine planning. Back-feed may improve reliability but often cannot fully meet the security standards.
3. These constraints will be addressed through the replacement of switchgear, which is scheduled under our renewal programme.
4. Transpower asset. Auxiliary components are the existing limitation. Transformers are due for renewal soon. Other projects (Sanson-Bulls) may drive this upgrade sooner.
5. Options to improve Sanson security may also bring improvements to Bulls through a new Sanson-Bulls tie line (refer to option discussion under section 8.5.11).

8.5.10.4 MAJOR GROWTH AND SECURITY PROJECTS

Although there are numerous issues (i.e. 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 8.5.11 for further details.

8.5.10.5 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.

8.5.11 MANAWATU

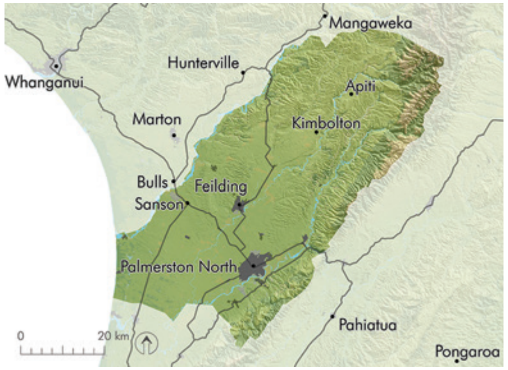
Palmerston North CBD has a meshed network supplied from two high capacity GXPs and uses several 33kV underground oil-filled cables. Some of our transformers at the CBD substations, and the 33kV cables feeding these, have exceeded or are approaching their secure capacity.

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 $28.1m. There are also a number of other projects planned to upgrade the transformers in existing substations and build a new substation at Rongotea.

Major and minor project spend related to growth and security over the next 10 years is $50.5m, the largest amount of any of our 13 areas.

8.5.11.1 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.

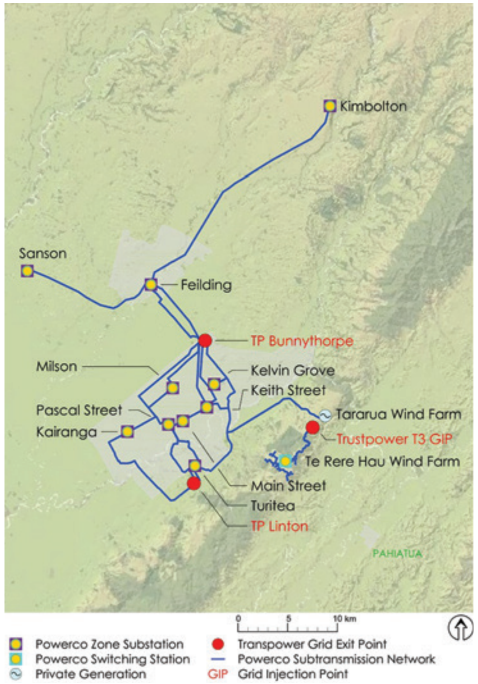
Bunnythorpe GXP supplies seven zone substations – Keith St, Kelvin Gr, Main St, Milson, Feilding, Kimbolton and Sanson.

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 (i.e. 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.

8.5.11.2 DEMAND FORECASTS

Demand forecasts for the Manawatu zone substations are shown below, with further detail provided in Appendix 7.

Table 8.25: **Manawatu zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Feilding	AAA	23.9	22.0	23.6	25.1	26.6
Kairanga	AAA	19.1	17.8	19.7	21.7	23.8
Keith St	AAA	23.8	20.5	22.0	23.2	24.2
Kelvin Grove	AAA	17.2	13.8	15.9	17.5	18.9
Kimbolton	A1	2.0	3.2	3.4	3.6	3.8
Main St	AAA	24.8	28.7	30.4	32.2	34.1
Milson	AAA	19.2	16.0	16.6	17.2	17.9
Pascal St	AAA	24.6	23.4	24.7	25.9	27.1
Sanson	AA+	5.2	9.0	9.7	10.4	11.0
Turitea	AAA	17.9	14.9	15.7	16.6	17.7

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 Gr 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.

8.5.11.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Manawatu area are set out in the following table.

Table 8.26: **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
Keith St substation	Demand exceeds firm capacity of the two transformers.	Palmerston North CBD
Kimbolton substation	Single 33kV circuit from Feilding to Kimbolton. The 11kV back-feed capacity does not meet security criteria.	Note 2
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

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.

8.5.11.4 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):	$28.1m
Expected project timing:	2015-2020

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):	$6.6m
Expected project timing:	2020-2022

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.

Further details of the options considered and reasons for adopting this strategy are included in Appendix 8.

This project is dependent on a number of inter-related issues – future plans for Ohakea, long-term solutions for Feilding and Bunnythorpe, and irrigation and other load growth around the Oroua Downs area, which may prompt a new substation at Rongotea.

RONGOTEA ZONE SUBSTATION

Estimated cost (concept):	$6.6m
Expected project timing:	2022-2024

The Rongotea area is supplied from the Sanson and Kairanga substations through a number of interconnected radial 11kV feeders. Because of strong growth in irrigation and other rural activities, these feeders are nearing their capacity. Interim solutions such as voltage regulators have already been used with another being installed this year.

Options considered are detailed in Appendix 8.

The proposed long-term solution involves building a new zone substation at Rongotea. The substation will supply parts of the existing Oroua Downs, Rongotea, Bainesse and Taikorea 11kV feeders. It will remove capacity constraints, enabling expansion of irrigation. The substation will also shorten all the 11kV feeder lengths, therefore improving network voltages and reliability. Offloading Sanson and Kairanga substations are also further benefits.

Our approach to the 33kV supply for Rongotea is to build a new 33kV capable line from Kairanga and operate this as an additional 11kV feeder to defer the new substation for as long as possible.

KAIRANGA TRANSFORMERS

Estimated cost:	$2.4m
Expected project timing:	2020-2022

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:	$2.0m
Expected project timing:	2021-2022

The Sanson substation supplies Sanson township, Rongotea and Himatangi areas, and the Ohakea air base. The substation contains two 7.5MVA rated transformers. 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:	2021-2023

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:	$2.4m
Expected project timing:	2021-2023

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.

8.5.11.5 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 (i.e. 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 (i.e. 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.

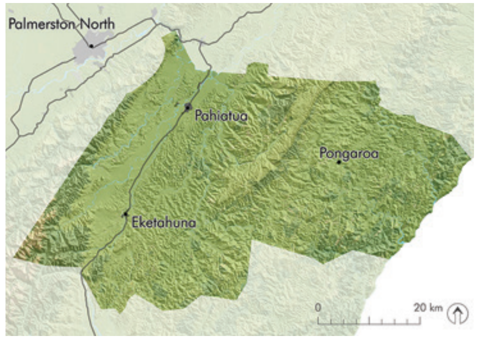
The Manawatu area is known for its wind generation. Most of the prime sites appear to have been used and we are not aware of any immediate new developments. The larger scale of wind generation often means these projects connect directly with the grid. Smaller embedded generation is not yet of a nature or scale to have an impact on demand peaks.

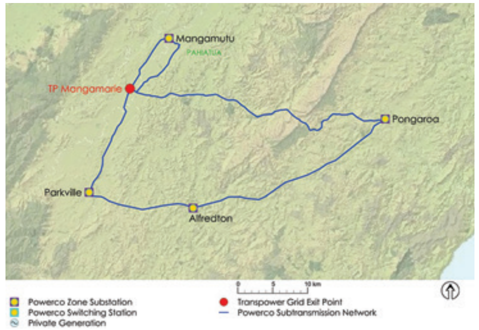
We will investigate non-network opportunities, particularly where this might defer major investment (i.e. cogeneration in central Palmerston North).

8.5.12 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.

8.5.12.1 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.

8.5.12.2 DEMAND FORECASTS

Demand forecasts for the Tararua zone substations are shown in the following table.

Table 8.27: **Tararua zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Alfredton	A1	0.6	0.4	0.5	0.5	0.5
Mangamutu	AA+	9.9	9.8	15.8	16.3	16.8
Parkville	A1	1.9	2.1	2.2	2.3	2.3
Pongaroa	A1	0.8	1.0	1.0	1.0	1.0

The high rate of demand growth 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 1.2%.

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.

8.5.12.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tararua area are shown below.

Table 8.28: **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	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.

8.5.12.4 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.

8.5.13 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.

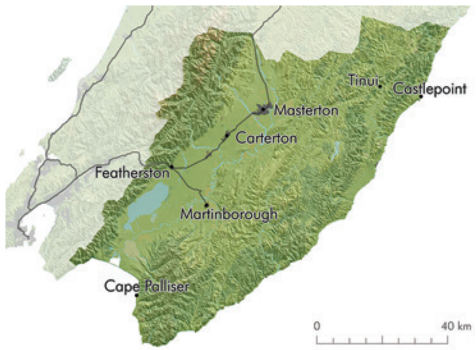
8.5.13.1 OVERVIEW

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.



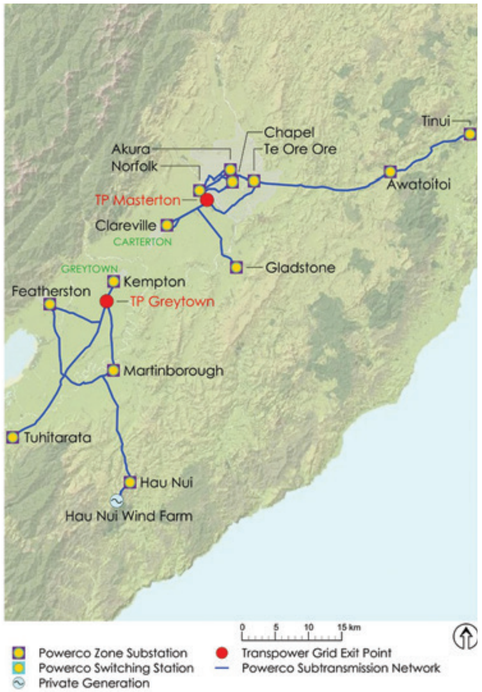
Adjacent is a low lying area that is generally flat or rolling and in which are located the main urban centres. To the east the terrain is generally hilly through to the coast.

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.

8.5.13.2 DEMAND FORECASTS

Demand forecasts for the Wairarapa Zone Substations are shown below, with further detail provided in Appendix 7.

Table 8.29: **Wairarapa zone substation demand forecast**

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2015	2020	2025	2030
Akura	AAA	10.9	13.5	14.2	14.9	15.8
Awatoitoi	A2	1.2	0.7	0.8	0.8	0.8
Chapel	AAA	22.9	14.9	16.0	17.2	18.5
Clareville	AA	10.5	11.2	11.7	12.1	12.5
Featherston	A1	4.0	5.7	6.0	6.4	6.8
Gladstone	A2	1.2	0.9	1.0	1.0	1.1
Hau Nui	A1	0.3	1.0	1.0	1.0	1.0
Kempton	A1	3.8	5.2	5.6	6.0	6.3
Martinborough	A1	2.5	5.3	5.6	5.9	6.2
Norfolk	AA+	7.0	6.4	6.7	7.1	7.6
Te Ore Ore	AA	6.9	7.8	8.3	8.8	9.3
Tinui	A2	0.8	0.6	0.7	0.7	0.7
Tuhitarata	A1	2.0	2.4	2.5	2.6	2.7

Growth in the Wairarapa area is modest. No significant residential demand increases (e.g. 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.

8.5.13.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Wairarapa area are shown below.

Table 8.30: **Tararua 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 1
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.	Note 3
Martinborough substation	Single transformer. The 11kV back-feed is insufficient to fully meet security criteria.	Note 3
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.	Note 3
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.	Note 3

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.

8.5.13.4 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.

8.6 TRANSMISSION AND 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 the following table, along with their respective peak load, capacity and security characteristics.

Table 8.31: **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	-

GXP NAME	TRANSFORMER (MVA)	N-1 CAP (MVA)	2015 MD (MVA)	N-1 SECURE	2015 MAX EXPORT (MW)
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	-
Wanganui (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 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 Wanganui 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 part of our growth and security plans for the past decade and is the main reason for 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 result of the customer's specific needs. Transpower are planning major replacement work at Kinleith soon, and designs are being developed to improve security to parts of the load and the Cogen plant.

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.

Spur acquisitions

Transpower have begun divesting spur assets to distributors when these assets could be more economically owned and operated by the distributor.

There are several possible divestments within our area, and the following are being considered:

- Hinuera GXP: a single radial 110kV circuit and GXP.
- Valley Spur: a dual circuit 110kV radial line serving 4 GXPs.

Other divestments that may be discussed in the future:

- Tauranga: 110kV ring serving Mt Maunganui and Tauranga GXPs (subject to the status of the circuits).
- Various 33kV switchboards and 110/33kV transformers.

Our previous initiatives to address security weaknesses affecting our GXPs at Waihou, Hinuera and Mt Maunganui helped instigate a strategy of increasing our capability to manage 110kV radial spur assets (both GXPs and supply circuits). This aligns with our business objectives and also the planned asset acquisitions from Transpower. We already operate some 110kV assets. We will build up fleets (spares, standards) and engineering capability (design, operation, maintenance) to manage these assets.

8.7 ROUTINE PROJECTS

8.7.1 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 Section 8.4.8). 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 (see other developments discussions in Sections 8.5.1 to 8.5.13).

8.7.2 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 strategy (refer Chapter 10) 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 Section 8.4.7), 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:

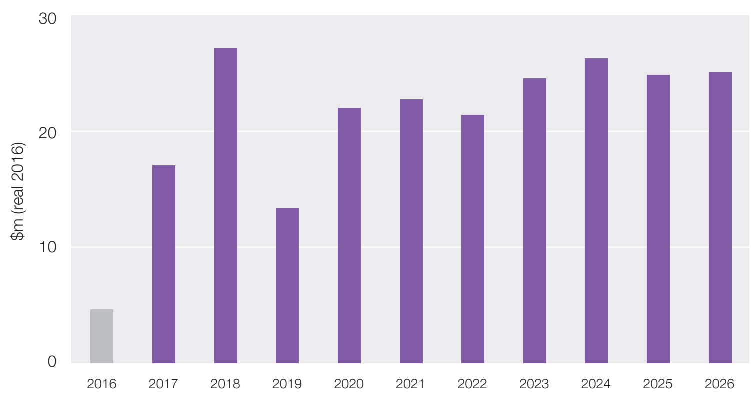
- Areas of intensive irrigation.
- Intensive dairy conversion, or existing dairy areas needing to upgrade plant.

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.

8.8 FORECAST GROWTH AND SECURITY CAPEX

The figures below show forecast growth and security Capex over the planning period.

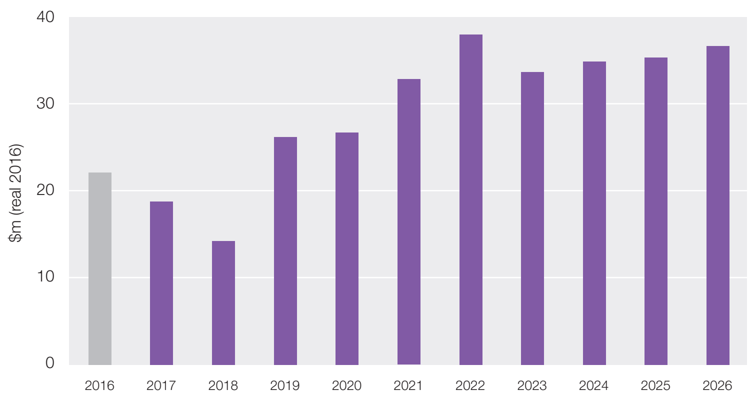
Figure 8.6: **Forecast Capex on major growth and security projects (Major Works portfolio)**



Major project expenditure has been unusually low in FY16, compared with historical years and the remainder of the planning period, due to the timing of individual needs. The small number of relatively large projects is also responsible for the 'lumpy' expenditure profile. Three large projects related to bulk supply investments are expected to be completed in the next two to three years, leading to reduced spend in FY19. Beyond this date a number of smaller projects will commence, resulting in stable spend for the remainder of the period.

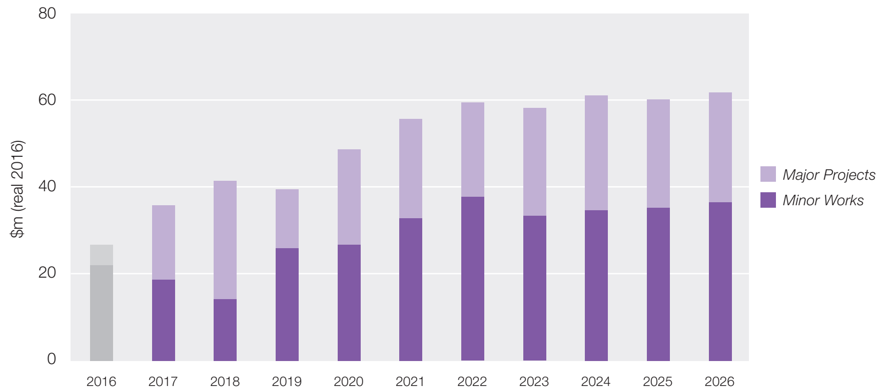
The figure below shows forecast expenditure for minor growth and security works.

Figure 8.7: **Forecast Capex on minor and routine projects (Minor Works portfolio)**



Expenditure increases over the planning period because of increasing needs across our network areas (discussed in the area summaries above). Minor projects have some timing flexibility and are responsible for the increase in spend in FY19 (this also balances the lower spend on major projects that year to maintain a steady, deliverable workload). Routine project works are expected to increase due to reinforcements required to support automation, emerging technology and underlying growth (discussed in Section 8.4.7).

Figure 8.8: **Total forecast growth and security Capex**



With both portfolio forecasts added together (shown above), overall growth and security expenditure is expected to increase significantly 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.

9. CUSTOMER CONNECTIONS

9.1 CHAPTER OVERVIEW

This chapter explains our approach to connecting new customers and how we forecast expenditure on these connections. It includes an overview of our connection process and how these works are funded. Our forecast Capex (net of capital contributions) during the planning period is also discussed.

Further detail on our customers and how they affect our investment plans can be found in Appendix 4.

9.2 OVERVIEW OF CUSTOMER CONNECTIONS

Every year several thousand homes and businesses connect to our electricity network. These new connections require investment in capital infrastructure. Residential connections range from a single new house to subdivisions with dozens 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 customer connections portfolio also includes works for customers, typically commercial, who want to upgrade the capacity of their existing electricity supply. We understand that customers want simple and efficient processes to ensure connections are completed in a timely and cost effective manner.

The expenditure we incur in connecting new consumers is defined as customer connections Capex.

9.3 OUR CONNECTION PROCESS

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.

Our customer connection process is set out on our website.

9.3.1 OVERVIEW OF 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 they often lead to expanded capacity that benefits customers in general. In most cases the customer requesting the work pays the majority of the cost.

Given that we require contributions from the customer, an important part of our process is providing a clear explanation and justification of the cost to connect. To ensure fairness to existing customers and those not increasing their load, 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.

The principal objective of the contribution is to create a price signal to encourage customers to assess the cost effectiveness of connecting to the network. They can also compare increasing their load against alternative options that may be available. A secondary objective is to share costs fairly between existing and new customers.

An alternative approach would be for us to bear the full investment and recover the additional costs from the customer as part of regular charges over a period of time. However, this approach is not practicable as the assets built are likely to have a long life (e.g. more than 40 years) beyond reasonable contract periods. At the time of connection it can be uncertain how new connections will be used in future and by whom so it is not feasible to definitively calculate the cost that should be recovered from an individual consumer. Also in practice, charging arrangements need to be reasonably simple and consistently applicable to a large number of customers. It is not usually feasible to tailor charges to individual customers unless they are very large.

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 high voltage (HV) levels is funded through our system growth expenditure.

9.4 FORECAST EXPENDITURE

Below we set out and explain our forecast customer connections Capex over the planning period.

9.4.1 EXPENDITURE DRIVERS

Customer 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

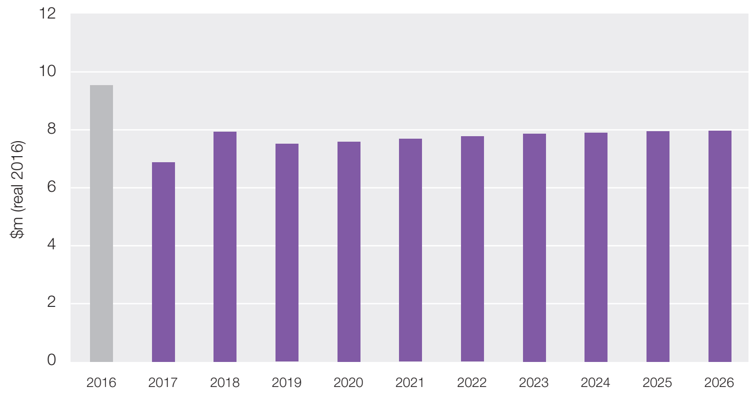
9.4.2 FORECAST CAPEX

Customer connection Capex is externally driven with short lead times so our ability to accurately forecast medium-term requirements is limited. As such, our forecast is based on trending historical activity. We use the last three years as a baseline as we believe it to be a reasonable indication of future activity. We then use the following drivers to escalate the base into a final forecast:

- Forecast domestic connections
- Expected commercial connections
- Specific information such as changes in dairy milk cooling regulation or indications of new large connections or upgrades from our larger customers

Forecasts of population growth in our regions are used to inform ICP growth which is used for our forecast of residential consumer connection Capex. Commercial and industrial connections are informed by historic trends, discussions with large customers, and forecasts of regional GDP growth. These drivers are also used to inform our demand forecast for growth and security investments.

Figure 9.1: **Forecast customer connection Capex (net of contributions)**



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.

The 2016 year has been an exceptional year for customer connections due to major investments in response to:

- A milk processing facility upgrading its capacity
- A cheese manufacturer expanding its factory
- A number of large subdivisions in the Tauranga region

We do not expect the level of investment seen in 2016 to continue and are not aware of any specific projects of material size in the coming years.

10. NETWORK ENHANCEMENTS

10.1 CHAPTER OVERVIEW

As discussed in Chapter 8, network enhancements are development works that make use of control and monitoring devices to improve our real time management of assets.

This chapter explains how we will enhance our electricity network over the planning period. It sets out our planned investments in automation and communications infrastructure.

10.2 ENHANCING OUR NETWORK

To support our reliability and future readiness objectives we will need to improve the real time management of the network. To achieve this we intend to deploy improved control and monitoring capability. We will also continue to focus on maintaining reliability by increasing the levels of feeder automation.

Network enhancements are key supporting investments for our future network. These systems will be enabled through new network devices and technologies. A wide array of new automated switchgear has become available in the last decade, plus monitoring and data logging devices. There are obvious overlaps between network enhancements and future technologies. We discuss future technologies further in Chapter 11.

During the planning period our network enhancement investments will focus on:

- Automation
- Communications infrastructure
- Enhancements to the SCADA system
- Network Insight

The two main programmes of work covered in this chapter are automation and communications.

Our SCADA system already provides real time monitoring and control at our zone substations. The system is largely mature and fully developed. In recent years we have upgraded and migrated our eastern and western systems on to a common platform.

Where new zone substations are required, the SCADA remote terminal unit (RTU), configuration and communications are included within the associated project. Similarly, the extension of improved control and monitoring capability to distribution switches is included under our automation programme. As such, we do not have a specific expenditure forecast covering SCADA system enhancement.

Network Insight is our term for a programme to install devices to monitor our LV network. It seeks to extend our visibility of the network state right down to the distribution transformer and LV reticulation. In its initial phase, Network Insight will monitor and log key parameters to improve our management of LV assets. The next phase will involve using these devices to serve as near real time control points for power flows, voltages and configuration of the LV network.

Network Insight is still in its research and development phase as we assess equipment specifications, communications systems and back-end data management. Through this phase we are also scoping the scale and priority of any future rollout. Key drivers include managing power quality with widespread PV deployment, improving fault location and managing LV networks in CBD areas.

Network Insights are currently part of our research and development portfolio, discussed in Chapter 11. Once equipment specifications and programme scope have been confirmed, we will transfer the work into a network enhancements programme.

10.3 NETWORK AUTOMATION

Network automation allows us to improve reliability performance by providing remote or automated operation of distribution switchgear. It also provides improved visibility of fault location and network state. This allows us to respond faster to events on the network.

Improved visibility of fault location and the ability to remotely isolate and reconfigure the network will allow us to improve our response times to faults, as well as reduce the number of ICPs affected by longer outages. In the short-term, this will help to stabilise network reliability.

Our network automation programme involves the installation of devices such as:

- Reclosers and sectionalisers
- Distribution automated switches (DAS)
- Line fault indicators (LFI)
- Electronic fuses

These devices will be located at selected switching points or critical network junctures. The devices will give us more extensive capability to monitor and control the network, particularly on distribution feeders.

10.3.1 OUR APPROACH TO AUTOMATION

Reliability investments support our Networks for Today and Tomorrow asset management objective. This objective specifically requires that we maintain overall network reliability at an acceptable level, reflecting our understanding of our customers' price/quality trade-off preferences.

In the longer term we are planning to lift renewal investment to address the underlying root cause of deteriorating network performance – ageing assets with deteriorating health. The reliability programme is of particular importance in the interim before the reliability benefits of renewed assets are realised.

Our future networks objective includes keeping up with technological change in the industry. New switching and control capabilities, especially when combined with communications technologies, have greatly improved utilities' capability to remotely control and monitor their networks.

Use of automation must be balanced against our most important asset management objective – safety. Smart grid infrastructure brings substantial benefits in improved reliability but there can be increased risk for the public and workers.

Worker safety is mostly a function of familiarity, training, work complexity, and ensuring there are no switching errors. An intuitive principle when dealing with electricity networks is that 'simple is safe'. This principle favours radial network architecture, with standardised devices and protocols. While we need to embrace new technologies and capabilities, these initiatives may initially lead to heightened risk. They need to be undertaken in a measured manner to ensure any safety implications are well understood and managed.

An important aspect of public safety is ensuring circuits are not re-energised when live conductors are in close proximity to members of the public or their property. We have therefore developed a robust risk-based process to assess the safety implications of automated reclosing schemes, either loop or radial.

With safety objectives foremost, we have adopted a strategy of centralised operator control (i.e. remote control), with improved fault and network state visibility. For the moment, we will not be deploying schemes where decision-making is decentralised (i.e. several field devices communicating and carrying out operations under their own programming).

We will initially favour operator initiated control in preference to fully automated switching, even under master station control. This ensures our NOC maintains visibility and control of the network and fault situations, especially during storm events. In future, we expect to deploy SCADA master station automated control functions through our newly implemented OMS. This will be implemented as our NOC gains better understanding and familiarity with OMS and field devices. We will develop training and standards to ensure consistency.

A further strategy is to prioritise sectionalisation and isolation capability over fully automated loop automation schemes. To ensure protection systems remain robust we have developed tactics around the maximum number of reclosers.

10.3.2 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 tactics around the desired density of reclosers, sectionalisers and DAS. This will lead to a scaled-up future programme to rollout these switches.

Our automation device rollout works plan uses a lifecycle costing approach. This identifies the benefits associated with additional switching devices, which informs the desired density of switching devices of each type.

Our rollout plan includes the following device types:

- Three-phase main line reclosers, sectionalisers or DAS, with SCADA control and visibility
- LFI to give indication of fault locations
- Single phase sectionalisers or reclosers, protecting spur lines, with SCADA visibility where available
- Ground fault neutralisers

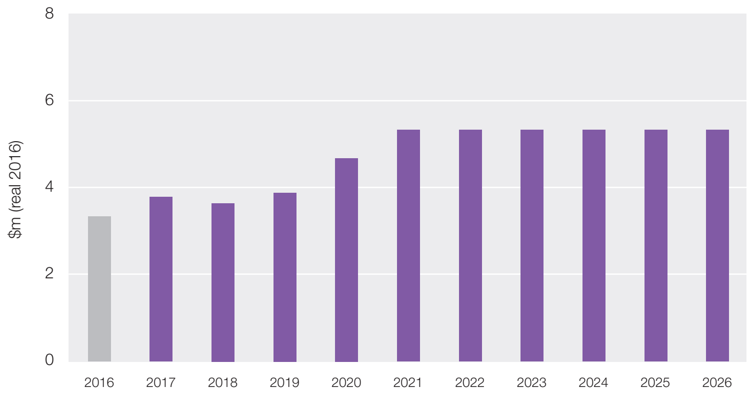
The table below shows the approximate number of automation devices we plan to install.

Table 10.1: **Number and type of automation devices**

DEVICE TYPE	DEVICES
SCADA controlled reclosers and DAS sectionalisers	450
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

Our forecast expenditure over the planning period is shown below. 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 10.1: **Forecast Capex – automation devices**



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.

The expenditure profile reflects our ability to deliver the works over the planning period. This includes deliverability constraints such as the availability of technicians. While we believe a faster rollout would be beneficial it would be difficult to deliver when overall investment levels are increasing.

Benefits of our automation plan:

Over the planning period we expect to see the following benefits from our investments in network automation.

Improved reliability for customers, especially on targeted poorly performing feeders:

- Shorter outages through faster fault location and reduced time to reconfigure the network
- Reduced number of customers affected by faults

Reduced unplanned SAIDI and SAIFI – particularly in the immediate future as we stabilise network performance until benefits of increased renewals are realised

Reduced costs relating to line patrols, manual switching and manual fault location

Reduced risks to assets and customer installations:

- Better visibility of network status reduces risk in re-energising after faults
- Reduced likelihood of equipment damage due to overloading, under-voltage or slow protection settings

10.4 COMMUNICATIONS INFRASTRUCTURE

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 and other new technologies have used public communication infrastructure. This is acceptable for archived or long-term planning data. 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.

10.4.1.1 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 11)
- **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 next table.

Table 10.2: **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 WIFI hotspots
Voice mobile – field crews	VHF DMR Tier 3 radio system
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 3rd party or internet
Customer metering or demand functions	Ripple system or future 3rd party or internet

As we discuss in Chapter 11, 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.

10.4.2 FUTURE ROLLOUT

As noted above, our communications investments are key enablers for our asset management objectives, particularly our future network strategies. Our main 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

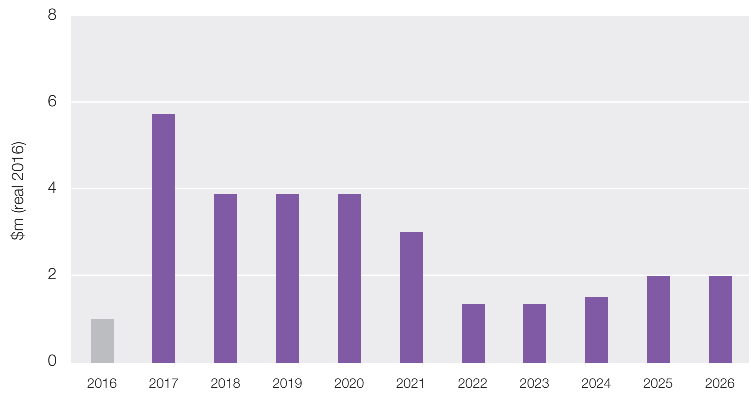
Our schedule for delivery of these programmes is spread over the planning period, with priority for core network, voice mobile and data mobility platforms. With the pace of change in network and customer technologies, we recognise our communication solutions need to be future proofed. The timing and scale of investment may need to be reassessed periodically.

Of particular interest are the numerous new network and customer side technologies that may alter historic 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.

10.4.3 FORECAST CAPEX

The figure below shows our forecast communications Capex for the planning period.

Figure 10.2: **Forecast Capex – Communications**



The increased investment at the beginning of the planning period is required to complete the following projects:

- **Trunk network upgrade** – vital to the reliability of all communications dependent devices, particularly SCADA
- **Voice mobile project** – a priority because it reduces safety risks
- **Field work mobile platform** – needed to facilitate improved information management, particularly condition data from inspections

Beyond these three projects, a number of smaller upgrade programmes will take place over the period. We will also need to consider new communication technologies that facilitate and are driven by new network management capabilities.

11. NETWORKS FOR THE FUTURE

11.1 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. We have a responsibility to ensure we can provide this service cost effectively.

This will need to be done while ensuring our network remains safe, reliable and affordable for all customers.

We believe that customers will continue to access electricity as they do today. Therefore, we are committed to ensuring that 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.

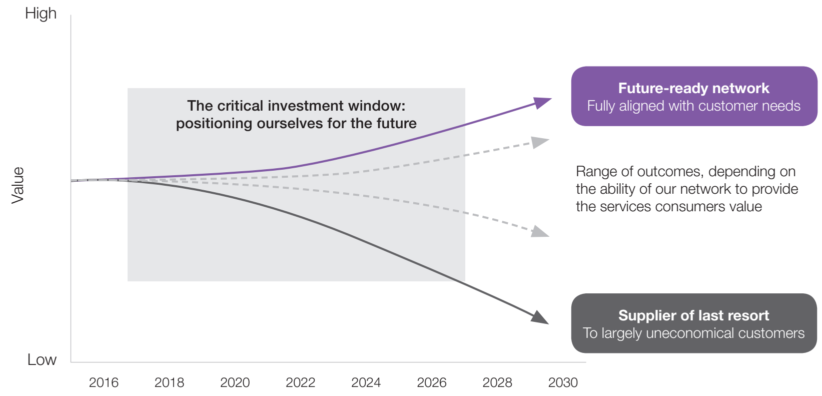
11.2 INTRODUCTION

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 prognoses 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 that they can provide the services that customers will require in the future, and remain relevant in the longer term.

We are fully cognisant of the emerging changes in the energy environment and the material impact that 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 that 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 11.1: **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 a 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.

11.3 THE CHANGING ENERGY ENVIRONMENT

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', at higher utilisation levels.
- 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. Over time, this viability will increase as cost-effective means of energy storage become available. 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.

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.

11.3.1 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. 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 not on our network). Internationally, changing energy consumption is the result of a number of factors (see examples below).

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:

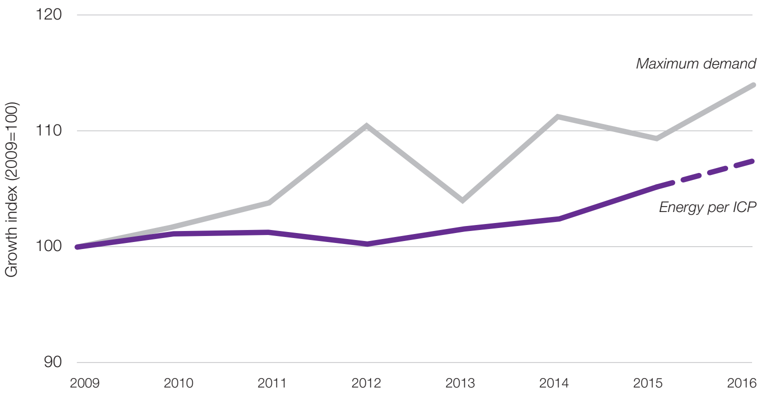
- **Electric vehicles** – as EVs become mainstream, more electricity will be used.
- **Household energy substitution** – in some jurisdictions there are programmes to substitute electricity for other forms of heating.[28]

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 the figure below. While showing year-on-year growth in both aspects, it does suggest that demand growth is outstripping consumption growth.[29]

[28] 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.
[29] 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.

Figure 11.2: **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. 2016 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.

11.3.2 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.

11.3.2.1 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 0.79% of electricity consumed in 2014 was produced by PV installations.[30] This proportion is much higher in developed countries, with the European average at 9.6% in 2013.[31]

By contrast, the uptake of PV in New Zealand, while growing substantially on an annual basis, is still at a very low level. In 2015, it was reported that 0.4% of 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 the three figures below.[34] At the end of November 2015, the total PV connection proportion on our network was 0.35% (1,108 ICPs).

[30] BP, Statistical Review of World Energy, 2015
[31] Eurostat, December 2015
[32] SEANZ, 2 December 2015
[33] MBIE, Electricity Graph and Data Tables, 17 September 2015
[34] EMI, Electricity Authority, December 2015

Figure 11.3: **PV uptake on our network (percentage of ICPs)**

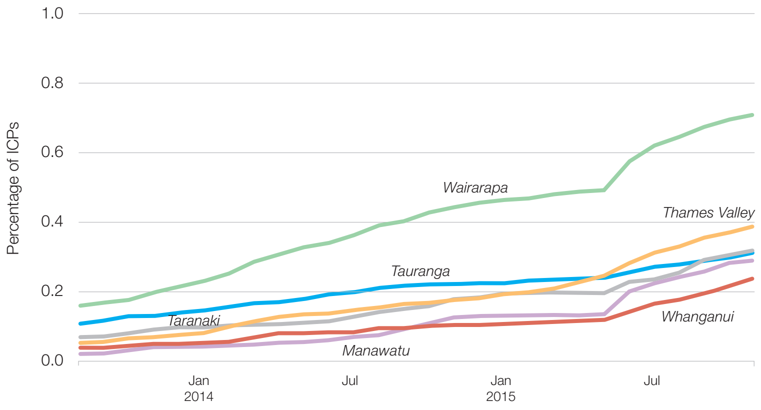


Figure 11.4: **PV uptake on our network (number of ICPs)**

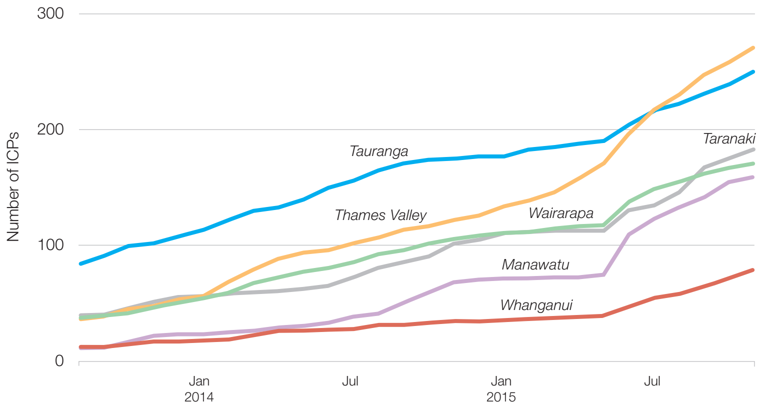
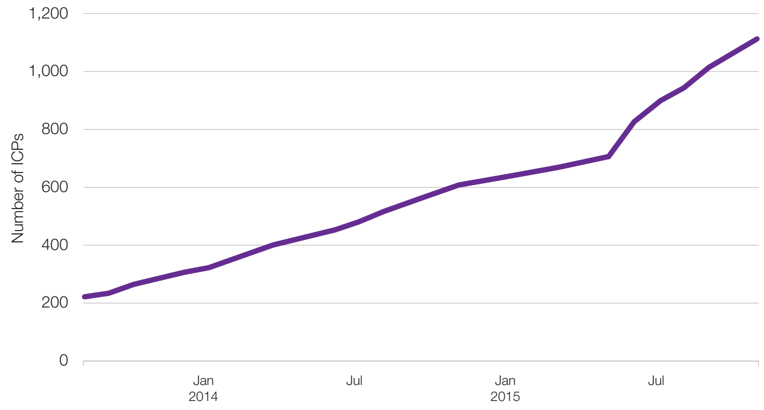


Figure 11.5: **Total PV uptake on our network (number of ICPs)**

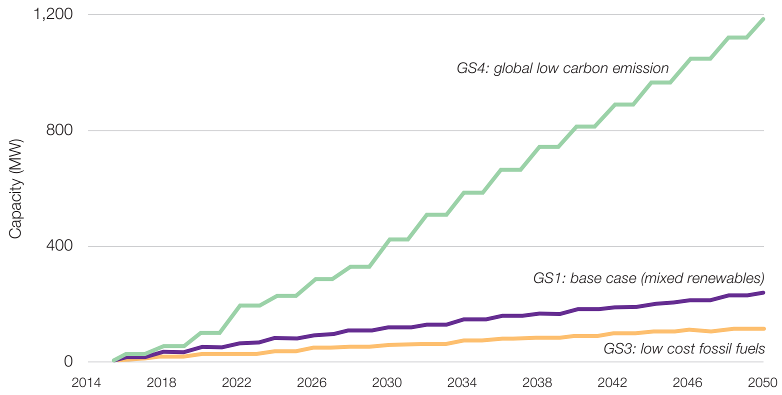


Although the current uptake rate for PV on our network is still very low, it has escalated over the last two years. If the current (exponential) uptake trend persists, an ICP penetration level of around 10% will be reached in seven to eight years. International literature suggests that when PV penetration reaches around this level, issues associated with the variability of its output could become material, requiring some form of network investment.[35]

In its consultation on electricity demand and generation scenarios during 2015, the Ministry of Business, Innovation and Employment (MBIE) provided the forecast in the figure below for the anticipated growth of PV under various scenarios. The aggressive (GS4) scenario suggests that PV generation could approach 10% of (current) installed NZ generation capacity by around 2045.

[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 11.6: **Forecast growth of PV installations in New Zealand**[36]



11.3.2.2 ELECTRIC VEHICLES

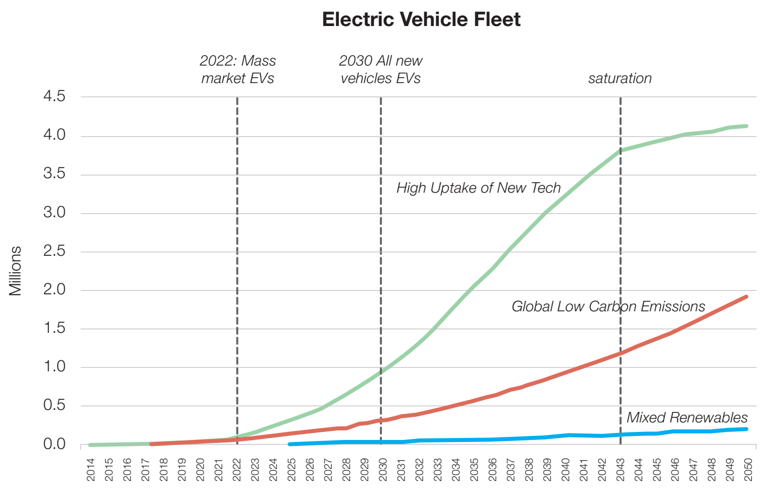
The use of EVs (full electric or plug-in hybrid) is still in its infancy in New Zealand, with a total of 905 vehicles registered at the end of 2015.[37] However, as with other emerging technologies, the uptake rate is accelerating and it is likely that these vehicles will be a regular feature on our 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.

[36] Based on MBIE, Draft EDGS 2015
[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

Figure 11.7: **Forecast growth of electric vehicle uptake in New Zealand**[39]



11.3.2.3 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 an 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.

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.

[39] Based on New Zealand Smart Grid Forum: Transform Modelling Paper, May 2015

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.

11.3.2.4 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.

11.3.3 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.

11.4 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 since the publication of the last AMP.

[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 enjoy 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).

11.4.1 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. It operates as a mini-AC grid managing the sources of generation, storage and loads across the connected loads. It is designed so it typically uses renewable PV generation and energy storage to meet consumer needs, supplemented by a diesel generator.

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.

11.4.2 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

11.5 OUR FUTURE NETWORK STRATEGY

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 future network 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 be ready with these when the real need emerges in future (and not have to scramble to find solutions), 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 utilise 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.

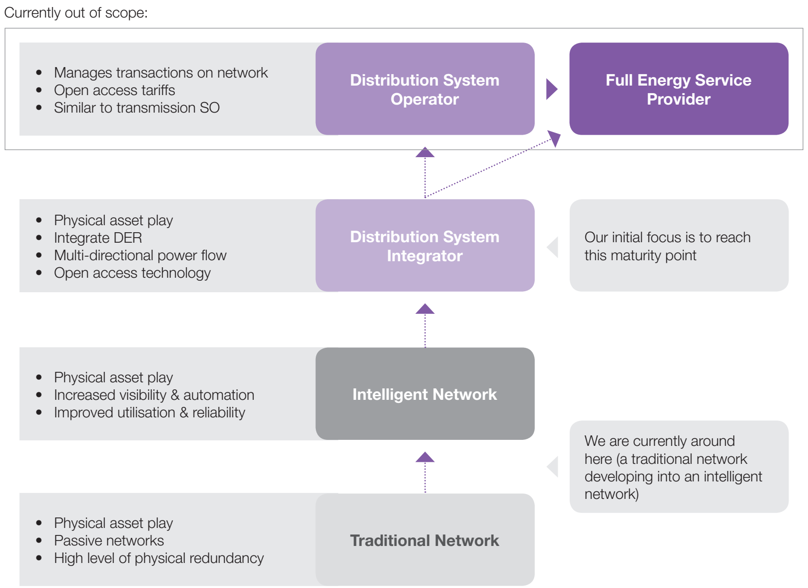
In the section below, the essence of our future network strategy is discussed. This will form the basis for the fully-fledged strategy to be released later in the year.

[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.

11.5.1 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 sets out how we see networks evolving in the short to medium term future is illustrated in the figure below.[43]

Figure 11.8: **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).

[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.

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 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 (for example 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.

11.5.1.1 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 5 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 the next table.

Table 11.1: **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

11.5.2 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 14-20, 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.

11.5.3 FUTURE NETWORK ARCHITECTURE

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.

[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.

- **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.

11.5.3.1 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 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).

[48] Networks have to be built with sufficient capacity to meet peak demands.

- 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.

11.5.3.2 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.

11.5.3.3 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 (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.)

11.5.4 DEVELOPING OUR FUTURE STRATEGY

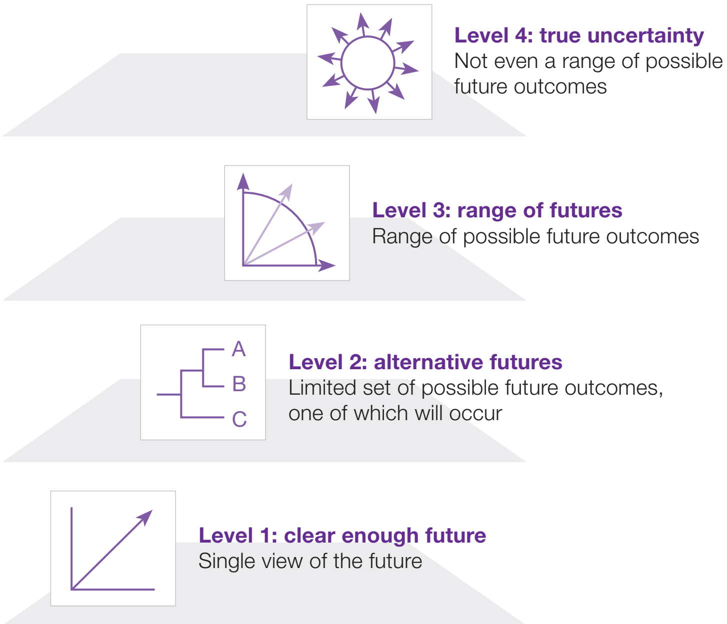
As noted above, it is our intention to complete a detailed future network strategy during the course of FY17, which will expand on the elements discussed in this chapter of the AMP. In this section, we discuss some of the main principles we will adopt in developing our future network strategy.

11.5.4.1 STRATEGY UNDER UNCERTAINTY

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 the figure below, 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 11.9: **Four levels of strategic uncertainty**[50]



[49] McKinsey & Company, Strategy under Uncertainty, McKinsey Quarterly, June 2000
[50] Ibid

11.5.4.2 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 11.3.2, 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.

11.5.4.3 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 23, we plan to develop our capability in these areas over the planning period.

11.5.4.4 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. These are discussed in more detail in Section 11.6.

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.

11.6 FOCUS AREAS FOR THE NEXT FIVE YEARS

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 ten 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 the figure below. 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), discussed in Section 11.5.4, 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 ten 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 11.2: **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*

11.6.1 STRATEGIC PLANS

11.6.1.1 FUTURE NETWORK STRATEGY

As already discussed, we intend to use FY17 to develop a detailed future network 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[51] and proof-of-concept projects we intend to undertake, along with the initial scope, intended outcomes , 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.

11.6.1.2 COMMUNICATIONS NETWORK STRATEGY

Communications infrastructure is a key enabler for the network of the future. It is therefore imperative that we develop a detailed communications network strategy in parallel with the future network strategy. These two documents will be fully integrated.

The essence of the communications network strategy, which will also be fully developed during the course of FY17, is set out in Chapter 10 of the AMP. It 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

[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.

- 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'

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.

11.6.1.3 INFORMATION SYSTEMS

As with communications networks, information systems are also a key enabler for the electricity network of the future. It is therefore imperative that we develop a detailed network information strategy in parallel with the future network strategy, and the communications network strategy. These documents will be fully integrated.

The essence of this network information strategy, which will also be fully developed during the course of FY17, is set out in Chapter 22 of the AMP. It will cover:

- The various information technology and systems we intend to adopt to support the electricity (and gas) networks
- Detailed rollout and implementation plans for these systems
- The information protocols and standards we intend to adopt
- Our strategy to collaborate with external parties
- Our plan to develop the required ICT system capabilities to support the future network strategy
- Plans to develop promising new solutions and evolve our ICT systems to expand their functionality
- Details of how the strategy itself will be kept 'live'

The information system strategy will be the responsibility of our Operations Support group, but will be developed in close consultation with network teams responsible for the future network strategy, and the Network Support team that will develop the communications network strategy.

11.6.1.4 SECURITY OF SUPPLY STANDARDS

Our existing security of supply standards are described in Chapter 8. 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 FY17, 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.

11.6.2 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

11.6.3 CAPABILITY BUILDING

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, as discussed in Section 11.5.4, is developing appropriate internal capability to deal with it. These aspects are also discussed in Chapter 23.

11.6.3.1 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.

11.6.3.2 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:

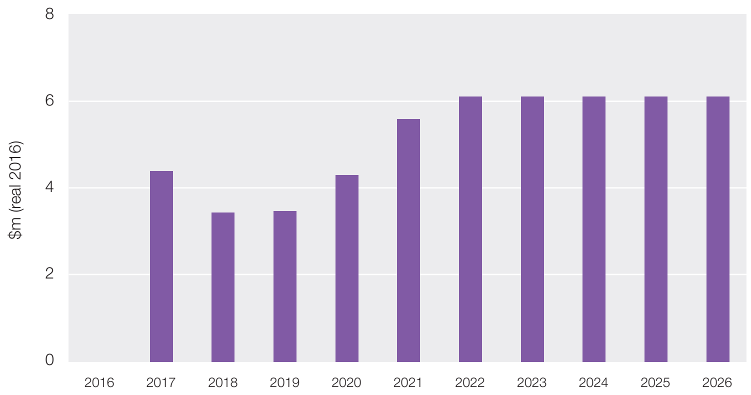
- **Solution agility** – our traditional network applications are largely based on well-proven, out of the box solutions requiring little by way of research or substantial product development. As many of the new network solutions are still in an early, even conceptual stage, these cannot be procured 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** – including 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 11.3.1, 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 6.
- **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.

11.7 FORECAST EXPENDITURE

The forecast Capex on future network activities is set out in in the figure below. Investment in this portfolio is low when compared against the expected benefits to customers of a network tailored to support new energy options.

Figure 11.10: **Forecast Capex – future network activities**



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.

Importantly, oversees and local studies (such as Transform) have shown that investing early to ensure networks are designed and developed to cope with changing energy patterns, prevents material costs later once large change is happening, at which point investments are often made in a reactive and uncoordinated way.

FLEET MANAGEMENT

This section explains our approach to managing our asset fleets.

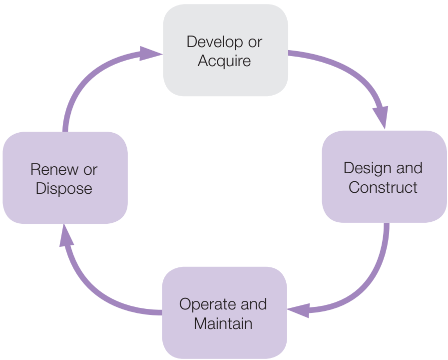
CONTENTS

Back to contents >

12.1 CHAPTER OVERVIEW

This chapter explains our approach to managing our asset fleets and provides an introduction to our fleet plans in Chapters 14-20. As discussed in Chapter 5, we use a life cycle based approach to asset management shown in the diagram below. We provide further detail on this approach and how it will support our asset management objectives over the planning period.

Figure 12.1: **Asset management life cycle**



The Develop or Acquire stage is described in Chapters 8-11.

The remainder of this chapter explains our approach to fleet management for the remaining three stages.

12.2 FLEET MANAGEMENT

Our fleet management approach includes the following three life cycle stages:

- Design and Construct
- Operate and Maintain
- Renew or Dispose

To support our asset management approach we use a set of asset fleets which forms the basis of our day-to-day asset intervention strategies. We have developed a comprehensive set of fleet management plans and a maintenance strategy that sets out our approach to managing our asset fleets.

12.2.1 DESIGN AND CONSTRUCT

The Design and Construct stage includes implementation of the capital projects approved in other stages. This stage sees the handover of capital projects from our Planning to Service Delivery teams. The main activities in this stage are:

- Detailed design
- Procurement
- Construction
- Project close-out

These stages are managed by a dedicated project manager. This person is responsible for ensuring the work is delivered on time, per specification and within budget.

12.2.1.1 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.

Detailed design process

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 detailed design identifies construction methods to help minimise risks to safety and reliability. The Design team is involved for the duration of the project, for example, when design variations are needed during construction.

Detailed design is not required in many cases, for example, standard installations and smaller defect jobs.

Design review

Design reviews take place at various stages of the project depending on scale, complexity and timing. Reviews cover completeness, adherence to standards, technical requirements and safety. Designs may be refined during the reviews to accommodate particular requirements in the construction phase.

We periodically engage external parties to undertake reviews of designs completed in-house. This ensures designs completed internally are aligned with good industry practice. To ensure designs are deliverable, projects are collectively reviewed by the designer, project manager, planning engineers and where required, the construction manager.

Standard designs and equipment

Standard designs allow for efficiencies in design, construction, maintenance, operations, and spares management. Our network standards set the requirements for the design and construction of equipment. We have split our approach to asset specification into three classes, as set out below.

Table 12.1: **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.

Our standards also set out requirements for maintenance inspections and servicing, and guidelines for the overhaul of equipment. The standards include specification requirements when purchases are being made by service providers on our behalf.

Design work is performed by our in-house design team or design consultants in line with defined standards. We maintain a standards library, which consists of 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.

12.2.1.2 PROCUREMENT

The procurement phase of projects includes tendering and other related processes. As discussed in Chapter 5, we have a long-term relationship with our main service provider and utilise additional providers to maintain competitive tension.

EFSA is the agreement we have with our main field work service provider for undertaking routine capital works and maintenance work (including fault and emergency response). EFSA sets out the scope of services and the terms and conditions that apply.

Larger works are individually tendered on a case-by-case basis according to the requirements of the specific project or programme.

12.2.1.3 CONSTRUCTION

We have a set of construction specifications that our service providers must follow and form part of the tender documents.

This process includes commissioning planning, construction, testing, livening, and handing over the asset to our operations and maintenance teams. Where appropriate, we prepare a commissioning plan to ensure all these activities are completed.

12.2.1.4 PROJECT CLOSE-OUT

We undertake project close-out activities when the works are complete. These include:

- Final capitalisation of the project within the financial systems
- Confirm that the asset information systems have been updated
- Archive relevant documentation
- Analyse final costs to update our unit rates and costing assumptions in our cost estimation price-book
- Undertake a review of lessons learned during the project, particularly on health and safety performance
- Feed these lessons back into our planning and design processes

12.2.2 OPERATE AND MAINTAIN

The Operate and Maintain stage includes the following activities.

- **Network operations** – includes real time network control, monitoring and event response. This 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 including our planned expenditure is included in Chapter 13.

Network operations

We operate our assets in a way that ensures we meet network, operational and asset performance objectives. We seek continuous improvement by providing feedback to our asset management teams and to avoid repeat outages. Activities associated with operations provide information to the planning process on network and asset performance or risks, and any lessons learned that will improve the planning process.

This includes taking into account reliability, cost, and safety and environmental requirements. As discussed in Chapter 6, these requirements are drawn from customers, regulators, and other stakeholders.

We consider operational requirements as part of our life cycle approach to managing our network. This involves considering how we operate our assets, such as loading and frequency of operation, and the impact on asset life and performance.

The operations function includes management of spares holdings and activities undertaken by our NOC. This includes considering how we can safely take these assets out of service for maintenance without compromising performance. Operational processes provide information on network and asset performance along with lessons learned to improve the planning process.

Maintenance

Maintenance involves monitoring and managing the deterioration of an asset in operation, or in the case of a defect or failure restoring the condition of the asset. Maintenance activities may also include minor modifications to assets to improve performance and reliability. Feedback from maintenance activities is used to continuously improve our asset standards and planning processes. Maintenance techniques can evolve as the condition and performance requirements of the assets change. Our maintenance activities are categorised into three portfolios:

- **Routine Maintenance and Inspection (RMI)** – includes scheduled work undertaken on our asset fleets
- **Asset Replacement and Renewal (ARR)** – includes corrective/defect repair work
- **Service Interruptions and Emergencies (SIE)** – includes reactive work largely in response to faults

These are discussed in Chapter 13.

Adopting a life cycle approach requires us to make trade-offs between Opex and Capex. For example, asset maintenance can have a significant impact on asset life.

Capex-Opex trade-offs

A life cycle based asset management approach requires a holistic view of asset expenditure. Total life cycle cost is a key consideration in our decision-making. Adopting a life cycle approach to managing our assets requires us to make trade-offs between Opex and Capex.

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

- The impact of maintenance activities on asset life and performance
- Considering 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.

Vegetation management

Vegetation management is another key activity that enables our assets to perform as expected. We undertake vegetation management to keep trees clear of overhead lines and other assets. This is necessary to minimise vegetation related outages and meet our safety obligations. Left unchecked, vegetation can have a significant impact on network reliability and public safety.

The main activities undertaken in the vegetation management portfolio are tree trimming, including removal of trees, and inspections to determine the amount of work required.

12.2.3 RENEW OR DISPOSE

The Renew or Dispose stage includes the following types of activities:

- **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

Renewal and disposal activities are discussed further in Chapters 14-20.

Renewal and refurbishment

Addressing asset deterioration is necessary to ensure that they remain in a serviceable and safe condition. As the level of condition 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 factors taken into account when assessing assets for renewal or refurbishment including:

- Asset health
- Safety risk
- Overall life cycle cost

Below we provide further detail on our development of asset health indices for our asset fleets.

Asset health indices (AHI)

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 AHI (see table below) 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 including:

- Power transformers
- Poles
- Crossarms

Fleets were selected for AHI because they include discrete, identifiable assets with reasonable data, and will be subject to material expenditure during this planning period. We are now developing AHI to cover additional fleets.

The design of an AHI model is based on factors relevant to the particular asset fleet and may include:

- 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

The table below sets out our AHI categories, including the basis for the category and the expected replacement period.

Table 12.2: **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

The chart below shows an example of the projected future asset health based on different intervention options.

Figure 12.2: **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 begun to implement an asset criticality framework as a proxy for the consequence of asset failure. This can be based on levels of redundancy, public safety, asset capacity, and the importance of the load served. A preliminary approach has been developed to assign criticality to power transformers and is used to prioritise replacement.

Future improvements

The design of the AHI and criticality approaches is still at an early stage. 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.

12.2.3.1 DISPOSAL

Asset disposal activities are generally 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 (e.g. contaminated oil) following servicing. Consistent with our Safety and Environment objectives we ensure waste materials are disposed of in a responsible manner. The table below gives an overview of the types of waste materials we manage.

Table 12.3: **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.

12.3 ASSET FLEETS

To support our asset management approach 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 below.

Table 12.4: **Portfolio and asset fleet mapping**[52]

PORTFOLIOS	ASSET FLEET
Overhead structures	Poles
	Crossarms
Overhead conductors	Subtransmission overhead conductors
	Distribution overhead conductors
	LV overhead conductors
Cables	Subtransmission cables
	Distribution cables
	LV 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

[52] 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.

13.1 CHAPTER OVERVIEW

This chapter sets out our approach to operating and maintaining our network assets. It describes our three portfolios of maintenance activities and our approach to vegetation management. For each of these portfolios we set out our forecast Opex for the planning period.[53]

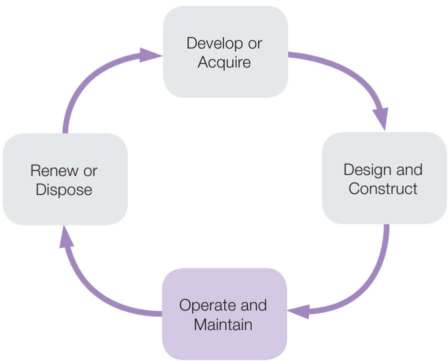
Network Opex is expenditure directly associated with operating and maintaining our network. Good asset management requires balancing Opex and Capex to cost effectively manage assets over the long-term.

We plan to increase network Opex significantly over the planning period. This is aimed at addressing increasing fault trends and defect numbers. It includes uplifts in vegetation management, inspections, and corrective maintenance. Further detail on network Opex during the planning period can be found in Appendix 10.

13.2 APPROACH TO OPERATIONS AND MAINTENANCE

As discussed in Chapter 12, we manage our asset fleets using an asset life cycle approach. The figure below depicts the four life cycle stages within our Asset Management System. 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 (e.g. need for renewal).

Figure 13.1: **Asset management life cycle**



Operations includes a number of 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.

[53] Direct network Opex includes Routine Maintenance and Inspection (RMI), Asset Replacement and Renewal (ARR) and System Interruptions and Emergencies (SIE), and vegetation management portfolios. It does not include System Operations and Network Support (SONS), which we categorise as indirect network Opex.

We define maintenance as the care of assets to ensure they are fit for purpose, enabling them to 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 defect or failure.

13.2.1 ESSENTIAL TO EFFECTIVE ASSET MANAGEMENT

Effective asset management relies on appropriate links between operations and maintenance, and the other life cycle activities.

Operations and maintenance activities are a key element of the asset life cycle. They include essential actions to enable expected asset life to be achieved, and those required to ensure a safe and reliable network. These activities include:

- Monitoring the health of assets, inspecting and collecting information on asset condition to guide corrective works, improving our understanding of asset deterioration and risk, and informing management of similar asset maintenance requirements in future.
- Undertaking work on assets to manage their health or to restore them to good working condition in the event of a defect or fault. Maintenance activities also include routine adjustments and minor modifications or additions to assets to sustain performance and reliability.
- Routine testing of earth systems to ensure statutory compliance and routine testing and calibration of devices such as protection relays to ensure they will operate when required.
- Real time operation of the electricity network through remote switching and monitoring of the network status and system load using our SCADA system.
- Operation of network release planning to ensure planned outages are coordinated and can occur safely on the network.
- Effective switching to allow work on assets with minimal disruption while ensuring the safety of field workers, staff and the public.
- Liaison and issuing of notices to tree owners telling them of any growth limit zone encroachment and undertaking the first cut or trim of encroaching trees.

13.2.2 ENSURING SAFETY

Operations and maintenance activities are necessary to ensure safety and form part of our obligations under the Electricity Safety Regulations. These activities include 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.

Encroachment by vegetation can lead to equipment failure, particularly for overhead conductors. Such failures lead to safety risks for both the public and our staff. We monitor and manage vegetation near our network to reduce these risks.

13.3 ROLE OF OPERATIONS

The prime role of network operations is to ensure a constant supply of electricity to our customers and to maintain the network in a safe condition 24 hours a day, 7 days a week.

13.3.1 NETWORK OPERATIONS CENTRE

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.

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.

To support these services we are building a new operating centre at our Junction St site in New Plymouth. This will bring together the operation of HV and LV networks with a goal of enhancing customer service.

13.3.2 SUPERVISORY CONTROL AND DATA ACQUISITION

Our SCADA system is one of the principal tools used by the NOC to monitor network performance and status. This includes the network parameters of load, current and voltage at key locations, the position (open/closed) status of circuit breakers, switches and reclosers, and the status of a wide range of alarms such as power transformer oil temperature or overcurrent.

SCADA is also used to perform load control functions and to remotely operate circuit breakers and switches in zone substations and other locations across the network. Zone substations and other network control points are connected to our SCADA master stations through telecommunications links. It is important that our communications infrastructure is fit for purpose and can scale up when necessary to support increasing use of automation and real time monitoring.

Development and maintenance of our SCADA system is undertaken by in-house SCADA engineers. SCADA is managed as part of our secondary systems portfolio and is discussed further in Chapter 20.

13.3.3 OUTAGE MANAGEMENT SYSTEM

Our 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.

13.3.4 RELEASE PLANNING

Release planning staff manage the process of isolating and releasing sections of the network to enable works to be undertaken. Release planning requests are processed and coordinated through OMS. This ensures that outage numbers and durations are minimised while allowing us to effectively manage multiple works during individual outages to deliver minimum disruption to customers.

13.3.5 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.

13.3.6 FUTURE OPPORTUNITIES

As set out in Chapter 4, we are looking to improve our asset management approach. As part of this effort we have identified a number of opportunities for operational systems development. These include:

- Enhancement of OMS to incorporate an electronic end-to-end process for network access applications. This will enable delivery of better quality information to maintenance crews and customers.
- Moving the switching process from the manual approach to an integrated electronic workflow. This will reduce processing time and will reduce the potential for switching errors.
- Enhancements to the OMS tool to improve its performance and usability.
- Upgrading to an Enterprise Resource Planning (ERP) system to better manage increased asset information.

13.4 MAINTENANCE STRATEGY

Our maintenance strategy is designed to ensure that our assets achieve their expected life and to minimise life cycle costs. We use information obtained during inspections to guide our maintenance programme and inform renewal decisions.

Our approach to maintenance is influenced by a number of factors. These include the number, type and diversity of our assets and their condition and age. It also takes into account external factors such as adverse weather, legislative requirements, environmental factors, and third party interference. All maintenance works are delivered by service providers.

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.

We have identified that some of our time and simple condition-based interventions do not provide optimal asset performance. 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 standards

Our maintenance standards, which have been specifically developed for our network, dictate how and when we undertake maintenance. They form the cornerstone of our maintenance regime.

Our standards are based on our knowledge of specific maintenance, operational and service requirements that have been developed over many years. They have been made available commercially and have been adopted by many electricity distributors.

We continually refine our maintenance standards to reflect the evolving nature of our asset fleets as we introduce new models and technologies.

13.4.1 MAINTENANCE PORTFOLIOS

For planning and budgeting purposes, we group our maintenance work into three network Opex portfolios. These are:

- **Routine maintenance and inspection (RMI)** – includes scheduled work on our asset fleets
- **Asset replacement and renewal (ARR)** – includes corrective/defect repair work
- **Service interruptions and emergencies (SIE)** – includes reactive work largely in response to faults

Our RMI portfolio was previously named Routine Corrective Maintenance and Inspections (RCI). The corrective maintenance component of this work is now part of our ARR portfolio.[54] This has been done to better reflect the drivers for these activities and the way we plan and deliver these works.

The figure below summarises how we categorise our maintenance activities.

Figure 13.2: **Our maintenance portfolios**

Routine Maintenance and Inspection
Scheduled work:
- inspections
- servicing
- condition assessments

Asset Replacement and Renewal
Corrective work:
- defect rectification
- repairs
- replace minor components

Service Interruptions and Emergencies
Reactive work:
- fault response
- emergency switching
- first response

13.4.2 ROUTINE MAINTENANCE AND INSPECTION

RMI 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.

[54] Our information disclosure schedules reflect the RCI definition consistent with our historical disclosures.

13.4.2.1 KEY ACTIVITIES

The main types of activities are set out below.

- **Inspections** – include 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 our knowledge of specific maintenance, operational and service requirements that have been developed over many years. 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.

Details of RMI activities undertaken on our asset fleets can be found in Chapters 14-20.

RMI 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. We then use this information to create work orders and purchase orders. It also stores the data collected from the field as a record of our maintenance activity for the scheduled asset.

The RMI portfolio also includes other activities such as 'stand-overs' and cable locations where we supervise a third party who is working close to our network.

13.4.2.2 STRATEGIES AND OBJECTIVES

To guide our strategy and activities during the planning period we have identified a number of high level objectives for our RMI activities.

Table 13.1: **RMI 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.

During the planning period our main strategies to achieve these objectives are to:

- Regularly review the effectiveness of our routine maintenance work for each asset type and update our maintenance standards to deliver improved performance.
- Regularly review the effectiveness of our condition monitoring programme to identify components that, for example, may require more intrusive inspection, or may need less frequent inspection.
- Ensure that staff are vigilant in identifying activities of third parties working near our network, and taking appropriate action to ensure the integrity of our network is not compromised.
- Educate the public and customers through regular media campaigns about the dangers of working near our network.

13.4.2.3 FUTURE OPPORTUNITIES

Our RMI standards and activities have generally been developed in line with manufacturers' recommendations and accepted industry practice. As set out in Chapter 4, 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. Additions and changes to RMI activities are set out below.

- **Information to support increased service life** – as we look to replace more assets near the end of their lives, it is important we have more information to be as effective as possible. Increases in RMI will help maximise the lives of assets for the next decade and moderate renewals to the levels set out in our fleet management plans.

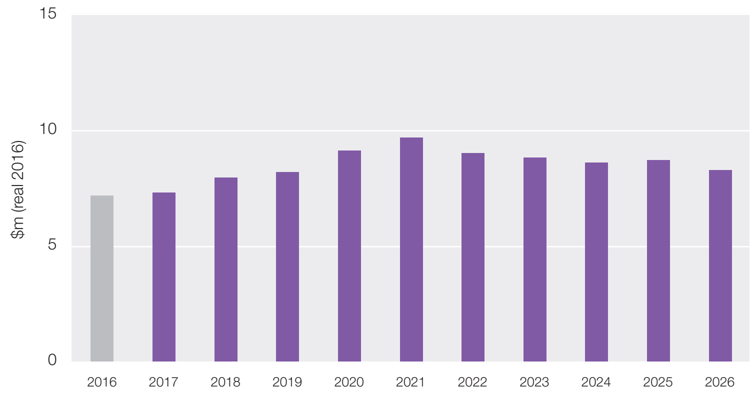
- **Condition-based maintenance** – we will begin to adopt a condition-based approach for a wider range of assets through revised standards. Initially this will focus on our larger switchgear, transformers and other zone substation assets. Condition-based maintenance is more cost effective than time-based maintenance. We plan to review our standards and investigate the opportunities for widening our condition-based maintenance work over the next two years.
- **Reliability analysis** – we are increasing the assessment of work history and other data to identify unreliable equipment, and support maintenance delivery with insights from benchmarking.
- **Expanded pole testing** – we are beginning to use non-destructive testing of wooden poles to better understand the effective life of these assets. Non-destructive testing of wood poles is undertaken by a number of New Zealand EDBs. We have been doing research into non-destructive wood pole testing over the past two years and plan to expand the use of this practice in FY17.
- **Expanded schedules** – we are developing and refining a comprehensive maintenance plan for our substation buildings. The plan will give us a clearer picture of the future maintenance required for major building components, such as roof replacements. We expect to start implementing a building maintenance plan for all substations during FY17.
- **Expanded subtransmission line patrols** – we are increasing the frequency of line patrols for subtransmission assets. In FY17 we plan to introduce an annual visual inspection of all subtransmission lines. The aim is to identify and remedy defects that could potentially result in a fault before the next scheduled inspection. Inspections will generally be done on foot with difficult to access sections undertaken by helicopter.
- **Adoption of acoustic testing** – acoustic testing has been demonstrated to be beneficial in identifying developing faults. In the short-term we plan to investigate the opportunities for acoustic testing to identify the specific benefits for various asset types including conductors, insulators and switchgear.
- **Expanded partial discharge (PD) testing** – we undertake PD testing on critical assets. PD testing is beneficial in identifying potential failure points in switchboards, power transformers and cables. We are considering expanding coverage of these tests. Initially we plan to investigate potential benefits for major zone substation equipment.
- **Lidar[55] surveys for line height measurement** – we are considering using Lidar-based inspections to improve the quality of our overhead line asset information, including vegetation surveys. This will include monitoring compliance with the ground clearance requirements of NZECP 34.[56] This is particularly important as infringements can occur because of changes in road height as reconstruction occurs, conductor stretch, or pole movement.

[55] Lidar is a non-contact high speed data imaging process that is used by utilities to capture line data.
[56] New Zealand Electrical Code of Practice for electrical safe distances – NZECP 34.

13.4.2.4 RMI OPEX FORECAST

Our RMI Opex forecast is shown in the chart below. As discussed above this varies in scope from our disclosed RCI expenditure.

Figure 13.3: **Forecast RMI expenditure**



Drivers for increasing RMI expenditure in coming years are listed below. Some of these (e.g. Lidar) will be temporary, leading to an eventual reduction in expenditure towards current levels.

- **Line patrols** – annual subtransmission line patrols to improve substation reliability, prioritised distribution feeders patrols based on condition and performance.
- **Lidar survey** – in FY18/FY19 we plan to complete a Lidar survey of the network.
- **Improved condition inspections** – during the planning period, we will introduce initiatives to improve our knowledge of asset condition and pre-empt potential component failures. Specific initiatives include:
  - Acoustic testing of overhead line components (conductor, insulators, terminations) to locate defects and to diagnose potential faults on key feeders, starting in FY17.
  - Acoustic resonance pole testing to determine internal condition of wooden poles, starting in FY17.

13.4.3 ASSET REPLACEMENT AND RENEWAL

The ARR portfolio includes corrective interventions, triggered by asset condition. Our ARR portfolio includes corrective maintenance that was previously included in the RCI portfolio of work.

13.4.3.1 KEY ACTIVITIES

The main types of ARR 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 RMI and SIE activities

The main purpose of ARR work is to restore an asset that is damaged, or does not perform its intended function. We undertake ARR maintenance to restore asset condition, make it safe and secure, prevent imminent failure, or address defects. ARR work is usually identified as a result of a fault or during scheduled maintenance inspections. Failure to undertake this work increases the risk of reduced network reliability and may lead to safety risks for our staff and the public.

ARR work is also undertaken as a follow up or second response to SIE work, where an initial fault response has restored supply but additional resources or equipment are needed to restore the network to its normal state.

ARR 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 improved our inspection regime and expanded its coverage over the past five years 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 period to 2026, our aim is to reduce the amber defect pool to a stock of no more than six months' work.

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 require rectification within 12 months
- Green defects require rectification within 36 months

The defects pool includes green and amber defects. Red defects are addressed as soon as practicable after they have been identified.

13.4.3.2 STRATEGIES AND OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high level objectives for our ARR activities.

Table 13.2: **ARR 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.

13.4.3.3 FUTURE OPPORTUNITIES

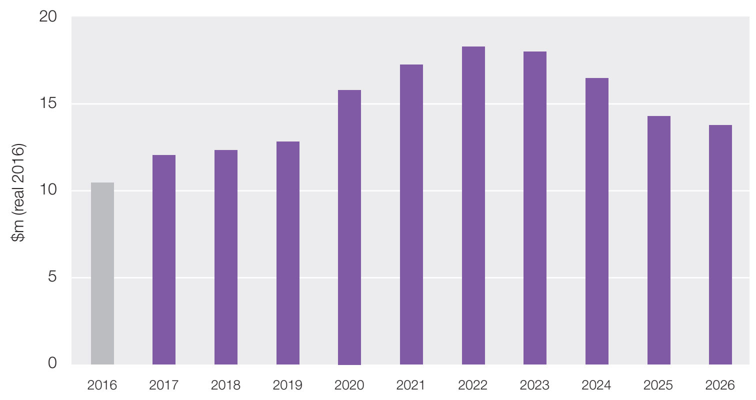
Our defect assessment and prioritisation process depends on staff identifying specific condition details of a range of assets. Assessments and prioritisation are somewhat subjective and there is room to improve consistency. We have identified a number of improvement opportunities, as listed below.

- **Field audits** – to maintain accuracy of inspection data and to ensure consistency with evolving standards.
- **Improved risk analysis** – using a new Defect Risk and Analysis Tool (DRAT) to prioritise defects based on their assessed risk to the public and the network. DRAT also allows us to more accurately report risk associated with defects and assess defect status in the future.
- **Defect analysis** – using root-cause analysis and failure investigations to ensure these problems do not reoccur.
- **Real time defect management** – as our field mobility capability improves we will move to a near real time view of our defect stock, allowing improved defect inventory management.

13.4.3.4 ARR OPEX FORECAST

Our ARR Opex forecast for the planning period is shown in the chart below. As discussed above, this varies from disclosed ARR expenditure because of the corrective maintenance component that was previously contained within RCI.

Figure 13.4: **Forecast ARR expenditure**



Our increased ARR expenditure over the period FY17 to FY26 is driven by our plan to reduce defect levels (and associated risk) and the introduction of initiatives to improve safety and overall network performance. The proactive initiatives include:

- Increased insulator replacements
- Vacuum circuit breaker interrupter replacements
- Pillar box labelling
- Security lock replacements
- Storm 'hardening' of overhead assets
- An extensive programme of LV fuse replacements

13.4.4 SYSTEM INTERRUPTIONS AND EMERGENCIES

The SIE Opex portfolio involves reactive interventions in response to unplanned network events.[57]

13.4.4.1 KEY ACTIVITIES

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.

SIE work is prioritised and dispatched by the NOC with the physical work carried out by our service provider. There is limited forward planning for SIE work other than ensuring there are sufficient resources on standby to respond to network faults. Failure to undertake SIE in a timely manner adversely affects the service provided to our customers and may pose risks to public safety.

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.

At all times our service provider maintains resources for fault response from strategically located depots across our network area. These are dispatched based on a number of factors including potential safety risks and the need to maintain service levels for customers and to consistently meet contractual response times.

SIE 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 ARR), and our protection philosophies.

[57] The SIE portfolio does not include second response, which is covered under the ARR portfolio.

13.4.4.2 STRATEGIES AND OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high level objectives for our SIE activities.

Table 13.3: **SIE 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.

To achieve these objectives we have a set of key strategies, as set out below.

- **Safety targets** – continue to use concise, explicit, and relevant safety targets that are widely understood and are part of the way we and our service providers operate.
- **Public education** – continue to focus on educating the public and customers through regular media programmes about the dangers of electricity networks.
- **Optimise field resources** – by ensuring the right mix of fault staff in the right locations across our network area.
- **Resource readiness** – ensure the availability of adequate resources and equipment to undertake SIE works, with relevant spares and materials available at strategic locations.
- **Leverage systems** – drive improvements through an appropriate set of systems and tools including communication systems, SCADA, GEM and OMS available to the NOC. These will be used to optimise network operations management and decision-making.

13.4.4.3 FUTURE OPPORTUNITIES

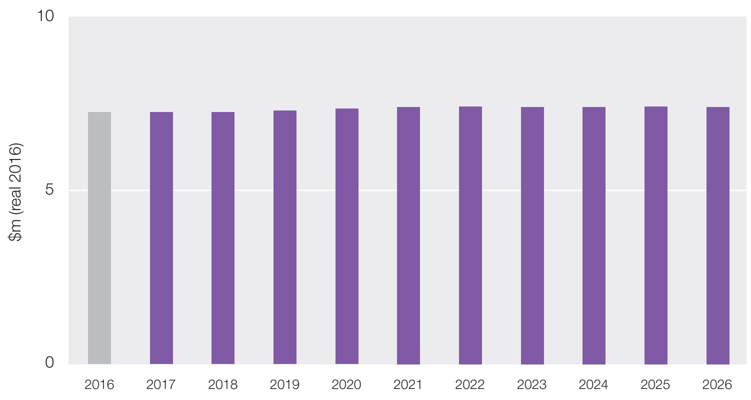
Our SIE work is dependent on technology to enable a timely response from information available to the NOC and our service provider staff through communications systems, SCADA and OMS. We have identified a number of improvement projects that will enable us to better meet our SIE objectives.

- **OMS refinements** – will focus on creating an electronic end-to-end process enabling delivery of better quality information to work crews and customers. Moving to an integrated electronic switching notification process enabling less processing time and fewer switching errors.
- **Enhanced communications network** – will bring radio communications coverage to more than 95% of our network area, improving worker safety, response times and reliability.
- **Field mobility solutions** – will provide field staff with access to asset data including standards, technical specifications, schedules and historical maintenance data, enabling more informed and timely decisions and actions.

13.4.4.4 SIE OPEX FORECAST

Our SIE expenditure forecast for the planning period is shown in the chart below.

Figure 13.5: **Forecast SIE expenditure**

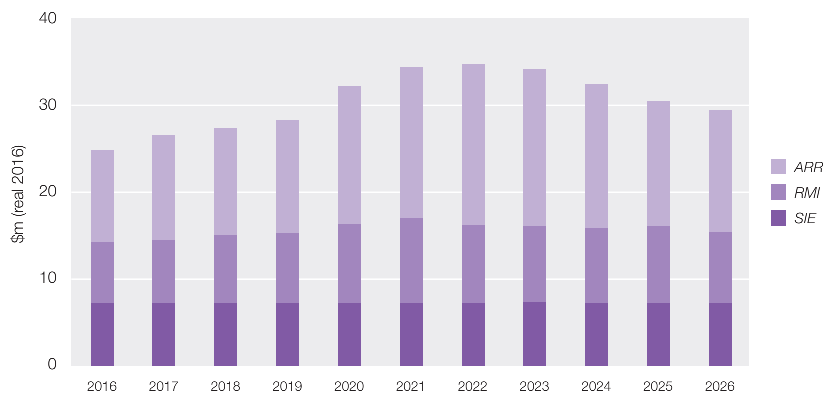


We have an ageing network that is likely to result in increased faults. However, overall we expect expenditure on SIE activities will remain consistent over time as the impact of a greater vegetation management programme and increased asset renewals takes effect. There have also been efficiency gains through our EFSA resulting in lower costs. SIE expenditure is expected to remain relatively stable.

13.4.5 OVERALL MAINTENANCE EXPENDITURE

Changes in our overall maintenance forecast over the planning period are mainly driven by our forecast increase in ARR expenditure. This in turn is driven by our plan to reduce defect levels and their associated risk and the introduction of proactive improvement initiatives across the network. RMI expenditure leads to variations because of increased line patrols, acoustic testing and use of Lidar. SIE expenditure will remain relatively constant.

Figure 13.6: **Overall maintenance expenditure**



13.5 VEGETATION MANAGEMENT

We undertake vegetation management to meet our safety obligations of keeping overhead lines clear of trees and to minimise vegetation related outages in support of our reliability targets. Outages caused by vegetation are a significant contributor to our overall SAIDI and SAIFI. The appropriate planning and management of tree trimming is highly effective in reducing these outages.

13.5.1 KEY ACTIVITIES

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.

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.

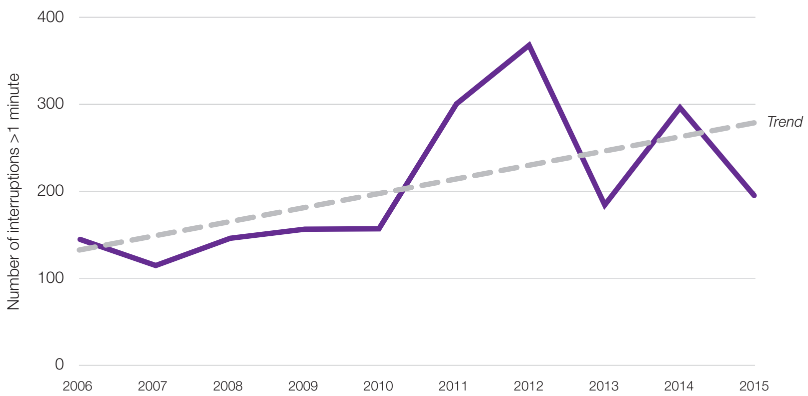
These regulations specify both the tree owners' and our responsibilities with regard to actions and cost.

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.

13.5.2 STRATEGIES AND OBJECTIVES

Vegetation management has a significant impact on network reliability and public safety. Our network performance is being adversely affected by an increasing number of interruptions (see figure below) caused by vegetation over recent years.

Figure 13.7: **Vegetation related interruptions**



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.

To guide our strategy and activities during the planning period we have identified a number of high level objectives for our vegetation management activities.

Table 13.4: **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.
	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.
	Consider the use of alternative tree surveying approaches, such as Lidar, to reduce inspection costs.
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.

To achieve these objectives, our key strategies are:

- **Cyclical trimming** – develop and implement a full cyclical trimming programme that ensures vegetation is managed across our entire network.
- **Achieve steady state** – develop and implement a catch-up programme of work for sections of the network that to date have not been part of a cyclical programme.
- **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.
- **Insourced liaison** – move from an outsourced to an in-sourced vegetation liaison model to better align liaison staff's objectives with that of the business. This will increase our direct interaction with tree owners, who are usually our customers. Also through negotiation we achieve greater than mandated clearances, which we expect will result in improved network reliability.

13.5.3 FUTURE OPPORTUNITIES AND RATIONALE FOR CHANGING OUR APPROACH

Our historical reactive approach was based on an expectation that the tree trimming regulations would result in increased volumes of trimming by tree owners. However, in practice reactive work tends to be less efficient and less effective than planned cyclical work because of the stop/start nature of the work and the travel costs associated with dealing with piecemeal urgent sites.

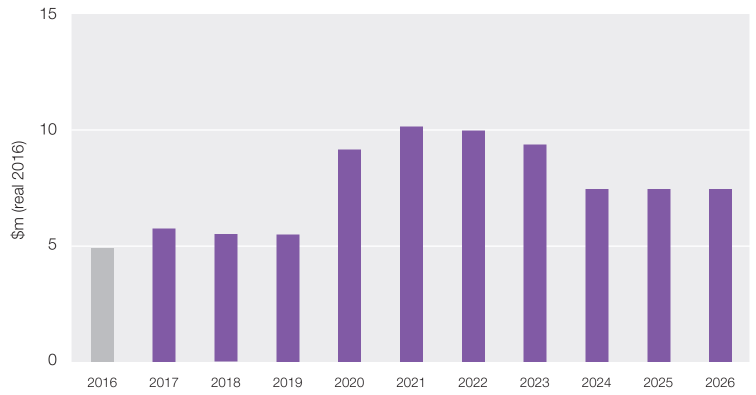
We plan to undertake an increased volume of risk-based work. This is because the mandated clearances specified in the regulations do not deal with trees that are outside the growth limit zone, but have the potential to cause significant damage to the network. A risk-based guide is being jointly developed by the EEA and Electricity Networks Association (ENA). We plan to adopt this guide for planning and managing risk-based work from 2016.

As we step up our vegetation management programme and move towards a second cycle of work, an increasing number of tree owners may consider trimming trees themselves to reduce costs, rather than using an approved contractor. This will require greater interaction and communication to ensure minimum approach distances are not breached and that tree owners do not damage our network by felling trees or branches on to our lines. Our public awareness campaigns will point out the potential dangers to tree owners who attempt to trim or cut trees near power lines.

13.5.4 VEGETATION MANAGEMENT OPEX FORECAST

Our vegetation management Opex forecast for the planning period is shown in the chart below.

Figure 13.8: **Vegetation management expenditure**



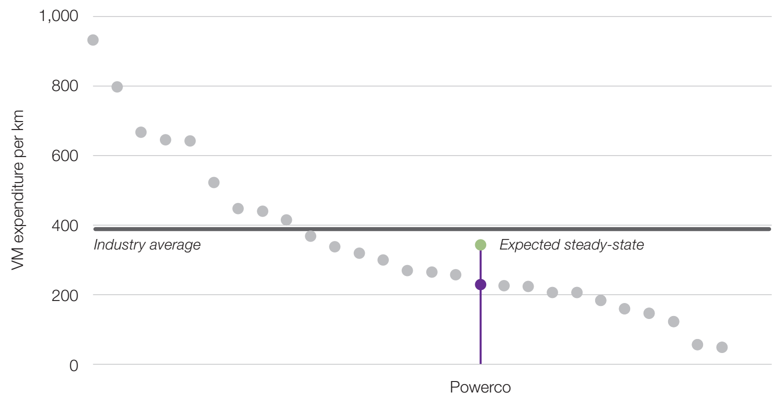
We have recognised that our risk profile in relation to tree encroachment near our lines is higher than we would like. To reduce this and achieve our objectives of improved performance and enhanced public safety will require a significant increase in expenditure. This reflects the following expenditure drivers.

- A significantly expanded programme of works targeting higher risk sites to improve network resilience. This includes annual liaison and cutting programmes on subtransmission circuits and an expanded cyclical programme on distribution lines.
- Use of new technology, including software and field machinery to assist with work planning, scheduling and delivery to improve overall performance. This includes having full access to current and historical work records in the field and improved systems and processes in place that promote operational excellence.
- Increased public awareness campaigns.

Our longer term forecasts include addressing a backlog of tree sites resulting in an additional expenditure requirement of approximately $10m between 2020 and 2023. Beyond then, expenditure will stabilise around $8m to maintain improved performance.

The chart below compares our current (2015, 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, but still less than the industry average.

Figure 13.9: **Vegetation expenditure per km of overhead line compared with other EDBs (2015)**



Source: Powerco and other distributors' 2015 Information Disclosures.

14. OVERHEAD STRUCTURES

14.1 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 $20m in 2016 to a peak of $44m in 2023. 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.

14.2 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 voltage.

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 4.

Table 14.1: 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 (e.g. 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.

14.3 POLES FLEET MANAGEMENT

14.3.1 FLEET OVERVIEW

Our network comprises concrete poles (84%), wooden poles (15%) and a small number of steel poles. We have approximately 266,000 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 (53%).

Pre-stressed poles are generally considered a robust, mature asset type and are expected to perform their function reliably over a long period of time.[58] Pre-stressed poles have been used for over 50 years and are manufactured with high tensioned steel tendons (cables or rods). Most new poles installed are pre-stressed and are designed and manufactured to meet stringent structural standards. Pre-stressed poles have a design life of 80 years.

[58] 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.

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 14.1: **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 have been copper chrome arsenic (CCA) treated. 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. 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.

14.3.2 POPULATION AND AGE STATISTICS

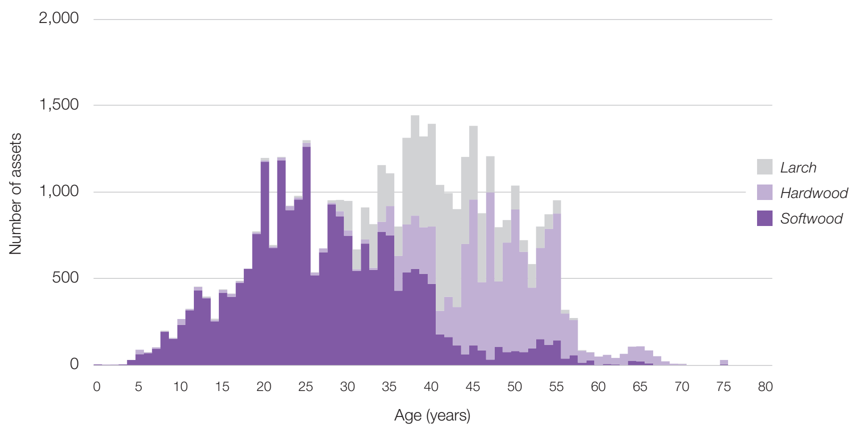
The table below summarises our population of poles by type. High performing pre-stressed concrete poles make up more than 50% of the pole population. Wooden poles make up only 15% of our pole fleet, but their large number means their replacement will still require a large investment.

Table 14.2: **Pole population by type at 31 March 2015**

POLE GROUP	POLE TYPE	NUMBER OF POLES	% OF FLEET
Concrete	Pre-stressed	141,341	53
	Reinforced	81,494	31
Wood	Hardwood	11,345	4
	Larch	8,312	3
	Softwood	22,368	8
Steel	Steel	1,150	0.4
Total		266,010	

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 lives of 50 years for hardwood and 35 years for softwood and larch poles.

Figure 14.2: **Wooden pole age profile**

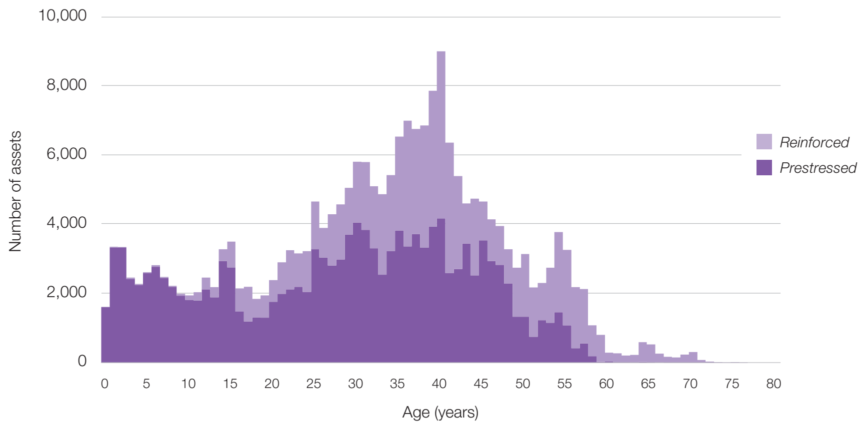


This is consistent with the high proportion of pole defects on our network involving these pole types. Softwood poles have an average age of 27 years and many have or soon will exceed their expected life.[59]

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 14.3: **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 28 years and no poles exceed their 80-year expected life, which is based on our survivorship analysis.[60]

14.3.3 CONDITION, PERFORMANCE AND RISKS

In-service pole failure is a serious safety issue. It is also a reliability issue as pole failure typically results in the loss of supply. We aim to replace poles before they fail 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 under stress (e.g. through high winds) can be triggered by existing condition defects.

[59] Note that actual pole replacement is based on condition assessment and field inspection results.

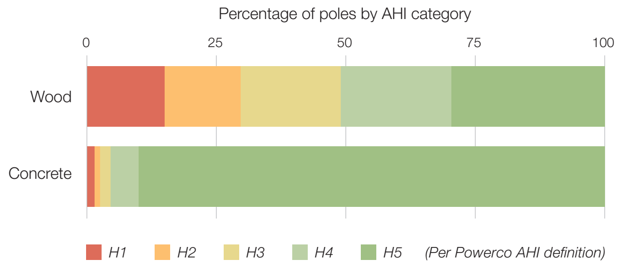
[60] Note that the industry standard life is 60 years.

Pole 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 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 14.4: **Wooden and concrete pole asset health as at 2015**



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 15% have already been identified for replacement (H1).

In contrast, the concrete pole fleet is in good overall health. Only 5% 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.

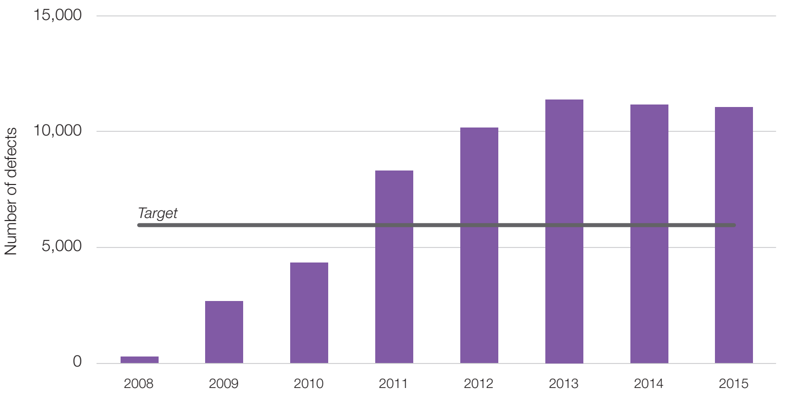
The main pole failure modes differ by pole type. Some common examples are set out in the table below. Our defect process aims to identify these issues well in advance of pole failure to allow planned and coordinated replacement.

Table 14.3: **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 14.5: **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[61] (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 are trialling a variety of techniques to improve the accuracy of our predictive models. One promising technique is acoustic resonance testing, using the relationship between wood structure elastic parameters and resonance frequency behaviour.

Poles already earmarked for replacement were tested with a lightweight portable testing device and then break tested to confirm failure load. The acoustic resonance test results showed good correlation with the break testing results (the only way to confirm the actual strength/condition of the pole). 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 asset renewals. We will continue our trials and refine our testing approaches.

Meeting our portfolio objectives

Operational Excellence: We are trialling 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[62] 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.

[61] 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.

[62] 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.

As noted above, reinforced concrete poles were made by a variety of manufacturers using local materials (e.g., 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.

14.3.4 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.

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.

14.3.5 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 routine pole inspections are summarised in the table below. The detailed regime for each type of pole is set out in our maintenance standards.

Table 14.4: **Pole 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 (i.e. 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 during any inspection or condition assessment work, 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.

14.3.6 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 considers the type and severity of the defect, how long the defect has been registered and criticality aspects such as public safety and connected load. 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 FY26.

Meeting our portfolio objectives

Asset Stewardship: Forecasted pole renewals expenditure will reduce the defect pool to sustainable levels by 2026.

A number of poles also get replaced through our reconductoring programmes.[63] 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 condition, if the additional load exceeds the residual strength of the pole then it must be replaced.

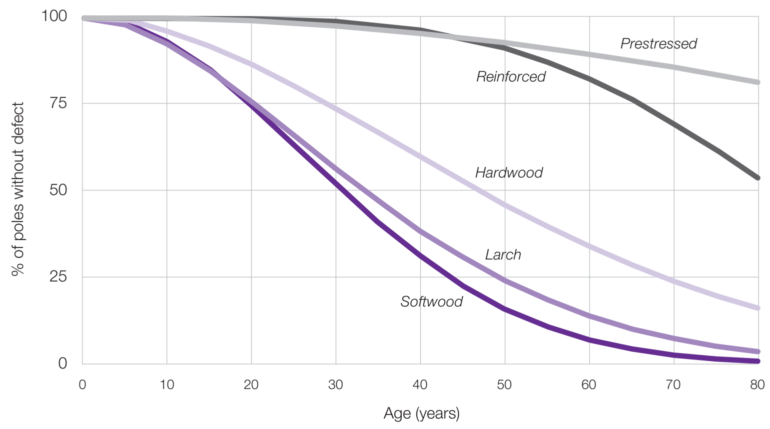
We have previously considered and trialled pole-life extension techniques, but generally found these not to be cost effective. An example of these techniques is ‘pole bandages’ that contain preservatives and fungicides around wood poles at ground level to prevent rot.

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 14.6: **Pole survivor curves**



[63] See chapter 15 on Overhead Conductors.

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. Softwood and larch poles have similar survivorship profiles, and on average require replacement earlier than hardwood poles.

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.

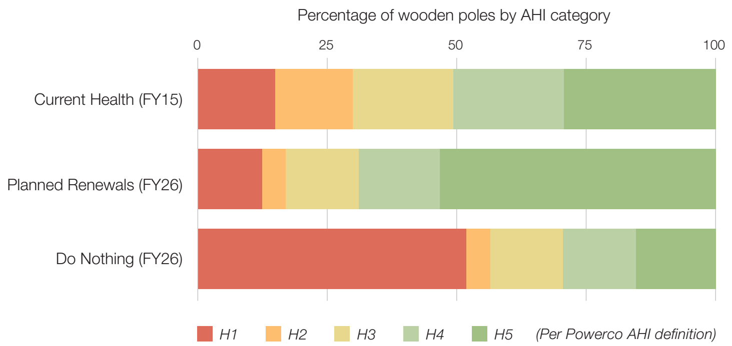
Volumes of pole renewals are forecast to increase over the next three to five years, primarily to reduce the size of the defect backlog. Longer term levels of defect based renewal are expected to stabilise at around today's volume.

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 2026 (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 14.7: **Projected wooden pole asset health as at 2026**[64]



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.

[64] Wooden poles will be replaced with modern pre-stressed concrete poles. To allow a consistent and meaningful comparison we have assumed like-for-like replacements in this chart.

Pole disposal

Poles are disposed of when they are no longer needed because of asset relocation (e.g. 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.

14.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 (through defect or condition assessment information) 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.

14.4 CROSSARMS FLEET MANAGEMENT

14.4.1 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 14.8: **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.

14.4.2 POPULATION AND AGE STATISTICS

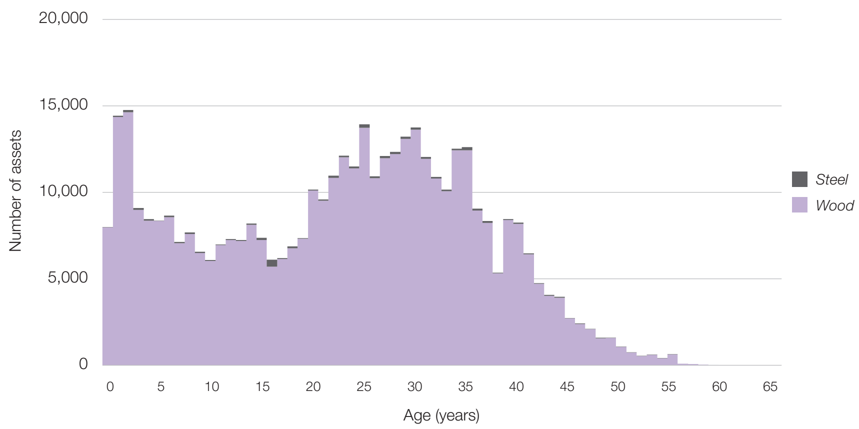
We have approximately 425,000 crossarms in service, comprising a number of sizes and configurations.

Table 14.5: **Crossarm population by type and voltage at 31 March 2015**

CROSSARM TYPE	VOLTAGE	COUNT	% OF TOTAL
Hardwood	Subtransmission	15,689	3.7
	Distribution	226,950	53.4
	Low voltage	178,152	41.8
Steel	Subtransmission	1,245	0.3
	Distribution	2,016	0.5
	Low voltage	1,161	0.3
Total		425,213	

The figure on the following page 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 14.9: **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.

14.4.3 CONDITION, PERFORMANCE AND RISKS

In-service failure of a crossarm can lead to dropped conductors or spans lowered to unsafe clearances. This presents 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 recently 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.[65]

Meeting our portfolio objectives

Safety and Environment: Crossarms are replaced proactively using condition and type information, thereby minimising safety risks.

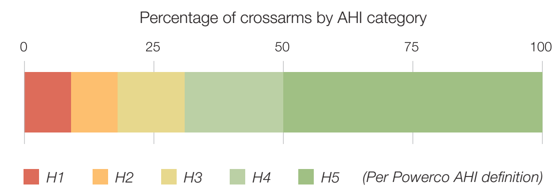
Insulators can crack or completely fail through shock loading, typically caused by adverse weather or tree strikes. Failures can also occur through flashovers, which are more prevalent in areas with high air pollution. These issues are fixed as needed (reactively).

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 14.10: **Crossarm asset health as at 2015**



Approximately 9% 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.

[65] 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.

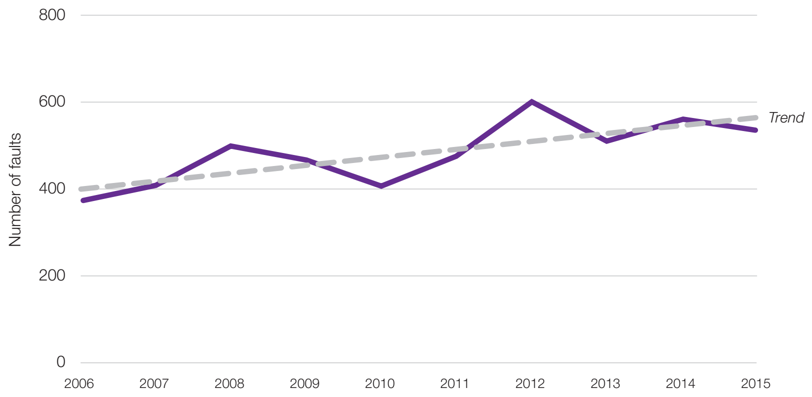
Crossarm defects

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 14.11: **Crossarm fault history**[66]



14.4.4 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.

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.

14.4.5 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 14.6: **Crossarm 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). Routine 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.

[66] Fault history excludes events related to vegetation, human elements, lightning and planned shutdowns.

14.4.6 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 and condition data to determine 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

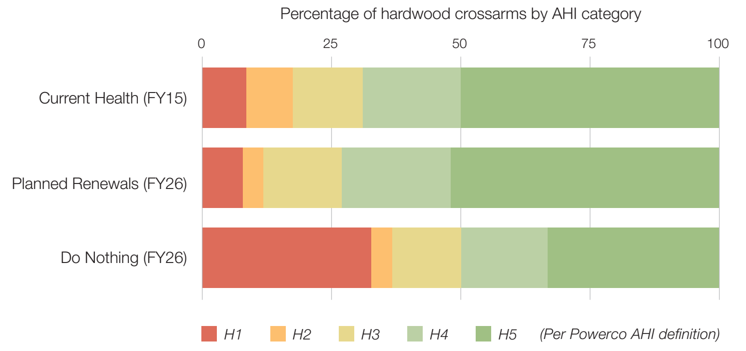
Networks for Today and Tomorrow: Crossarm replacements are forecast to increase, improving the reliability of poor performing feeders and managing network SAIDI and SAIFI.

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 2026 (following planned renewals) with a ‘do nothing’ scenario. Our investment will lead to an improvement in overall health.

Figure 14.12: **Projected crossarm asset health in 2026**



A significant number of crossarms will still require replacement after 2026, as indicated by the H1-H3 portion in Planned Renewals (FY26).

14.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

14.5 OVERHEAD STRUCTURES RENEWALS FORECAST

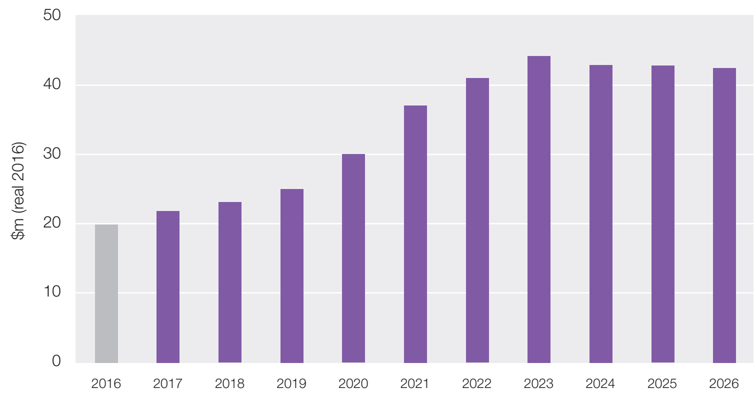
Renewal Capex in our overhead structures portfolio includes planned investments in our pole and crossarm fleets. Over the planning period we plan to replace 40,000 poles and 154,000 crossarms. This will require an investment of approximately $350m.

Pole and crossarm renewals 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 in Chapter 15.

The chart below shows our forecast Capex on overhead structures during the planning period.

Figure 14.13: **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 2026.

Further details on expenditure forecasts are contained in Chapter 24.

15. OVERHEAD CONDUCTORS

15.1 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 $3m in 2016 to $23m in 2026. This portfolio accounts for 17% 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 conductor due to their type, age and accelerated degradation due to coastal environments.

Certain types of distribution conductor on our network perform more poorly than others. Our average conductor failure rate is 1.4 faults per 100 km per annum.[67] However, we have five types of conductor with failure rates between 1.6 and 3.8 per km per annum. These types of conductor make up 18% of our distribution overhead fleet (or 2,700km). During the planning period we will prioritise the replacement of these type of conductors.

Below we set out the asset management objectives that guide our approach to managing our overhead conductor fleets.

15.2 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 4.

Table 15.1: Overhead conductors 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 by 15% compared to 2015 levels by 2030.
	Maintain the failure rate of subtransmission and LV overhead conductors at or below 2015 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.

[67] This failure rate refers to asset related conductor faults and not totals overhead line fault performance.

15.3 SUBTRANSMISSION OVERHEAD CONDUCTORS FLEET MANAGEMENT

15.3.1 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 15.1: **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) has been preferred to AAC conductor. 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.

15.3.2 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 15.2: Subtransmission conductor population by type at 31 March 2015

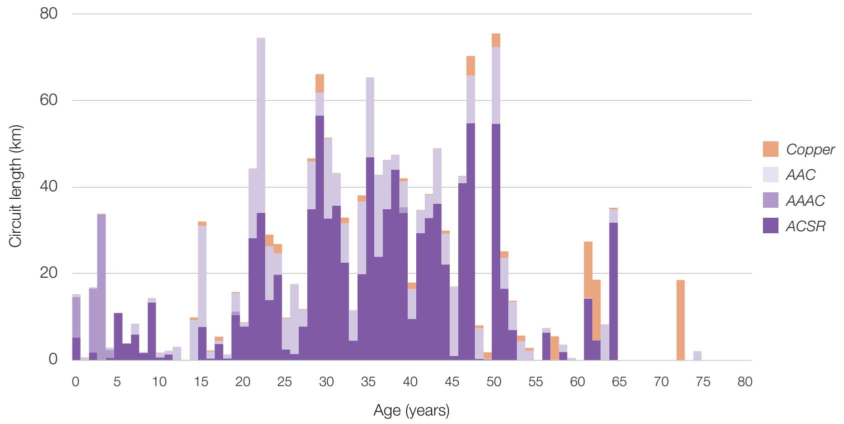
CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	62	4
AAC	415	27
ACSR	944	63
Copper	85	6
Total	1,506	

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 37. 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.[68] The figure below shows our subtransmission conductor age profile.

[68] Note that actual replacement is a condition-based decision.

Figure 15.2: **Subtransmission conductor age profile**



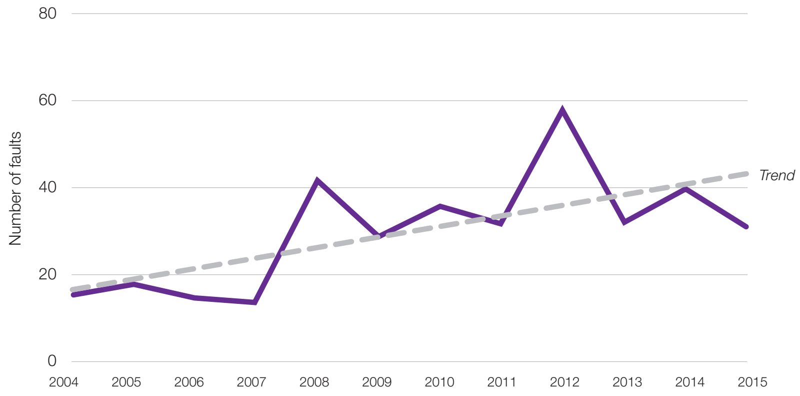
15.3.3 CONDITION, PERFORMANCE AND RISKS

Subtransmission conductor failure rates are lower compared to distribution and LV conductor. Subtransmission conductor makes up 9% of HV conductor length but is only responsible for 5% of total HV conductor failures.

Failure rates are lower because subtransmission conductor tends to be heavier and more robust than distribution and LV conductor. Subtransmission conductor is inspected more frequently due to its higher importance in maintaining reliable supply and has a higher ground clearance.

The figure below shows subtransmission conductor related faults. Fault rates on subtransmission conductors have been increasing over the past decade, although potentially have stabilised more recently.

Figure 15.3: **Conductor related faults on subtransmission overhead lines**



The table below summarises the common failure modes for all overhead conductor, including distribution and LV.

Table 15.3: **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 conductor 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 conductor 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.

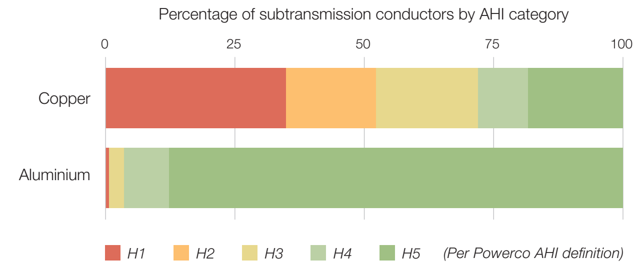
The poorest condition conductors in this fleet are our cooper subtransmission conductor and certain ACSR conductor. Our copper subtransmission conductor is ageing and makes up the majority of our expected renewals during the planning period. We have recently noticed some accelerated corrosion of ACSR conductor. 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 conductor we define end-of-life as when the asset can no longer be relied upon to safely carry its 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 15.4: **Subtransmission overhead conductors asset health as at 2015**



The health of our aluminium conductors is very good. Most of the subtransmission conductor fleet is made of aluminium. Of aluminium conductors, only 4% will require renewal over the next 10 years (H1-3).

However, the health of our copper conductor is a concern. Although only 6% of subtransmission conductor is made of copper, most of it will require renewal over the next 10 years. This conductor will make up the majority of our subtransmission conductor replacement over the planning period.

15.3.4 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 (e.g. 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.

15.3.5 OPERATE AND MAINTAIN

Maintenance and inspection regimes applied to overhead conductors generally involve visual inspections and condition assessments. The table below summarises the maintenance and inspection tasks. The detailed regime for each type of subtransmission overhead conductor is set out in our maintenance standard.

Table 15.4: **Subtransmission overhead conductors 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 conductor 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.[69]

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.

[69] Corona is an electrical discharge bought on by the ionization of air surrounding a charged conductor.

15.3.6 RENEW OR DISPOSE

We use a condition-based renewal strategy for subtransmission overhead conductors, where degradation is related to their age and location (e.g. 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

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.[70]

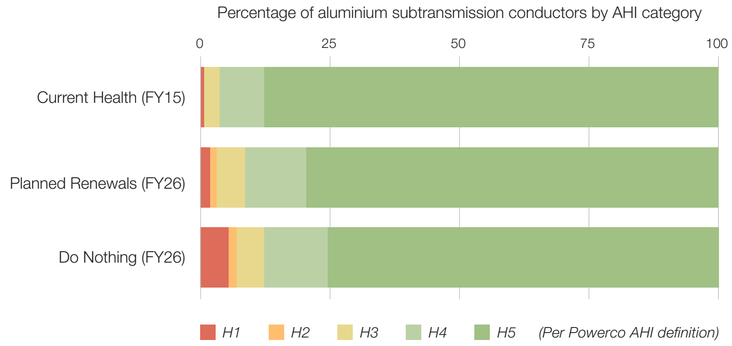
We expect subtransmission overhead conductor replacements to remain fairly constant over the next five to ten years and then to start increasing. A substantial number of aluminium circuits constructed from the mid-1950s onwards will need to be replaced.

By 2026 we expect to have replaced the majority of our remaining copper subtransmission circuits, most likely with aluminium conductor (AAAC). This means that the asset health of copper conductor will no longer be a concern. We therefore do not provide an AHI projection for copper conductor.

[70] We intend to further develop and refine our asset degradation and asset health models.

The figure below compares aluminium conductor projected asset health in 2026 (following planned renewals) with a 'do-nothing' scenario.

Figure 15.5: **Projected aluminium subtransmission conductor asset health as at 2026**



The small amount of planned conductor renewal will maintain aluminium conductors in overall good health, indicated by the H1 portion in Planned Renewals (FY26). Beyond 2026 there will be a growing need for conductor renewal (H2 and H3).

15.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.[71] 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 conductor will not need to be also replaced at a later date due to load growth.

[71] Work and expenditure in this chapter only relates to renewals.

15.4 DISTRIBUTION OVERHEAD CONDUCTORS FLEET MANAGEMENT

15.4.1 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 15.6: **Distribution overhead line with LV underbuilt**

In general, we use the same conductor types at the distribution level as for subtransmission. We also have a small population of steel wire[72] conductors.

The backbone of the main distribution network is formed of medium and heavy conductors.[73] 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.

[72] Steel wire conductors (predominantly number 8 wire) are galvanised steel conductor. They are typically installed in remote rural areas where only a low current capacity is required. They were installed predominantly during the 1950s and 1960s as a cost effective alternative to ACSR and copper conductors.

[73] Medium and heavy conductors are defined as those of >50mm^2 and >150mm^2 equivalent aluminium cross sectional area respectively.

15.4.2 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 conductor remains in this fleet.

Table 15.5: **Distribution conductor population by type at 31 March 2015**

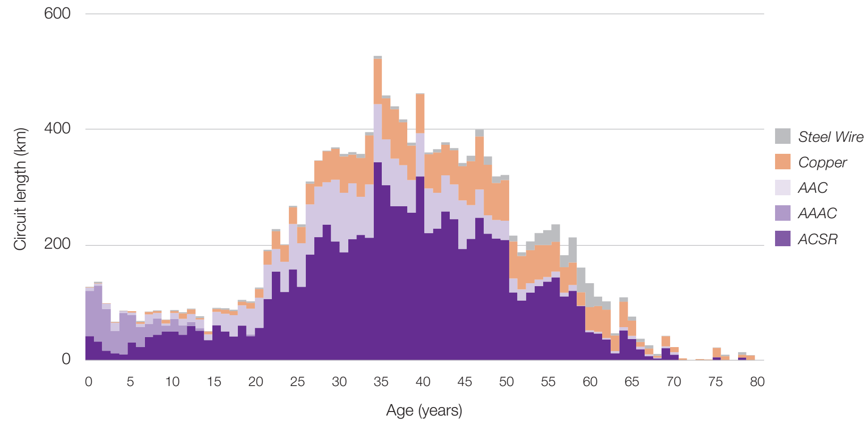
CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	598	4
AAC	2,535	17
ACSR	8,569	57
Copper	2,619	18
Steel wire	522	4
Total	14,843	

The average age of the distribution overhead conductor fleet is 37 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.

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 15.7: **Distribution conductor age profile**



15.4.3 CONDITION, PERFORMANCE AND RISKS

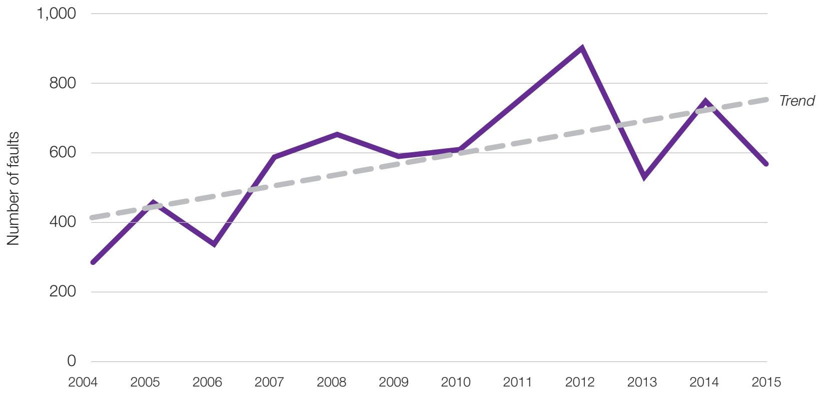
Overhead conductors, by their nature, create risks to public and personnel safety, including:

- 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 on the following page shows historical distribution conductor related faults on our network.

Figure 15.8: **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 conductor in order to reduce overall failure rates. Below we discuss our poor performing conductors, fault targets and findings from our failure analysis.

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, steel wire and AAC conductors is consistently poor, regardless of age.

The table below lists the five worst performing conductor types, the length installed on our network and their respective failure rates.

Table 15.6: **Poor performing distribution conductor types**

CONDUCTOR	KM OF LINE	FAILURE RATE[74]	DESCRIPTION
AAC Namu	811	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 major failure modes as line guards / armour rods are installed on most of the lines with Namu conductor.
AAC Poko	156	3.8	Used almost exclusively in Egmont area. Many of the failures to date 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.
Steel wire No. 8	496	1.6	Typically used on older parts of the western network, in low density rural applications. Performance has been better than the other types described in this table, but still below that of ACSR, and is of an age (average age 50+ years, with 60% over 55 years) where replacement is under warrantee.
Copper 16mm^2	524	3.0	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 ages.
Copper 7/0.064	744	2.8	

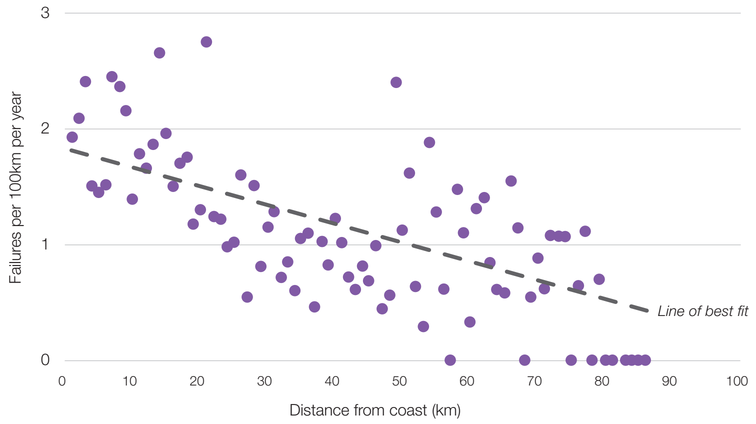
To reduce the number of distribution conductor faults to our target these conductors will need to be replaced. We target average failure rates[75] of 1.3-1.5 failures per 100km, depending on whether the circuits are in urban or rural areas. Failure rates of our five worst performing conductors vary from 1.6-3.8 failures per 100km.[76] 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.[77] This finding is consistent with our knowledge of failure modes. Other than foreign object strikes, all failure modes worsen as the conductor ages.

[74] 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.
[75] 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.
[76] Other conductors on our network average approximately 1.4 failures per 100km.
[77] 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 15.9: **Distribution conductor failures compared to coastal proximity**



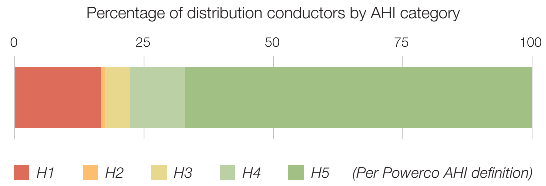
We found this relationship to be particularly strong within 20km of the coast in the Western Region. With other factors constant, we expect conductors to have a shorter life near the coast, particularly for lightweight conductors and those using steel (ACSR and No.8 steel wire).

Distribution overhead conductors 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 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 15.10: **Distribution overhead conductors asset health as at 2015**



The health of the fleet indicates the need to replace significant amounts of conductor (17% of the fleet, H1) to improve the health to a more sustainable level, and therefore improve our reliability performance.

15.4.4 DESIGN AND CONSTRUCT

The renewal of smaller diameter distribution conductor 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 (e.g. 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.[78]

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.

15.4.5 OPERATE AND MAINTAIN

Distribution conductors are inspected less frequently than subtransmission conductor, 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.

[78] These are conductor code names used by manufacturers and the electricity industry.

Table 15.7: **Distribution overhead conductor 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 wind conditions. 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.

15.4.6 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, No. 8 wire, 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 conductor that meets these indicators. Safety is our key concern around distribution conductor failure. We prioritise the renewal of conductor in more densely populated areas, typically urban areas. Worst performing feeders will also be targeted for conductor renewal.

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.

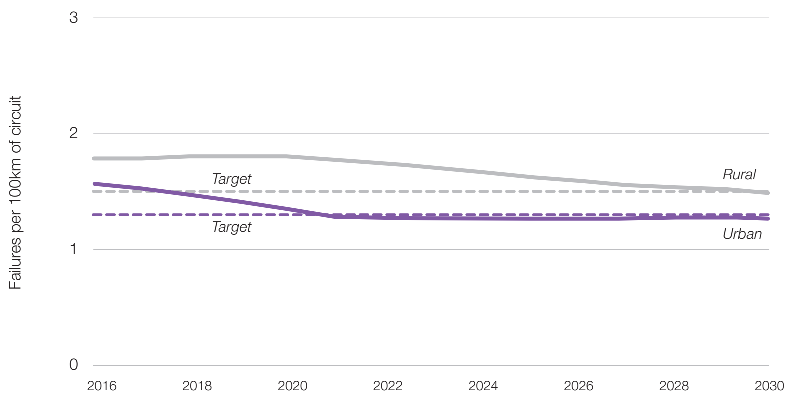
Renewals forecasting

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.[79] We have set ourselves the target of reducing failure rates to good practice levels by 2020 for urban conductor and 2030 for rural conductor.

The figure on the following page 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.

[79] 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 15.11: **Distribution conductor expected failure rates**



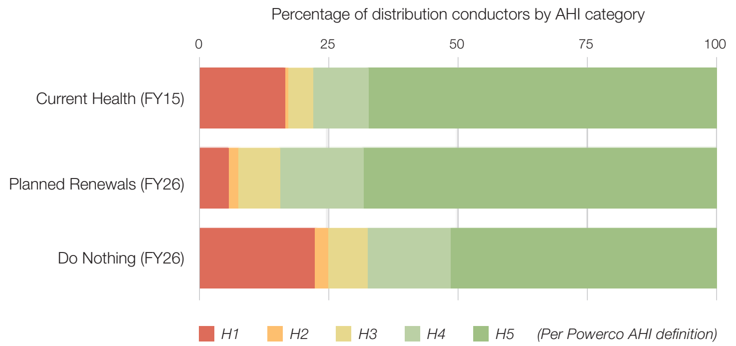
We forecast the amount of conductor renewal required to meet these targets using our modelled failure rates, assuming we replace the worst performing conductor first. This indicates the need for a large step change in renewal quantities over the next 10 to 15 years. Replacement quantities needed are expected to reduce once we reach our failure rate targets. Some ongoing replacements will still be necessary to maintain overall performance at target levels.

Meeting our portfolio objectives

Asset Stewardship: Forecasted distribution overhead conductor renewal is expected to reduce failure rates by 15% by 2030.

The next figure compares projected asset health in 2026 (following planned renewals) with a 'do nothing' scenario. Our investment will lead to an improvement in overall health by 2026 (as shown by the reduced H1 portion) though not to long-term sustainable levels (in line with our 2030 target).

Figure 15.12: **Projected distribution conductor asset health in 2026**



Significant conductor will still need to be replaced after 2026 as indicated by the H1-H3 portion in Planned Renewals (FY26). However, it will not be at the same level as this planning period.

15.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 on the next page.

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 utilise 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.

15.5 LOW VOLTAGE OVERHEAD CONDUCTORS FLEET MANAGEMENT

15.5.1 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.[80] This helps to mitigate safety risks and reduces vegetation related faults.

Figure 15.13: **LV overhead circuit**

[80] The covering is not considered electrical insulation, but does provide some mitigation of safety risk from accidental contact or a fallen conductor.

15.5.2 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.

The table below summarises our LV conductor population by type. Most of our LV conductor is made of copper (52%). 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 15.8: **LV conductor population by type at 31 March 2015**

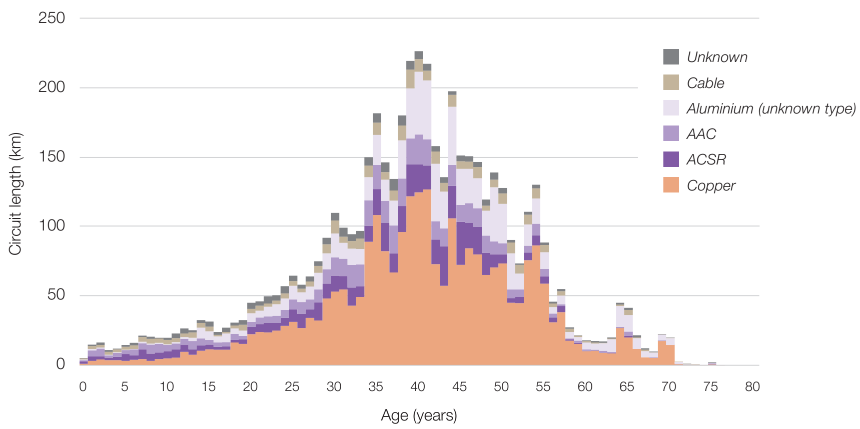
CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	6	0.1
AAC	515	10
ACSR	547	11
Unknown aluminium	855	17
Copper	2,715	52
Steel wire	5	0.1
Cable[81]	298	6
Unknown	212	4
Total	5,154	

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 conductor recorded in our information systems is 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.

[81] 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 15.14: **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.

15.5.3 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 conductor, assess the public safety risk due to conductor or binding failure, and prioritise its replacement with covered conductor. 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.

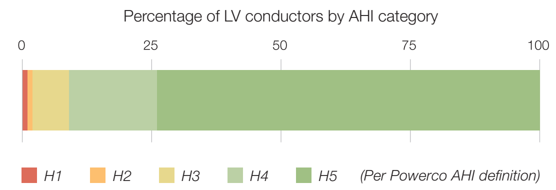
Ageing will continue to cause condition degradation, with coastal proximity causing faster degradation. Similar to distribution conductors we expect LV conductor failure rates to increase from approximately 60 years of age.

LV overhead conductors 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 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 15.15: **LV overhead conductors asset health as at 2015**



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, 10% 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.

15.5.4 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[82] 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 conductor 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.

15.5.5 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 15.9: **LV overhead conductor maintenance and inspection tasks**

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of LV overhead conductor, as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

15.5.6 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.

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.

SUMMARY OF LV OVERHEAD CONDUCTOR RENEWALS APPROACH	
Renewal trigger	Condition-based considering failure risk
Forecasting approach	Age
Cost estimation	Volumetric average historic rate

[82] Insulated clamp brackets are still required.

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.

Renewals forecasting

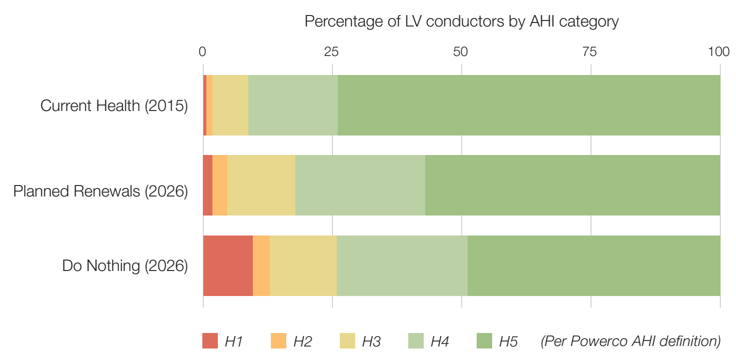
To forecast future renewal needs, we use age as a proxy for condition. Rather than using a simple 'birthday' type age model, we use a statistical distribution modelling approach. This approach reflects more closely actual replacement decisions. It reflects that the need for conductor renewal can be expected 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 LV conductor. This is more conservative than the indicative 60-year life of distribution conductor.

Although conservative, our model forecasts the need for a large step in LV conductor renewal. We plan to slowly increase renewals from today's levels out to FY19. 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.

The figure below compares projected asset health in 2026 (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 15.16: **Projected LV conductor asset health in 2026**



The amount of conductor that needs to be replaced will grow by 2026, as indicated by the H1-H3 portion in Planned Renewals (FY26). This indicates that long-term replacement volumes will need to increase further.

15.5.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 11) 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 SSDG.

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 21 Asset Relocations).

15.6 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 150km of subtransmission conductor, 2,400km of distribution conductor, and 400km of LV conductor. This will require an investment of approximately $145m over the planning period.

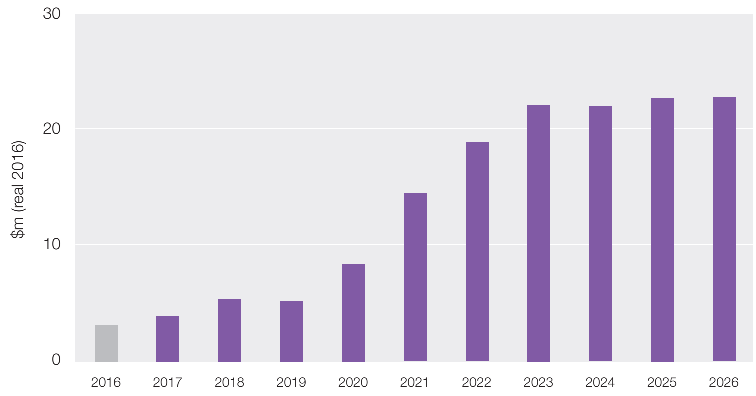
Subtransmission, distribution and LV conductor renewals are derived from bottom up models. Subtransmission reconductoring projects can be scoped at a high level a number of years before implementation. This means we can carry out desktop cost estimates for each project which take into account factors such as terrain difficulties, span lengths, and pole and crossarm renewals.

Distribution and LV renewals forecasts are generally volumetric estimates (explained in Chapter 24). 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.[83]

[83] 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.

Figure 15.17: **Overhead conductors renewal forecast expenditure**



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 conductor.

Longer term levels of renewals are expected to remain at these increased levels beyond the 10-year planning horizon, as more conductor constructed during the 1950s to 1970s requires 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 24.

16.1 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 $66m renewing our cables fleets. This accounts for 8% 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 and FY19-20 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 3,200 pillar boxes with safety-related risks. We have been working to remove these types of pillar 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.

16.2 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 4.

Table 16.1: **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 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.
Asset Stewardship	Maintain the failure rate of cable assets at or below 2015 levels.
Operational Excellence	Improve our knowledge of the LV cable fleet.

16.3 SUBTRANSMISSION CABLES FLEET MANAGEMENT

16.3.1 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.

16.3.2 POPULATION AND AGE STATISTICS

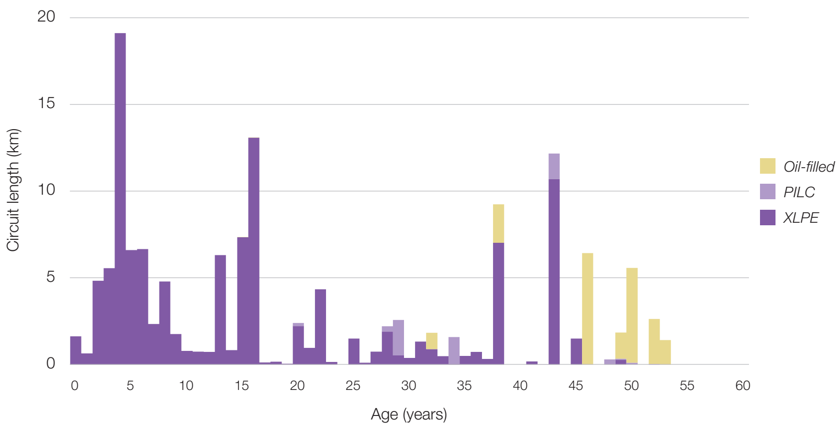
The majority of our approximately 150km of subtransmission cable is XLPE cable. XLPE has been the preferred cable insulation technology for over 30 years. The table below summarises our subtransmission cable population.

Table 16.2: **Subtransmission cable population by type at 31 March 2015**

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	121	82
PILC	6	4
Oil-filled	20	14
Total	147	

The subtransmission cable fleet is relatively young, with an average age of 22 years. The figure below depicts our subtransmission cable age profile.

Figure 16.1: **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.

16.3.3 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 cables ability to sustain thermal cycling. We have applied reduced cable ratings to these circuits to limit thermal cycling but oil leaks are continuing.

We plan to retire the majority of the affected cable circuits. 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 Kairanga to Pascal cable circuit has recently begun leaking at a faster rate than previously. The cable has been shut down due to catastrophic failure concerns and the ongoing environmental impacts. It will be replaced in FY17. The remaining cable work will be coordinated with the wider Palmerston North CBD project, discussed in Chapter 8.

Table 16.3: **Palmerston North subtransmission cable circuits**

CABLE CIRCUIT	CIRCUIT LENGTH	ACTION
Keith St to Main St (two circuits)	2.7km (x2)	Replace with two new underground circuits from Ferguson to Main St – length 2km each. Assess cable for possible use as a redundant emergency backup.
Kairanga to Pascal	2.9km	Replace with new underground cable in FY17.
Pascal to Main St	1.8km	Decommission cable made redundant by Palmerston North CBD reinforcement project.

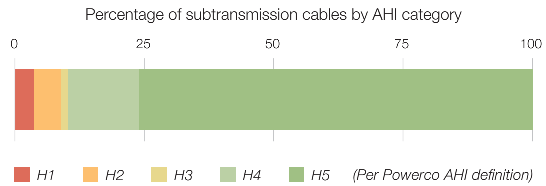
An issue has been identified with a certain type of 33kV indoor heat shrink terminations, where poor installation causes premature failure. An inspection and testing programme identifies affected terminations which are replaced if necessary.

Subtransmission cables asset health

As outlined in Chapter 12, 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 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 16.2: **Subtransmission cables asset health as at 2015**



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.

16.3.4 DESIGN AND CONSTRUCT

All new subtransmission cable circuits utilise XLPE insulated cable with stranded aluminium conductor 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 utilisation 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 asset ratings for subtransmission cables to increase their effective capacity.

16.3.5 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 16.4: **Subtransmission Cable 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.

16.3.6 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 need was assessed in conjunction with the CBD load growth. Based on an options analysis we decided to:

- Retire the Pascal to Main St cable
- Replace the Kairanga to Pascal cable
- Install new cables from Ferguson to Main St in place of the existing Keith St to Main St cables

Cost estimates for these projects have been developed from desktop studies of proposed cable routes using typical component costs or 'building block' costs.

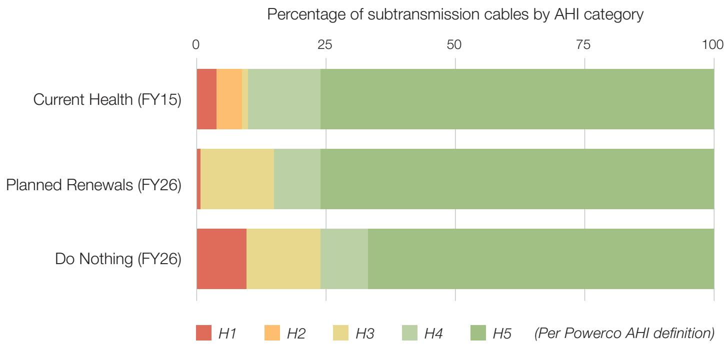
SUMMARY OF SUBTRANSMISSION CABLES RENEWALS APPROACH

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 2026 (following planned renewals) with a 'do nothing' scenario. Our investment in replacing the Palmerston North will lead to an improvement in overall health.

Figure 16.3: **Projected subtransmission cables asset health as at 2026**



By 2026, the oldest of the XLPE circuits will be coming due for replacement, as indicated in the H2 and H3 portion in Planned Renewals (FY26).

16.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

16.4 DISTRIBUTION CABLES FLEET MANAGEMENT

16.4.1 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'[84] 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.

16.4.2 POPULATION AND AGE STATISTICS

We have approximately 1,900km 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.

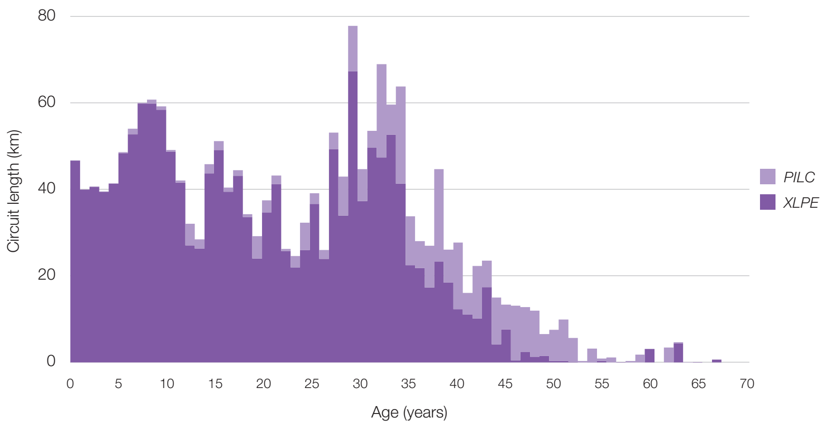
[84] 'Water treeing' results from condensed steam which was used to assist the polyethylene insulation curing as part of the manufacturing process.

Table 16.5: **Distribution cable population by type at 31 March 2015**

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	1,634	84
PILC	312	16
Total	1,946	

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 16.4: **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.[85] 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.

[85] Expected lives for distribution cables are 55 and 70 years for XLPE and PILC respectively.

16.4.3 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 (e.g. 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

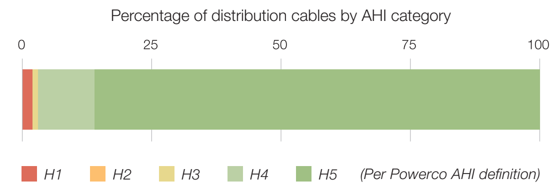
Asset Stewardship: Distribution cables with known high rates of failure are replaced to maintain overall fleet reliability, and manage network SAIDI and SAIFI.

Distribution cables asset health

As outlined in Chapter 12, 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 16.5: **Distribution cables asset health as at 2015**



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).

16.4.4 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.

16.4.5 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 following table. The detailed regime for each type of cable is set out in our maintenance standard.

Table 16.6: **Distribution cable 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.

16.4.6 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 2020.

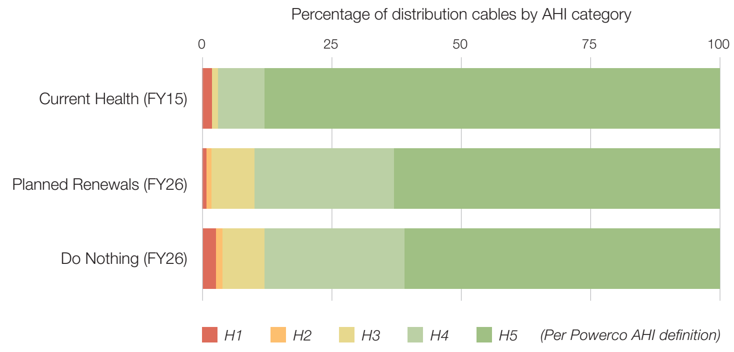
Cable insulation generally degrades over time, with the largest influences being operating temperatures and exposure to UV (which in turn influences the life of insulation, screens and cable finishes). Condition assessment, inspections and multiple failures can indicate a cable in poor condition and 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 2026 (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 16.6: **Projected distribution cables asset health in 2026**



16.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

16.5 LOW VOLTAGE CABLES FLEET MANAGEMENT

16.5.1 FLEET OVERVIEW

The LV cable fleet operates at below 1kV (230/400V). The main assets within the fleet are cables, link boxes, LV cabinets and pillar 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 pillar box usually located on the property boundary. The integrity of pillar boxes is a key public safety concern. We have a variety of different styles and materials installed on our network.

Figure 16.7: **Pillar boxes**

16.5.2 POPULATION AND AGE STATISTICS

Our LV underground network consists of 5,605 circuit km of cable. This includes 1,660km of dedicated street lighting circuits and 403km of hot water pilot circuits.

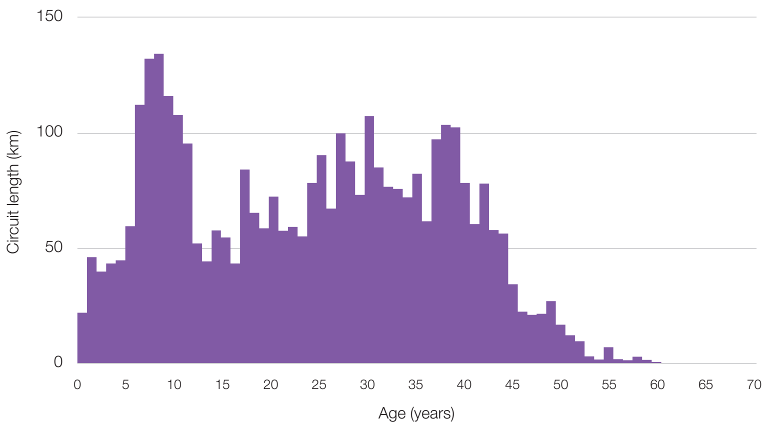
Data on our LV cable fleet is incomplete as detailed information was normally not recorded prior to 2000. We intend to significantly lift our knowledge of the LV network over the planning period. We plan to undertake a detailed programme of LV pillar box data capture and labelling.

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).[86]

Figure 16.8: **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.

16.5.3 CONDITION, PERFORMANCE AND RISKS

The key risk in the fleet relates to our pillar 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 pillar 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 pillar boxes, typically at infill developments. These overcrowded pillar boxes present a safety hazard during servicing and can lead to overheating. We schedule the replacement of identified pillar boxes through the defects process.

A large number of defects and faults are due to physical damage, often caused by vehicles. Although a pillar 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.

[86] Around 10% of the fleet's age is unknown and has been excluded from the chart.

Another safety issue relating to pillar boxes are those of metallic construction which can be inadvertently livened. Affected pillar boxes have been identified and replacement is planned during the planning period.

We have identified a total of approximately 3,200 pillar box defects. The pillar boxes will be replaced as part of our ongoing LV safety-related investment programme.

16.5.4 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 (e.g. commercial, residential, and industrial). Voltage drop, fault current capacity and mechanical performance are considered when designing LV cable networks.

Pillar box types are closely controlled before being approved for use on the network. We use pillar boxes from two manufacturer ranges, both of which been through our asset specification approval process.

16.5.5 OPERATE AND MAINTAIN

Maintenance of the LV cable fleet focuses on the inspection of pillar 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 16.7: **LV cable network maintenance and inspection tasks**

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Thermal imaging scan of CBD distribution boxes	1 yearly
Detailed inspection of pillar boxes located near parks, public amenities, schools and business districts	2 ½ yearly
Detailed inspection of pillar 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 pillar box data capture and labelling. This will improve our knowledge of the LV network. We expect that it will also identify further pillar box defects. Pillar 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.

Meeting our portfolio objectives

Safety and Environment: Pillar boxes are being tracked and labelled to improve our management of assets that are in a public space to minimise safety risks.

16.5.6 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.

Pillar boxes present a safety risk to the public and their condition is more easily understood through visual inspection. We are continuing our programme of pillar box replacement with known type issues. There will also be an ongoing need to reactively replace pillar 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 (pillar boxes)
Forecasting approach	Historic trend (cable) and defect rates (pillar boxes)
Cost estimation	Volumetric average historic rate

LV cable fleet renewal investment is expected to remain relatively constant over the next ten 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.

16.5.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

16.6 CABLES RENEWALS FORECAST

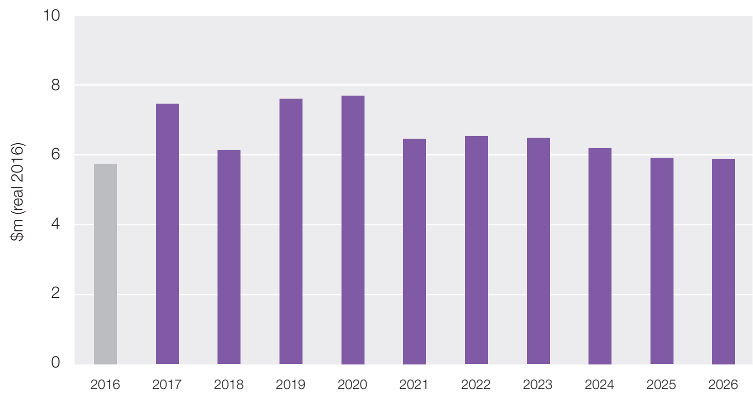
Renewal Capex in our cable portfolio includes planned investments in our subtransmission, distribution and LV cable fleets. Over the planning period we will invest approximately $66m on cable renewal.

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 24).

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.[87] 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.

Figure 16.9: **Cables renewal forecast expenditure**



The forecast renewal expenditure for the cable portfolio is in line with historical levels. Additional expenditure in 2017 and 2019-20 is due to the subtransmission cable works in the Palmerston North CBD.

Further details on expenditure forecasts are contained in Chapter 24.

[87] As the primary driver for the Palmerston North subtransmission cable replacement is condition, this expenditure is classed as renewals.

17. ZONE SUBSTATIONS

17.1 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 $117m in zone substation renewals. This accounts for 13% 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, 17% of our outdoor switchgear currently requires replacement and a further 19% of the fleet is expected to require 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.

In the next column we set out the asset management objectives that guide our approach to managing our six zone substation fleets.

17.2 ZONE SUBSTATIONS OBJECTIVES

Zone substations take supply from the national grid through subtransmission feeders. They provide connection points between subtransmission circuits, step-down voltage through power transformers to distribution levels and incorporate switching and isolation equipment to enable operation of the network.

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 4.

Table 17.1: 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.

17.3 POWER TRANSFORMERS FLEET MANAGEMENT

17.3.1 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 17.1: **Power transformer installation at Waharoa**

17.3.2 POPULATION AND AGE STATISTICS

There are 188 power transformers in service on our network, of which 167 are 33/11kV units. The table below summarises our population of power transformers by rating.

Table 17.2: **Power transformer population by rating at 31 March 2015**

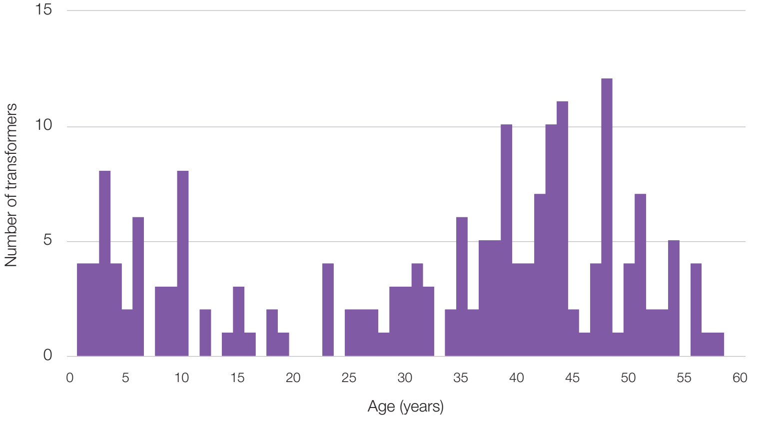
MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
<5	26	14
≥5 to <10	80	42
≥10 to <15	20	11
≥15 to <20	37	20
≥20	25	13
Total	188	

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 32 years.

Figure 17.2: **Power transformer age profile**



A number of our power transformers are approaching their expected 60-year life span and will soon likely require replacement.

17.3.3 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

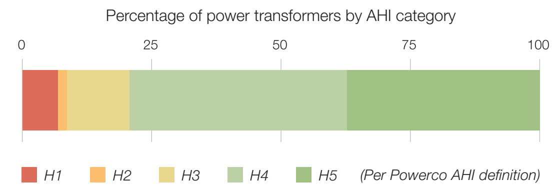
Safety and Environment: Power transformer bunding and oil containment systems are being upgraded to reduce the risk of oil spills.

Power transformers asset health

As outlined in Chapter 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. 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 17.3: **Power transformer asset health as at 2015**



About 13 power transformers need replacement (H1). These transformers make up about 7% of the power transformer fleet.

17.3.4 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[88] for 33/11kV transformers are:

- 5MVA
- 7.5/10MVA
- 12.5/17MVA
- 16/24MVA

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.

[88] Some units have two cooling ratings. They represent natural and forced (i.e. with pumps and fans) cooling.

Meeting our portfolio objectives

Safety and Environment: Noise levels are reviewed when new transformers are installed to minimise noise pollution.

17.3.5 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 17.3: **Power transformer 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. We are planning to procure a mobile substation during FY17-18.

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.

17.3.6 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.

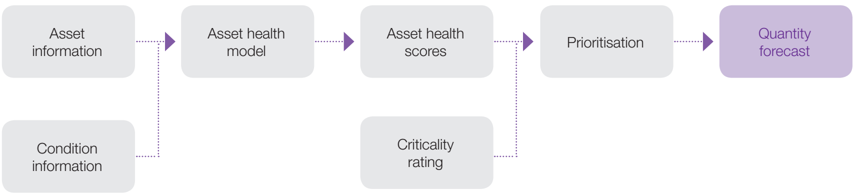
Our power transformer asset health model is based on work by the EEA,[89] and our experience and asset information. Condition indicators used in the model include DGA, paper insulation DP, external tank condition and known type or design issues.

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).

[89] EEA Asset Health Indicator Guide

The figure below provides an overview of the asset health based renewal quantity forecast.

Figure 17.4: **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 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.

17.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 requires additional redundancy. For further discussion refer to our zone substation security standards in Chapter 8.

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.

17.4 INDOOR SWITCHGEAR FLEET MANAGEMENT

17.4.1 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 17.5: **11kV indoor switchboard at Main St, Palmerston North**

17.4.2 POPULATION AND AGE STATISTICS

There are 906 circuit breaker panels within 113 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 17.4: **Indoor switchgear circuit breaker and switchboard populations by type at 31 March 2015**

INTERRUPTER TYPE	CIRCUIT BREAKERS	SWITCHBOARDS
Oil	444	59
SF_6	131	20
Vacuum	331	34
Total	906	113

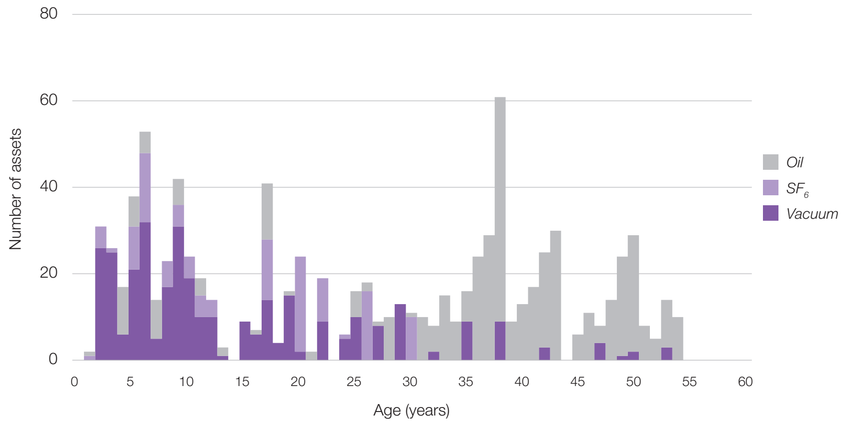
Indoor switchgear technology has evolved over time. Prior to the 1990s the majority of switchgear installed used oil as the circuit breaker insulation and arc quenching medium. The older segment of our population is primarily made up of oil-filled switchgear.

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 17.6: **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.

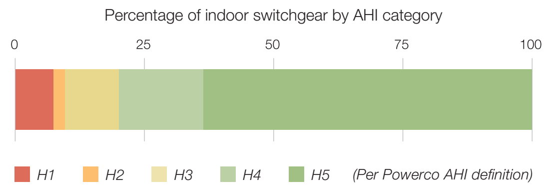
17.4.3 CONDITION, PERFORMANCE AND RISKS

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 their 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 primarily calculated using asset age and typical expected lives (noting that actual replacement is informed by detailed condition assessment).

The figure below shows current overall AHI of the indoor switchgear fleet.

Figure 17.7: **Indoor switchgear asset health as at 2015**



About 20% of our indoor switchgear requires replacement over the next 10 years (H1-H3). About 7% of our indoor switchboards have already been identified for replacement (H1).

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[90] to be no more than 8 cal/cm². 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 18% of our 11kV 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 17.5: **11 kV indoor switchgear arc flash risk as at 2015 (% of total asset fleet)**

ARC FLASH CATEGORY	ASSET HEALTH INDEX				
	H5	H4	H3	H2	H1
≥ 8 cal/cm² (oil switchgear)	5%	6%	3%	-	2%
≥ 8 cal/cm² (not oil switchgear)	18%	-	-	-	-
< 8 cal/cm²	41%	10%	8%	2%	5%

We mitigate this risk through one of three approaches:

- Remove the entire switchboard from service to perform 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.

[90] Arc flash energy is described in calories per centimetre squared (cal/cm²). Our limit is based on the EEA's 'Guide for the Management of Arc Flash Hazards'.

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.

17.4.4 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 process 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.

17.4.5 OPERATE AND MAINTAIN

Indoor switchgear undergoes routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in the table below.

Table 17.6: **Indoor switchgear 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 (e.g. HV withstand). Switchboard partial discharge test.	6 yearly

17.4.6 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

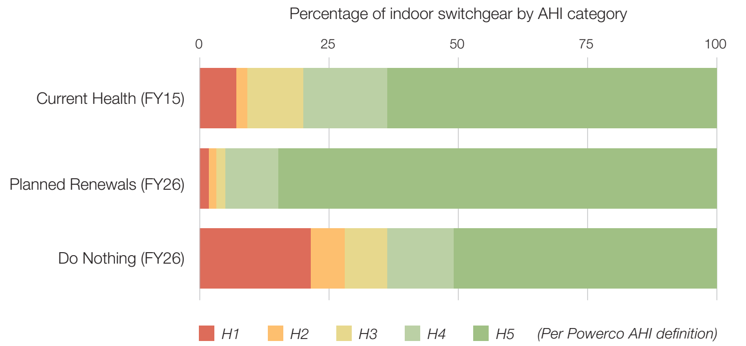
Renewals forecasting

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 2026 (following planned renewals) with a 'do nothing' scenario. Our investment will lead to an improvement in overall health, as indicated by the H1-H3 portion in Planned Renewals (FY26).

Figure 17.8: **Projected indoor switchgear asset health in 2026**



Overall indoor switchgear asset health will improve through our planned replacement of switchboards with high arc flash risk and those in poor condition. After 2026 the renewal volume will be lower, as indicated H2-H3 in Planned Renewals (FY26).

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 17.7: **Projected 11kV indoor switchgear arc flash risk as at 2026 (% of total asset fleet)**

ARC FLASH CATEGORY	ASSET HEALTH INDEX				
	H5	H4	H3	H2	H1
≥ 8 cal/cm² (oil switchgear)	2%	6%	3%	-	-
≥ 8 cal/cm² (not oil switchgear)	2%	-	-	-	-
< 8 cal/cm²	78%	10%	3%	-	4%

We have identified the need for a site rebuild project[91] 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 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.[92] These are described in further detail in the outdoor switchgear section below.

17.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

[91] This expenditure is included within the indoor switchgear fleet, as this is the largest cost component of the project.
[92] 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.

17.5 OUTDOOR SWITCHGEAR FLEET MANAGEMENT

17.5.1 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 17.9: **Typical outdoor 33kV switchgear bay**

17.5.2 POPULATION AND AGE STATISTICS

The following table summarises our population of outdoor switchgear by type. Circuit breakers are also broken out by interrupter type.

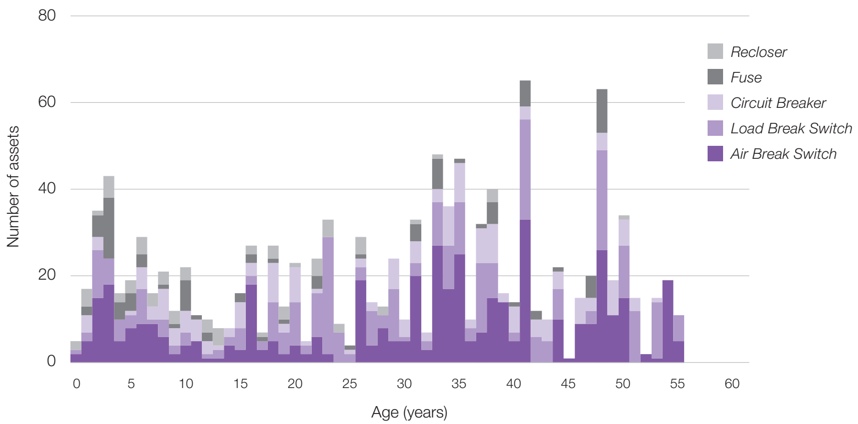
Table 17.8: **Outdoor switchgear numbers by asset type at 31 March 2015**

SWITCHGEAR TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Air break switch		459	39
Load break switch		335	29
Circuit breaker		193	17
of which:	Oil	141	
	SF_6	39	
	Vacuum	13	
Fuse		99	9
Recloser		72	6
Total		1,158	

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 17.10: **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).

17.5.3 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.

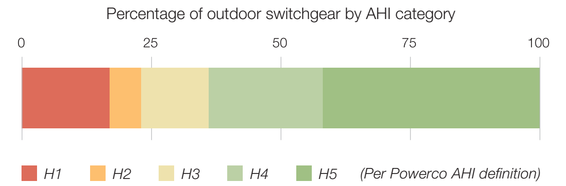
To minimise this failure risk we service our oil circuit breakers after they have performed a specified number of switching operations. The number is determined based on the type of circuit breaker and the fault current breaking energy.

Outdoor switchgear asset health

As outlined in Chapter 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 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 asset age and expected lives.

The figure below shows current overall AHI for our population of outdoor switchgear.

Figure 17.11: **Outdoor switchgear asset health as at 2015**



The overall health of the outdoor switchgear fleet is poor as we expect that 36% of the fleet will require renewal over the next 10 years (H1-H3). 17% of the fleet has already been identified for replacement (H1). A significant increase in renewal investment is required to stabilise the health of this fleet.

17.5.4 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.[93]

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 17.12: **Live tank SF_6 outdoor 33kV circuit breaker**

[93] A SF_6 user becomes a major user when it has more than 1000kg of the gas in stock.

17.5.5 OPERATE AND MAINTAIN

Outdoor switchgear undergoes routine maintenance to ensure safe and reliable operation. We also undertake routine maintenance on the basis of circuit breaker operations to mitigate against failure modes associated with excess duty.

Our various routine maintenance tasks are summarised in the table below. The detailed regime for each asset is set out in our maintenance standard.

Table 17.9: **Outdoor switchgear 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 routine and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

17.5.6 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.

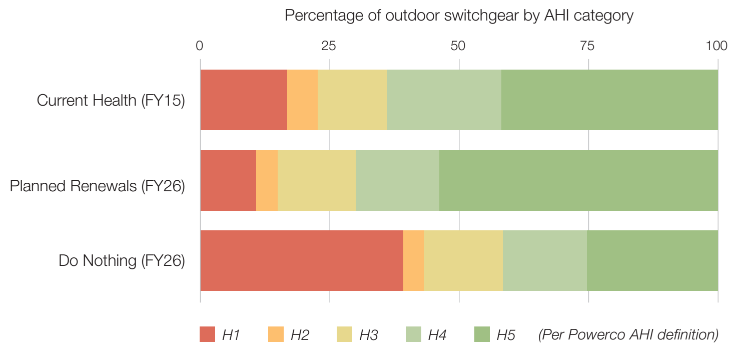
Outdoor to indoor conversion project[94] planning considers a range of drivers, including condition, safety and criticality. The high level scope of these projects is used to develop an indicative cost estimate. We intend to further refine our quantitative analysis to help identify the need for conversions.

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 FY20.

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 2026 (following planned renewals) with a 'do nothing' scenario. Our investment will lead to an improvement in overall health as we increase our renewal investment targeting assets in poor condition.

Figure 17.13: **Projected outdoor switchgear asset health in 2026**



Replacement levels will need to remain at these increased levels beyond 2026 as indicated by the large H2-H3 portion in Planned Renewals (FY26).

[94] 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.

17.5.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

17.6 BUILDINGS FLEET MANAGEMENT

17.6.1 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 recently 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 17.14: **Masonry constructed building**

17.6.2 POPULATION AND AGE STATISTICS

We have 158 buildings[95] at our zone substations. These are constructed of various materials including concrete, timber and masonry.

17.6.3 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.[96]

We recently assessed 73 of our zone substation buildings[97] 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.

Table 17.10: **Zone substation buildings by NZSEE seismic grade at 31 March 2015**

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS	% OF TOTAL
A+	>100	7	4
A	80-100	29	19
B	67-79	8	5
C	34-66	20	13
D	20-33	25	16
E	<20	10	6
Not assessed[97]		59	37
Total		158	

[95] This excludes 'minor' buildings, such as sheds.
[96] 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.
[97] 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.

Twenty eight 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.

17.6.4 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 17.15: **Urban zone substation building**

17.6.5 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 17.11: **Building 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

17.6.6 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.[98]

17.6.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

[98] Note that the cost of new buildings or building extensions is covered within the forecasts for the related asset (e.g. indoor switchgear).

17.7 LOAD CONTROL INJECTION PLANT FLEET MANAGEMENT

17.7.1 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 (e.g. 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 17.16: **Load control injection plant**

17.7.2 POPULATION AND AGE STATISTICS

We currently operate 37 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 17.12: **Load control injection plant by type at 31 March 2015**

TYPE	PLANT	% OF TOTAL
Modern ripple plant	17	46
Legacy ripple plant	10	27
CycloControl plant	10	27
Total	37	

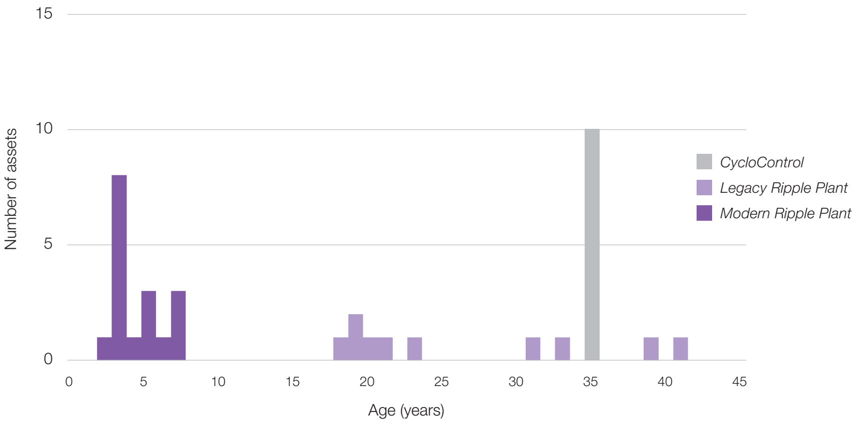
One of the aged types is the CycloControl system which is a voltage distortion system used in the Stratford and Huirangi regions. Its method of transmitting load control commands differs from all other systems on our networks and has more faults.

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 17.17: **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.

17.7.3 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.

17.7.4 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.

17.7.5 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 17.13: **Load control injection 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

17.7.6 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 renewals in this planning period.

SUMMARY OF LOAD CONTROL INJECTION PLANT RENEWALS APPROACH	
Renewal trigger	Obsolescence
Forecasting approach	Type
Cost estimation	Average historic rate

17.7.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 8.

17.8 OTHER ZONE SUBSTATION ASSETS FLEET MANAGEMENT

17.8.1 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.

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.

17.8.2 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 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.

17.8.3 OPERATE AND MAINTAIN

Our general zone substation maintenance tasks are summarised in the next table. The detailed regime is set out in our maintenance standards.

Table 17.14: **Zone substation general 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

17.8.4 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 FY26.

SUMMARY OF OTHER ZONE SUBSTATION ASSETS RENEWALS APPROACH	
Renewal trigger	Safety and reliability risk
Forecasting approach	Programmes
Cost estimation	Historical rates

17.9 ZONE SUBSTATIONS RENEWALS FORECAST

Renewal Capex in our zone substations portfolio includes planned investments in the following fleets:

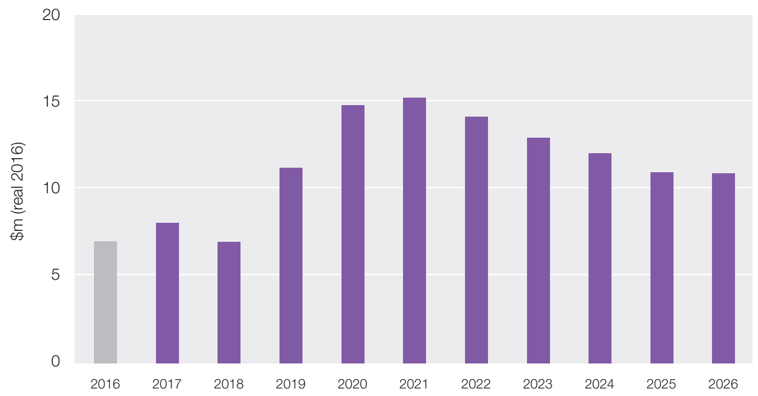
- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control plant
- Other zone substation assets

Over the planning period we plan to invest $117m in zone substation asset renewal.

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 17.18: **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 updates, the deteriorating condition of the portfolio means that substantial renewal investment is now warranted.

Further details on expenditure forecasts are contained in Chapter 24.

18. DISTRIBUTION TRANSFORMERS

18.1 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 includes 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 $94m in distribution transformer renewals. This accounts for 11% 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. Between FY19-FY23 we intend to convert these units to ground mounted equivalents or upgrade the associated poles.
- 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).

Below we set out the asset management objectives that guide our approach to managing our distribution transformer fleets.

18.2 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 4.

Table 18.1: **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.
	Installation compliance 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 (e.g. 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.

18.3 POLE MOUNTED DISTRIBUTION TRANSFORMERS FLEET MANAGEMENT

18.3.1 FLEET OVERVIEW

There are approximately 28,000 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.[99] This means any pole mounted transformers greater than 100kVA that require replacement is 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.

[99] 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.

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.

Figure 18.1: **100kVA pole mounted transformer**

18.3.2 POPULATION AND AGE STATISTICS

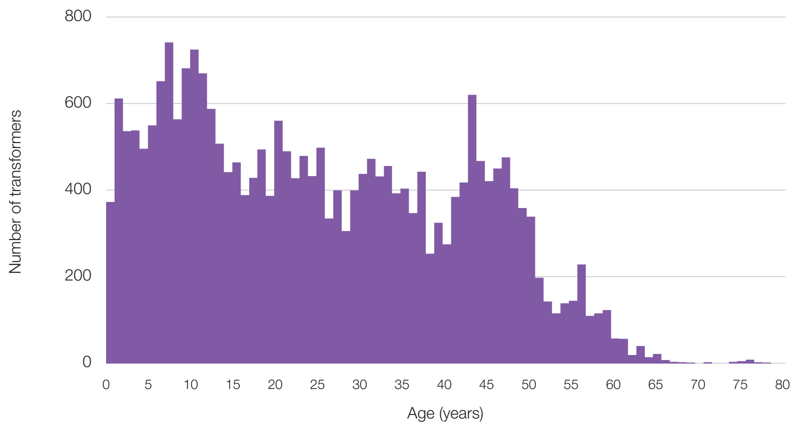
The table below summarises our population of pole mounted distribution transformers by kVA rating. Most are very small, with more than 40% at 15kVA or below. A transformer of this size typically supplies a few houses in a rural area.

Table 18.2: **Pole mounted distribution transformer population by rating at 31 March 2015**

MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
≤ 15kVA	10,367	41
> 15 and ≤ 30kVA	8,613	34
> 30 and ≤ 100kVA	5,554	22
> 100kVA	751	3
Total	25,285	

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 18.2: **Pole mounted distribution transformer age profile**



18.3.3 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 (e.g. 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.

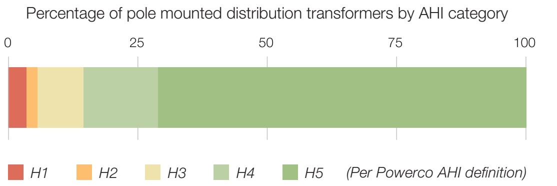
We work with the NZTA to identify distribution lines and poles alongside highways and roads with a high likelihood of vehicle accidents. Once identified, we aim to underground the overhead line to eliminate the risk of vehicles hitting our poles. The associated pole mounted distribution transformers are converted to ground mounted equivalents. For more information refer to the Asset Relocations Chapter 21.

Pole 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 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 18.3: **Pole mounted distribution transformer asset health as at 2015**



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).

18.3.4 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 11 Networks for the Future.

Distribution transformer monitoring

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.

18.3.5 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 routine inspections are summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 18.3: **Pole mounted distribution transformer 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.

18.3.6 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.

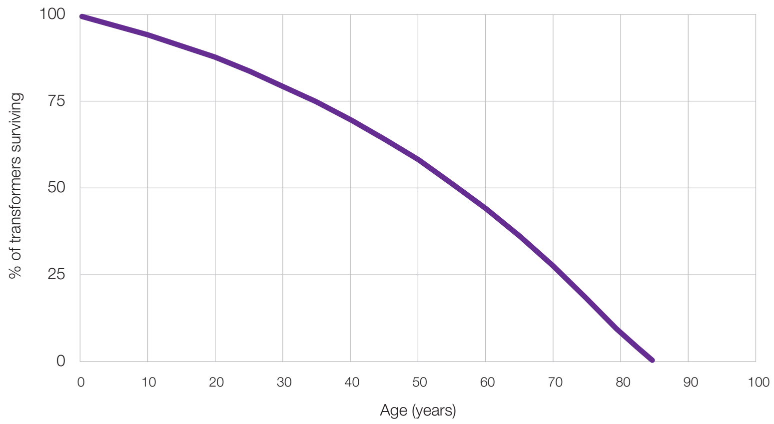
SUMMARY OF POLE MOUNTED DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Reactive and condition based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

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 following figure shows a pole mounted distribution transformer survivor curve. The curve indicates the percentage of transformer population remaining at a given age.

Figure 18.4: **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.

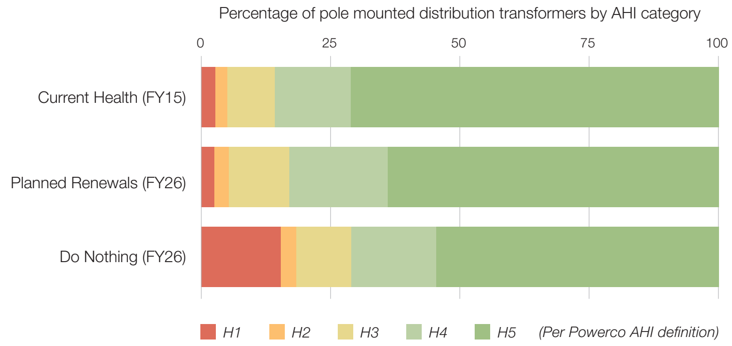
We have also identified approximately 250 larger pole mounted distribution transformers on pole structures that may be at risk of failing during seismic events. These units will be replaced and converted to ground mounted equivalents.

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 2026 (following planned renewals) with a 'do nothing' scenario. Our investment targets the minimum renewal needed to maintain the health of the fleet.

Figure 18.5: **Projected pole mounted distribution transformer asset health as at 2026**



The figure indicates stable renewal levels continuing beyond 2026, as indicated by the H1-H3 portion in Planned Renewals (FY26).

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. When we find PCBs a specialist disposal company is employed to undertake removal.

18.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

18.4 GROUND MOUNTED DISTRIBUTION TRANSFORMERS FLEET MANAGEMENT

18.4.1 FLEET OVERVIEW

There are approximately 7,800 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.

Figure 18.6: **300 kVA ground mounted transformer**

18.4.2 POPULATION AND AGE STATISTICS

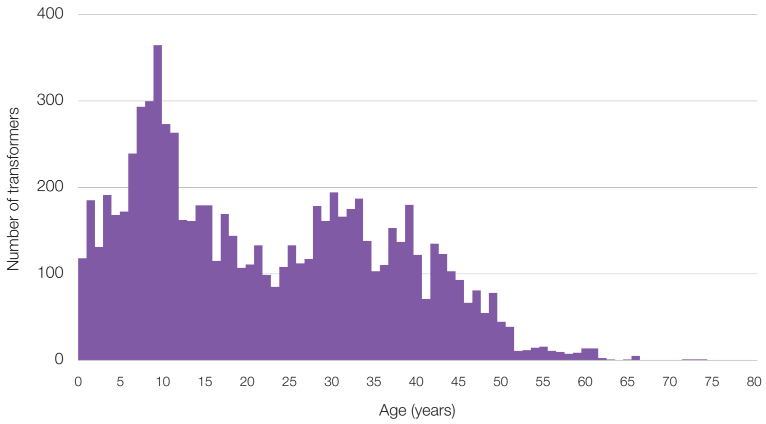
The table below summarises our population of ground mounted distribution transformers by kVA rating. The smallest units have a size of approximately 100kVA, with larger units used for higher capacity installations.

Table 18.4: **Ground mounted distribution transformer population by rating at 31 March 2015**

MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
≤ 100kVA	2,747	35
> 100 and ≤ 200kVA	1,868	24
> 200 and ≤ 300kVA	1,842	24
> 300kVA	1,381	18
Total	7,838	

The figure below shows our ground mounted distribution transformer age profile.

Figure 18.7: **Ground mounted distribution transformer age profile**



The ground mounted transformer fleet is relatively young, with an average age of 23 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.

18.4.3 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 (e.g. 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

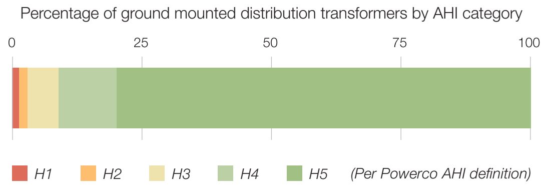
LV panels are treated as separate assets. Renewals of LV panels can occur separately to the transformer unit (typically in the case of reactive replacement following a failure). LV panels fail mainly because of overheating or insulation failure.

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 their 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 18.8: **Ground mounted distribution transformer asset health as at 2015**



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.

18.4.4 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 11 Networks of the Future.

To ensure distribution transformer monitors can be retrospectively installed we will fit new ground mounted distribution transformers with larger LV frames.

18.4.5 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 routine maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standard.

Table 18.5: **Ground mounted distribution transformer 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 based 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.

18.4.6 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.

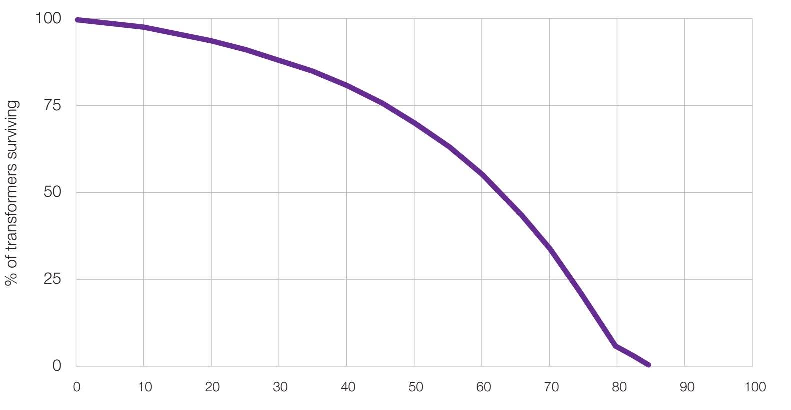
SUMMARY OF GROUND MOUNTED DISTRIBUTION TRANSFORMER RENEWALS APPROACH	
Renewal trigger	Proactive condition based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

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 18.9: **Ground mounted distribution transformer survivor curve**

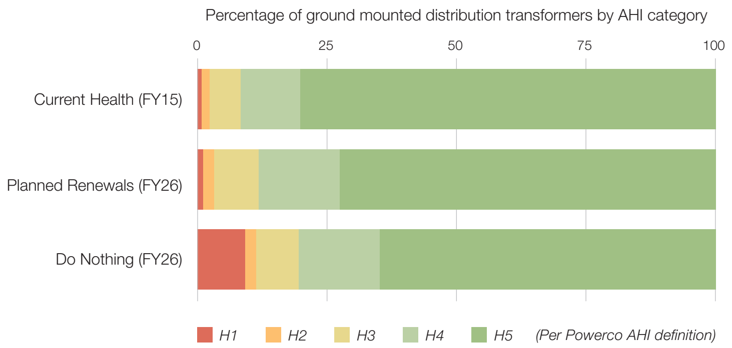


We have found that, similar to pole mounted distribution transformers, ground mounted distribution transformer replacement occurs over a wide range of ages, primarily because of factors such as type, manufacturer, location or inherent durability. The survivorship forecasting approach is therefore more 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 discussed above (condition, performance and risks section), our ground mounted transformer fleet is in good health. The figure below compares projected asset health in 2026 (following planned renewals) with a 'do nothing' scenario. Our investment targets the minimum renewal needed to maintain the health of the fleet.

Figure 18.10: **Projected ground mounted distribution transformer asset health as at 2026**



The figure indicates stable renewal levels continuing beyond 2026, as indicated by the H1-H3 portion in Planned Renewals (FY26).

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 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 the work.

18.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 (e.g. new residential subdivisions) are usually underground and the associated distribution transformers are ground mounted.

18.5 'OTHER' DISTRIBUTION TRANSFORMERS FLEET MANAGEMENT

18.5.1 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 18.11: **Collection of 'other' distribution transformers**

Capacitors *Voltage regulator* *SWER isolating transformer*

18.5.2 POPULATION AND AGE STATISTICS

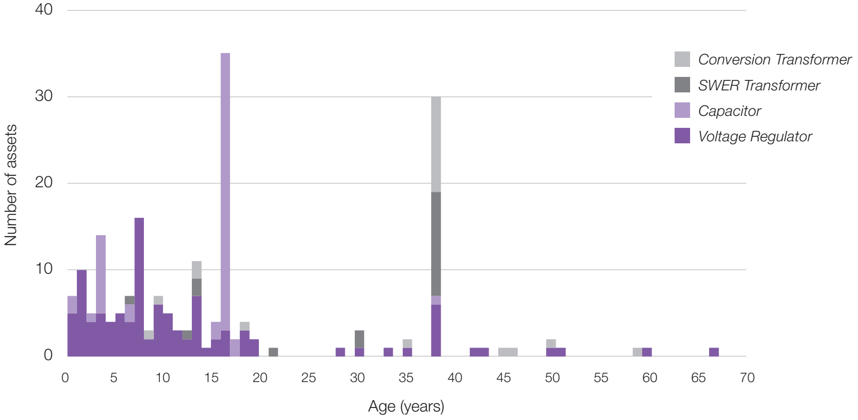
The table below summarises our population of 'other' distribution transformers by type. Voltage regulators make up the largest portion of the fleet. We have been installing these devices during the last 15 years to manage voltage issues on the network.

Table 18.6: **'Other' distribution transformer population by type at 31 March 2015**

TYPE	NUMBER OF ASSETS	% OF TOTAL
Voltage regulator	105	53
Capacitor	51	26
Conversion transformer	21	11
SWER isolation transformer	19	10
Total	196	

The figure below shows our 'other' distribution transformers age profile. The population is young, with an average age of 12 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 18.12: **'Other' distribution transformer age profile**



18.5.3 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.

18.5.4 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.

18.5.5 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 routine maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 18.7: **'Other' distribution transformer 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.	

18.5.6 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.

18.5.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 (e.g. 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.

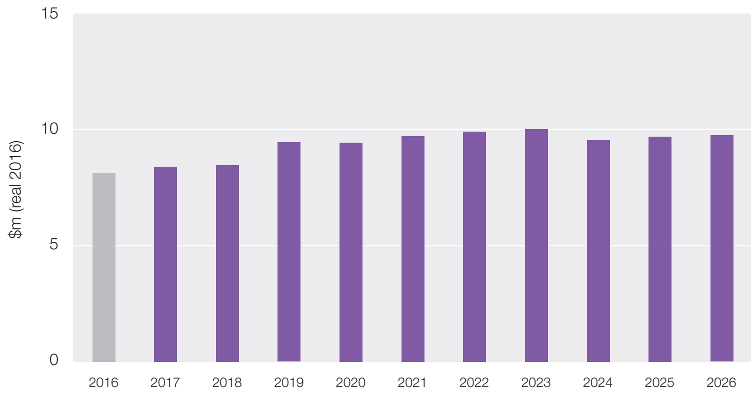
18.6 DISTRIBUTION TRANSFORMERS RENEWALS FORECAST

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 $94m in distribution transformer renewals

Renewals are derived from bottom up models. These forecasts are volumetric estimates (explained in Chapter 24). 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 18.13: **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 24.

19. DISTRIBUTION SWITCHGEAR

19.1 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 $82m 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 FY18-20 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.

Below we set out the asset management objectives that guide our approach to managing our distribution switchgear fleets.

19.2 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.

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 4.

Table 19.1: **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.

19.3 GROUND MOUNTED SWITCHGEAR FLEET MANAGEMENT

19.3.1 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 19.1: **Ground mounted switchgear**

19.3.2 **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 19.2: **Ground mounted switchgear population by type at 31 March 2015**

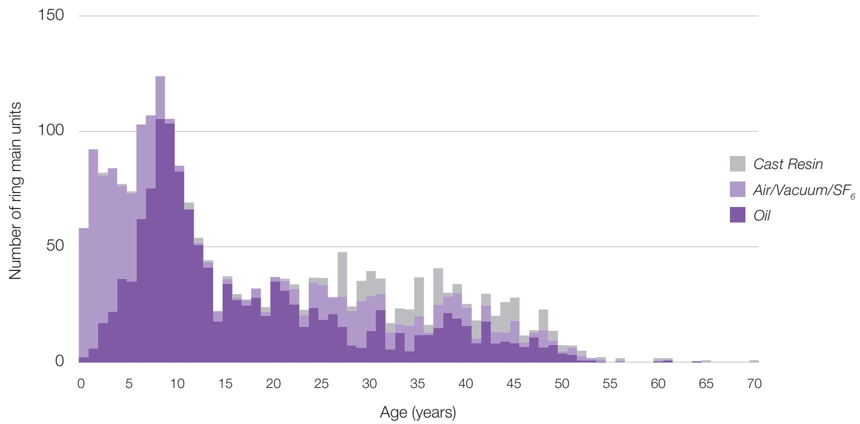
INSULATION TYPE	NUMBER OF RING MAIN UNITS	NUMBER OF INDIVIDUAL SWITCH UNITS
Oil	1,313	342
Air/Vacuum/SF_6	700	118
Cast resin	206	8
Total	2,219	468

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 19.2: **Ring main units age profile**

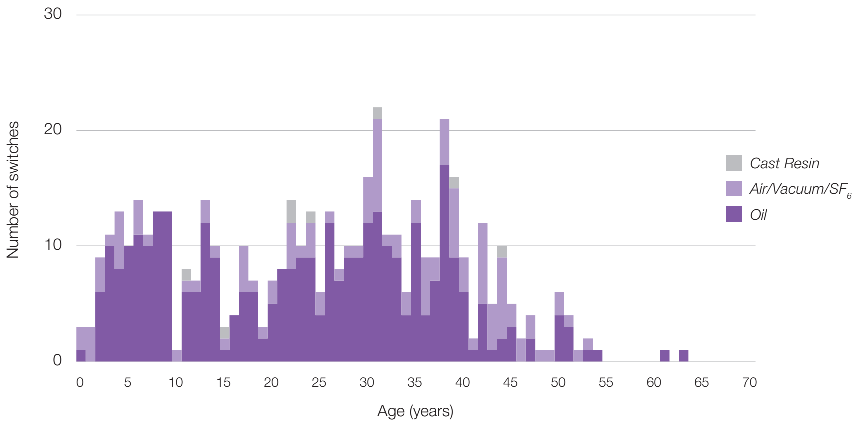


RMUs have been installed on our network for more than 40 years. Their use has increased markedly over the past decade as they have replaced individual switches to enable better network connectivity.

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 19.3: **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).

19.3.3 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.

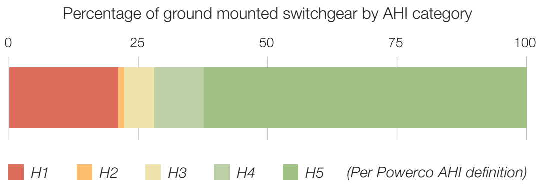
While the condition of other oil-filled switchgear assets is reasonable, most models of oil switchgear are no longer supported by manufacturers. Many have extensive maintenance requirements relative to their modern equivalent asset.

Ground mounted switchgear asset health

As outlined in Chapter 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 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 on the following page shows current overall AHI for our ground mounted switchgear fleet.

Figure 19.4: **Ground mounted switchgear asset health as at 2015**



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.

19.3.4 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.

19.3.5 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 maintenance tasks are summarised in the table below. The detailed regime is set out in our maintenance standard.

[100] Refer to Chapter 12 for more information on our asset specification and approval processes.

Table 19.3: **Ground mounted switchgear 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

19.3.6 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.

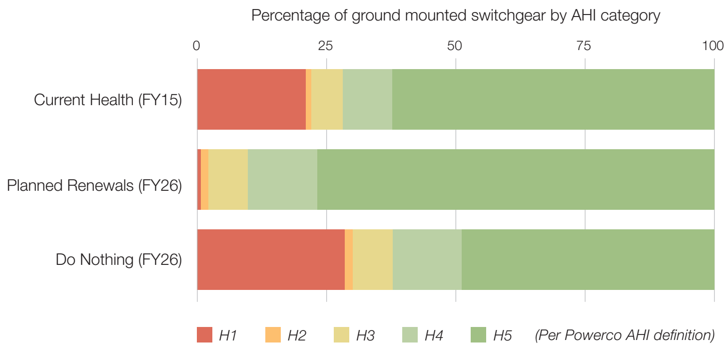
Renewals forecasting

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 (e.g. 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 2026 (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 19.5: **Projected ground mounted switchgear asset health as at 2026**



Further replacements will still be needed post 2026, as indicated by the H1-H3 portion in Planned Renewals (FY26). However, we expect the renewal quantity to drop as the majority of older, poor performing, ground mounted switches will have been replaced by then.

19.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

19.4 POLE MOUNTED FUSES FLEET MANAGEMENT

19.4.1 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.

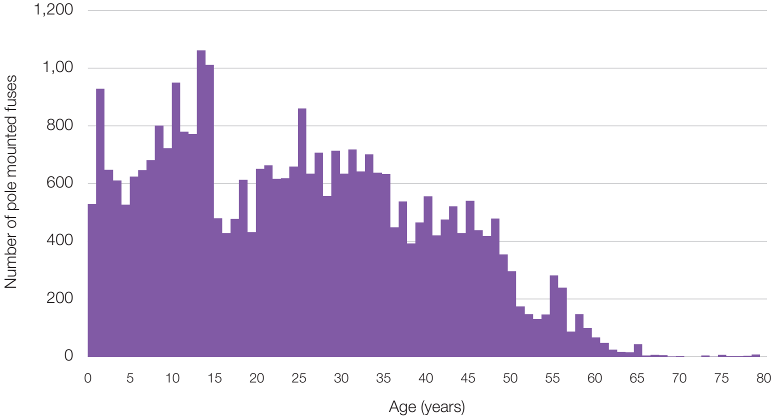
Figure 19.6: **Pole mounted drop out fuse**

19.4.2 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 following figure shows the age profile of our population of pole mounted fuses.

Figure 19.7: **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.

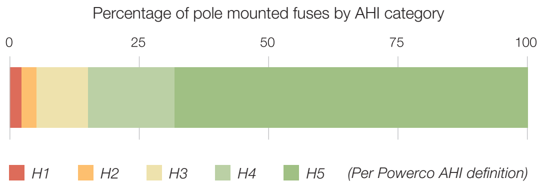
19.4.3 CONDITION, PERFORMANCE AND RISKS

Pole mounted fuses 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 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 19.8: **Pole mounted fuses asset health as at 2015**



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.

19.4.4 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.

19.4.5 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 19.4: **Pole mounted fuse maintenance and inspection tasks**

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection for corrosion and defects.	5 yearly

19.4.6 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

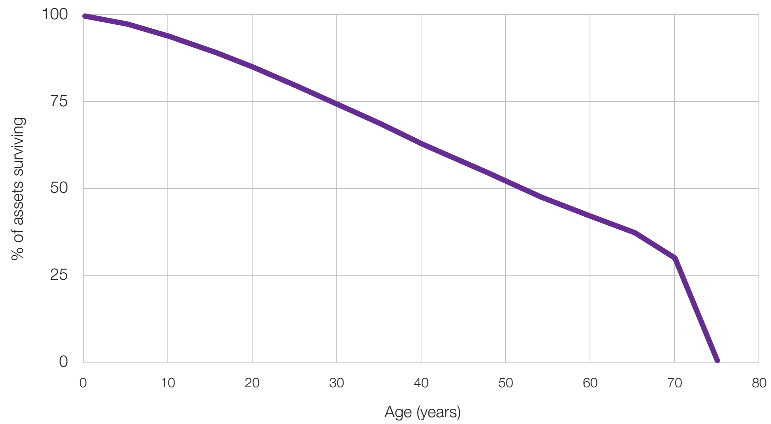
Renewals forecasting

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.

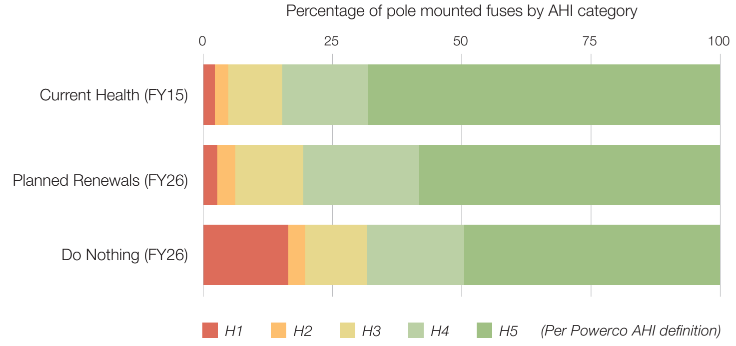
Figure 19.9: **Pole mounted fuse survivor curve**



Due to the relatively uniform age profile (see Figure 19.7), 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 following figure compares projected asset health in 2026 (following planned renewals) with a 'do nothing' scenario. The health of the fleet is forecast to remain stable out to 2026.

Figure 19.10: **Projected pole mounted fuses asset health as at 2026**



19.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

19.5 POLE MOUNTED SWITCHES FLEET MANAGEMENT

19.5.1 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 19.11: **Air break switch**

19.5.2 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.

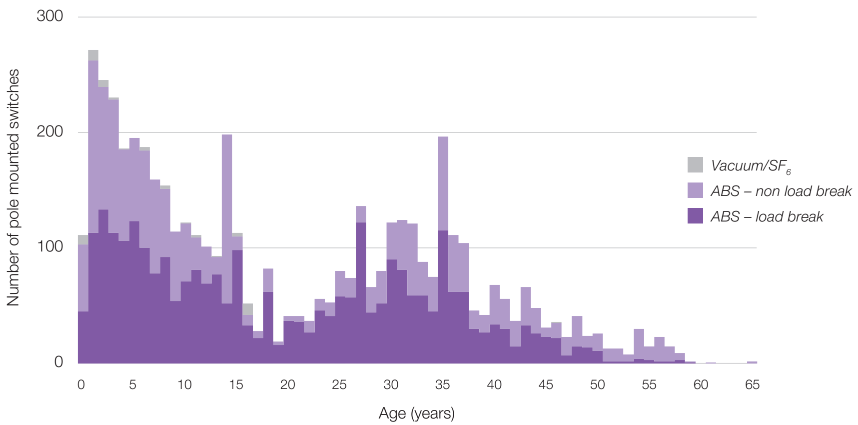
Table 19.5: **Pole mounted switch population by type at 31 March 2015**

TYPE	NUMBER OF ASSETS	% OF TOTAL
ABS – load break capable	2,939	58
ABS – non-load break	2,062	41
Vacuum or SF_6	50	1
Total	5,051	

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 19.12: **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.

19.5.3 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.

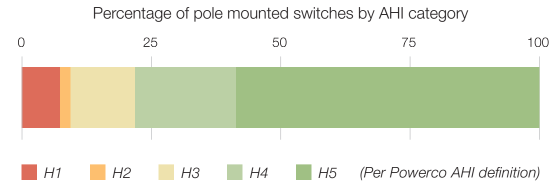
Another issue relates to operating mechanisms which tend to seize up when switches are not operated. This is addressed through our maintenance regime which specifies periodic operation of switches, alongside inspection and alignment of units. This frees up the operating mechanism and new contacts are 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 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 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 19.13: **Pole mounted switches asset health as at 2015**



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).

19.5.4 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.

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.

19.5.5 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 maintenance tasks for this fleet are summarised in the table below. The detailed regime is set out in our maintenance standards.

Table 19.6: **Pole mounted switch maintenance and inspection tasks**

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
ABS – built up area	Operation and major maintenance of contacts, pantographs, mechanisms	5 yearly
	Contacts and jumpers thermal scan	
	(Both tasks done 5 yearly, but alternate 2 ½ years apart)	
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

19.5.6 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.

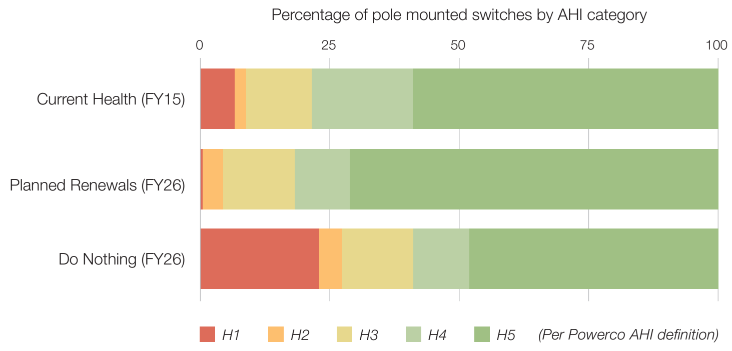
Renewals forecasting

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 2026 (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 (FY26).

Figure 19.14: **Projected pole mounted switches asset health as at 2026**



19.5.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

19.6 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS MANAGEMENT

19.6.1 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.[101] Circuit breakers are not widely used on the distribution network but are typically installed within major customer facilities.

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 19.15: **A pole mounted recloser**

[101] Zone substation circuit breakers are discussed in Chapter 17.

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 a 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.

19.6.2 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).

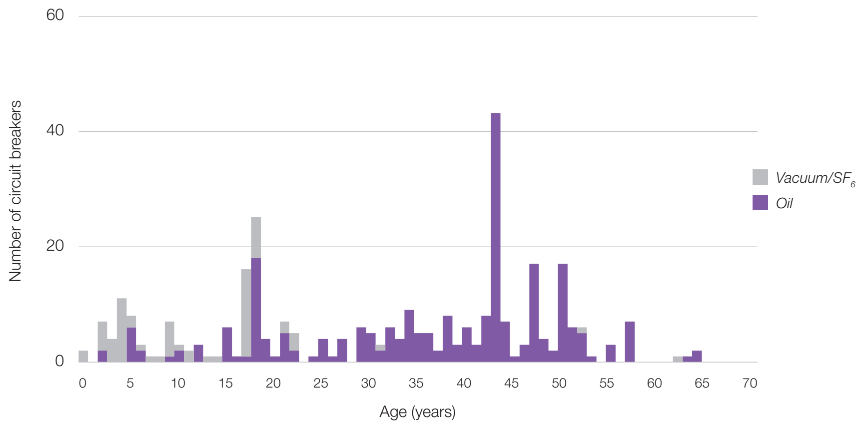
Approximately 80% of the circuit breaker fleet is oil-based, almost half of which are located at a single customer site at Kinleith.

Table 19.7: **Circuit breakers, reclosers and sectionalisers population by type at 31 March 2015**

TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Circuit Breakers	Oil	256	33
	SF_6/Vacuum	68	9
Reclosers	Oil	33	4
	SF_6/Vacuum	317	42
Sectionalisers	Oil	28	4
	SF_6/Vacuum	65	8
Total		767	

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).

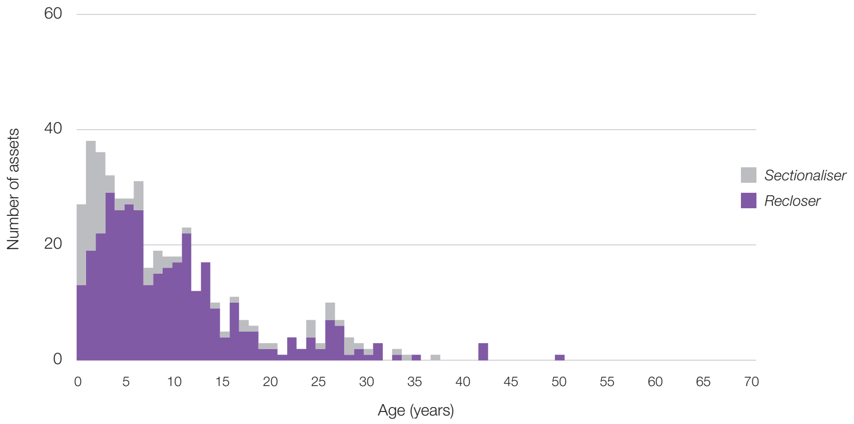
Figure 19.16: **Circuit breaker age profile**



Older assets are primarily made up of the oil-filled circuit breakers at Kinleith. A planned replacement project at that site from 2018-2020 will remove many of these. Oil-filled circuit breakers are no longer purchased. All new circuit breakers are SF6 or vacuum types.

In contrast, our recloser 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 19.17: **Recloser and sectionaliser age profile**



19.6.3 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.

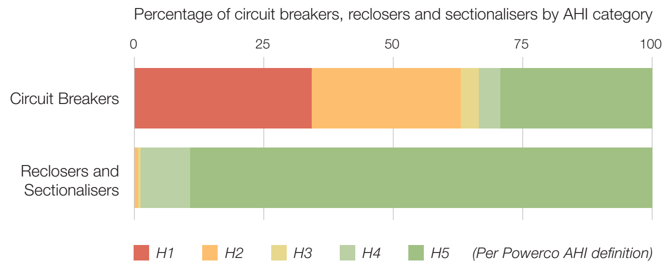
The 11kV fault levels at Kinleith are some of the highest on our network. The number of faults, coupled with the longer protection operating times prevalent at the site, presents a high arc flash safety risk. Many of the circuit breakers are manually operated. This is considered unsafe especially given 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 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 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 following figure shows current overall AHI for our population of circuit breakers and reclosers/sectionalisers.

Figure 19.18: **Circuit breakers, reclosers and sectionalisers asset health as at 2015**



The asset health of the combined recloser and sectionaliser sub-fleet is very good. Less than 2% (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.

19.6.4 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.

19.6.5 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 routine maintenance tasks for this fleet. The detailed regime is set out in our maintenance standards.

Table 19.8: **Circuit breakers, reclosers and sectionalisers 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

19.6.6 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

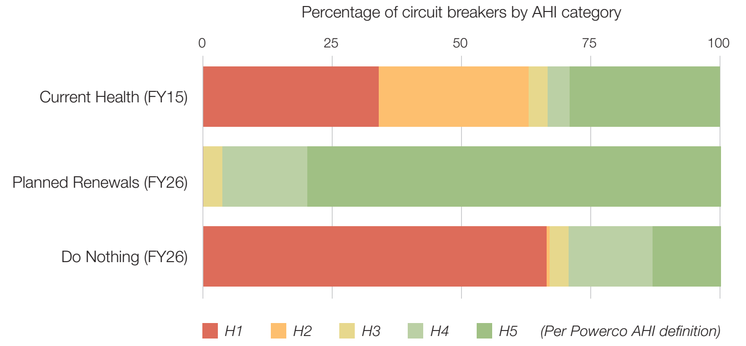
Renewals forecasting

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 feature 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 2026 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 19.19: **Projected circuit breakers asset health as at 2026**



19.6.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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 10.

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.

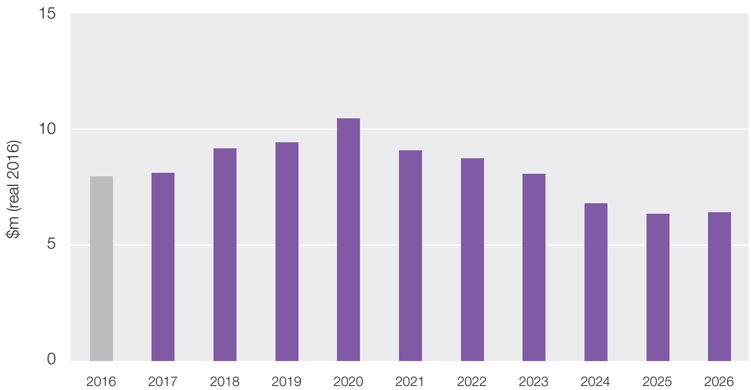
19.7 DISTRIBUTION SWITCHGEAR RENEWALS FORECAST

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 $82m in distribution switchgear renewal.

Distribution switchgear renewals 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, 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 19.20: **Distribution switchgear renewal forecast expenditure**



The forecast renewal expenditure is generally in line with historical levels. Additional expenditure from FY18-20 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 24.

20.1 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 $24m in secondary systems. This accounts for 3% of renewals Capex over the period. This is approximately 15% above current spend mostly due to the modernisation of our protection fleet. 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.

Below we set out the asset management objectives that guide our approach to managing our secondary systems fleets.

20.2 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 4.

Table 20.1: **Secondary systems portfolio objectives**

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	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, and enabling increasing levels of distribution automation.
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.

20.3 SCADA AND COMMUNICATIONS FLEET MANAGEMENT

20.3.1 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

A master station is essentially a central host computer server that manages the SCADA system. We currently have two master stations – the primary 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 a number of 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 20.1: **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 20.2: **Communications mast with associated radio antennae**

20.3.2 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 following table summarises our population of RTUs by type.[102]

[102] This population excludes telemetered sites with Intelligent Electronic Devices (IEDs) directly connected to the SCADA network, such as those on modern automated reclosers.

Table 20.2: **RTU population by type at 31 March 2015**

TYPE	RTUS	% OF TOTAL
Modern	294	89
Legacy	36	11
Total	330	

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.

20.3.3 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 (e.g. 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.

20.3.4 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.

20.3.5 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 20.3: **SCADA and communications 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

20.3.6 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 10. 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.

20.3.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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[103] is extending the control and monitoring capability out to selected distribution switches.

20.4 PROTECTION FLEET MANAGEMENT

20.4.1 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.

[103] We discuss the network automation programme in Chapter 10.

Figure 20.3: **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 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 (e.g. fault location and type; before, during and post fault currents and voltages; 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 20.4: **Modern numerical relays**

20.4.2 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.

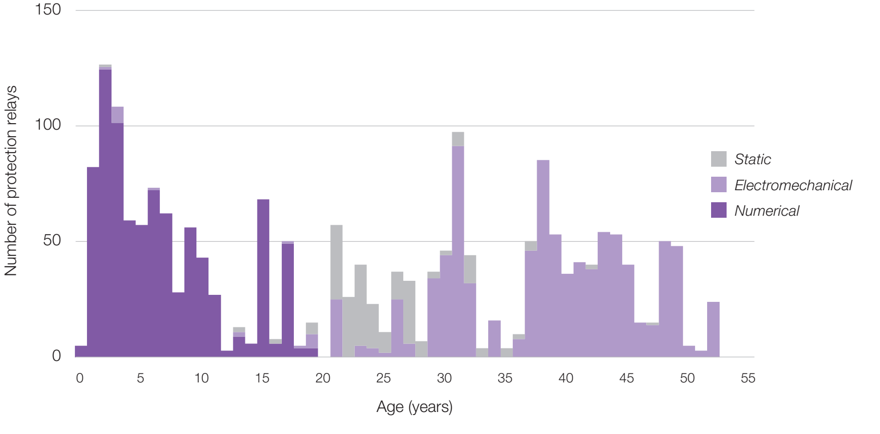
Table 20.4: **Protection asset population by type at 31 March 2015**

TYPE	RELAYS	% OF TOTAL
Electromechanical	921	46
Numerical	861	43
Static	217	11
Total	1,999	

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 20.5: **Protection relay age profile**



20.4.3 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.

20.4.4 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 (e.g. 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 (e.g. 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) – a new international standard (not a protocol) for communication in substations. 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.

20.4.5 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 routine maintenance schedule for protection relays is outlined in the following table. The detailed regime is set out in our maintenance standards.

Table 20.5: **Protection 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 (e.g., overcurrent, distance).	3 yearly
Detailed condition assessment and operational checks for **numerical relays**. Perform diagnostic tests relevant to relay function (e.g., overcurrent, distance).	6 yearly

20.4.6 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 (e.g. switchboard replacements) to ensure efficient delivery. This may mean some relay replacements are brought forward or deferred for a period.

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. Longer term, renewals 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.

20.4.6.1 INTERACTION WITH NETWORK DEVELOPMENT

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.

20.5 DC SUPPLIES FLEET MANAGEMENT

20.5.1 FLEET OVERVIEW

Our DC supply systems are required to provide a reliable and efficient DC power supply to the vital elements within our network (e.g. 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 20.6: **DC charger and battery bank**

20.5.2 POPULATION AND AGE STATISTICS

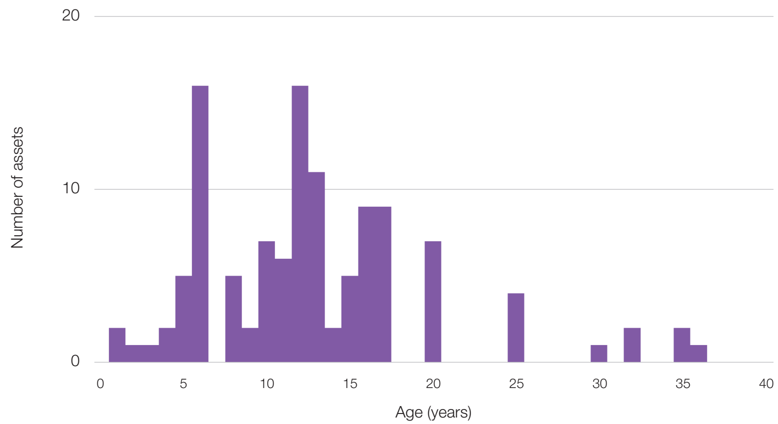
The following table summarises our population of DC supply systems by type. DC systems have been installed using many different supply voltages because of different load requirements and network amalgamation. We expect the diversity to reduce as we replace non-standard voltage systems with modern equivalents.

Table 20.6: **DC supplies population by voltage at 31 March 2015**

VOLTAGE	DC SYSTEMS	% OF TOTAL
110V	73	43
48V	25	15
36V	1	1
24V	17	10
12V	2	1
Communications[104]	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 20.7: **DC supplies age profile**



[104] Communication DC supplies refer to 48V DC rectifiers with 12V and 24V DC converters.

20.5.3 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.

20.5.4 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 routine inspection regime for DC supply systems is outlined in the table below. The detailed regime is set out in our maintenance standard.

Table 20.7: **DC supplies 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.

20.5.5 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[105] 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.

[105] 'Carry over time' means the time the DC system can supply the connected load in the event of an outage.

20.6 METERING FLEET MANAGEMENT

20.6.1 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 (e.g. 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.[106]

20.6.2 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.

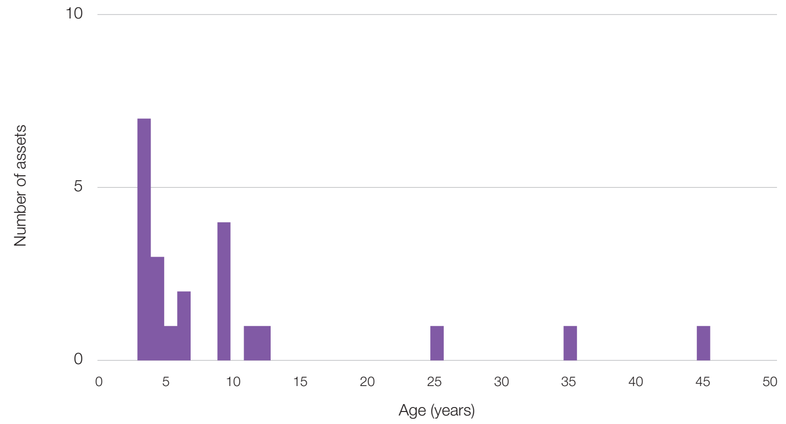
Table 20.8: **GXP metering population by type at 31 March 2015**

TYPE	SUB-TYPE	GXP METERS
ION meter		24
Legacy	Enermet	1
	L&G FF34	2

In addition to the GXP meters, we have 182 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.

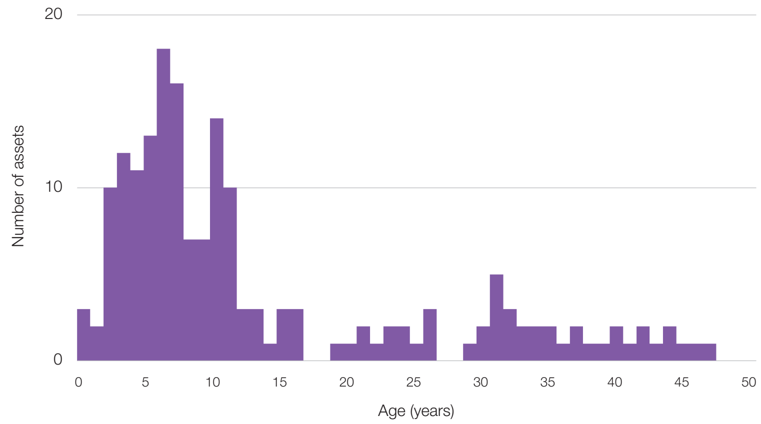
Figure 20.8: **GXP metering age profile**



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.

[106] We discuss our load control plant fleet in Chapter 17.

Figure 20.9: **HV metering unit age profile**



20.6.3 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.

20.6.4 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 routine metering inspection tasks are summarised in the following table. The detailed regime is set out in our maintenance standards.

Table 20.9: **HV metering 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 routine maintenance but provide alerts when they are faulty.

20.6.5 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

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.

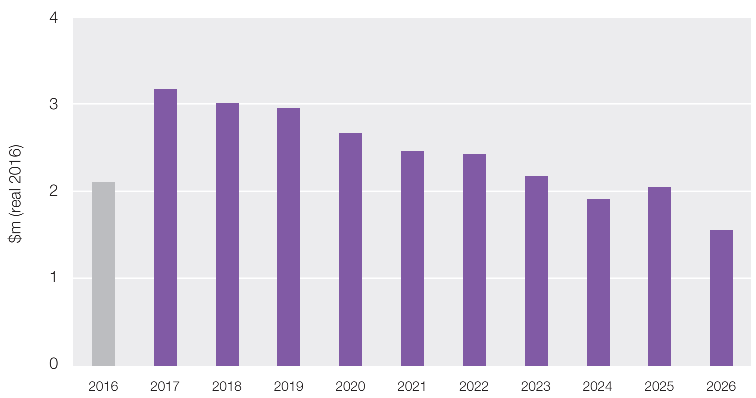
20.7 SECONDARY SYSTEMS RENEWALS FORECAST

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 $24m in secondary systems renewals.

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 24). 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 20.10: **Secondary systems renewal forecast expenditure**



The forecast renewal expenditure is somewhat higher than 2016 levels, primarily 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 24.

21. ASSET RELOCATIONS

21.1 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.

The most common driver of asset relocations is roading projects and in these cases our contribution is set by legislation. We expect asset relocation investment to be in line with historical trends.

Further detail on our stakeholders and how they affect our investment plans can be found in Appendix 3.

21.2 OVERVIEW OF ASSET RELOCATIONS

Our assets are often located alongside other infrastructure such as roads, water pipes, and telecommunications cables. The owners of this infrastructure may need us to move our assets as they undertake their own projects. A common example of this is moving poles and lines to accommodate the widening of a road. Capex associated with facilitating asset moves for third parties is included in our asset relocations portfolio.

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 (e.g. 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.

21.3 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 builds approach. We find this provides the most customer-centric service. When a customer seeks an 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. Historically, we have completed between 75 and 125 relocation projects each year.

We take the opportunity to upgrade and address defects in assets that are relocated. This takes advantage of road closures, reducing the need for planned outages.

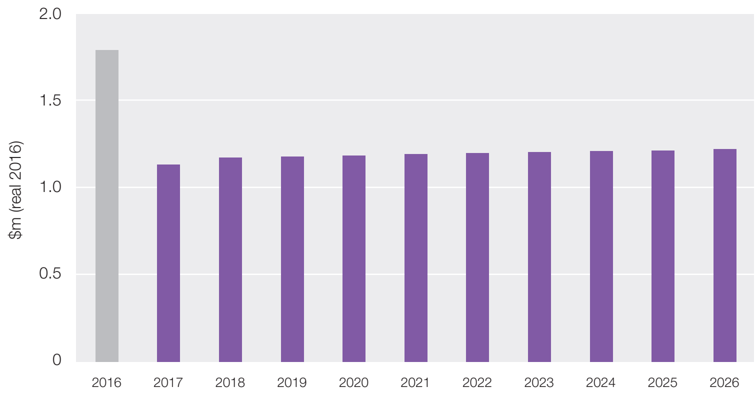
In most circumstances we receive contributions from the third party requesting the relocation, reducing the amount of our investment in these projects. For roading and other infrastructure projects, the level of our investment is governed by legislation which often requires us to fund the materials portion of the project.[107] 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.

[107] Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act

21.4 FORECAST EXPENDITURE

The chart below shows our expected investment (net of contributions) in asset relocation works during the planning period.

Figure 21.1: **Forecast asset relocation Capex (net of contributions)**



Asset relocations Capex is customer driven, often with short lead times so our ability to forecast this expenditure on a volume or project basis is limited. As such, our forecast is based on trending, using a base-step-trend approach. We use the average level of activity over the last five years as our baseline.

We expect to see a degree of variation year-on-year, as projects are completed and we have limited ability to smooth the expenditure across years.

We regularly consult with the NZTA and councils and are aware of the following major projects during the planning period. These are incorporated into our forecast.

- NZTA completion of the Baypark to Bayfair link upgrade including rail diversion and road widening. The project requires removing 1.5km of 33kV underground cable and 2km of overhead line
- NZTA completion of the Hairini Link Project between the Maungatapu and Hairini roundabouts which requires relocating two 11kV feeders

21.4.1 ALIGNMENT WITH RENEWAL CAPEX FORECASTS

Asset relocation investments generally relate to poles, crossarms, overhead conductor, and underground cables. As we do not know the locations of future work with accuracy and the lead times on this type of work can be quite short, it is difficult to incorporate this work into our forecast renewal programmes.

However, we do not consider this an issue as asset relocation work often relates to small sections of network and can be incorporated into our short-term plans relatively easily. Due to their small size they have a minor impact on our renewal programmes.

ASSET MANAGEMENT SUPPORT

This section explains how we plan to improve our ICT systems and develop our asset management capability.

CONTENTS

Back to contents >

22.1 CHAPTER OVERVIEW

This chapter sets out our Information Communications Technology (ICT) strategy, and aspects of our Information Services Strategic Plan (ISSP). It explains our approach to delivering ICT capabilities and managing our ICT assets. It also discusses our other non-network assets (e.g. our office buildings).

Our non-network strategy and approach ensures we develop capabilities that allow us to support our planned asset management changes over the planning period, including:

- Enhancing our asset management analysis capabilities
- Supporting increased work volumes on our network
- Providing real time information to our customers, including through new information channels
- Supporting our evolution to a Distribution System Integrator (DSI), through increased data capture and data analytics
- Enhancing the way we deliver works with our service providers

Over the planning period the range of options available to deliver ICT capability will shift and evolve rapidly. Our strategies and plans are designed to maximise flexibility in a changing environment.

22.2 INTRODUCTION

By the year 2026 the New Zealand energy sector will have evolved significantly. While much of the core infrastructure will be the same, we recognise the way many customers interact with the energy sector will be different.

We have developed our ICT strategies and plans to directly support the programmes of work facilitating this change, recognising that ICT provides a critical enabling platform for enhancing the value we provide to customers.

The approach taken to developing our ICT assets and capabilities is informed by our asset management strategy (see Chapter 4), customer strategy (see Chapter 6) and our future networks strategy (see Chapter 11).

Key ICT outcomes related to each of these strategies are set out in the following tables.

Table 22.1: Asset management strategy – key ICT outcomes

KEY OUTCOMES
Governance: underpinning asset management decisions with structured processes and systems.
Information management: managing data as an asset, through structured development.
Decision-making tools: ensuring asset management decisions are supported by accurate and timely information.
Capability support: continually improving our asset management capability and skills over time.
ISO 55000 certification: supporting the alignment of our asset management approach with leading practice to help achieve ISO 55000 certification.

Table 22.2: Customer strategy – key ICT outcomes

KEY OUTCOMES
Access to information: residential consumers' expectations for near-instantaneous access to information in other industries is driving higher service expectations.
Support new customer technologies: as the adoption of products such as distributed generation, battery storage and EVs increases as they become more affordable.
Support for tailored pricing: will become important as new retailer markets form around consumers ability to tailor their energy needs and use the grid to exchange energy with market.
Changing usage patterns: due to changes in how customers consume electricity (e.g. energy efficiency initiatives) will mean traditional tariff structures may not suit customers.
Increasing reliability needs: due to increasing commercial customer reliance on electricity. Customers are expecting ever-higher standards of reliability, whether in urban or rural locations.

Table 22.3: Future networks strategy – key ICT outcomes

KEY OUTCOMES
New customer technologies: improve understanding and modelling of the impact of increased energy efficiency and other demand management measures by customers, as well as potential for EVs or other customer technology, especially when used in clusters.
Small scale distributed generation: improve understanding and modelling of the impact of distributed generation, especially PV, on our network.
Network monitoring: increasing visibility of power flows and power quality across the network, to provide early identification of where intervention may be required. This will also help further optimise future network planning.
State estimation: providing real (or close to real) time views of network loading, configuration and power flows. This will in turn support several applications ranging from self-healing networks, network meshing and automation through to operational support with pinpointing the extent and exact location of outages and the optimal restoration options.

This needs driven development of ICT capability is key to ensuring its focus, though there is a wider context to be considered. ICT technology is changing rapidly, and is enabling new opportunities for customers that are difficult to predict accurately over the medium-term. There is a need for ICT strategy to be flexible as the outcomes above will change as our business evolves. This point is explored more in the sections that follow.

22.3 OUR EVOLVING BUSINESS

Customers used to instantly accessing information through various devices will increasingly expect their utilities to be available to deal with queries virtually instantaneously and provide open access to important information in real time across a range of channels.

At the same time we know that energy markets will evolve, new energy solutions will develop, and that utilities will have an increasing role in managing more diverse energy flows. This change is at the centre of our DSI strategies discussed in Chapter 11.

To meet these evolving customer expectations and requirements we must become a progressive utility, integrating traditional energy distribution services with emerging digital services. These new digital services will enable customers to better leverage the value of their home energy investments.

This model will require a high level of information connectivity across the traditional energy sector but also behind the meter into customers' properties. It is an area that is developing quickly because of the reducing costs of computing, communication, and energy solutions. It is also one that requires a flexible approach given the speed of technological change.

22.3.1 FUTURE CHALLENGES

While it is not possible to say with certainty exactly how the new energy future will manifest, technology trends indicate that customer requirements will differ.

While we can expect many customers will simply want a safe and reliable supply of electricity to their homes and businesses, we anticipate others will invest in solar, home energy storage, smart appliances, and EVs.

These customers will expect their service providers to accommodate their more complex needs, whether they be cost reduction, energy trading or even donating surplus home energy to their communities.

This uncertain future steers our investments towards 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.

At the same time, we recognise that our core business is managing and operating electricity infrastructure.

To meet our organisational objectives, we must continue to focus on capturing accurate data at source and making information accessible to the business with tools that allow us to leverage value and improve our performance.

We expect combined annual network capital and operating expenditure to increase significantly during the 10-year period of this plan, reflecting the replacement of ageing infrastructure. To achieve our Operational Excellence objective, capital expenditure per full time equivalent employee will need to increase. This will be supported through increased digitisation of processes delivering improved efficiency.

As a 'lifeline' utility we also recognise that system resilience is fundamental. Our architecture must be developed on industry accepted standards for cyber security in an increasingly connected communications landscape.

In summary, over the planning period we need to ensure that our ICT assets are:

- Flexible, built on technologies forming a solid central platform that allow rapid development of new capabilities around the margins
- Scalable to accommodate increased data processing / storage and accessible to ensure customers and internal users have real time access to the information they need and can rely on the quality and security of that information
- Resilient to maintain 'lifeline' utility levels of reliability, ensuring our systems are resilient, reliable and responsive, designed with multiple layers of redundancy matched to the criticality of the capabilities they support

Our plan to meet these challenges is outlined further on in this document and can be summarised as follows:

- **Phase 1:** Building the foundation (now to 2019)
- **Phase 2:** Leveraging the investment (2019 – 2021)
- **Phase 3:** Enabling insight and energy platforms (2021 onwards)

22.3.2 SUPPORTING EFFICIENT DELIVERY

While our business has been traditionally focused on assets, our strategy now emphasises the importance of our customers, their needs and a growing expectation of Operational Excellence. To give context to this summary of our non-network investment plan we need to consider how different groups will use our services towards the end of the planning period.

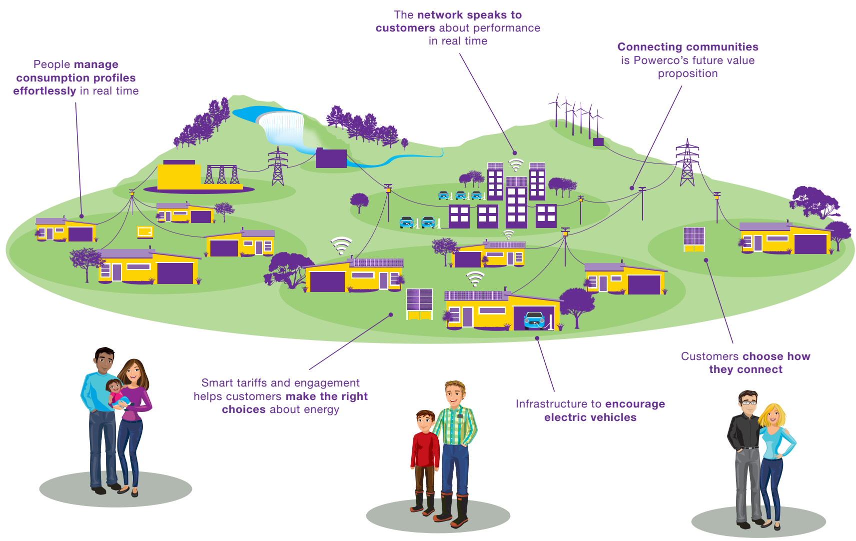
A customer:

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.

Figure 22.1: **Potential future energy 'eco-system' in 10 years**



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-builts 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 GPS locations 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.

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 lowasset 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.

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 e.g. for UFB rollout.

22.4 ENHANCING OUR INFORMATION SYSTEMS

Our current systems and processes are largely reliable, producing consistent and repeatable results. However, we recognise that our ICT functions exist to address the multiple perspectives discussed above. A key short-term focus is to meet our real-time operational needs today, and to support the business as we increase our investments in our network.

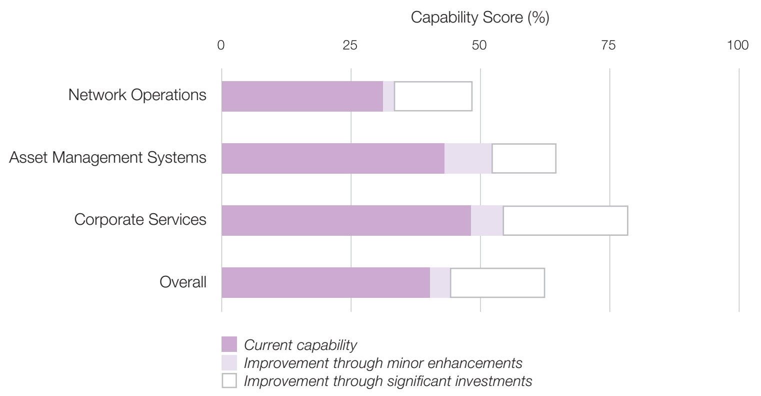
In addition we need to develop new offerings for our customers in the medium-term, maintain adequate flexibility to accommodate new ICT developments, and address changing business needs.

Within this context we have concluded that our evolving business will place increasing pressure on our existing systems and processes. Our current approach of adding new capabilities through small incremental projects will lead to an increasingly complicated and expensive ICT service if we are going to be able to:

- Deliver significant increases in the amount of real time information available to customers and business users
- Deliver mobile capabilities to support operational efficiency in the field and capture information at the source
- Manage significantly increased data volumes and develop tools that help business users create value from that information
- Create a flexible digital environment that empowers customers to satisfy a wide range of constantly changing energy needs

We engaged external specialists to undertake an assessment of our current system capabilities. This included the expected improvement under different investment scenarios. The results are summarised in figure below.[108]

Figure 22.2: **Current Systems – Key Capability Evaluation**



The figure above illustrates that if we are to achieve our strategic goals the current ICT environment will require major upgrades across all service categories.

While our systems are capable of meeting current needs our analysis has determined they will not be able to support the increased activity resulting from our planned investments. Similarly, they will not be able to support greater interaction with customers or the capability demands of internal users.

We have identified two alternative long-term development paths for our ICT service offering and assessed their relative merits. These are explained in our ISSP.

[108] The 100% figure reflects best industry practice capabilities for ICT systems used to support these functions.

22.4.1 OUR INFORMATION SERVICES STRATEGIC PLAN

The challenge in developing both an ISSP and an ICT framework against a backdrop of rapid technological change is that as plans and frameworks are completed, they run the risk of becoming outdated.

Our ISSP is closely aligned with our asset management, customer, and future network strategies. Updates to any of these strategies are coordinated.

The exponential growth of data is driving the development of increasingly intelligent systems. These systems are capable of pulling together information from a diverse range of sources, analysing information and relationships between data sets and delivering new insights.

The speed of change in the ICT sector comes with risks as solution providers with new and innovative offerings do not necessarily have the scale or financial backing to mitigate the risk of them not being able to support their products over their expected useful life.

Our approach to addressing these challenges is to develop a plan and framework which allows flexibility to adapt to changing business capability requirements while governance processes ensure a consistent approach to decision-making and risk management.

In developing our ISSP we assessed our operating model against the future requirements as outlined in Chapter 4.

We identified that it will not be possible to achieve our goals by keeping current systems in place as is, and continuing to deliver new point solutions to meet specific needs.

As part of the ISSP development process undertaken at the end of 2013 we considered two options: the ‘Evolutionary Path’ and the ‘New Foundation’ path.

22.4.1.1 EVOLUTIONARY PATH

The first option was an Evolutionary Path under which we could become an ‘integration expert’ to design and build a mature solution integrating best of breed products. This would aim to have our current systems working effectively with new capabilities.

While this option has the potential to deliver the required outcomes for users and the business, it would be difficult, with no guarantee of success. As there are no other users of our particular combination of solutions, we would have to follow this path at our own cost, effort, time, and risk, and develop most of the intellectual property required.

Our overall information systems costs would continue to rise as a result of adding new components and technical complexity to the current portfolio, putting us at odds with our Operational Excellence objective.

22.4.1.2 NEW FOUNDATION

The other option considered was the 'New Foundation' path comprised of implementing an off-the-shelf Enterprise Resource Planning (ERP) system.

Based on the experiences of our industry peers internationally, New Foundation has demonstrated the ability to deliver the required outcomes for users and the business and would result in a more commercially-driven and externally-focused information systems solution.

New Foundation requires an initial uplift in Capex which would stabilise as operational efficiencies are realised.

Prioritisation of business outcomes ove r technical capabilities led to a recommendation for New Foundation as the preferred path for further investigation.

Implementation plan

A successful ERP implementation would need to make changes to or replace core systems that interact with all our current processes and data flows.

A project on this scale is a significant undertaking. Discussions with peer businesses embarking on similar development paths identified a number of critical success factors and potential pitfalls.

We will need to choose the right product and the right vendor and undertake careful planning and preparation to minimise disruption to the business during the transition from historical systems to an ERP.

Therefore we have determined that the appropriate timeframe for implementation is the next two to four years, allowing adequate time to undertake detailed planning and ensure our business is prepared.

We have developed a phased approach to maturing the capabilities required by the business. In developing our strategy we have worked closely with the Electricity Division to understand our future capability requirements which are summarised in Appendix 12.

We identified initiatives which will enable us to meet our strategic objectives over the next decade. These initiatives will progressively deliver the capability requirements of the electricity business.

Below we discuss our three-phased approach to delivering an ERP solution to meet the needs of the wider business.

Phase 1: Building the foundation (now to 2019)

The initial focus is on developing a robust technology environment and supporting processes. Key initiatives during this phase are set out in the following table.

Table 22.4: **Key initiatives during Phase 1**

KEY INITIATIVES
Implementing an industry best practice approach to governance and architecture, ensuring our strategy and implementation framework are aligned to our strategic objectives.
Ensuring our programme of work is developed to fit within our desired information system environment and matched to business capability requirements and timeframes
Delivery of a significant change in asset management capabilities and adoption of a digitised approached to collection, curation and dissemination of information to support the business objective of operational excellence.
Delivering improved network operation management, geographical information management and customer communications systems to drive improved network reliability, communication and customer outcomes.
Improve system reliability and uptime for business users through a focus on problem and event management analysis as a core ICT capability.
Apply the electricity asset management approach of ensuring security of supply for critical feeders to our data centres by developing an N-1 system.
Ensuring industry best practise in systems and data security through the development of multiple layers of protection.

Phase 2: Leveraging the investment (2019 – 2021)

Having successfully implemented Phase 1, our focus will turn to working with the business to effectively leverage the existing ICT investment and support the changes required to deliver operational excellence. Some of the expected key initiatives during this phase are set out in the following table.

Table 22.5: **Key initiatives during Phase 2**

KEY INITIATIVES
Develop advanced asset management systems capable of processing a broad range of data and modelling a range of possible future investment scenarios.
Expand our OMS's reach out into our network, providing greater visibility for improved real time management and increasing the volume of network performance data, fault locations and load flows to aid in our asset management planning.
Expand SCADA to reach out further into our network providing increased visibility, control and data to our operational and asset management teams as well as providing this information to customers or their agents to help them manage their energy consumption.

There are three main ICT work streams required to support the electricity business' approach:

- Ongoing process improvement and operational efficiency initiatives aimed at maximising the benefits of the ERP and integrated processes and systems
- Working collaboratively with the business to improve decision-making by providing improved insights and value from the data captured by the ERP and other operational processes
- Enabling advanced features of the OMS such as distribution management, storm management and automated switching

Phase 3: Enabling insight and energy platforms (2021 onwards)

While leveraging the ERP investment will be an ongoing focus, over the planning period the ICT team will work across the business to deliver new and innovative digital services to support evolving business capability requirements.

Due to the speed of technology change it is difficult to predict exactly what these new services will be. However, it is prudent to consider how we can position our business to manage disruptive technologies and facilitate smart grid technologies. These will enable enhanced customer participation and more efficient use of resources.

Progress to date

We have begun investigating options to significantly enhance our existing systems. At the end of this investigation we will have identified how far we can develop our core systems and the related risks, costs and capabilities.

We have also initiated a detailed investigation into available ERP solutions and their relative suitability to meet our future capability requirements.

At the end of this preparatory work we will have identified the best option for our business including the relative risks, costs, capabilities and indicative timeframes. Our expectation is that this work will be completed within the next 12 months.

22.5 DELIVERING BUSINESS CAPABILITIES

22.5.1 BUSINESS SERVICE CATEGORIES

Guided by our long-term ICT strategy, we have developed an approach to manage our ICT and non-network assets. This will help ensure the specific needs of our business are addressed.

We manage our ICT assets through six business service categories. These were established by taking a step back from the technology and instead viewing our service offering from what we require to meet our strategic objectives.

By breaking business needs down to a small number of service categories and then understanding what capabilities will be required in each of these categories over time we are able to establish detailed plans to support the needs of the business.

The six service categories are outlined in the table below.

Table 22.6: **Business service categories**

BUSINESS SERVICE CATEGORY	DESCRIPTION
Network operations	Support core network operations through the provision of real time and time-series network information systems and the management of the distribution network information (for example using SCADA and OMS).
Asset management systems	Support asset management through an integrated suite of information systems and tools (including JDE, ArcFM and ESRI software).
ICT shared services	Support the ICT services and infrastructure, which in turn support the operations of our information systems (such as authentication services, storage area networks and hardware virtualisation tools like VMWARE).
Corporate systems	Support our corporate operations and obligations by providing human resource, finance, risk, audit, compliance and project management information and systems (including JDE, PayGlobal, Project Server and Methodware applications).
Customer systems	Support our electricity and gas commercial teams through the timely capture and distribution of customer-centric information (including OMS, CWMS and Billing).
Security services	Ensure the availability and integrity of our information systems by applying the correct security classifications and controls to minimise risk (such as firewalls, and host or network intrusion systems).

We further explain the systems used across our service categories below and in Appendix 12.

22.6 MANAGING OUR ICT ASSETS

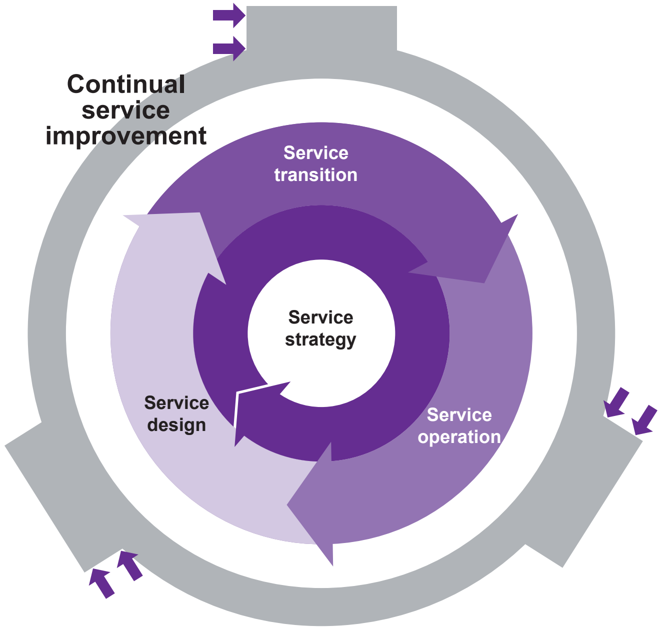
This section discusses our approach to managing current capabilities and assets.

22.6.1 SYSTEMS LIFE CYCLE

We use a set of processes, based on the ITIL framework, to manage our current systems. ITIL is a best practice framework that has been drawn from both the public and private sectors internationally. It describes how ICT resources should be organised to deliver business value – documenting the processes, functions and roles of IT Service Management.

The ITIL framework considers the strategy, design, transition, operation and continual improvement of IT services as illustrated in the following figure.

Figure 22.3: **ITIL systems life cycle**[109]



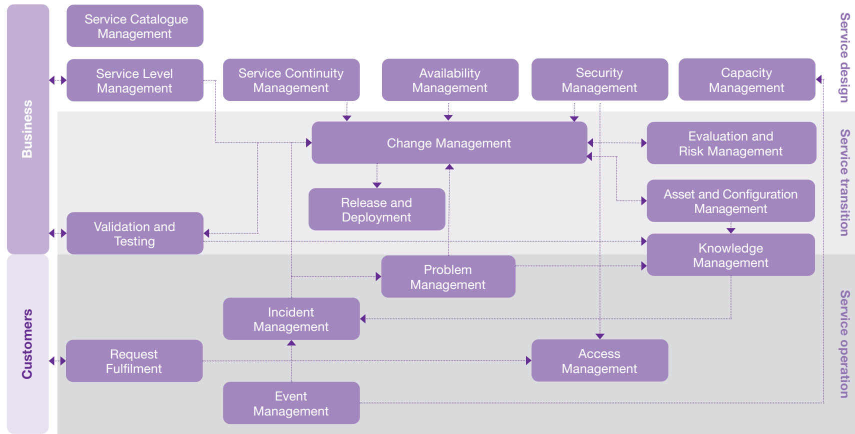
By implementing ITIL we ensure our management of systems is scalable, documented and repeatable. Because ITIL is international best practice, implementing the framework speeds up the induction of new staff or contractors with ITIL skills and knowledge as they are quickly able to understand our system environment.

The phases of the system are as follows:

- **Service strategy** – provides definition of the perspective, positions, plans and patterns that need to be considered to meet our desired business objectives.
- **Service design** – provides a 'plan' on what will be delivered to achieve the business capabilities and how. This phase focusses on designing with the 'four Ps' in mind – people, processes, products, and partners.
- **Service transition** – provides a means of migrating new or changed services into operational use. Testing, risk management, deployment and handover are all performed in this phase.
- **Service operation** – provides operational activities to deliver and manage the services at agreed levels to the business users and customers. This phase is where actual value is seen by the business.
- **Continual service improvement** – provides an opportunity to align IT services with changing business needs and technology. Renew, refurbish and dispose are all outcomes in this 'wraparound' phase.

We are working through implementation of the ITIL framework and our focus has been bedding in service transition and service operations phases as outlined in the figure below.

Figure 22.4: **ITIL framework**



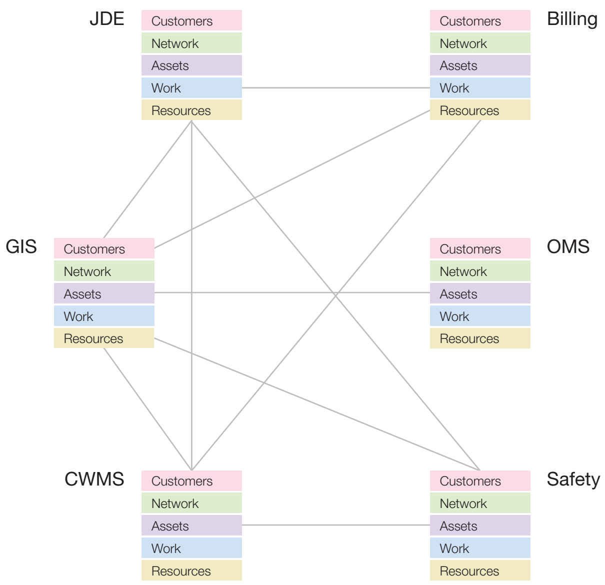
22.6.2 MANAGING CURRENT ICT SYSTEMS

Good quality data on our physical assets is critical to making informed asset management decisions.

The diagram below shows the core systems used to manage asset data and the flow of information between them.

[109] Source: Alexos, ITIL, www.axelos.com/best-practice-solutions/itil.

Figure 22.5: **Our current core systems and their integration**



Note: Lines represent current integration (bespoke or manual).

Our core systems are:

- **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

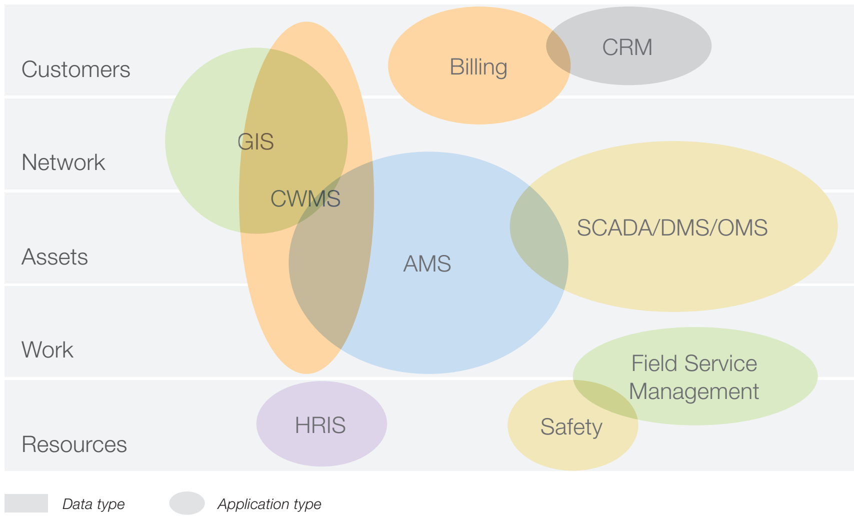
GIS is our main asset register, but each system holds certain information on electricity network and non-network assets. The lines in the diagram above show levels of integration between systems. Currently these links are created with bespoke software or involve manual updates. For a more detailed overview of the systems used to manage asset data refer to Appendix 12.

We have a range of mechanisms to ensure asset knowledge held by service providers is fed 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 our systems, such as GIS.

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 manual processes have been developed to compensate.

As part of the process of developing our long-term plan to deliver future capabilities we have developed the following desired future state, which consolidates business information.

Figure 22.6: **Desired future state of core systems and information flow**



22.6.3 ICT ASSET RENEWAL STRATEGY

Our asset renewal strategy encompasses three main themes, each of which is appropriate for different asset types.

- An age-based replacement strategy is applied to assets that have a high level of interdependence with other network assets (that is, the integrity of these assets is reliant on the operation of the system as a whole). It includes the need to replace equipment because of the availability of spares, for standardisation, or to ensure a product is kept under warranty or within vendors determined support lifecycles.
- An obsolescence replacement strategy is applied where there have been significant advances in the technology of an asset type. This is used where appropriate across all asset classes. We may choose to replace an asset because technology has advanced to a point where we are at a disadvantage by not having it, or a newer version of the same asset can increase our efficiency, safety of staff and service providers.
- A run to failure strategy is applied to assets where the consequences of failure are not major and where the costs of ongoing condition monitoring outweigh the costs of failure. This strategy is applied to equipment such as projectors, monitors, keyboards, mice and other consumable assets.

The table below shows the renewal cycles for our critical infrastructure and software.[110]

Table 22.7: **Renewal cycles for our critical infrastructure and software**

ASSET TYPE	LIFECYCLE
End user devices (laptops, tablets, desktops)	Three years
Server hardware	Three years
Storage hardware	Five years
Software	as per each vendors lifecycle policy

We further explain the systems used across our service categories below and in Appendix 12.

[110] As part of our risk management process we ensure all hardware has an attached warranty and software is under mainstream support from the vendor.

22.7 ICT ASSET PORTFOLIO MANAGEMENT

Our ICT asset management processes reflect a systems life cycle approach supported by our non-network governance process as well as our programme and project delivery framework. These are described in Section 5.9.

22.7.1 BUILDING FUTURE CAPABILITIES

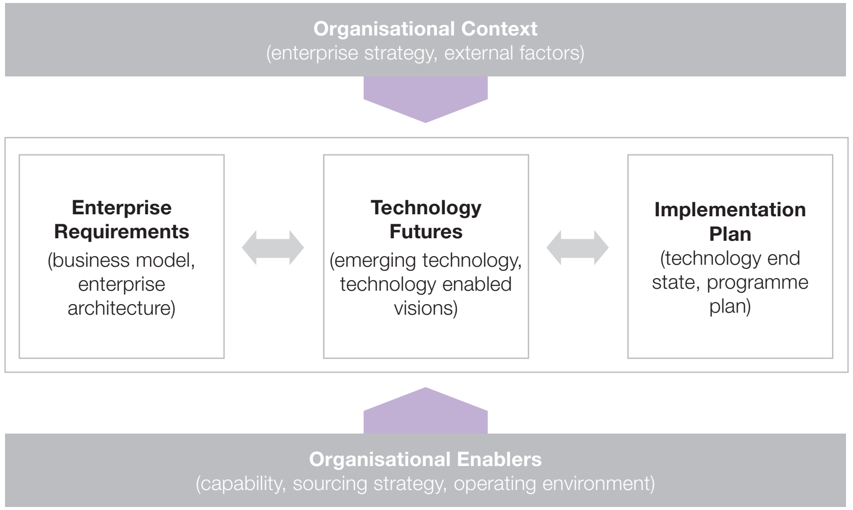
Identifying capability requirements

We use the term 'capability' in this context to mean the people, processes and technology required to run our business. One example is our investment in our OMS to allow accurate, timely visibility of outages and the ability to undertake remote switching.

The approach taken to identify future capabilities starts with a review of our strategy and more specifically the changes required to deliver on strategic objectives as illustrated in the following diagram.

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.

Figure 22.7: **Developing future capability requirements**



Brief descriptions of the key steps in this process are given below.

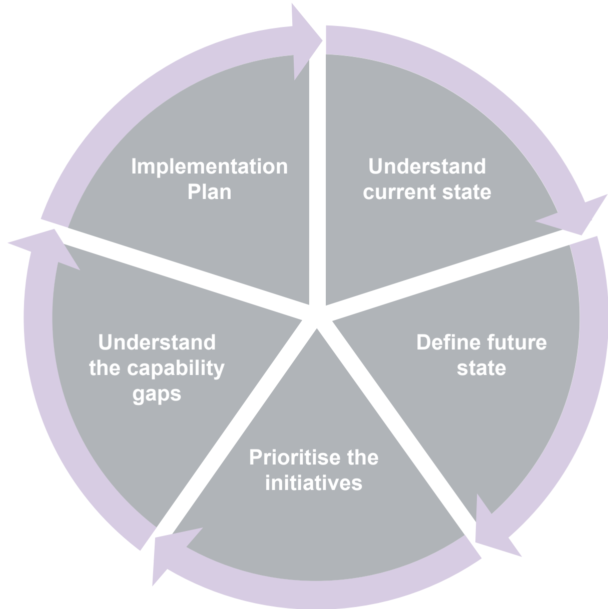
- **Understand organisational context** – is the first step taken to develop the non-network 10-year plan. It sets out to understand our current service offering and whether this meets the needs of the electricity business.
- **Organisational enablers** – is the step that defines the organisational capabilities that will need to be developed to ensure our strategy is deliverable and that we can maintain the new environment. There are two key sets of organisational enablers to be considered.
  - The first is to understand the key capabilities that the business will need to successfully implement the strategy and where these capabilities should be sourced from (internal vs external).
  - The second is to understand the ICT operating environment that will need to be created, specifically, the level of maturity that will be required to successfully execute the strategy.
- **Define and agree enterprise requirements** – is the step to understand and document what processes and functions our business performs, and the associated decisions that need to be made, and therefore what potential opportunities there are for technology to contribute to performance. This is also the step where the business prioritises required capabilities and determines phasing to match organisational objectives.
- **Create technology futures** – examines the technology options that exist to meet our enterprise requirements. Various technologies are considered and a high level evaluation of their suitability is completed. Based on this, a future technology vision is created along with completed high level enterprise architecture and future state technology architecture. Finally, the potential impact of emerging technologies is evaluated and fed back into the process.
- **Define the implementation plan** – provides a view of the required technology projects through to the end of the period. The level of detail in the plan will vary, with significantly more detail for the first 24 months than the later years.

22.7.2 DIAGNOSTIC PROCESS

A standard diagnostic process was used to develop the ISSP. It has five key steps.

- Understand the state of capability requirements, technology and its maturity
- Define the desired future state
- Prioritise the identified initiatives
- Understand the gap between the current state and the desired state
- Prioritise the gaps to determine critical needs and to inform the development of the implementation plans

Figure 22.8: **Diagnostic process**



22.7.3 ASSET INFORMATION AND INFORMATION MANAGEMENT

Our approach to information management is to 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 from being able to make well informed decisions.

22.7.3.1 ASSET INFORMATION

Much of the data we use is collected as part of our asset inspections. We have standards that prescribe the information that has to be gathered (including asset condition). This information is then made available to the business through the systems described earlier in this chapter.

As part of our ongoing asset management journey (discussed in Chapters 4 and 23) the importance of good quality information will increase as we move from making predominantly time based or reactive decisions to decisions that are based on condition and criticality-based analytics.

We rely on a range of processes to identify changes to our asset management data and tools. This includes feedback from asset data users and asset managers considering future needs of our network. We discuss changes in data requirements in more detail in our fleet management chapters (Chapters 14-20).

Our work since the last AMP has revealed scope for improving our asset information. This is reflected in our AMMAT assessment (see Chapter 23), which has shown the feedback loops for information, data quality and structures are in need of improvement.

In preparing this AMP we have used the best information available. We continuously assess our needs and identify gaps in our data. The initiatives discussed in this chapter will further improve the quality of asset management data. Initiatives designed to improve the availability or completeness of asset data include:

- **Improved condition inspections** – including acoustic testing of overhead line components (conductor, insulators, terminations etc.) to locate defects and to diagnose potential faults on key feeders, and acoustic resonance pole testing to determine internal condition of wooden poles, starting in FY17.
- **Improved asset health and criticality data** – to inform our renewal decisions. The design of the AHI and criticality approaches is still at an early stage. We expect that these approaches will be continually refined as our asset management approach improves, and we obtain more consistent and higher-quality condition data to support the models.
- **Better information on our LV network** – to focus more on improving our knowledge of the LV network in coming years.
- **Better information on our overhead network** – using Lidar-based inspections to improve the quality of our overhead line asset information (e.g. line height and vegetation growth near lines).

22.7.3.2 INFORMATION MANAGEMENT

Below we introduce our strategy aimed at improving the management of business information. It has the following themes.

Capture and validate at source – we understand that effective business information starts with standards to ensure we capture the right information once, and at source. To achieve this we need to validate information at the point of capture and provide tools that simplify the process in the field. Improvements in this area will be driven by a combination of the core ERP, mobility and an alignment with our standards to ensure consistency and quality.

Storage and retrieval – to meet the future needs of the business the majority of information must be available in as close to real time as possible. We anticipate that while much of our business information will be hosted within our ICT environment, a significant amount of critical information will be stored at a range of locations including supplier and customer portals, cloud systems and with customers. It follows that we must develop systems capable of aggregating data from multiple sources and presenting that data to business users.

Security and access – as we transition to a more customer focused organisation we will look to open up access to business information. This will assist us and customers to make informed decisions but will require the development of an improved cyber security environment. This will be achieved through our cyber security initiatives which will deliver an open and secure platform. 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.

As an example we aim to publish more business information via multiple channels including the internet, apps and social media. At the same time we aim to increase engagement with customers and their information must be protected in accordance with privacy laws and for commercial reasons. At the other end of the spectrum, commercially sensitive and operationally critical information will only be available to a limited core of authorised users and support staff.

Analyse and model – as we improve the quality of asset data, continue to collect data about customer relationships and monitor more asset components on our network the volume of data captured will increase significantly. We will enable analysts and ‘knowledge workers’ across the business to use the data and enhance our performance through data driven business decision-making.

Distribute – historically we have required business information users to provide a summary of their needs and then developed bespoke reports and datasets to meet their needs. We plan to transition to a new model where:

- Tailored information is pushed to end customers via multiple channels including the internet, social media, apps and interactive voice recognition systems – e.g. outage, pricing or time of use information affecting their properties or businesses.
- Business users become ‘knowledge workers’ driving insight and mastering business tools. With access to all relevant business information they can develop their own reports, dashboards and analytics supported by advanced users who assist them in developing these tools.
- Interfaces for all business information are easy-to-use and intuitive, allowing users to drill down into business information without the need for significant system training.

Our skills and services – our information is moving from paper-based to electronic delivery. This shift is driving a change in the skills required from our people:

- From data input to data validation
- From processing to monitoring of automated data receipt processes
- From reporting to analysis of new data sources
- From basic analysis to analysis and support of increasingly larger and more complicated datasets from multiple sources
- From standardised presentations and reporting formats to utilising the full set of presentation tools to match customer and user needs

Both customers and business users have growing expectations of easy-to-use interfaces designed to provide them with the information relevant to them.

Our planned information management improvements will help us achieve the asset management goal set out in Chapter 4.

GOAL	SUPPORTING INITATIVE
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.

22.7.4 PLANNED INVESTMENTS DURING THE PERIOD

Below we set out the main investments in ICT capabilities we plan to make during the planning period.

- **Core ERP** – including financial management, information management, works management. ERP allows an organisation to use a system of integrated applications or modules to manage its activities. An ERP is designed to combine all of a company's activities into a single system eliminating incompatible and duplicate technologies.
- **Advanced asset management** – developing our capabilities to capture and track asset life cycle activities, such as network and asset modelling and planning, as well as developing our asset maintenance strategy. For example, modelling as-built networks, analysing environmental factors, analysing failure modes, life cycle costing, scenario-based forecasting and estimating resource requirements to inform our capital and operating forecasts.
- **OMS** – a series of projects to build on and refine our OMS. This includes refining the existing platform, enabling a read only real time version of our SCADA system to be available, moving switching from a manual system to an electronic system, integrating our planned outages and demand management system into our OMS.
- **Mobility** – developing a number of mobility solutions that will allow real time availability of information for field service providers and our staff while out of the office. This will enable more information to be available and better decision-making. This also includes the ability to reduce manual data entry, by capturing information at source in the field and transferring it into other systems.
- **Customer relationship management** – part of enhancing the way we interact with our customers, developing and improving our ability to receive and respond to consumer contacts, and managing resulting workflows to deliver information and services to consumers.
- **Cyber security programme** – to ensure compliance with the NCSC cyber security standard up to a maturity level of 4 (defined). The NIST cyber security framework (Identify, Protect, Detect, Respond, and Recover) will be used as a basis for this initiative.
- **GIS development** – to operate in as close to real time as possible, improving data quality to support improved analysis and decision-making.
- **Enhanced ICT services initiatives** – implementation of the ITIL operating framework across a strong infrastructure foundation to improve system uptime, resilience and responsiveness to changing business needs.

We are confident our approach ensures that the scope, specification and approach for each project will remain appropriate against a changing technical landscape.

22.8 ICT CAPEX AND OPEX

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.[111]

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.

Due to the rapidly changing nature and relatively short lifecycle of ICT related hardware and software it is difficult to accurately estimate costs for products and service implementations more than two years out.[111]

To develop expenditure forecasts for the planning period we assumed the following:

- Data storage costs will continue to decrease for the next two to three years before stabilising.
- Data distribution costs will continue to decrease for the next two to three years before stabilising.
- Software costs will progressively move from Capex to Opex as software providers shift to the Software as a Service (SaaS) model.
- New or replacement hardware and software costs are likely to be stable over the planning period on a like-for-like basis.

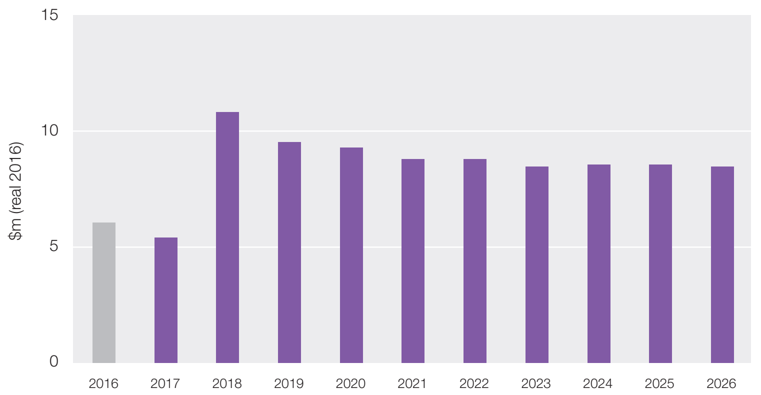
We believe an uplift in ICT expenditure will be required over the early years of the planning period due to our ERP investment. Later in the period expenditure is expected to stabilis

[111] ICT Opex is included as part of our business support expenditure forecasts (refer to Chapter 24).

22.8.1 ICT CAPEX FORECAST

The figure below shows our forecast ICT Capex for the planning period.

Figure 22.9: **ICT Capex forecast**



The main driver of ICT Capex for the period 2016 to 2019 is our investment in ERP Phase 1. ICT Capex is then expected to stabilise as we transition to the second and third phases between 2020 and 2026.

22.9 MINOR FIXED ASSETS

Our minor fixed assets portfolio covers ICT costs associated with the lifecycle management of minor fixed assets.

Our offices are fitted out with work stations to accommodate more than 300 employees. The standard setup of a workstation includes a desk, chair, storage, PC and communication equipment.

Offices also have meeting spaces and relevant office equipment required to operate effectively, such as printers, storage and meeting room technology. Specialist equipment and technology, such as CAD printers is also available. All sites have robust communication links.

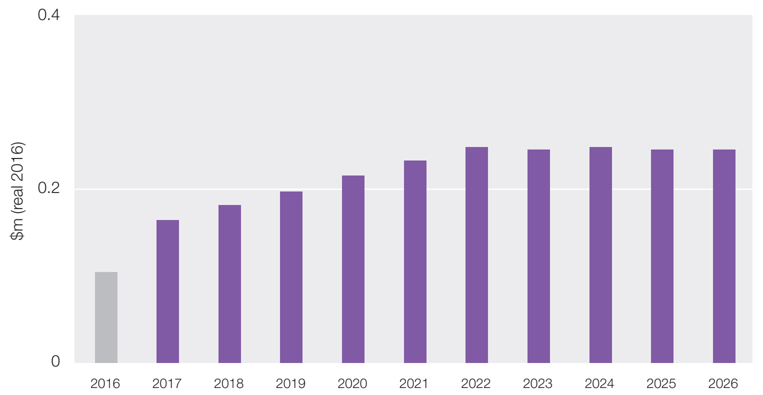
We classify minor technology fixed assets to include the following:

- Desktop hardware and laptops
- Monitors and video conferencing equipment
- Other peripherals (e.g. scanners, printers)

22.9.1 MINOR FIXED ASSETS CAPEX FORECAST

The figure below shows forecast minor fixed assets Capex for the planning period.

Figure 22.10: **Minor fixed assets Capex forecast**



The key driver of expenditure on minor fixed assets is the number of employees, which determines the volumes of desktop computers, handsets and related peripherals required to service their ICT needs. Employee numbers are forecast to increase up to 2022 and then stabilise.

22.10 FACILITIES

Below we describe the other main non-network assets we own or use. These include office buildings, depots, workshops, and motor vehicles.

22.10.1 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 operate from facilities strategically located throughout our network footprint. This has many advantages, including employees with local knowledge being situated close to customers and service providers.

We have a mixed portfolio of facilities that includes ownership of office buildings, workshops and depots. We also lease some office space. The table below summarises the location of our offices and depots and their ownership arrangements.

Table 22.8: **Offices and depots**

LOCATION	OWNERSHIP
Coromandel, Devon St East (New Plymouth), Junction St office and depot (New Plymouth), Masterton, Mihaere Dr (Palmerston North), Pahiatua, Taihape, Raetihi	Owned
Grey St office (Wellington), Liardet St office (New Plymouth), Tauranga office	Leased

22.10.2 NETWORK OPERATIONS CENTRE

We are constructing a new, purpose built NOC at our Junction St site in New Plymouth in FY17 and expect the facility to be commissioned in FY18.

The facility has been designed to improve operational resilience as well as supporting improved productivity and efficiency.

22.10.3 VEHICLES

We have a fully maintained fleet of about 40 vehicles in the first year of a three-year lease.

A recent review of our fleet has resulted in the selection of new vehicles that fit defined criteria, including that vehicles must have a five-star NCAP rating, low emissions and be fit for purpose i.e. all-wheel-drive with suitable ground clearance.

We undertake lease versus ownership analysis for our vehicles fleet. The analysis includes considering whether fully-maintained or company-maintained leases are more cost effective. We lease all of our vehicles apart from one or two speciality vehicles which cannot be leased at economical rates.

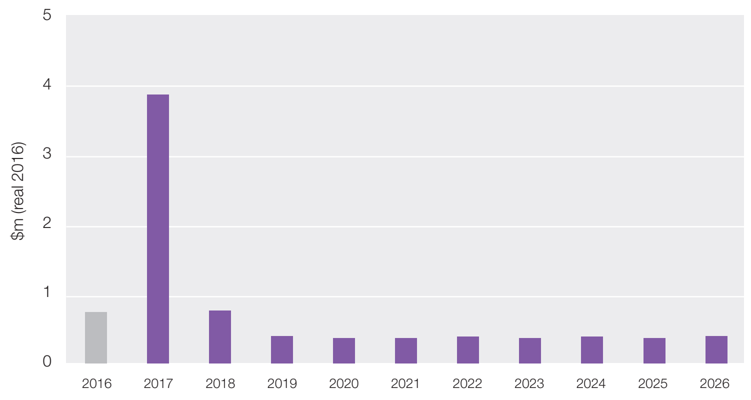
Lease costs for selected vehicle types have been sought from a range of leading fleet providers in New Zealand. The choice of provider was based on the best fit for us including pricing, servicing and location of support.

Our vehicle leasing costs are generally included within our business support Opex category.

22.10.4 FACILITIES CAPEX FORECAST

The figure below shows our facilities Capex forecast.

Table 22.11: **Facilities Capex forecast**



The key driver of facilities Capex for the period is the design and construction of the new NOC between 2016 and 2018. The NOC will improve business resilience and facilitate changing operations processes. It will also free up the old NOC area to create new meeting rooms and office space.

23. ASSET MANAGEMENT CAPABILITY

23.1 CHAPTER OVERVIEW

This chapter discusses our asset management capability, including the results of our latest AMMAT assessment. It explains how we intend to improve asset management capability over the planning period. Finally, it sets out our planned investment in asset management capability through our SONS portfolio.

23.2 OUR ASSET MANAGEMENT CAPABILITY

We have made good progress in improving our asset management capability over the past few years. During this period asset management has matured as a discipline beyond its traditional core of good engineering practice.

As an organisation committed to continually improving our asset management approach, we understand that capability development (e.g. embedding appropriate processes, systems, and techniques in the culture of the organisation) is a key enabling step and we will continue to focus on this over the planning period.

Ensuring we mature our approach to achieve consistent and high quality asset management over the planning period is particularly important. The levels of network investment we are proposing are significant. Effective asset management will help ensure this is prudent and efficient, thereby moderating costs and limiting price increases to customers.

In this chapter we discuss two main elements of our asset management capability – our organisation's overall capability and capacity, and the asset management competencies of our people. We also explain the Opex required to support our improvement initiatives and asset management objectives over the planning period.

Our strategies to improve our asset management capability relate to our Operational Excellence objective.

Operational Excellence

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

At an organisational level, we think about asset management as consisting of the following subject groups.[112]

Table 23.1: **Asset management subject groups**

SUBJECT GROUP	DESCRIPTION	MAIN CHAPTER DISCUSSED
Strategy and planning	Aligns our asset management activities and network outputs with our overall organisational objectives. This line-of-sight helps individuals carry out day-to-day asset management activities. It traces the rationale for what we are doing through our activity plans and asset management objectives.	Chapters 4-5
Asset management decision-making	This considers the challenges faced and the approaches to decision-making for three of the stages of an asset's life (develop or acquire, operate and maintain, renew or dispose). Decisions made at each stage have an impact on subsequent stages.	Chapter 5
Life cycle delivery	It implements our activity plans and allows appropriate control of activities and associated risks. Ensures we can undertake the activities needed for the successful delivery of our planned works.	Chapters 8-21
Asset information	We rely on asset data and information as key enablers across our asset management activities.	Chapter 22
Organisation and people	This includes reviews of organisational structures, processes, roles and responsibilities and contractual relationships. Effective leadership is crucial for building an organisation with a corporate culture that supports the delivery of good asset management.	This chapter
Risk and review	Core activities include identifying, understanding and managing risk. Establishing effective feedback and review mechanisms to provide assurance that objectives are being achieved is also necessary as is support of the continual improvement of asset management activities.	Chapter 5

23.3 OUR PEOPLE

People are essential to everything we do. Our organisational asset management capability is the result of our people, the tools we use, and the processes we follow.

Ensuring we have enough people with the right competencies is essential if we are to achieve our asset management objectives over the planning period.

[112] Based on The Institute of Asset Management, 'Asset Management – an anatomy, Version 3' https://theiam.org/what-is-asset-management/anatomy-asset-management

23.3.1 MANAGING OUR PEOPLE

We directly employ about 160 people in our Electricity Division and are supported by a further 140 staff from across the business (who also support our Gas Division). We indirectly employ hundreds more field staff and engineers through our service providers. We are more than an asset owning business. We are, by the nature of what we do, a people management business.

Below we discuss some of our ongoing people-related challenges and the characteristics of these challenges.

23.3.1.1 EXTENSIVE FOOTPRINT

We serve an area of about 40,000km^2 across the North Island. Around two thirds of our Electricity Division staff are based in New Plymouth with most of the rest in our Palmerston North and Tauranga offices. Some are based in our Wellington office and service providers' offices in Te Aroha, Masterton and Whanganui.

Having staff across a wide area is necessary for a number of reasons, including allowing us to be close to our customers and service providers. We are experienced in operating this distributed delivery model and believe that having staff close to the network and communities they serve creates a strong sense of ownership from our staff.

23.3.1.2 REGIONAL EMPLOYER

With our varied locations, we can offer diversity of office locations to help us attract quality staff. Our Wellington office gives us access to professionals who might favour larger city locations. Tauranga, New Plymouth, Whanganui and Palmerston North provide flexibility to work from smaller centres.

As a regional employer, and in common with other lines companies, we sometimes struggle to attract specialist professionals, particularly from overseas, who are less familiar with our locations. This means we need to remain competitive with our relocation and salary packages.

As a company experienced at managing a distributed workforce, we seek to maximise collaboration and communication across our offices. We use video conferencing and other technology wherever possible to ensure our people stay connected. We also ensure staff meet face-to-face when appropriate. This is a critical part of ensuring a well-connected and supportive team culture.

23.3.1.3 CHANGING COMPETENCY NEEDS

Engineering and network asset management continues to be our core business. During the past few years we have responded to changing skill requirements as the industry matures. This has meant expanding our teams to include health and safety, and economic regulation teams.

More traditional network competencies (e.g. network planning and demand forecasting) have also seen change and development. Accounting for uncertainties in network architecture and new generation sources will need new skillsets and analytical techniques. These change drivers are discussed further in Chapter 11.

As we discuss below, over the planning period we anticipate our competency need will continue to broaden and deepen.

23.3.1.4 WORKFORCE PLANNING

As with many other distribution and transmission utilities, a high proportion of our staff in management and senior technical roles is more than 50 years old. These older staff benefited from tailored and prescribed training of a type that is not available today (e.g. New Zealand Certificate of Engineering, NZCE). These staff now play a central role in training our younger staff.

Our service providers have also begun to experience a shortage of engineering technicians, many of whom become project managers and design engineers. This is an issue we recognise and will influence our future training programmes (e.g. engineering cadet programme).

During the planning period we anticipate that effective workforce competency planning and training will become critical, as older and experienced staff retire, and are no longer available for on the job training. For this reason we are placingan increasing focus on formal competency planning.

23.3.1.5 DEVELOPING THE NEXT GENERATION OF PEOPLE

Ensuring a sustainable workforce also means investing in the next generation of people who will take care of our network. We do this, for example, through our comprehensive graduate and cadet rotation system. Successful cadets and graduates who complete these programmes can progress to permanent roles within our engineering teams.

We take on many well trained people from overseas, and are likely to continue to do so. We benefit from a reasonably standard distribution delivery approach across European and Commonwealth countries, and New Zealand is an attractive place to work. We will place an increasing focus on this recruitment channel where skill shortages emerge. However, this has a tendency to increase recruitment and relocation costs.

Training the next generation is an industry-wide effort. We recognise this and are supporting future training through initiatives such as sponsorship of the Electric Power Engineering Centre, within the College of Engineering at the University of Canterbury. We are committed to doing our part in this cross-industry effort.

23.3.2 FUTURE CHALLENGES

People play a central role in asset management. As we deploy new technologies and asset management techniques we need to make sure our people have the right capabilities.

We are planning a significant increase in the volume and complexity of work on our network. As discussed in Chapter 11, part of the complexity will be due to the technological changes that lie ahead of us. As discussed in Chapter 6, we also aim to become more focused on our customer needs.

This means the people working for us, directly or through our service providers, will need to:

- Be available to deliver the increase in investment
- Have the right capabilities (including in emerging areas such as asset analytics and intelligent devices)
- Be willing to learn and adapt as the energy sector evolves

Below are examples of developments that offer substantial opportunities for our consumers but will be challenging to deal with:

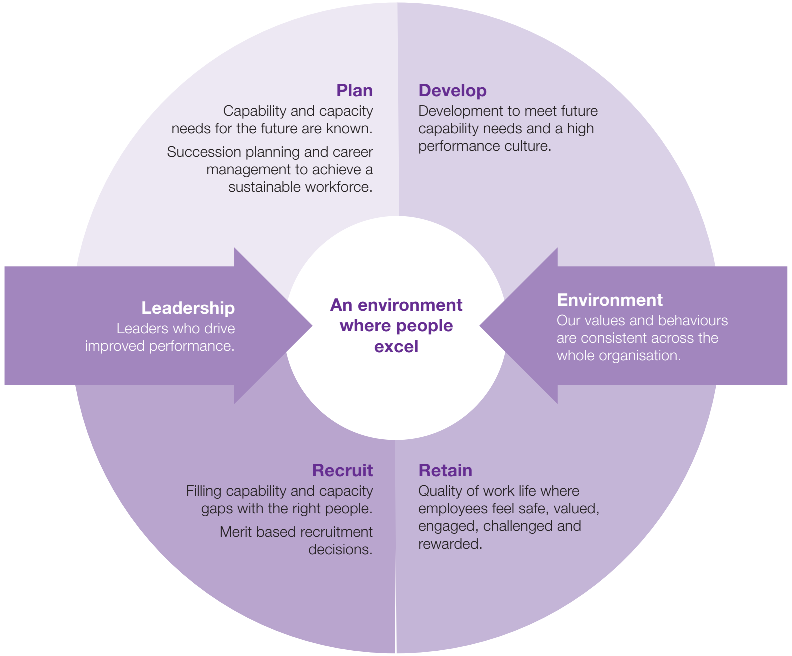
- The energy environment is in the early stages of a major transformation that is (or will be) largely driven by changing customer expectations and needs
- The increasing use of economic SSDG and energy storage
- The increasing use of intelligent devices on the network and on the customer side of the meter, allowing far-reaching changes to how we operate

23.3.3 OUR PEOPLE STRATEGY

Our People Strategy aims to ensure our people thrive and have the capabilities we need over the planning period.

Our vision is to create an environment where people excel. The figure below summarises our People Strategy to achieve this vision. It has six components, with goals within each of these components.

Figure 23.1: **Our People Strategy**



23.3.3.1 COMPETENCY IMPROVEMENT AREAS AND PLAN

The table below summarises the improvement areas and action plan to achieve our strategy.

Table 23.2: **Improvement areas and action plan**

GOAL	PROGRESS TO DATE	FURTHER ACTIONS
Plan		
Future capability and capacity needs are met	Key needs have been assessed and summarised	Continue to refine understanding and monitor needs
Workforce planning and career management to achieve sustainable workforce	Succession planning across key roles complete and reviewed annually	Develop workforce planning schedule to inform specific actions required (over the next 3 years)
Develop		
Development to meet future capability needs and create a high performance culture	Developed competency across all employees with targeted training Graduate and cadet programme (in place for six years) Enabled secondments to allow staff to develop new skills, and provide new challenges	Continue to develop our asset management competency framework Improve asset management communications framework Develop mid-manager programme (including coaching and mentoring) Encourage cross-team collaboration
Retain		
A quality of work life where employees feel safe, valued, engaged, challenged and rewarded	We monitor and respond to quality of work life measures, including staff engagement (above industry benchmark) and other measures such as turnover (relatively low turnover) We ensure fair remuneration	Focus on further lifting managers' capabilities
Recruit		
A merit-based recruitment process that fills capability gaps with the right high performing people at the right place and time	Recruitment is aligned with our succession planning strategy We address skills shortages by developing staff	Continue refining recruitment process to include improved branding and employee value proposition
Leadership		
Leaders who drive improved performance	Have in place targeted leadership training programmes	Focus on senior managers demonstrating key values and behaviours we seek Further targeted training and performance measures for managers
Environment		
Our values and behaviours are consistent across the whole organisation	Values and behaviours are part of annual performance reviews, and used in performance improvement discussions	Role modelling (see Leadership) Encourage cross-team collaboration Encourage organisational citizenship behaviours

Below we list specific examples of training initiatives and tools we intend to further develop.

- **Techniques for coaching and mentoring** – focus will be on improving participants understanding of how to effectively transfer knowledge
- **Leadership and management** – training for selected staff through NZIM[113]
- **Additional management training and support materials** – including developing tools and providing a dedicated people and performance resource

23.4 ASSET MANAGEMENT COMPETENCY FRAMEWORK

One of our key people development initiatives is our asset management competency framework. This ensures there is a direct link between our asset management objectives and the skills of our people.

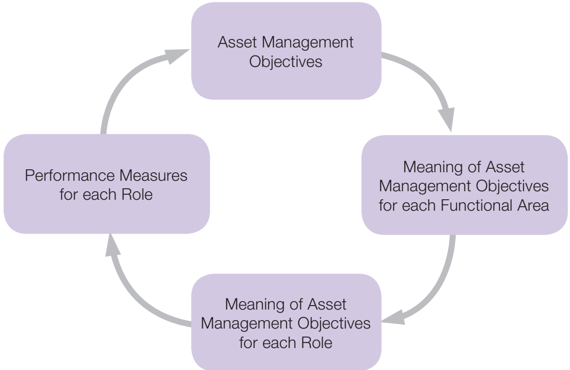
A well-performing asset management process has lines of sight that link the objectives, delivery activities and the roles and responsibilities of an organisation's staff. Linking what staff do day-to-day to the asset management objectives is critical to efficient service provision to our customers and effective management of long-life critical infrastructure assets.

Having a clear, common understanding of this line-of-sight is a key factor in successful asset management organisations. Other factors include staff engagement, clarity of direction and effective collaboration between departments and functions.

[113] NZIM means New Zealand Institute of Management.

We are currently developing an asset management competency framework that enhances this line-of-sight by linking our objectives to required competencies. We have found it useful to create a shared understanding, identify gaps in capability and communicate our People Strategy. Refining and fully implementing the framework will be an important tool for achieving our asset management objectives. The figure below provides an overview of the framework.

Figure 23.2: **Our Asset Management Competency Framework**



Below we briefly introduce each element of the framework.

23.4.1.1 ASSET MANAGEMENT OBJECTIVES AT FUNCTIONAL AREA LEVEL

The first part of the framework defines the competencies needed to achieve our asset management objectives for each functional area in the Electricity Division.[114] Below is a summary of competency requirements for these functional areas.

- Developing policy and standards
- Maintenance and renewal strategy
- Planning and design guidance
- Materials and equipment specification and evaluation
- Special equipment advice (load control, meters, SCADA, protection)
- Operating standards and training evaluation
- Network information interpretation

23.4.1.2 ASSET MANAGEMENT OBJECTIVES FOR EACH ROLE

The framework then defines the current and future competencies needed to achieve our asset management objectives for each role. For example, a person in a role that involves developing policy and standards requires strong competencies in:

- Undertaking consultation across multiple teams
- Precise and descriptive writing
- Applying a wide general knowledge of network assets
- Applying in-depth working knowledge of the standards, understanding their purpose and relevant context

23.4.1.3 PERFORMANCE MEASURES FOR EACH ROLE

To ensure relevance to each job we are developing competency measures which can be used, for example, as part of annual performance reviews. Similar to the 2012 IAM competencies framework this will include input, output and behavioural measures.

The most basic and most easily measurable attributes are input based. Good output and behavioural measures are more powerful but harder to develop and measure.

Table 23.3: **Types of performance measures**

MEASURE	DESCRIPTION
Input	The qualifications, training courses, and personal development needed to ensure a person is competent
Output	A person's performance and delivery that can be observed when they act competently
Behavioural	The way a person goes about their work, and the personal attributes someone needs to display when performing competently

23.4.1.4 CAPABILITY NEEDS

The core capabilities of many of our people will continue to be engineering related. But to deal with the challenges over the planning period and beyond we will require a wider range of capabilities.

The following table provides an overview of our future capability areas, drivers and needs (in addition to current capabilities).

[114] The five functional areas are: asset strategy, planning, service delivery, NOC, design, and commercial.

Table 23.4: **Capability drivers and improvement needs**

MEASURE	ATTRIBUTE/DRIVER	IMPROVEMENT NEED
Asset management	Good asset management adopts a longer term strategic approach	Operational and/or technical understanding of the network, analytical skills, critical thinking and decision-making, commercial acumen, knowledge of economics and finance
Customer focus and engagement	Improved customer focus Improved responsiveness to customer needs	Understanding interaction between customer needs and business decisions Adopt a more customer-centric approach when making asset management decisions Ability to quickly adapt to new customer expectations
Delivery	Smooth processes required to deliver efficient outcomes	Increased focus on project management techniques
Leadership	Communicate vision, drive business direction, optimise outcomes through effective people leadership and use of metrics	Strategic thinking, performance management, change management continuous improvement, networking both internally and externally.

23.4.2 MINIMUM COMPETENCY STANDARD FOR FIELD SERVICE WORKERS

Most of the physical work completed on the network is done by our service providers. To help ensure that the work effectively supports our asset management objectives we have developed field work competency requirements.

The main aim of these 'must have' competency standards is to ensure field work is undertaken safely. Appropriate and continually improving worker competency is one of the main controls for managing the many field work hazards.

We support the New Zealand Qualifications Association (NZQA) training framework and are committed to supporting industry-wide training that is standardised, easy to access, and transferable between companies. We believe this will help build a well trained workforce and help meet increased demand for skilled workers in the future.

The competency standard prescribes input measures (e.g. skills and qualifications) that each field worker needs to have before working on our network. It also encourages training to improve competency above the minimum required level.

Our service providers have to comply with these competency standards so that their staff can work on our network. We monitor compliance with these standards.

The quality of training provided to our staff and our contractors is an important input to overall competency. We recently assessed the quality of our training providers and identified several possible areas of improvement.

Below we set out goals and supporting initiatives to help us achieve our Operational Excellence objective.

GOAL	SUPPORTING INITIATIVE
We ensure competent technical staff look after our assets and further grow our capabilities to match increasing future requirements	Continually develop our asset management capability through effective recruitment and development of our staff, ensuring appropriate competency levels and breadth of skills.
We support a culture of continuous learning	Encourage a culture of continuous learning and innovation.

23.4.2.1 ASSET MANAGEMENT COMPETENCY IMPROVEMENT

In addition to further developing and implementing our asset management competency framework, based on the work described above we have identified the following development areas:

- **Asset management** – to provide our people a better understanding of the benefits of good asset management. In particular this would include skills around option analysis, business case development and communication with executives and directors.
- **Project management** – influences the efficiency of project delivery and the fulfilment of stakeholder needs, and is an important link to programme deliverability.
- **Succession planning** – ensures effective transfer of knowledge from our experienced staff to our young graduates, in a practical, proactive way.

23.5 ASSESSING OUR ASSET MANAGEMENT CAPABILITY

One of the tools we use to assess our 'maturity' as an asset manager is the AMMAT. It consists of a self-assessment of our maturity compared with good asset management practices. We published our first assessment in the 2013 AMP, and have repeated the assessment in this AMP.[115]

AMMAT consists of 31 questions taken from a self-assessment of how aligned an organisation's asset management practices are with PAS55. Schedule 13 in Appendix 2 includes templates that summarise our assessment for each question.

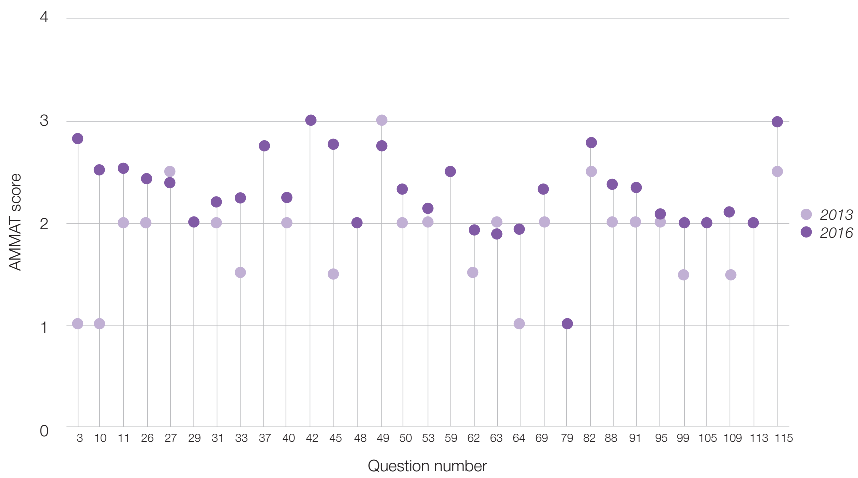
Overall, we have found the repeated use of the AMMAT approach useful, and some of the improvement initiatives we identified originated from the AMMAT assessment.

[115] As an electricity distributor we are required to undertake and publicly disclose AMMAT results.

23.5.1. AMMAT ASSESSMENT

The figure below shows the AMMAT results from this year's assessment and compares them with the 2013 scores. Scores range from 0 ('innocent' maturity level) to 4 (excellent maturity level).

Figure 23.3: **Asset maturity self-assessment scores for 2013 and 2016**

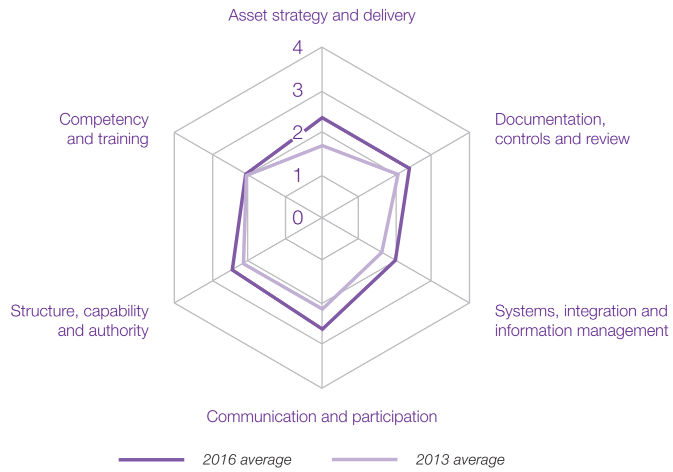


We apply a very stringent methodology when evaluating ourselves against the AMMAT criteria. The scores above should be viewed in this context. We believe that asset management is a professional discipline. Therefore we will only score ourselves at maturity level 3 if we believe the item assessed is developed to a level reflecting advanced asset management practice and is appropriately embedded within our organisation.

For most questions our maturity score increased compared with 2013. On seven questions our score is the same as in 2013, and on three questions our score decreased slightly. These decreases were the result of our improved understanding of what is required to deliver in the assessment areas.

Below we show the scores grouped by assessment areas. Our maturity improved in five of the six areas, and stayed similar in the competency and training area.

Figure 23.4: **Summary of asset maturity self-assessment scores by assessment area**



Differing scores between the two assessments reflects changes to our asset management approaches. But some differences are due to changes in our assessment approach. This includes our understanding of the meaning of maturity levels and the assessment criteria – not actual maturity. Examples include:

- **Changes in understanding of AMMAT over time** – 2013 was the first time we undertook the assessment. While in both cases we used the EEA AMMAT Guide, the industry undertook significant additional work to improve the guidance. We contributed to the development of the EEA guide in 2012 and the subsequent update in 2014.[116]
- **Circumstances at the time** – on some assessment topics, the score depends on circumstances at the time and can vary subsequently. For example, in 2013 we assessed ourselves as reasonably advanced on the availability of asset information. However, more in-depth asset renewal modelling since then revealed a need for richer, more comprehensive information to support our asset management decisions.
- **Partial improvements** – in some areas we noted that core attributes were in place but we reduced scores because they were not systematically linked to the asset management system. In some areas we noted major improvements in part of an assessment question but reduced the score due to insufficient improvements on other aspects of the question.

[116] Electricity Engineers' Association, AMMAT – Revised Guide (May 2014) www.eea.co.nz/tools/products/details.aspx?SECT=publications&ITEM=2564

23.5.2 IMPROVEMENT INITIATIVES

Many of the maturity improvements have resulted from new field service arrangements and improved documentation such as our fleet management plans. Below we set out capability improvements targeted for the planning period.

23.5.2.1 ISO 55000 CERTIFICATION BY 2022

As discussed in Chapter 4, to provide evidence to our stakeholders of our improvement as an asset manager we have set the goal of achieving ISO 55000 certification by 2022. This means reaching, a ‘competent’ or level 3 maturity across all 120 assessment questions.[117]

GOAL	SUPPORTING INITIATIVE
ISO 55000 Certification	Identify and address the necessary steps to achieve ISO 55000 certification by 2022, to at least level 3 maturity on all measures.

Certification will require significant work to set up the system and process linkages within the organisation. It will involve formally assessing our status against additional questions, identifying gaps and putting in place improvements to close any gaps.

23.5.2.2 OTHER IMPROVEMENT INITIATIVES

We have started to develop the relevant documentation, systems and processes needed for ISO certification, including:

- **Asset management communications plan** – to help lift the profile of our asset management system across the company and improve the linkages of the good attributes we already have with the asset management system.
- **Competency framework** – expanding our people competency framework to strengthen linkages with the risk management system.
- **Asset management information strategy** – to improve our asset management information practices.

The asset management communications plan will set out how we communicate with stakeholders involved in activities such as developing asset management strategies, objectives and plans.

[117] This new, more challenging target replaces the target we set in the 2013 AMP (an average AMMAT score of 2.9 by 2018).

23.6 SYSTEM OPERATIONS AND NETWORK SUPPORT

The need for an expanded range of competencies and capabilities, along with the capacity required to adequately manage increasing network investment requires growing expenditure in our SONS portfolio. This is necessary if we are to maintain the capability necessary to be effective asset managers and increase efficiency.

The main increases will be from work related to:

- Project managing the delivery of our renewal and growth investments
- Positioning ourselves for future network scenarios – including increased network analytics
- Conducting research and developing proofs of concepts for future network technology and applications
- Managing services providers undertaking increased maintenance work
- Increasing our asset management capability
- Better focusing on our customers’ needs
- Improving capacity and capability of the NOC

Finding the right people and developing the skills required for the future network will take time. It is a prerequisite for our future readiness and proposed investments to have the right people and sufficient resources in place. Early recruitment and the associated expenditure are essential before the start of the planned CPP period (although the uplift is expected to continue into the period as well, as the scale and complexity of work grows).

The table below sets out the additional roles required within our functional units.

Table 23.5: **Additional roles and responsibilities**

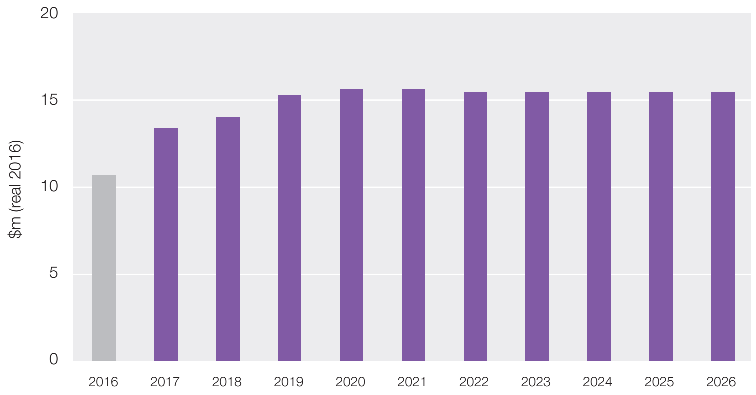
UNIT	ROLES	
Asset management	line managers	GIS operators
	network planners	database administrators
	protection engineers	business analyst
	asset information analysts	data scientists
	asset managers	
Operations	technical project managers	network coordinators
	vegetation management planners	shift operators
	vegetation management liaisons	dispatchers
	release planners	

23.6.1 FORECAST EXPENDITURE

Due to the highly specialised nature of some roles, and the multiple locations at which they will be required, we believe it may be difficult to fill some of the positions discussed above. For example, some NOC specialists will need to be specifically trained, and as such we need to start the recruitment process well in advance of requirements. Similarly, obtaining business analysts and specialist GIS skills in some of our outlying locations may require specific strategies.

Developing and sourcing these specialist skills will require increased investment in new staff. Additional training of existing staff will also be required due to the expansion or changes in their roles. The following chart shows our forecast SONS Opex for the planning period.[118]

Figure 23.5: **Forecast SONS Opex**



Our SONS forecast increases from $10.6m in 2016 to around $15m after 2020. The initial increase will deliver the up-front planning work needed to deliver our renewals and growth and security investments. It will also deliver asset management improvements and data improvements needed to ensure we are able to seek ISO 55000 certification.

Forecast SONS expenditure is expected to rise, but this increase is moderate compared to the planned investment this increase will support.

[118] People in the SONS portfolio also support and enable capital works. This expenditure is capitalised in accordance with our capitalisation policy and included in the relevant assets.

Our increased competency will allow us to improve our productivity through:

- Improved project management
- Simplified and optimised delivery processes to enable higher delivery volumes per employee
- Better and more accessible information
- Economies of scale and scope
- Improved analytical capabilities

It will take time to hire people with the specialised skills we need, train new people and structure ourselves in the most effective way to manage our network over the planning period.

EXPENDITURE FORECASTS

This section summarises our Capex and Opex forecasts for the planning period.

CONTENTS

Back to contents >

24. EXPENDITURE FORECASTS

24.1 CHAPTER OVERVIEW

This chapter sets out a summary of our expenditure forecasts over the planning period. It is structured to align with our internal expenditure categories and with information summarising the forecasts provided in earlier chapters.

It provides further commentary and context for our forecasts including key assumptions. It discusses 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 2016 financial year (2015/16) and our forecasts (purple columns) for the remainder of the planning period.

Expenditure is presented according to our internal categories. It is also provided in Information Disclosure categories in Schedules 11a and 11b in Appendix 2.

All dollars are denominated in constant price terms using FY16 dollars.

24.2 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.

24.2.1 CAPEX

Our current 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. We expect this expenditure profile, particularly later in the period, to be further refined as we enhance our modelling approaches and improve our underlying asset management capability. This includes periodically reviewing our proposed level of investment against the revenue we are allowed under the DPP. These changes will be reflected in subsequent updates of the AMP.

The expenditure forecasts also reflect our current understanding of the regulatory environment and the Input Methodologies. Since further development of the regulatory environment is underway this may result in future changes to our strategic positioning and associated investment profiles.

Total Capex includes the following three expenditure categories:

- **Network development Capex**: discussed in Chapters 8-11
- **Fleet management Capex**: discussed in Chapters 14-21
- **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 Capex work volumes. Below we set out our total Capex for the planning period.

Figure 24.1: **Total forecast Capex for the planning period**

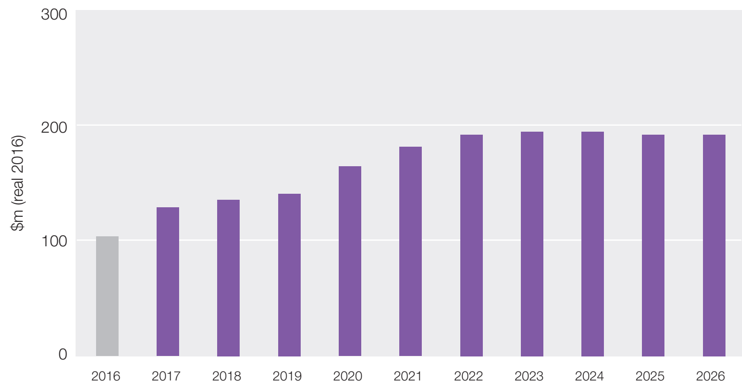


Table 24.1: **Total forecast Capex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
103.0	127.7	135.1	139.9	163.2	181.6	191.7	194.7	193.3	191.7	192.8

Our Capex profile reflects the underlying network needs discussed in this AMP. Initial expenditure uplifts has been specified to allow for the mobilisation of increased service provider resources and to allow sufficient time to expand our internal engineering capacity and capability. The profile also takes into account our planned CPP timing.

24.2.1.1 NETWORK DEVELOPMENT CAPEX

As discussed in Chapter 8, our network development Capex is split into four portfolios. These are:

- Growth and security
- Customer connections
- Network enhancements
- Research and development (future network activities)

The combined expenditure in these portfolios is shown below.

Figure 24.2: **Total network development Capex for the planning period**

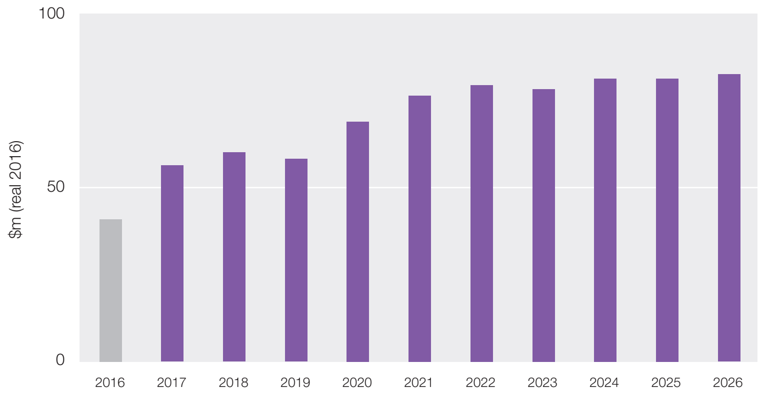


Table 24.2: **Total network development Capex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
40.4	56.4	60.1	58.1	69.0	76.9	79.7	78.6	81.8	81.3	82.8

During FY17, FY18 and FY19 we will invest in a number of major security upgrade projects that will address issues in key urban centres such as Palmerston North and Tauranga. Expenditure in the middle and later years of the period is designed to ensure that the security of our network is appropriate to meet our customers' needs. It will also include our planned trials of new network solutions and investments to ensure we are able to accommodate new edge technologies such as EV and PV as they grow in significance.

24.2.1.2 FLEET MANAGEMENT CAPEX

As discussed in Chapter 12, our fleet management Capex is split into eight portfolios. These are:

- Overhead Structures
- Overhead Conductors
- Cables
- Zone Substations
- Distribution Transformers
- Distribution Switchgear
- Secondary Systems
- Asset Relocations

The combined expenditure in these portfolios is shown below.

Figure 24.3: **Total fleet management Capex for the planning period**

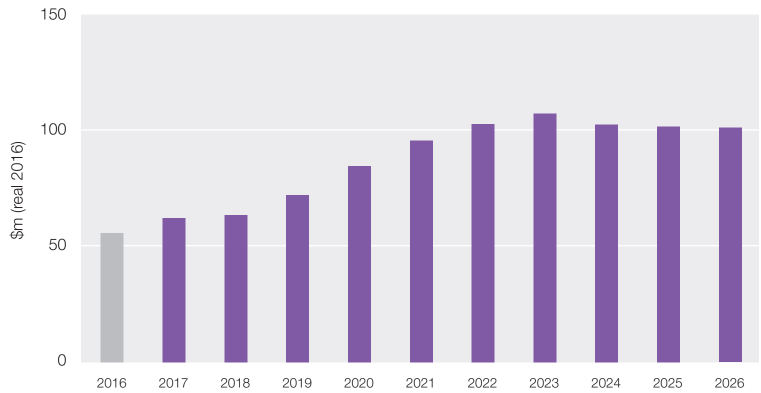


Table 24.3: **Total fleet management Capex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
55.7	62.0	63.3	71.9	84.6	95.4	102.6	107.0	102.4	101.3	101.0

As discussed in previous chapters, the main driver for our increased forecasts over the planning period is the need to renew our asset fleets. The profile above reflects this need and allows for the cost effective mobilisation of increased field and engineering resources. It also reflects the timing of our planned CPP.

24.2.1.3 NON-NETWORK CAPEX

As discussed in Chapter 22, our non-network Capex is split into three portfolios. These are:

- ICT
- Minor Fixed Assets
- Facilities

The combined expenditure in these portfolios is shown below.

Figure 24.4: **Total non-network Capex for the planning period**

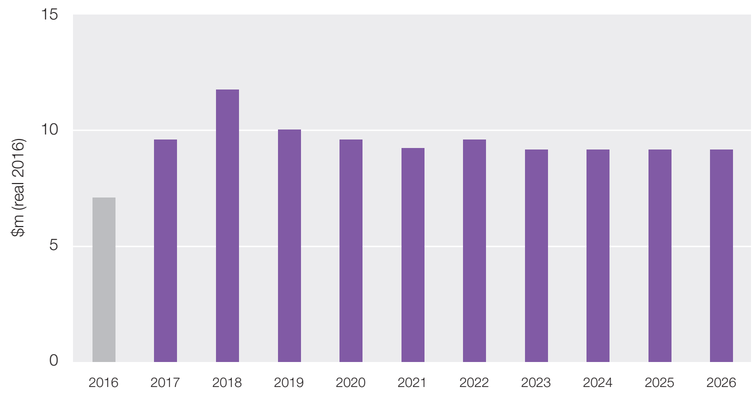


Table 24.4: **Non-network Capex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
6.9	9.3	11.6	9.9	9.6	9.3	9.4	9.0	9.0	9.0	9.0

Our main non-network investments in the planning period include an upgraded NOC and development of an ERP system during FY17, FY18 and FY19. These investments are critical enablers of our asset management capability and increased activity levels in the later part of the period. Expenditure in the middle and later years of the period will include software and hardware lifecycle renewals and new capabilities to support the increased complexity and functionality of our network arising from new customer side solutions. This will include the likely development of an Distribution Management System (DMS). Given the rapidly changing nature of ICT solutions the exact solutions implemented and resulting costs are less certain later in the period.

24.2.2 OPEX

Our current Opex forecast increases over the planning period. We expect this profile to evolve as we refine our asset management approaches and modelling in a similar way to our Capex forecast. This includes periodically reviewing our proposed levels of expenditure against the revenue we are allowed under the DPP. These represent our best forecasts using currently available information.

Total Opex includes the following three expenditure categories:

- **Direct network Opex:** discussed in Chapter 13
- **Indirect network Opex:** discussed in Chapter 23
- **Non-network Opex**

Similar to Capex, increases during the planning period relate almost entirely to network Opex. Opex increases are proposed where we believe they can provide material benefits to network performance and direct benefits to customers. 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 24.5: **Total forecast Opex for the planning period**

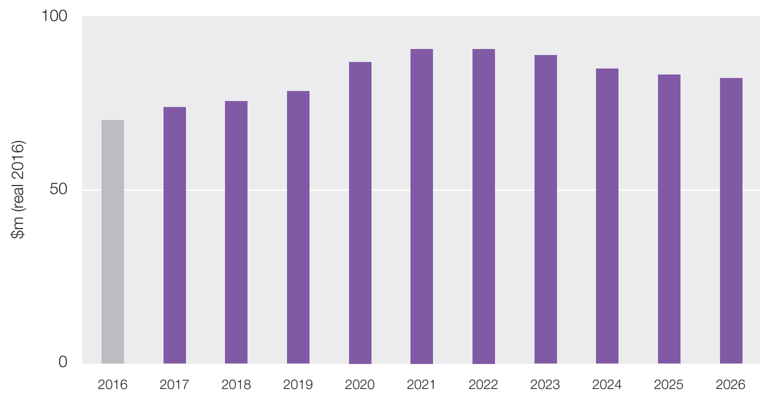


Table 24.5: **Total forecast Opex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
70.2	73.7	75.7	78.5	87.2	90.5	90.4	89.4	85.8	83.7	82.8

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 and allow us to reach sustainable levels of vegetation management. It includes investment in our people to ensure we can undertake our work programmes. This will also expand our internal engineering capacity and capability to reflect the more sophisticated asset management, innovation and data analysis needs of the future. Similar to Capex, it takes into account the timing of our planned CPP.

24.2.2.1 DIRECT NETWORK OPEX

Our direct network Opex forecast includes our planned expenditure in the following portfolios. Further information on the forecasts can be found in Chapter 13.

- Routine maintenance and inspections
- Asset renewal and replacement
- Service interruptions and emergencies
- Vegetation management

The combined expenditure in these portfolios is shown below.

Figure 24.6: **Direct network Opex for the planning period**

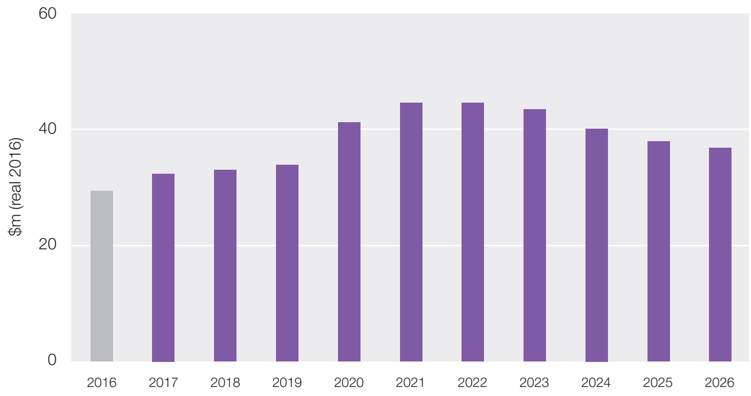


Table 24.6: **Direct network Opex over the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
29.8	32.4	33.0	33.8	41.4	44.5	44.7	43.6	40.0	37.9	36.9

The higher Opex levels during the middle years of the period are mainly due to increased expenditure in our ARR portfolio to address a high number of end of life component replacements (defects). Towards the end of the period we expect to reach a sustainable level of direct Opex. This reflects the expected benefits of increased renewals and our cyclical vegetation programme being embedded.

24.2.2.2 INDIRECT NETWORK OPEX

Our indirect network Opex forecast includes our forecast expenditure on SONS. Details of this expenditure can be found in Chapter 23.

Figure 24.7: **Indirect network Opex for the planning period**

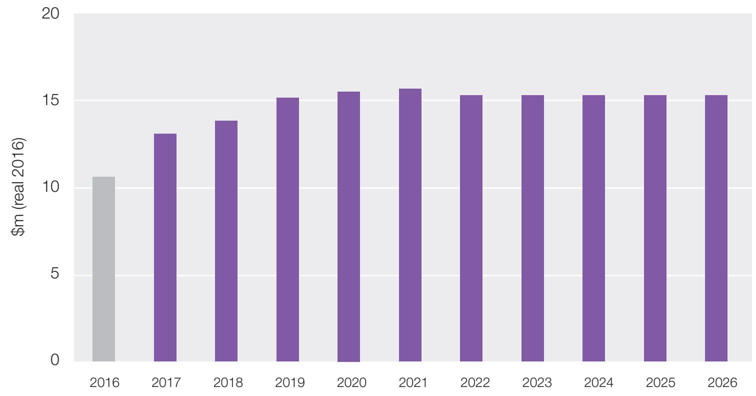


Table 24.7: **Indirect network Opex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
10.6	13.3	13.9	15.1	15.5	15.6	15.3	15.3	15.3	15.3	15.3

Our SONS forecast reflects the need to continue developing our people and their capabilities. It includes increased engineering capacity to process additional work volumes, and to enable us to accommodate new technology solutions essential to providing a network for the future. Ensuring we have the necessary skills to manage a changing sector is essential to achieving our asset management objectives.

24.2.2.3 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 24.8: **Non-network Opex for the planning period**

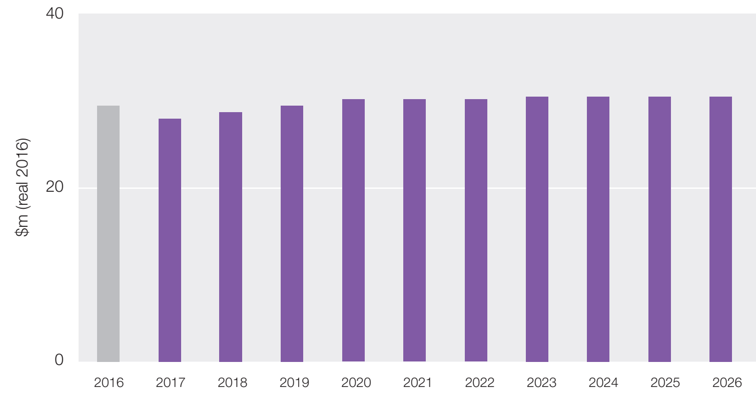


Table 24.8: **Non-network Opex for the planning period ($m real 2016)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
29.8	28.1	28.8	29.6	30.2	30.4	30.4	30.5	30.5	30.5	30.5

Our forecast expenditure is largely constant over the planning period. While we have an ongoing focus on improving our efficiency and are confident that improvements can be made, we also recognise that there will be additional demands and requirements that may offset these savings.

24.3 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.

24.3.1 FORECASTING INPUTS AND ASSUMPTIONS

The table below sets out the main inputs and assumptions underpinning our forecasts for the planning period.

Table 24.9: **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 most cases (e.g. 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 14-20).
Expected asset lives, based on experience operating our network, provide an appropriate proxy for longer term asset replacement forecasting.	For longer term forecasting we often 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 14-20 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 next few years. In the medium term the increasing adoption of new technologies (see Chapter 11) 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. We will refine our approach to demand forecasting in the next 12-18 months and adapt our approach as our understanding evolves.
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 we consider this assumption 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 cancel 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 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. We consider this assumption to be conservative.
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, 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.
Current network Capex unit rates reflect likely costs over the planning period.	There may be some economies of scale realised in future years as a result of increased work volumes but that is likely to be offset by factors such as requirements to manage network outages (e.g. using portable generators).

INPUTS AND ASSUMPTIONS	DISCUSSION
Current maintenance unit rates reflect likely costs over the planning period.	We may realise some economies of scale in future years due to increased maintenance volumes, though these may be 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.
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 SF6 switches will generally replace air break switches over the planning period – refer Chapter 19).

24.3.2 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.[119]

24.3.2.1 APPROACH TO DEVELOPING COST ESCALATORS

Our approach 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).
- Weighting factors for cost categories, such as transformers, that are made up of a range of inputs.[120]

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.

[119] 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.
[120] 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.

24.4 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.[121] 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[122] uses a combination of the following approaches:

- **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 reactive maintenance and indirect network Opex. It is also used for non-network Opex and certain trend-based Capex forecasts such as asset relocations.

These estimate types are discussed below.

24.4.1 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.

[121] The P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.
[122] Budgeting for the earlier part of the period is based on tendered work, detailed project-specific estimates, or maintenance delivery plans.

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 (e.g., 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.

24.4.2 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[123] 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 (e.g. IT hardware) we have used expected volumes and unit rates informed by discussions with vendors and historical outturns.

[123] The net impact of cost variances will tend to diminish in a portfolio containing a large number of P50 estimates.

24.4.3 BASE-STEP-TREND

We have used a 'base-step-trend' approach to forecast part of our expenditure.[124] The approach is used by many utilities and economic regulators for forecasting expenditure that is recurring.[125] The figure below sets out the steps in developing base-step-trend forecasts.

Figure 24.9: **Base-step-trend forecasting steps**

Select base year
↓
Adjust base year (if required)
↓
Adjust for significant, non-recurring items
↓
Adjust for step changes
↓
Apply trends for ongoing drivers
↓
Adjust for expected cost efficiencies
↓
Expenditure forecast

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 (e.g. 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.

[124] This includes reactive maintenance and indirect network Opex. It is also used to a lesser extent for non-network Opex and certain Capex forecasts, such as asset relocations.

[125] 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.

24.4.4 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. There are a number of benefits including having a centralised system to manage overhead allocation and uncertainty. Standardised cost-curves are used to aid expenditure planning. We are making significant improvements to ensure we capture the actual project cost and then feed it back into relevant future cost estimates.

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APPENDICES

This section provides additional information to support our AMP. It includes our Information Disclosure schedules.

CONTENTS

Back to contents >

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.

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.

ARR means Asset Replacement and Renewal which is one of our maintenance portfolios.

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.

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.

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.

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.

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.

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.

Distribution System Integrator 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.

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.

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.

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.

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.

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.

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.

NOC is our Network Operations Centre which is responsible for dispatch, coordinating/planning works, restoring supply and operating our network.

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.

PILC means Paper Insulated Lead Covered which is a type of power cable.

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.

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.

RMI is Routine Maintenance and Inspection which is one of our maintenance portfolios. It differs from the Commission's routine corrective and inspection expenditure category (RCI).

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.

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.

SIE means Service Interruptions and Emergencies is one of our maintenance portfolios.

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

Company Name	**Powerco**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	23,502	21,421	24,250	23,293	24,167	25,079	26,040	27,048	27,941	28,895	29,885
11	System growth	27,609	47,206	50,978	50,243	62,885	73,110	78,819	80,225	87,012	89,335	94,519
12	Asset replacement and renewal	52,907	60,964	63,080	74,410	88,785	104,438	115,014	125,449	126,066	128,797	132,061
13	Asset relocations	3,494	2,909	3,020	3,107	3,203	3,303	3,407	3,516	3,622	3,732	3,846
14	Reliability, safety and environment:											
15	Quality of supply	3,329	3,890	3,835	4,175	5,154	6,018	6,178	6,351	6,529	6,712	6,900
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,020	1,495	1,718	1,156	3,245	2,977	4,326	3,197	1,085	1,050	1,635
18	**Total reliability, safety and environment**	4,349	5,385	5,553	5,332	8,398	8,994	10,504	9,548	7,614	7,762	8,535
19	**Expenditure on network assets**	111,861	137,884	146,882	156,384	187,437	214,925	233,784	245,786	252,255	258,521	268,845
20	Expenditure on non-network assets	6,910	9,471	12,027	10,528	10,575	10,513	10,963	10,746	11,006	11,270	11,542
21	**Expenditure on assets**	118,771	147,355	158,909	166,912	198,012	225,437	244,747	256,532	263,260	269,792	280,387
22												
23	*plus* Cost of financing	1,800	2,446	2,171	2,415	3,010	3,793	4,111	4,721	5,075	5,210	5,419
24	*less* Value of capital contributions	15,724	16,123	17,811	17,131	17,667	18,215	18,779	19,361	19,856	20,381	20,920
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	104,847	133,679	143,269	152,196	183,354	211,015	230,079	241,892	248,479	254,620	264,886
28												
29	Assets commissioned	102,500	124,098	156,990	131,871	195,613	194,956	235,425	252,276	235,546	244,732	261,014
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
32		**$000 (in constant prices)**										
33	Consumer connection	23,502	21,017	23,378	21,956	22,197	22,442	22,695	22,952	23,080	23,232	23,383
34	System growth	27,609	45,818	48,611	46,725	56,730	63,968	66,624	65,488	68,607	68,081	69,558
35	Asset replacement and renewal	52,907	59,402	60,491	69,652	80,462	91,620	97,740	103,250	100,381	99,321	98,556
36	Asset relocations	3,494	2,849	2,901	2,918	2,936	2,953	2,971	2,990	3,002	3,016	3,029
37	Reliability, safety and environment:											
38	Quality of supply	3,329	3,773	3,639	3,868	4,665	5,314	5,314	5,314	5,314	5,314	5,314
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,020	1,461	1,667	1,096	2,951	2,599	3,619	2,581	857	805	1,190
41	**Total reliability, safety and environment**	4,349	5,234	5,307	4,965	7,616	7,913	8,934	7,896	6,171	6,120	6,505
42	**Expenditure on network assets**	111,861	134,318	140,688	146,215	169,941	188,897	198,965	202,576	201,241	199,769	201,031
43	Expenditure on non-network assets	6,910	9,290	11,599	9,902	9,634	9,284	9,427	9,020	9,021	9,021	9,022
44	**Expenditure on assets**	118,771	143,608	152,287	156,117	179,576	198,181	208,392	211,596	210,262	208,790	210,053
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

for year ended	Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21	CY+6 31 Mar 22	CY+7 31 Mar 23	CY+8 31 Mar 24	CY+9 31 Mar 25	CY+10 31 Mar 26
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	405	872	1,338	1,969	2,637	3,344	4,096	4,861	5,663	6,502
System growth	-	1,388	2,368	3,518	6,155	9,143	12,195	14,737	18,406	21,255	24,961
Asset replacement and renewal	-	1,562	2,589	4,758	8,323	12,818	17,273	22,199	25,685	29,476	33,505
Asset relocations	-	60	118	189	267	350	436	526	619	716	817
Reliability, safety and environment:											
Quality of supply	-	117	196	307	488	703	864	1,036	1,214	1,397	1,585
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	34	51	60	294	378	706	616	229	245	444
Total reliability, safety and environment	-	151	246	367	782	1,081	1,570	1,652	1,443	1,642	2,030
Expenditure on network assets	-	3,566	6,194	10,169	17,496	26,028	34,818	43,210	51,014	58,753	67,814
Expenditure on non-network assets	-	182	428	626	940	1,228	1,536	1,726	1,985	2,249	2,520
Expenditure on assets	-	3,747	6,621	10,795	18,436	27,256	36,354	44,937	52,998	61,002	70,334

11a(ii): Consumer Connection

for year ended	Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21
*Consumer types defined by EDB**	$000 (in constant prices)					
All Consumers	23,502	21,017	23,378	21,956	22,197	22,442
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	23,502	21,017	23,378	21,956	22,197	22,442
less Capital contributions funding consumer connection	14,012	14,164	15,479	14,474	14,632	14,793
Consumer connection less capital contributions	9,490	6,853	7,898	7,482	7,565	7,649

11a(iii): System Growth

	Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21
Subtransmission	6,245	12,209	16,711	13,535	19,184	19,892
Zone substations	7,605	10,785	14,154	12,693	15,143	18,030
Distribution and LV lines	5,238	4,969	3,965	5,625	5,899	7,161
Distribution and LV cables	5,310	5,406	4,436	5,283	5,678	6,813
Distribution substations and transformers	2,124	2,163	1,774	2,116	2,284	2,757
Distribution switchgear	-	2	-	29	107	243
Other network assets	1,087	10,283	7,571	7,443	8,434	9,073
System growth expenditure	27,609	45,818	48,611	46,725	56,730	63,968
less Capital contributions funding system growth						
System growth less capital contributions	27,609	45,818	48,611	46,725	56,730	63,968

11a(iv): Asset Replacement and Renewal

for year ended	Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21
	$000 (in constant prices)					
Subtransmission	4,691	6,700	5,518	6,814	7,205	6,684
Zone substations	5,916	9,537	8,237	12,976	12,842	13,334
Distribution and LV lines	18,525	20,562	22,916	24,577	32,468	44,715
Distribution and LV cables	5,553	5,890	6,126	6,355	6,448	6,455
Distribution substations and transformers	7,293	7,538	7,633	8,618	8,746	8,885
Distribution switchgear	8,106	8,277	9,322	9,550	10,414	9,202
Other network assets	2,822	898	740	761	2,339	2,344
Asset replacement and renewal expenditure	52,907	59,402	60,491	69,652	80,462	91,620
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	52,907	59,402	60,491	69,652	80,462	91,620

11a(v):Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Project or programme**		$000 (in 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		3,494	2,849	2,901	2,918	2,936	2,953
Asset relocations expenditure		3,494	2,849	2,901	2,918	2,936	2,953
less Capital contributions funding asset relocations		1,713	1,723	1,733	1,744	1,755	1,766
Asset relocations less capital contributions		1,782	1,126	1,168	1,174	1,180	1,187

11a(vi):Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Project or programme**		$000 (in 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		3,329	3,773	3,639	3,868	4,665	5,314
Quality of supply expenditure		3,329	3,773	3,639	3,868	4,665	5,314
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		3,329	3,773	3,639	3,868	4,665	5,314

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Project or programme**		$000 (in 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 - legislative and regulatory							
Legislative and regulatory expenditure		-	-	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Project or programme**		$000 (in 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 - other reliability, safety and environment		1,020	1,461	1,667	1,096	2,951	2,599
Other reliability, safety and environment expenditure		1,020	1,461	1,667	1,096	2,951	2,599
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		1,020	1,461	1,667	1,096	2,951	2,599

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
164		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	[Description of material project or programme]						
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	[Description of material project or programme]						
173	[Description of material project or programme]						
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	6,910	9,290	11,599	9,902	9,634	9,284
176	**Routine expenditure**	6,910	9,290	11,599	9,902	9,634	9,284
177	**Atypical expenditure**						
178	*Project or programme**						
179	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	[Description of material project or programme]						
183	[Description of material project or programme]						
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	6,910	9,290	11,599	9,902	9,634	9,284

A2.2 SCHEDULE 11B

Company Name	**Powerco**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	7,237	7,374	7,512	7,718	7,934	8,151	8,314	8,480	8,650	8,823	9,000
11	Vegetation management	4,923	5,859	5,709	5,822	9,874	11,174	11,240	10,731	8,700	8,874	9,052
12	Routine and corrective maintenance and inspection	9,729	10,689	11,543	12,031	13,275	14,163	13,688	13,731	13,765	14,159	13,926
13	Asset replacement and renewal	7,930	9,068	9,529	10,255	13,691	15,563	17,021	17,032	15,618	13,306	12,935
14	**Network Opex**	29,819	32,989	34,294	35,827	44,775	49,051	50,262	49,974	46,733	45,163	44,912
15	System operations and network support	10,637	13,502	14,407	15,950	16,739	17,203	17,200	17,544	17,895	18,253	18,618
16	Business support	29,777	28,642	29,844	31,346	32,671	33,473	34,138	35,023	35,723	36,438	37,167
17	**Non-network opex**	40,415	42,145	44,252	47,297	49,410	50,676	51,339	52,567	53,619	54,691	55,785
18	**Operational expenditure**	70,234	75,134	78,545	83,123	94,185	99,727	101,601	102,541	100,352	99,854	100,697

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	7,237	7,237	7,237	7,290	7,343	7,396	7,396	7,396	7,396	7,396	7,396
23	Vegetation management	4,923	5,750	5,500	5,500	9,139	10,139	9,999	9,359	7,439	7,439	7,439
24	Routine and corrective maintenance and inspection	9,729	10,491	11,121	11,365	12,287	12,851	12,176	11,975	11,770	11,870	11,445
25	Asset replacement and renewal	7,930	8,900	9,181	9,687	12,672	14,122	15,142	14,854	13,354	11,154	10,631
26	**Network Opex**	29,819	32,378	33,039	33,842	41,441	44,509	44,714	43,585	39,960	37,860	36,911
27	System operations and network support	10,637	13,252	13,880	15,067	15,493	15,610	15,301	15,301	15,301	15,301	15,301
28	Business support	29,777	28,112	28,752	29,610	30,239	30,373	30,370	30,546	30,546	30,546	30,546
29	**Non-network opex**	40,415	41,364	42,632	44,677	45,731	45,984	45,671	45,847	45,847	45,847	45,847
30	**Operational expenditure**	70,234	73,741	75,671	78,520	87,173	90,492	90,385	89,432	85,807	83,707	82,759
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	137	275	427	591	755	918	1,084	1,254	1,427	1,603
43	Vegetation management	-	109	209	322	735	1,035	1,241	1,372	1,261	1,435	1,613
44	Routine and corrective maintenance and inspection	-	198	422	666	988	1,312	1,511	1,755	1,995	2,290	2,481
45	Asset replacement and renewal	-	168	349	568	1,019	1,441	1,879	2,177	2,264	2,152	2,304
46	**Network Opex**	-	612	1,255	1,984	3,334	4,542	5,549	6,389	6,774	7,303	8,001
47	System operations and network support	-	250	527	883	1,246	1,593	1,899	2,243	2,594	2,952	3,317
48	Business support	-	531	1,092	1,736	2,433	3,100	3,769	4,477	5,178	5,892	6,621
49	**Non-network opex**	-	781	1,620	2,619	3,679	4,693	5,668	6,720	7,772	8,844	9,938
50	**Operational expenditure**	-	1,393	2,875	4,604	7,013	9,235	11,216	13,109	14,545	16,147	17,939

A2.3 SCHEDULE 12A

Company Name **Powerco**

AMP Planning Period **1 April 2016 – 31 March 2026**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)						
7											
8											
9	**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**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.40%	2.40%	7.60%	89.60%	-	4	1.90%
11	All	Overhead Line	Wood poles	No.	20.10%	9.90%	39.00%	31.00%	-	4	21.50%
12	All	Overhead Line	Other pole types	No.	-	-	-	19.00%	81.00%	1	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.80%	0.90%	13.00%	84.30%	-	4	4.30%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	17.60%	82.40%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	27.90%	35.50%	7.00%	29.60%	-	4	63.40%
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	-	-	4.00%	96.00%	-	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.	9.80%	42.16%	7.84%	37.25%	2.94%	3	17.70%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	11.00%	4.50%	35.50%	49.00%	-	4	12.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	75.00%	25.00%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	13.80%	3.00%	39.00%	44.20%	-	4	12.90%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	100.00%	-	-	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.	-	-	-	78.50%	21.50%	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	10.10%	7.60%	17.00%	65.30%	-	4	16.50%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3.70%	-	18.60%	77.70%	-	4	1.90%
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.	7.50%	1.60%	53.80%	37.10%	-	4	8.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	8.50%	-	10.30%	81.20%	-	3	4.50%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	8.50%	-	18.70%	72.80%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1.70%	0.10%	12.10%	86.10%	-	3	1.30%
44	HV	Distribution Cable	Distribution UG PILC	km	3.70%	-	7.00%	89.30%	-	3	5.70%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	100.00%	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	0.70%	9.80%	89.50%	-	4	0.70%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	31.80%	27.50%	7.80%	32.90%	-	4	47.60%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3.40%	2.70%	27.20%	66.70%	-	3	7.40%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	16.70%	1.10%	38.30%	43.90%	-	4	16.90%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	19.40%	1.60%	11.60%	67.40%	-	4	17.10%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.60%	2.60%	24.10%	69.70%	-	3	7.20%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.10%	1.30%	18.00%	79.60%	-	4	4.10%
53	HV	Distribution Transformer	Voltage regulators	No.	2.90%	-	10.50%	86.60%	-	4	3.90%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.40%	1.50%	18.60%	78.50%	-	4	4.10%
55	LV	LV Line	LV OH Conductor	km	1.20%	1.50%	25.30%	72.00%	-	2	3.50%
56	LV	LV Cable	LV UG Cable	km	-	0.10%	17.30%	82.60%	-	2	1.60%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.10%	1.10%	28.80%	69.00%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	1.90%	11.00%	35.40%	51.70%	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	34.90%	21.80%	43.30%	-	3	28.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	25.40%	12.50%	62.10%	-	3	16.70%
61	All	Capacitor Banks	Capacitors including controls	No.	-	2.20%	-	97.80%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	27.00%	-	73.00%	-	4	5.40%
63	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

A2.4 SCHEDULE 12B

Company Name: **Powerco**

AMP Planning Period: **1 April 2016 – 31 March 2026**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Coromandel	5	-	N-1	-	-	-	-	Subtransmission circuit	Single 66kV circuit.
10	Kerepehi	10	3	N-1	3	329%	3	350%	Subtransmission Circuit	Single 66kV circuit. Project in progress to upgrade.
11	Matatoki	5	3	N	3	161%	3	175%	Transformer	Single Tx
12	Tairua	9	9	N	1	101%	9	107%	Transformer	Just over Tx firm capacity.
13	Thames	12	6	N-1	6	197%	6	201%	Subtransmission circuit	Project in progress to upgrade.
14	Thames T3	3	7	N-1 SW	7	49%	7	52%	No constraint within +5 years	
15	Whitianga	17	2	N-1	2	1,118%	2	1,189%	Subtransmission circuit	Projects in progress to upgrade, incl new Sub.
16	Paeroa	8	8	N	3	104%	8	110%	No constraint within +5 years	Operationally manageable - e.g. 11kV backfeeds.
17	Waihi	19	12	N	2	159%	12	171%	No constraint within +5 years	Customer agreed security.
18	Waihi Beach	6	2	N	2	276%	2	292%	Subtransmission Circuit	Single 33kV circuit. Look at improving backfeed.
19	Whangamata	10	2	N	2	486%	12	85%	No constraint within +5 years	Assumes 2nd 33kV circuit completed by 2021.
20	Aongatete	6	7	N-1	5	87%	7	94%	Subtransmission circuit	Project planned just beyond 2021
21	Bethlehem	8	9	N-1 SW	9	94%	9	102%	No constraint within +5 years	New Substation - will require 2nd Tx soon after 2021
22	Hamilton St	16	26	N-1	6	62%	26	67%	No constraint within +5 years	
23	Katikati	8	4	N	4	196%	7	119%	Subtransmission circuit	Upgrades (Subtrans & Txs) pre 2021, & post 2021.
24	Kauri Pt	3	2	N	2	138%	2	146%	Subtransmission Circuit	Single Tx and 33kV circuit limit security.
25	Matua	11	4	N	4	306%	4	329%	Subtransmission circuit	Single 33kV circuit. Long term plans include 2nd circuit
26	Omokoroa	12	12	N-1	2	98%	12	106%	Subtransmission circuit	Upgrades planned, but completed beyond 2021
27	Otumoetai	9	14	N-1	4	65%	14	69%	No constraint within +5 years	
28	Waihi Rd	22	26	N-1	5	84%	26	91%	No constraint within +5 years	
29	Welcome Bay	22	22	N	2	101%	22	114%	Transformer	
30	Matapihi	12	26	N-1	10	46%	26	49%	No constraint within +5 years	
31	Omanu	15	26	N-1	10	56%	26	61%	No constraint within +5 years	
32	Papamoa	23	23	N	4	100%	24	74%	No constraint within +5 years	Offload to new Subs restores security.
33	Te Maunga	7	7	N-1 SW	7	94%	7	102%	No constraint within +5 years	New Substation - will require 2nd Tx in future.
34	Triton	21	23	N-1	10	92%	23	101%	Transformer	No upgrade planned. Possible transfer to other Subs
35	Atuaroa	8	5	N	5	158%	5	172%	Subtransmission Circuit	Security limited by single Tx & a section of single circuit
36	Paengaroa	4	4	N-1 SW	4	100%	4	111%	Subtransmission Circuit	New N security Sub - future plans to improve security
37	Pongakawa	7	4	N-1	3	181%	4	198%	Subtransmission Circuit	Single 33kV circuit
38	Te Puke	20	23	N-1	3	86%	23	93%	No constraint within +5 years	
39	Farmer Rd	6	6	N-1	3	91%	6	106%	No constraint within +5 years	Minor risk managed operationally (e.g. backfeeds)
40	Inghams	4	5	N-1 SW	5	77%	5	81%	No constraint within +5 years	Customer agreed security
41	Mikkelsen Rd	15	21	N-1	4	74%	21	77%	No constraint within +5 years	
42	Morrinsville	10	3	N-1	3	335%	3	341%	Subtransmission circuit	2nd 33kV circuit completed 2022.
43	Piako	14	22	N-1	4	63%	22	68%	No constraint within +5 years	
44	Tahuna	6	3	N-1	3	193%	3	201%	Subtransmission Circuit	Single transformer. Look at improving backfeed.
45	Tatua	4	5	N-1 SW	5	79%	5	84%	No constraint within +5 years	Customer agreed security
46	Waitoa	15	20	N-1	-	75%	20	78%	No constraint within +5 years	
47	Walton	6	4	N	4	180%	4	198%	Transformer	Single Transformer.
48	Browne St	9	13	N-1	3	74%	13	80%	No constraint within +5 years	
49	Lake Rd	6	2	N	2	248%	2	272%	Transformer	Single transformer. Long term plan for 2nd transformer.
50	Tirau	10	3	N	3	342%	3	364%	Transformer	Single transformer. Customer requirement drives security

51		Putaruru	11	4	N-1	4	326%	14	90%	No constraint within +5 years	New GXP, Subtrans. & transf. upgrades complete.
52		Tower Rd	9	3	N	3	307%	5	199%	Subtransmission circuit	GXP and Subtrans upgraded, but further work needed.
53		Waharoa	9	3	N-1	3	312%	6	197%	Subtransmission Circuit	Planned upgrades to be completed ~2022
54		Baird Rd	9	5	N-1	5	183%	15	64%	No constraint within +5 years	Subtransmission upgraded pre 2021
55		Lakeside + Midway	4	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security
56		Maraetai Rd	12	4	N-1	4	298%	15	86%	No constraint within +5 years	Subtransmission upgraded pre 2021
57		Bell Block	18	23	N-1	10	78%	23	85%	No constraint within +5 years	
58		Brooklands	22	27	N-1	12	80%	27	93%	No constraint within +5 years	
59		Cardiff	2	1	N	1	124%	1	133%	Transformer	Single transformer
60		City	21	23	N-1	15	91%	23	98%	No constraint within +5 years	
61		Cloton Rd	11	15	N-1	4	75%	15	83%	No constraint within +5 years	
62		Douglas	2	2	N	2	126%	2	133%	Subtransmission circuit	Single circuit
63		Eltham	10	11	N-1	5	92%	11	97%	No constraint within +5 years	
64		Inglewood	5	6	N-1	1	89%	6	92%	No constraint within +5 years	
65		Kaponga	4	3	N	1	117%	3	122%	No constraint within +5 years	Operationally managed - e.g. backfeed capacity
66		Katere	12	24	N-1	5	50%	24	58%	No constraint within +5 years	
67		McKee	1	2	N-1	1	88%	2	92%	No constraint within +5 years	
68		Motukawa	1	1	N	1	108%	1	114%	Transformer	Single transformer
69		Moturoa	22	23	N-1	10	95%	23	98%	No constraint within +5 years	
70		Oakura	3	3	N	3	104%	4	90%	No constraint within +5 years	New single cct & Tx Substation. 11kV backfed
71		Pohokura	7	10	N-1	-	73%	10	73%	No constraint within +5 years	
72		Waihapa	1	2	N-1	1	82%	1	183%	Subtransmission circuit	Single 33kV Tee
73		Waitara East	7	10	N-1	4	66%	10	66%	No constraint within +5 years	
74		Waitara West	8	9	N-1	4	92%	12	77%	No constraint within +5 years	
75		Cambria	15	19	N-1	5	77%	19	78%	No constraint within +5 years	
76		Kapuni	10	7	N-1	3	142%	15	70%	No constraint within +5 years	
77		Livingstone	3	3	N	1	120%	3	123%	Transformer	
78		Manaia	8	6	N	6	152%	8	106%	Transformer	Single transformer. Existing 33kV tee removed.
79		Ngariki	4	3	N	3	137%	3	146%	Transformer	Single transformer.
80		Pungarehu	5	5	N	1	106%	5	112%	Transformer	Low risk - operationally managed (e.g. backfeeds)
81		Tasman	7	6	N-1	3	113%	6	117%	Transformer	Low risk - operationally managed (e.g. backfeeds)
82		Whareroa	7	4	N	4	176%	7	97%	No constraint within +5 years	Sub to be relocated (Mokoia Sub) and upgraded
83		Beach Rd	15	6	N-1	6	250%	15	124%	Transformer	Subtrans upgrades complete pre 2021.
84		Blink Bonnie	5	3	N	3	178%	3	195%	Transformer	Single transformer
85		Castlecliff	11	9	N-1	5	121%	11	104%	Transpower	N security GXP. Subtrans upgrades in progress.
86		Hatricks Wharf	13	9	N	9	137%	12	109%	Transformer	Single transf. with bus tie to Taupo Quay limits security
87		Kai Iwi	2	2	N	2	162%	2	173%	Subtransmission Circuit	Single 33kV cct & single Tx. Also N security GXP.
88		Peat St	17	22	N-1	10	80%	22	79%	Transpower	N security GXP.
89		Roberts Ave	11	5	N	5	240%	5	251%	Transpower	N security GXP, single cct & transf. Upgrades post 2021
90		Taupo Quay	11	8	N	10	139%	12	95%	No constraint within +5 years	Planned 2nd circuit removes Subtrans security limits.
91		Wanganui East	8	6	N	6	137%	6	142%	Subtransmission Circuit	Single 33kV circuit & single transformer
92		Taihape	5	3	N	3	180%	3	183%	Transformer	Single transformer
93		Waiouru	3	3	N	3	101%	3	101%	Subtransmission circuit	Single 33kV circuit & single transformer
94		Arahina	9	7	N	7	125%	7	125%	Subtransmission Circuit	Single 33kV circuit & single transformer
95		Bulls	6	4	N	4	170%	4	182%	Subtransmission Circuit	Single 33kV circuit & single transformer
96		Pukepapa	9	4	N	4	232%	4	255%	Transformer	Single transformer. Look at improving backfeed
97		Rata	3	2	N	2	126%	2	136%	Subtransmission circuit	Single 33kV circuit & single transformer
98		Feilding	22	24	N-1	4	94%	24	100%	No constraint within +5 years	Proposed 33kV upgrades in longer term plan.

99	Kairanga	18	19	N-1	7	95%	25	80%	No constraint within +5 years	
100	Keith St	21	24	N-1	9	88%	24	93%	No constraint within +5 years	New Sub offloads 33kV circuits
101	Kelvin Grove	14	17	N-1	11	82%	17	94%	No constraint within +5 years	
102	Kimbolton	3	2	N	2	165%	2	173%	Subtransmission Circuit	Single 33kV circuit & single transformer
103	Main St	29	25	N-1	12	118%	28	88%	No constraint within +5 years	Proposed new Sub and 33kV circuits in next 5 yrs
104	Milson	16	19	N-1	7	85%	19	87%	No constraint within +5 years	
105	Pascal St	24	25	N-1	16	97%	28	75%	No constraint within +5 years	Planned 33kV upgrades and offload maintain security.
106	Sanson	9	5	N-1	5	177%	12	82%	No constraint within +5 years	Upgrades to subtransmission resolve existing security.
107	Turitea	15	18	N-1	3	85%	18	88%	Subtransmission Circuit	Single 33kV circuit - switched backfeed below security
108	Alfredton	0	1	N-1 SW	1	77%	1	80%	No constraint within +5 years	Single Transf. but adequate backfeed.
109	Mangamutu	10	10	N	2	101%	20	80%	No constraint within +5 years	Major customer driving transformer upgrade soon.
110	Parkville	2	2	N	2	112%	2	115%	Transformer	Single transformer
111	Pongaroa	1	1	N	1	125%	1	125%	Transformer	Single transformer
112	Akura	14	11	N-1	7	126%	14	102%	Subtransmission circuit	Txs upgraded. Subtrans loading managed operationally.
113	Awatoitoi	1	1	N-1 SW	1	61%	1	64%	No constraint within +5 years	
114	Chapel	15	23	N-1	9	66%	23	71%	No constraint within +5 years	
115	Clareville	11	11	N	2	109%	11	112%	Transformer	
116	Featherston	6	4	N	4	145%	4	153%	Transformer	Single transformer
117	Gladstone	1	1	N-1 SW	1	79%	1	83%	No constraint within +5 years	
118	Hau Nui	1	0	N	-	340%	0	333%	No constraint within +5 years	Generaton site. Not economic to provide higher security
119	Kempton	5	4	N	4	140%	4	149%	Subtransmission Circuit	Single 33kV circuit & single transformer
120	Martinborough	5	3	N	3	218%	3	228%	Transformer	Single transformer. Look at improving backfeed.
121	Norfolk	6	7	N-1	4	93%	7	96%	No constraint within +5 years	
122	Te Ore Ore	8	7	N	7	116%	7	122%	Transformer	Single transformer
123	Tinui	1	1	N-1 SW	1	79%	1	83%	No constraint within +5 years	
124	Tuhitarata	2	2	N	2	124%	2	128%	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 2016 – 31 March 2026

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref								
7	**12c(i): Consumer Connections**							
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**							
12	Small		4,148	4,107	3,901	3,706	3,521	3,345
13	Commercial		47	47	44	42	40	38
14	Industrial		19	19	18	17	16	15
15	[EDB consumer type]							
16	[EDB consumer type]							
17	**Connections total**		4,214	4,172	3,963	3,765	3,577	3,398
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		560	560	560	560	560	560
21	Capacity of distributed generation installed in year (MVA)		2	2	2	2	2	2
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25	GXP demand		770	781	793	804	816	827
26	*plus* Distributed generation output at HV and above		132	132	133	133	134	134
27	**Maximum coincident system demand**		902	913	925	937	949	961
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		902	913	925	937	949	961
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		4,432	4,487	4,541	4,596	4,651	4,705
32	*less* Electricity exports to GXPs		192	194	196	199	201	203
33	*plus* Electricity supplied from distributed generation		978	981	984	987	990	992
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		5,219	5,274	5,329	5,384	5,439	5,494
36	*less* Total energy delivered to ICPs		4,906	4,958	5,009	5,061	5,113	5,164
37	**Losses**		313	316	320	323	326	330
38								
39	**Load factor**		66%	66%	66%	66%	65%	65%
40	**Loss ratio**		6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

A2.6 SCHEDULE 12D

Company Name	**Powerco**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	23.5	23.5	23.5	23.5	37.9	42.7
12	Class C (unplanned interruptions on the network)	144.1	165.4	165.4	165.4	165.4	165.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.10	0.10	0.10	0.10	0.16	0.18
15	Class C (unplanned interruptions on the network)	1.89	2.24	2.24	2.24	2.24	2.24

Company Name	**Powerco**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	23.5	23.5	23.5	23.5	37.9	42.7
12	Class C (unplanned interruptions on the network)	144.1	165.4	165.4	165.4	165.4	165.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.10	0.10	0.10	0.10	0.16	0.18
15	Class C (unplanned interruptions on the network)	1.89	2.24	2.24	2.24	2.24	2.24

Company Name	Powerco
AMP Planning Period	1 April 2016 – 31 March 2026
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 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
10	**SAIDI**						
11	Class B (planned interruptions on the network)	23.5	23.5	23.5	23.5	37.9	42.7
12	Class C (unplanned interruptions on the network)	144.1	165.4	165.4	165.4	165.4	165.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.10	0.10	0.10	0.10	0.16	0.18
15	Class C (unplanned interruptions on the network)	1.89	2.24	2.24	2.24	2.24	2.24

A2.7 **SCHEDULE 13**

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?	2.5	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?	2.4	We have developed a new 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?	2.4	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)	2.3	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 5 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?	2.3	The AMP provides an overview of responsibilities and delegations, with a dedicated electricity division, led by the General Manager Electricity, to provide an end to end process. Field provision responsibilities have developed following the change in the outsourcing contract arrangements and reviews of future work plan deliverability. Responsibilities are reflected in the business plan, tactical plans, position descriptions and personal objectives.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3.0	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)?	2.0	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 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?	2.3	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.

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?	2.1	Powerco's Asset Management Policy is available to all employees. Powerco's progress on KPI's is reported on the intranet for all staff to view. 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. 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. We intend to move into phase 2 of this project in FY17.
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?	1.9	Powerco has a range of controls to ensure data is accurate and there is an adequate process of change management, 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?	1.9	As described in this AMP, we have recognised that we would benefit from a fit for purpose asset infomration system, and details or our ERP Project is provided in Chapter 22. We also 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 5 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 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?	2.4	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 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?	2.3	We have good documentation and contractual controls around maintenance. We have been continuously improving the way we manage our defects. This includes developing a new tool to prioritise defects.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.1	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?	2.0	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

Commentary on difference between nominal and constant price capital expenditure forecasts (schedule 11A) and capital expenditure (schedule 11B).

- We explain our approach to forecast escalation in Chapter 24.
- We also required to identify any material changes to our network development plan disclosed in our previous AMP. We discuss our current plans in Chapter 8 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.

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

For this AMP we have changed 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 12, 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.

A2.9.2 MATERIAL CHANGES TO SCHEDULE 12B

Schedule 12B has been populated in line with the updated information disclosure requirements published in 2015. This affected the disclosure of zone substation capacities, which are no longer comparable to previous disclosures.

A2.9.3 MATERIAL CHANGES TO SCHEDULE 13

The AMMAT Schedule has been populated using guidance from the EEA 'Guide to Commerce Commission Asset Management Maturity Assessment Tool (AMMAT)'. This guide has changed significantly since the schedule was last populated in 2013, and hence some changes in scoring approach have been applied.

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 a richer overview of each stakeholder, the latest information on what we have been advised they want from our asset management, and references to where this is discussed in more detail in this AMP.

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:

- 326,941 homes and businesses consisting of:
  - Residential consumers and small businesses ("Mass Market")
  - Medium sized commercial businesses
  - Large commercial or industrial businesses
- twenty-four 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 our customers' expectation of the availability and quality of their 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 detail in Chapter 6. In summary, customers' interests are:

- 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 that 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, and want more real time information available through digital channels.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Consumer surveys, meetings with consumer representatives and major consumers. Feedback from complaints and compliments.	Chapters 5, 6, 7, 9, 21

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.

A3.3.1 STAKEHOLDER INTEREST

We recognise the importance of consulting with iwi and communities on significant new projects, particularly development of new subtransmission line routes. We ensure that 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 that 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.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Meetings with landowners, iwi and local community groups.	Chapter 6, 13

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, meaning that 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.

A3.4.1 STAKEHOLDER INTEREST

Retailer interests follow customers' interests, 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

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Dedicated retailer relationship management service	Chapter 6

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.

A3.5.1 STAKEHOLDER INTEREST

The Commerce Commission has responsibilities under Part 4 of the Commerce Act 1986, where the Commission:

- 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 that interested parties are able to assess whether or not the regulatory objectives are being met.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Meetings with Commissioners and staff. Consultation papers, decision papers and determinations. Requirements of the Commerce Act 1986.	Chapter 5, 7 The economic regulator influences the selection of performance criteria.

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 that 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 that 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 of 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, including terms of access to the grid, use of system agreements with retailers, as well as metering, load control, electricity losses and distribution pricing methodologies.

A3.6.1 STAKEHOLDER INTEREST

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

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Requirements of various Acts relating to electricity. Consultation papers, decision papers and regulations. Government statements, consultation documents and policy announcements.	Chapter 5, 7 The industry regulators impact our statutory compliance regimes, and adherence to industry codes and complaints structures.

A3.7 TERRITORIAL LOCAL AUTHORITIES

As the largest electricity distributor by geographical size, we cross a large number of local and regional councils.

A3.7.1 STAKEHOLDER INTEREST

These organisations are not only valued customers, but 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, and 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.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
National policy statements. Strategic meetings with authorities Hearings and submissions.	Chapters 5 and 8

A3.8 OUR EMPLOYEES

We have around 350 staff, based in offices in New Plymouth, Tauranga, Wanganui, 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.

A3.8.1 STAKEHOLDER INTEREST

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 that our assets are safe for contractors and the public. Safety in design principles are a key part of our design and construction standards.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Internal communications Employee surveys	Chapter 23

A3.9 OUR SERVICE PROVIDERS

We operate an Electricity Field Services Agreement with Downer Limited. 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 that 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.

A3.9.1 STAKEHOLDER INTEREST

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 that service provider employees work in a safe environment. This is accomplished through a competency certification framework, procedures and through audit processes.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Contractor relationship meetings. Contractual agreements.	Chapter 5, 23

A3.10 OUR INVESTORS

We are a privately-owned utility with two institutional shareholders: Queensland Investment Corporation (58%) and AMP Capital (42%).

A3.10.1 STAKEHOLDER INTEREST

As the electricity distribution sector is regulated, regulatory certainty is a key issue that affects our owners' investment decisions. As discussed in this AMP, while we plan to lodge a CPP application, the precise timing for this is uncertain and a confirmed decision is dependent on certain aspects of the regulatory regime being changed and clarified through the Commission's formal review of the Input Methodology rules.

- 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.

Owners (as represented by the directors) have overall responsibility for Powerco and expect our management team to address a wide range of business drivers.

METHOD IDENTIFYING STAKEHOLDER INTEREST	HOW THESE LINK TO OUR AMP
Our Board meetings and KPIs	Chapter 4, 5

A3.11 OTHER STAKEHOLDERS

Other stakeholders with an interest in our asset management process include Transpower and 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 6, we have 581 customers with demand greater than 300 kVA, who 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	

APPENDIX 5: WORKS PROGRAMME COMPLETION

A5.1 APPENDIX OVERVIEW

This appendix provides information on our progress against physical and financial plans set out in our 2015 AMP.

In summary, we completed all of our scheduled capital works programme for FY15, and completed over 95% of our scheduled maintenance programme. Any incomplete maintenance work has been carried over to the FY16 programme.

A5.2 DEVELOPMENT PROJECT COMPLETION

During FY15 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 FY15	REASONS FOR SUBSTANTIAL VARIANCES
Taranaki			
Oakura substation	New zone substation	Construction complete	No major variances
Manawapou Road reconstruction	Overhead line reconstruction project	Construction complete	No major variances
Tauranga			
Sub-transmission ducting	Install 33kV duct and cable in conjunction with NZTA highway construction	Project complete at FY15 year end	Project completed under budget
Paengaroa substation	New zone substation construction	Construction underway	No major variances
Valley			
Hinuera to Tirau circuit	New 33kV circuit Hinuera – Tirau Sub	Cabling work largely completed by 31st March 2015	Project completed under budget
Maraetai Road substation transformer	Upgrade 33kV transformer	Construction completed end March 2015.	Project completed under budget
Tahuna transformer install	Upgrade 33kV transformer	Construction complete March 2015. As-build information delayed until August 2015.	Project completed under budget
Mikkelsen Road substation	Upgrade switchroom building, replace switchgear, shift all communications to adjoining site	Practical completion achieved, substation in service. Minor site works to be closed out as at 31st March 2015.	Project completed with no major variances
Tirau Sub rebuild	New 33kV switchroom construction	Detailed design completed 31st March 2015. Construction was subsequently completed in Oct 2015.	Construction scheduled for completion FY16
Maraetai Road substation switchgear	Upgrade 33kV switchgear	Construction completed end March 2015	Project completed under budget
Morrinsville substation upgrade	Upgrade 33kV transformer	Construction completed by FY2015 end. Delays with final as-built information being received.	Project completed under budget
Whanganui			
Blink Bonnie upgrade	Replace transformer	Construction complete	No major variances

Most of the projects' actual costs to date are in line with the total project budget. There is one notable project where the costs to date have exceeded the budget.

The Kopu to Kaureranga 110kV line cost more than budgeted for the design and consents and easements stage. This is a large project which involves the construction of an 8km subtransmission circuit near Thames. Extensive easements are required with a number of land access and consent difficulties increasing costs and timelines beyond initial expectations.

There are often timing variances due to delays in obtaining consents and the lumpy nature of some projects. In some cases, there have been project delays so not all the expected expenditure has been incurred in FY15.

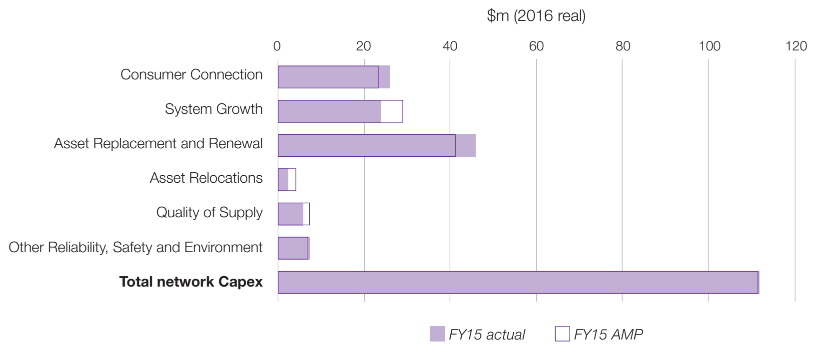
A5.3 MAINTENANCE PROGRAMME DELIVERY

The FY15 maintenance programme was largely completed, with 97% of scheduled activities achieved by year end. During FY15 we entered into a new field services agreement with our primary service provider which includes scheduled maintenance. Given this large contract change it has been a good result to deliver our scheduled maintenance programme.

A5.4 FINANCIAL PROGRESS AGAINST PLAN

Total direct expenditure on our distribution network was largely in line with the 2015 AMP forecast. There are some variances between categories which are shown in the figures below.

Figure A5.1: **Capex variance FY15**

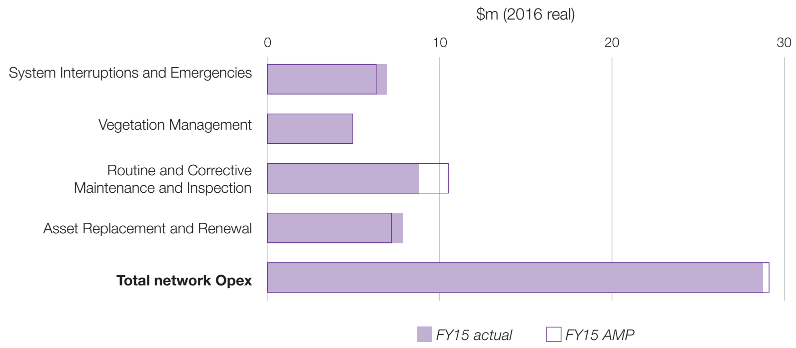


Customer connection Capex is largely determined by changes in the level of economic activity. The variance was due to higher than forecast customer demand from new subdivision connections, small commercial upgrades and higher than anticipated load growth in the dairy sector. System growth was lower than forecast by 17.2% primarily due to planning delays in some of our larger projects.

Asset replacement and renewal exceeded forecast by 12% in part due to the reclassification of projects. This has contributed to total Reliability, Safety and Environment Capex being less than forecast.

Asset relocations expenditure was less than forecast by 43%. This reduction was due to the early completion of the Tauranga Eastern Link motorway project, along with less roading activity. Any significant relocation costs associated with the Baypark to Bayfair SH2 project (Mt Maunganui) are not expected until FY17/FY18.

Figure A5.2: **Opex variance FY15**



Both service interruptions and emergencies and asset replacement and renewal expenditure exceeded forecast by around 10%. SIE activity and associated spend varies as it is influenced by the weather. ARR Opex is higher than forecast due to increased unplanned work. Vegetation expenditure was in line with forecast.

RCI expenditure was below forecast. While we largely delivered our scheduled maintenance programme, we did not complete the expected level of corrective work.

Overall operational expenditure is in line with the 2015 AMP 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 6 and our future networks strategy in Chapter 11, we are creating a strong platform to be ready for these changes when they occur.

#	RISK	DESCRIPTION	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 – Incorrect or inadequate information or instructions given to service providers or other 3rd parties – Lack of competence – Stress – Not aware of potential hazards – Unauthorised access to our network – Vandalism	– 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 Network Operations Centre. – Competency framework to ensure staff working on our assets are competent to complete the task. – Specialist and fully resourced internal Health, Safety, Environment and Quality team. – Independent network audit process covers health and safety 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 – Public awareness programmes aimed at specific target audience. (e.g. field days, seminars, art promoting safety in public places and our website) – Free cable location and stand-over service – All incidents are reviewed, corrective actions entered into Safety Manager and followed-up	Unlikely	Major	Medium

#	RISK	DESCRIPTION	CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
2	**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.	– Business Continuity plans (BMS documents) and regular desktop exercises for planning purposes. Pandemic Preparedness Plan and Overseas Travel Guidelines. – Duplicate Control Centre facilities – hot backup Control Centre in Tauranga office; cold backup Control Centre built at Bell Block substation. – 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). – ENA and EEA facilitate Service Provider arrangements in event of a national disaster (e.g. Christchurch earthquake).	Rare	Major	Medium
3	**Regulatory – Insufficient Cash Flow to Maintain Network Assets**	The DPP does not provide the level of funding we require to effectively maintain and renew our electricity assets in the long-term. There are indications that underlying reliability performance at specific locations across our networks 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. We are planning to submit a CPP application which may alleviate the risk over the medium to long-term.	– Regulatory presence in Wellington ensures a continued focus on maintaining relationships with the Commerce Commission. – Current operational constraints, future investment requirements and our planned CPP are clearly signalled in the 2016 AMP. – Dedicated focus on lifting our level of asset management maturity – Engagement with the Commission via the ongoing IM review process is seeking to streamline the CPP application process. – A formal stakeholder engagement program is being enacted with consumers, interested parties and consultants.	Likely	Moderate	Medium
4	**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 (e.g. pillar boxes, ground mounted transformers, protective earths) creates an inherent network hazard which results in harm to public. – Faulty or damaged equipment (e.g. fallen power lines) creates a hazard which results in harm to the public. – Lack of care when working around network assets (e.g. cable strikes during construction, line contact by agricultural contractors etc.) results in serious harm to a member of the public.	– Public safety education program. – Asset identification and mark out processes. – Safety warning signage. Security fences. Security locks. – Asset renewal and routine maintenance inspection programs. – 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 Programs** – 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	CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
5	**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 (e.g. Te Ore Ore, Bulls) and therefore N security only for maintenance purposes. – Accepted risks associated with remote but growing locations of the network (e.g. 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 (e.g. Putararu, Tauranga North, Papamoa GXP projects; Palmerston North subtransmision, 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 provide 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
6	**Business / Operational Continuity**	Natural disaster, multiple event or severe weather event which adversely affects 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 Street is damaged or unable to be accessed.	– Business continuity plans and regular desktop exercises for planning purposes. – Duplicate control centre facilities - hot backup control centre in Tauranga office; cold backup control centre built at Bell Block substation. – Levels and locations of emergency and critical spares holdings are documented. Also levels of general materials (e.g. poles, cable) and where located. 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 our employees and service providers). – 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 line cos to use their Service providers and materials in an emergency.	Possible	Moderate	Medium

#	RISK	DESCRIPTION	CONTROLS	CONTROLLED LIKELIHOOD	CONTROLLED CONSEQUENCE	CONTROLLED RISK
7	**Technology Change**	Technology risk has a material impact on revenues, both from an asset stranding and from a customer defection potential.	– Move to more cost reflective pricing (FY18) to improve appropriate signals for usage patterns. – Lack of Government subsidies and winter evening peak nature of system limits the effectiveness and hence likely impact from PV generation. – Electric vehicle uptake forecast to somewhat offset reduction in throughput from distributed micro-generation (i.e. PV). – Population growth predicted to be the biggest driver of demand for the foreseeable future. – Complete off-grid consumer solutions remain uneconomical for the large majority of customers for the foreseeable future, especially those with large industrial processes. – 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	Moderate	Low
8	**Economic – Falling Demand Impacts Revenue**	Falling demand driven by population, energy efficiency and/or changed network utilisation	– 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. – Customer-led energy platform strategy will help position us to ensure assets remain used and useful (i.e. 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	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coromandel	0.0	1.2%	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.4
Kerepehi	3.0	1.6%	9.7	9.8	9.9	10.1	10.2	10.4	10.5	10.7	10.8	11.0	11.1	11.3	11.5	11.6	11.8	12.0
Matatoki	3.0	2.0%	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2
Tairua	8.5	1.4%	8.4	8.5	8.6	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.6	9.7	9.8	9.9	10.1	10.2
Thames T1 & T2	6.1	1.0%	11.8	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.5	12.7	12.8	13.0	13.1	13.3	13.4	13.6
Thames T3	6.9	1.3%	3.3	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.7	3.7	3.8	3.8	3.9	3.9	3.9	4.0
Whitianga	1.5	1.6%	16.4	16.7	16.9	17.1	17.3	17.6	17.8	18.1	18.4	18.6	18.9	19.2	19.5	19.8	20.1	20.4
Paeroa	7.8	1.3%	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.4	9.5	9.6

A7.3 DEMAND FORECAST FOR WAIKINO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Paeroa	7.8	1.3%	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.4	9.5	9.6
Waihi	12.0	1.7%	18.7	19.0	19.3	19.7	20.0	20.3	20.6	20.9	21.2	21.5	21.8	22.1	22.4	22.8	23.1	23.4
Waihi Beach	2.0	1.4%	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.0	6.1	6.1	6.2	6.3	6.4	6.5	6.5
Whangamata	2.0	1.3%	9.5	9.6	9.8	9.9	10.0	10.1	10.2	10.4	10.5	10.6	10.8	10.9	11.0	11.2	11.3	11.4

A7.4 DEMAND FORECAST FOR TAURANGA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Aongatete	5.0	1.7%	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.8
Bethlehem	8.9	1.9%	8.2	8.3	8.5	8.7	8.8	9.0	9.1	9.3	9.4	9.6	9.7	9.9	10.0	10.2	10.3	10.5
Hamilton St	26.2	2.1%	16.0	16.2	16.5	16.7	17.0	17.4	17.7	18.0	18.4	18.7	19.1	19.5	20.0	20.4	20.8	21.3
Katikati	4.0	1.5%	7.7	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.6	8.7	8.8	8.9	9.0	9.2	9.3	9.4
Kauri Pt	2.0	1.3%	2.7	2.7	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.3
Matua	3.5	1.5%	10.5	10.7	10.9	11.1	11.2	11.4	11.5	11.7	11.8	12.0	12.1	12.3	12.4	12.6	12.7	12.9
Omokoroa	12.1	1.8%	11.6	11.8	12.0	12.3	12.4	12.6	12.8	13.0	13.2	13.4	13.6	13.9	14.1	14.3	14.5	14.7
Otumoetai	13.6	1.4%	8.7	8.8	8.9	9.0	9.1	9.3	9.4	9.5	9.6	9.7	9.9	10.0	10.1	10.2	10.4	10.5
Tauranga 11	30.0	2.2%	28.4	28.8	29.1	29.5	29.9	30.5	31.2	31.9	32.6	33.4	34.1	34.9	35.6	36.4	37.3	38.1
Waihi Rd	26.1	2.1%	21.4	21.8	22.2	22.6	23.0	23.4	23.8	24.3	24.7	25.2	25.7	26.1	26.6	27.1	27.6	28.1
Welcome Bay	22.2	2.4%	22.0	22.6	23.2	23.8	24.4	24.9	25.4	25.9	26.5	26.9	27.4	27.8	28.3	28.8	29.2	29.7

A7.5 DEMAND FORECAST FOR MOUNT MAUNGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Matapihi	26.2	1.5%	11.9	12.0	12.2	12.4	12.5	12.7	12.9	13.1	13.2	13.4	13.6	13.8	14.0	14.2	14.4	14.6
Omanu	26.2	1.8%	14.4	14.6	14.9	15.1	15.4	15.6	15.9	16.1	16.4	16.6	16.9	17.2	17.4	17.7	18.0	18.3
Papamoa	22.6	1.9%	22.2	22.6	23.1	23.5	23.9	24.3	24.7	25.2	25.6	26.0	26.4	26.8	27.2	27.7	28.1	28.5
Te Maunga	7.0	1.9%	6.5	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.5	7.7	7.8	7.9	8.1	8.2	8.3
Triton	22.9	2.2%	20.6	21.0	21.4	21.8	22.2	22.7	23.1	23.6	24.1	24.5	25.0	25.5	26.0	26.5	27.1	27.6
Atuaroa	5.0	1.9%	7.8	7.9	8.0	8.2	8.3	8.4	8.6	8.7	8.9	9.0	9.2	9.3	9.5	9.7	9.8	10.0
Paengaroa	6.5	2.0%	6.5	6.6	6.8	6.9	7.0	7.2	7.3	7.4	7.6	7.7	7.9	8.0	8.2	8.4	8.5	8.7
Pongakawa	3.2	3.2%	4.8	4.9	5.0	5.2	5.3	5.5	5.7	5.8	6.0	6.2	6.3	6.5	6.7	6.9	7.0	7.2
Te Puke	22.9	2.3%	15.6	16.0	16.3	16.7	17.0	17.4	17.7	18.1	18.4	18.8	19.2	19.5	19.9	20.3	20.7	21.1

A7.6 DEMAND FORECAST FOR WAIKATO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Farmer Rd	6.4	2.8%	5.7	6.3	6.3	6.4	6.5	6.6	6.8	6.9	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.2
Inghams	5.0	1.2%	3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5
Mikkelsen Rd	20.7	1.4%	15.0	15.1	15.3	15.4	15.6	15.8	16.0	16.2	16.4	16.7	17.0	17.2	17.5	17.8	18.1	18.4
Morrinsville	3.0	1.0%	9.8	9.9	9.9	10.0	10.1	10.2	10.2	10.3	10.4	10.6	10.7	10.8	11.0	11.1	11.3	11.4
Piako	21.8	1.7%	13.5	13.7	13.9	14.1	14.3	14.5	14.7	14.9	15.2	15.4	15.6	15.9	16.1	16.4	16.6	16.9
Tahuna	3.0	1.2%	5.7	5.7	5.8	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4	6.5	6.6	6.7	6.8
Tatua	5.0	1.4%	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.6	4.7
Waitoa	20.0	1.1%	14.7	14.9	15.0	15.2	15.3	15.5	15.6	15.8	15.9	16.1	16.3	16.4	16.6	16.8	17.0	17.1
Walton	3.5	2.2%	6.2	6.3	6.4	6.5	6.7	6.8	6.9	7.1	7.2	7.3	7.5	7.6	7.8	7.9	8.1	8.2
Browne St	12.8	2.0%	9.3	9.4	9.6	9.8	9.9	10.1	10.3	10.5	10.6	10.8	11.0	11.2	11.4	11.6	11.8	12.0
Lake Rd	2.4	2.0%	5.8	5.9	6.1	6.2	6.3	6.4	6.5	6.6	6.8	6.9	7.0	7.1	7.2	7.4	7.5	7.6
Putaruru	3.5	1.6%	11.2	11.3	11.5	11.7	11.8	12.0	12.2	12.4	12.5	12.7	12.9	13.1	13.3	13.5	13.7	13.9
Tirau	2.8	1.2%	9.4	9.5	9.6	9.8	9.9	10.0	10.2	10.3	10.5	10.6	10.6	10.7	10.8	10.9	11.0	11.1
Tower Rd	3.0	1.8%	9.0	9.2	9.3	9.5	9.6	9.8	9.9	10.1	10.3	10.4	10.6	10.8	11.0	11.1	11.3	11.5
Waharoa	3.0	3.2%	9.2	10.2	11.3	11.4	11.5	11.7	11.8	12.0	12.2	12.3	12.5	12.7	12.9	13.0	13.2	13.4

A7.7 DEMAND FORECAST FOR KINLEITH AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Baird Rd	5.0	1.3%	9.0	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	10.0	10.1	10.2	10.4	10.5	10.6	10.7
Maraetai Rd	4.0	1.7%	11.7	11.9	12.1	12.3	12.6	12.8	13.0	13.2	13.4	13.6	13.8	13.9	14.1	14.3	14.5	14.7
Midway / Lakeside	5.2	0.5%	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4

A7.8 DEMAND FORECAST FOR TARANAKI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Bell Block	22.9	2.1%	17.6	17.7	18.1	18.3	18.7	19.1	19.5	19.9	20.3	20.7	21.1	21.5	21.9	22.3	22.8	23.2
Brooklands	27.0	3.1%	21.1	21.8	22.4	23.1	23.7	24.4	25.0	25.7	26.3	27.0	27.7	28.3	29.0	29.7	30.4	31.0
Cardiff	1.4	1.5%	1.7	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.1
City	22.9	1.9%	20.3	20.7	21.0	21.4	21.8	22.1	22.5	22.9	23.3	23.7	24.1	24.5	24.9	25.3	25.8	26.2
Cloton Rd	14.6	1.9%	10.8	11.0	11.2	11.5	11.7	11.9	12.1	12.3	12.5	12.7	12.9	13.1	13.3	13.5	13.7	13.9
Douglas	1.5	1.6%	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3
Eltham	11.3	1.4%	10.2	10.3	10.4	10.5	10.6	10.8	10.9	11.1	11.2	11.4	11.5	11.7	11.9	12.1	12.2	12.4
Inglewood	6.0	1.0%	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0
Kaponga	3.0	1.5%	3.4	3.5	3.5	3.5	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.1	4.1	4.2	4.3
Katere	24.3	3.0%	11.8	12.1	12.3	13.0	13.3	13.7	14.0	14.3	14.7	15.0	15.4	15.7	16.1	16.4	16.8	17.1
Mckee	1.5	1.3%	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.6
Motukawa	1.1	1.3%	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4
Moturoa	22.9	0.9%	21.3	21.5	21.7	21.9	22.1	22.3	22.5	22.7	22.8	23.0	23.2	23.4	23.6	23.8	24.0	24.2
Oakura	3.0	2.2%	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.0	4.1
Pohokura	10.0	0.7%	7.2	7.2	7.2	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.6	7.7	7.7	7.8	7.9	8.0
Waihapa	0.6	0.5%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Waitara East	10.1	0.4%	6.5	6.5	6.6	6.6	6.6	6.6	6.7	6.7	6.7	6.7	6.8	6.8	6.8	6.9	6.9	6.9
Waitara West	9.0	2.1%	8.1	8.3	8.6	8.8	8.9	9.1	9.2	9.4	9.5	9.7	9.9	10.0	10.2	10.3	10.5	10.7

A7.9 DEMAND FORECAST FOR EGMONT AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambria	19.1	0.6%	14.5	14.5	14.5	14.5	14.6	14.7	14.8	14.9	15.0	15.1	15.2	15.3	15.5	15.6	15.7	15.8
Kapuni	7.1	1.7%	9.9	10.0	10.1	10.2	10.3	10.5	10.7	10.8	11.0	11.2	11.4	11.7	11.9	12.1	12.4	12.6
Livingstone	2.9	0.9%	3.4	3.4	3.5	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9
Manaia	5.5	1.6%	8.2	8.3	8.4	8.6	8.7	8.8	8.9	9.1	9.2	9.3	9.4	9.6	9.7	9.9	10.0	10.1
Ngariki	3.0	1.7%	4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.7	4.8	4.9	4.9	5.0	5.1
Pungarehu	4.5	1.4%	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.2	5.2	5.3	5.4	5.4	5.5	5.6	5.6
Tasman	6.1	1.0%	6.8	6.8	6.9	7.0	7.0	7.1	7.1	7.2	7.3	7.4	7.4	7.5	7.6	7.7	7.7	7.8
Whareroa	3.8	0.7%	6.6	6.6	6.6	6.7	6.7	6.8	6.8	6.8	6.9	7.0	7.0	7.1	7.1	7.2	7.2	7.3

A7.10 DEMAND FORECAST FOR WHANGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Beach Rd	6.0	3.2%	14.7	16.7	17.1	17.5	17.9	18.3	18.6	19.0	19.4	19.7	20.0	20.3	20.6	20.9	21.2	21.5
Blink Bonnie	2.7	1.6%	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.3	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.8
Castlecliff	9.2	0.8%	10.9	11.0	11.1	11.2	11.3	11.4	11.5	11.5	11.6	11.7	11.8	11.9	12.0	12.1	12.1	12.2
Hatricks Wharf	9.2	1.1%	12.4	12.5	12.6	12.7	12.9	13.0	13.1	13.2	13.4	13.5	13.6	13.8	13.9	14.1	14.2	14.4
Kai Iwi	1.5	1.5%	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9
Peat St	21.8	0.4%	17.1	17.1	17.1	17.1	17.2	17.3	17.3	17.4	17.4	17.5	17.6	17.7	17.8	17.9	18.0	18.1
Roberts Ave	4.5	0.9%	10.6	10.7	10.8	11.0	11.1	11.2	11.3	11.4	11.5	11.6	11.6	11.7	11.8	11.9	12.0	12.0
Taupo Quay	8.0	1.0%	10.9	11.0	11.1	11.1	11.2	11.3	11.4	11.5	11.6	11.8	11.9	12.1	12.2	12.3	12.5	12.6
Whanganui East	5.9	0.9%	7.9	8.0	8.1	8.2	8.2	8.3	8.4	8.5	8.5	8.6	8.7	8.7	8.8	8.8	8.9	9.0

A7.11 DEMAND FORECAST FOR RANGITIKEI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Taihape	3.0	0.6%	5.3	5.3	5.4	5.4	5.4	5.5	5.5	5.5	5.6	5.6	5.6	5.7	5.7	5.7	5.8	5.8
Waiouru	2.6	0.4%	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
Arahina	7.4	0.5%	9.1	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.4	9.4	9.5	9.6	9.6	9.7	9.7	9.8
Bulls	3.6	1.5%	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4
Pukepapa	4.0	2.0%	9.1	9.3	9.5	9.6	9.8	10.0	10.2	10.4	10.5	10.7	10.9	11.1	11.3	11.5	11.7	11.8
Rata	2.0	1.6%	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.1

A7.12 DEMAND FORECAST FOR MANAWATU AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Feilding	23.9	1.4%	22.0	22.3	22.6	23.0	23.3	23.6	23.9	24.2	24.5	24.8	25.1	25.4	25.7	26.0	26.3	26.6
Kairanga	19.1	2.2%	17.8	18.0	18.1	18.8	19.2	19.7	20.1	20.5	20.9	21.3	21.7	22.1	22.5	22.9	23.4	23.8
Keith St	23.8	1.3%	20.5	20.8	21.1	21.4	21.7	22.0	22.2	22.5	22.8	23.0	23.2	23.4	23.6	23.8	24.0	24.2
Kelvin Grove	17.2	2.5%	13.8	14.3	14.7	15.2	15.5	15.9	16.2	16.6	16.9	17.2	17.5	17.8	18.1	18.4	18.6	18.9
Kimbolton	2.0	1.2%	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8
Main St	24.8	1.3%	28.7	29.0	29.3	29.7	30.0	30.4	30.7	31.1	31.5	31.8	32.2	32.6	33.0	33.3	33.7	34.1
Milson	19.2	0.8%	16.0	16.1	16.2	16.3	16.4	16.6	16.7	16.8	17.0	17.1	17.2	17.4	17.5	17.6	17.8	17.9
Pascal St	24.6	1.0%	23.4	23.7	23.9	24.2	24.4	24.7	24.9	25.2	25.4	25.6	25.9	26.1	26.3	26.6	26.8	27.1
Sanson	5.2	1.5%	9.0	9.1	9.3	9.4	9.6	9.7	9.8	10.0	10.1	10.3	10.4	10.5	10.6	10.8	10.9	11.0
Turitea	17.9	1.2%	14.9	15.0	15.2	15.3	15.5	15.7	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.3	17.5	17.7

A7.13 DEMAND FORECAST FOR TARARUA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Alfredton	0.6	1.2%	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
Mangamutu	9.9	5.3%	9.8	15.6	15.6	15.7	15.8	15.8	15.9	16.0	16.1	16.2	16.3	16.4	16.5	16.6	16.7	16.8
Parkville	1.9	0.8%	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3
Pongaroa	0.8	0.4%	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

A7.14 DEMAND FORECAST FOR WAIRARAPA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Akura	10.9	1.1%	13.5	13.6	13.7	13.9	14.0	14.2	14.3	14.5	14.6	14.8	14.9	15.1	15.3	15.5	15.6	15.8
Awatoitoi	1.2	1.2%	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Chapel	22.9	1.6%	14.9	15.1	15.3	15.5	15.8	16.0	16.2	16.5	16.7	17.0	17.2	17.5	17.7	18.0	18.2	18.5
Clareville	10.5	0.8%	11.2	11.3	11.4	11.5	11.6	11.7	11.7	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.5	12.5
Featherston	4.0	1.3%	5.7	5.8	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4	6.5	6.5	6.6	6.7	6.8
Gladstone	1.2	1.2%	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1
Hau Nui	0.3	0.0%	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Kempton	3.8	1.4%	5.2	5.3	5.4	5.4	5.5	5.6	5.7	5.7	5.8	5.9	6.0	6.0	6.1	6.2	6.3	6.3
Martinborough	2.5	1.1%	5.3	5.4	5.5	5.5	5.6	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.2	6.2
Norfolk	7.0	1.2%	6.4	6.4	6.5	6.5	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6
Te Ore Ore	6.9	1.3%	7.8	7.9	8.0	8.2	8.3	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.3
Tinui	0.8	1.2%	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Tuhitarata	2.0	0.7%	2.4	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7

Note: comparisons between the historical growth (Figures 8.4 and 8.5 in Chapter 8) and forecast growth need to be interpreted with the relevant context.

- Because the demand tables in this appendix inform our development planning, the tables show P90 demand levels and growth rates. The growth rates in our regional maps reflect historical average growth rates.
- Because of diversity between substations, the overall regional growth rates shown in the maps do not necessarily align with those at individual substations shown in this appendix.

A8.1 CHAPTER PURPOSE

This section provides additional details of the constraints, analysis options, and preferred solution for the growth and security projects outlined in Chapter 8. Detailed descriptions are included for projects above $1m, which are in progress or commencing in the next financial year, and also for projects which are expected to exceed $5m and start in the next five years.

A8.1.1 KAIMARAMA – WHITIANGA

NEW KAIMARAMA – WHITIANGA CIRCUIT

Constraint

The combined 2015 peak demand on the Coromandel, Whitianga & 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 & Tairua substations has a history of poor reliability performance due to the long overhead lines that traverse across 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. A particular issue is the fact that the Coromandel substation is supplied via a 66kV line that tee's 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 and 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. The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred due to the cost and environmental/consenting challenges. Capacity in excess of 10MW is needed, operating in an under-utilised standby mode most of the year. The capital cost of such a large unit, including site works, would be substantial, and long-term maintenance and operating costs are a further risk.
- **Renewable generation** – no viable option has been identified that would provide the required capacity, and renewable energy sources without storage do not provide any security.
- **Energy storage** – the potential use of energy storage, ideally in conjunction with renewable generation, is a focus of our R&D trials to inform our future network strategies (refer Chapter 11). Until trials and feasibility studies are completed, the long-term costs, both capital and operating, are still very much unknown and would represent a very high risk if undertaken at the scale this project requires. Widespread distributed renewable / storage could not be coordinated in the time frame required to secure existing loads.
- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies and are not preferred due to the relatively high demand growth rates in the Coromandel Area and the fact that the network security levels are already well exceeded. Another factor is that we currently use a mains-borne ripple control system to manage significant amounts of hot water cylinder load in the Coromandel Area. During peak loading periods most hot water cylinders are already turned off.

The following network solutions have been considered

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 Option

The currently preferred option is the installation of an 110kV underground cable between Kaimarama and Whitianga (Option 5 above). This underground cable option 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 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.

A8.1.2 KOPU – TAIRUA

KOPU – TAIRUA LINE UPGRADE

Constraint

The combined 2015 peak demand on the Coromandel, Whitianga & 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 (i.e. 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. The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred due to the cost and environmental/consenting challenges in the Coromandel.
- **Renewable generation** – no viable option has been identified that would provide the required security of supply.
- **Energy storage** – this is potentially viable but the costs associated with a backup battery plant would be significant and thus energy storage is not the preferred option.
- **Fuel switching and demand side response (DSR);** these are considered to be deferment strategies and are not preferred due to the relatively high growth rates and the fact that the network security levels are already exceeded. The hot water ripple control system already makes use of the main demand side resource.

The following network solutions have been considered:

1. Re-conductor existing Kopu-Tairua 66kV line.
2. Duplex the existing Kopu-Tairua 66kV line.
3. Build a second Kopu-Tairua 66kV line.

All of the above options would also require the installation of 66kV capacitor banks at Tairua and Whitianga.

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 a 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 in order to address the voltage constraints – this will occur as a separate project prior to the line upgrade.

A8.1.3 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 & G Price and Thames Toyota. Under normal operating conditions the supply to Thames is via a single 66kV circuit. In the event that 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 & 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.

In addition the subtransmission network in the Coromandel Area has a long history of poor performance due to the long overhead lines that traverse across rugged terrain coupled with 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 have been considered.

The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred due to the cost and environmental/consenting challenges. Under network contingencies there would presently be a shortfall of ≈10MW that would need to be “made up” using standby generation. Generation would not address the configuration issues that impact reliability, and could exacerbate them.

- **Renewable generation** – no viable option has been identified that would provide the required security of supply.
- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies and are not preferred due to the fact that network security levels are already well exceeded.
- **Energy storage** – this is potentially viable but the costs associated with a 10MW plant would be significant.

The following network solutions have been considered:

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.

A8.1.4 WHENUAKITE SUBSTATION

WHENUAKITE SUBSTATION

Constraint

Over the period 2007 through 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 (i.e. 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 & 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

Both non-network and network solutions have been considered to manage or remove the existing constraint.

The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred due to the cost and environmental/consenting challenges. Deployment of multiple units at various points on the feeder would also require sophisticated coordination and communications.
- **Renewable generation** – no viable option has been identified. Renewable generation does not provide sufficient confidence of availability during demand peaks to significantly improve security.
- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies and are not preferred due to the relatively high demand growth rates. Another factor is that we currently use a mains-borne ripple control system to manage significant amounts of hot water cylinder load on the Whitianga 11kV feeders. During peak network periods most hot water cylinders are turned off.
- **Energy storage** – this is potentially viable but the high costs associated with energy storage mean that this is not presently the preferred option.

The following network solutions have been considered:

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Whenuakite substation (in & out 66kV configuration).
3. New Whenuakite substation (66kV tee connection).
4. New Whenuakite Substation (66kV switching station)

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 & 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, and obtaining property and consents for both a substation and a switching station (option 4) would considerably add to costs and project complexity.

A8.1.5 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 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 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 Road 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.
- Kuaotunui 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 (i.e. during an outage of the other feeder).

Options

Both non-network and network solutions have been considered to manage or remove the existing constraint.

The following non-network solutions have been considered:

- **Fossil fuelled generation** – deployment of multiple units at various points on the feeder would require sophisticated coordination and communications, and is also highly undesirable in an environmentally sensitive area.
- **Renewable generation** – no viable option has been identified that would provide a secure supply during network peaks.
- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies and are not preferred due to the relatively high demand growth rates. The primary issue in this case is feeder customer numbers, and demand management would not assist this.
- **Energy storage** – energy storage would need to be distributed and would essentially suffer from the same drawbacks as other demand side approaches – does not impact the number of connected customers.

The following network solutions have been considered:

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.

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.

A8.1.6 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 hence much of the load is only N secure which falls well short of our security standard. Loading is forecast to steadily increase, and towards the end of the planning period the substation is projected to exceed secure capacity.

Options

Both non-network and network solutions are considered to manage or remove the existing constraint.

The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred due to the cost of a plant to supply ≈7MVA of load.
- **Renewable generation** – no viable option has been identified that would provide a secure backup supply during peak network loading periods.
- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies and are not preferred due to the relatively large load involved.
- **Energy storage** – this is potentially viable but the high costs associated with energy storage mean that this is not presently the preferred option.

The following network solutions have been considered:

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 (i.e. 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 course of action 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 need to re-evaluate the potential options. There remains a possibility therefore that the final solution may be different to that indicated here.

A8.1.7 WHANGAMATA

WHANGAMATA 2ND 33KV CIRCUIT

Constraint

The existing 33kV network supplying the Whangamata substation has a number of constraints/issues as follows:

- 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).
- The 11kV backfeed which serves Whangamata is via an 11kV feeder located under the 33kV circuit. Certain contingencies (e.g. car vs pole) can render both circuits out of service, meaning no 11kV backup is then available.
- 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 (i.e. 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.
- 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.
- The Waihi-Whangamata 33kV line has a history of relatively poor reliability. Between 2002 and 2009 Whangamata experienced ten line outages greater than 30 minutes, and five of these exceeded 4 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 solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable and is included below in conjunction with network option 4.

- **Renewable generation** – no viable grid scale (~10MW) option has been identified that would provide a secure supply. Widely distributed PV is conceptually possible, but would need to be combined with storage and would be very demanding logistically.
- **Energy storage** – as with diesel generation, we are actively investigating the possibilities for targeted energy storage (e.g. 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 completed.
- **Fuel switching and demand side response (DSR)** – there are no immediate options for large scale fuel switching. Demand side response approaches can only moderate the existing demand peak, but cannot address the central issue at Whangamata of having only N security (i.e. a single circuit) 33kV supply to the substation.

The following network solutions have been considered:

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 tee'd 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.

Preferred Option

The preferred long-term option is to construct a 2nd circuit to Whangamata via Golden Cross mine (option 1 above). This option is optimal in several ways – making use of existing infrastructure through the mine and at Waikino GXP, and the solution affords a robust, reliable and operationally elegant solution. We have therefore been working through the complex consenting, access, engineering, construction and design issues. While the outlook is promising, there is no guarantee until final routes are confirmed. Other options are therefore being kept in consideration especially where they provide a means of mitigating existing risks.

Options 2 & 3 above 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.

A8.1.8 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 consists of 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 kiwi fruit 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:

- 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.
- During outages of one of the Greerton-Omokoroa circuits the 33kV voltages at Katikati and Kauri Pt substations are low with the result that the 33/11kV zone transformer tap-changers exceed their tap range.
- 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 (i.e. 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 remove the existing constraint(s).

The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred due to the cost and environmental/consenting challenges.
- **Renewable generation** – no economically viable options have been identified that would provide a secure supply especially during winter evening peaks.

- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies but could “supplement” a network solution. However, they are not preferred due to the relatively high demand growth rate.
- **Energy storage** – this is potentially viable but the high costs associated with energy storage mean that this is not presently the preferred option.

The following network solutions have been considered:

- Construction of a third Greerton to Omokoroa 33kV overhead line.
- Construction of a new Greerton to Omokoroa 33kV underground cable circuit.
- Upgrade of the existing Greerton to Omokoroa 33kV overhead line circuits.
- 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 Option

Option 2, being a 3rd circuit using underground cable, is presently preferred, for the following reasons:

- Acquiring and consenting a new overhead line route (option 1) via either public road state (including state highway) or private land (intensive horticulture or lifestyle) would be very challenging.
- Further upgrade of the existing lines (option 3) would require conductor replacement, 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.

A8.1.9 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

The following non-network considerations are pertinent:

- **Fossil fuelled generation** – this is considered impractical in this urban residential environment.
- **Renewable generation** – new subdivisions offer the opportunity for widespread distributed PV, but without storage this does not affect peak demand. Network scale renewable generation is not feasible in this location.
- **Energy storage** – this is conceptually viable (particularly in conjunction with PV) in the future, but overcoming the operational challenges of coordinating widespread resources has yet to be proved, and requires customer involvement from the early stages of subdivision development.
- **Alternate heating fuels and DSR** – these are considered to be deferment strategies and, in the long-term, cannot provide the capacity (or demand reduction) required for a subdivision of this size.

The following network solutions have been considered

1. Reinforce the existing 11kV network from the Tauranga 11kV GXP. This would result in long, heavily loaded feeders with no backfeed, 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 Option

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 & 2, involving varying degrees of 11kV reinforcement, are less cost effective and provide poor quality of supply.

Timing of the new substation build is a function of section uptake. This has now reached a point where construction of the substation is essential to avoid deteriorating reliability, feeder constraints or sub-optimal “work-around” temporary solutions.

A8.1.10 OTUMOETAI – BETHLEHEM SUBTRANSMISSION

OTUMOETAI – BETHLEHEM SUBTRANSMISSION

Constraint

With connection of the new Bethlehem substation to the 33kV ring from Greerton to Otumoetai, there is insufficient N-1 capacity for the future load at the three substations: Bethlehem, Otumoetai and Matua. Voltage constraints are also experienced when either circuit from Greerton is out of service.

Growth in this area has been strong, and is expected to be sustained for the next decade, especially in the burgeoning greenfield subdivisions served by Bethlehem substation.

The Otumoetai and Greerton 33kV switchboards are also in need of replacement, which makes the provision of additional circuits more economic if coordinated at the same time.

Options

The rapidly growing nature of the load renders demand side approaches (including energy storage) largely ineffective. Even as a deferral strategy, the deferral time purchased would be minimal and DSR approaches also require earlier coordination with developers and customers to improve uptake. Network scale generation would be inappropriate in a residential environment such as this, and renewable generation such as solar PV would not address evening winter peaks.

The following network solutions have therefore been considered:

1. Upgrade existing 33kV circuits where overhead and replace/upgrade underground sections.
2. New overhead / underground 33kV circuit from Greerton to Otumoetai.
3. New overhead / underground 33kV circuit from Greerton to Bethlehem.
4. 33kV links to the Omokoroa 33kV network.

Preferred Option

The preferred solution (option 2), which is now in the design and consenting phase, is to install a new 33kV cable from Greerton to Otumoetai, with a new switchboard at Otumoetai to provide a fully secure N-1 network into the future.

Additional circuits from Greerton are considered necessary in the long-term, recognising the magnitude of additional load indicated by the greenfield subdivisions and land zoning. Overlaying underground cables to upgrade these circuits is also very expensive for the MW gained. A new circuit will mostly be underground as the route will pass through built up and established urban areas. An additional circuit to Otumoetai was preferred over an additional circuit to Bethlehem, since the load of Matua substation is connected at Otumoetai, plus Otumoetai offers a synergistic opportunity to add extra 33kV circuits while the switchboard is renewed. Options to mesh the Bethlehem – Otumoetai ring with the northern Tauranga 33kV (Omokoroa etc.) were considered, but add complexity and cost to protection, switching and operations, plus the northern Tauranga ring already has security and voltage issues.

A8.1.11 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 2 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:

- 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. Backfeed capacity at 11kV is reducing as new development connects, and is insufficient to meet our security requirements now.
- 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 future. Most of the growth is on the south-east of Papamoa (i.e. Wairakei).
- 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.
- 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.
- In 2028 the unconstrained peak demand on the 33kV cables from Te Maunga to Papamoa would exceed the N-1 rating.

Options

The following non-network solutions have been considered in the course of developing our long-term strategies and projects.

- **Fossil fuelled generation** – inappropriate for an intensive urban development and coastal lifestyle environment.
- **Renewable generation** – does not support security without storage. No feasible grid scale opportunities in an urban setting. Operational control of widespread distributed PV is not yet mature.
- **Energy storage** – potentially viable, especially in synergy with distributed PV, but deployment at the rate required to accommodate the rapid growth would be very risky.
- **Fuel switching and demand side response (DSR)** – as with energy storage, this could be a deferment strategy, but matching the rate of demand growth would be challenging, with uncertainty still in the amount of controllable load.

The following network 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 Option

Option 1 was initially preferred but all reasonable attempts to secure access for new 110kV lines have been effectively exhausted. We have therefore 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.

- It has the lowest overall long-term cost while still managing risks and security levels adequately.
- It is practical and achievable (unlike overhead options), in what is now a tight timeframe as growth picks up again.
- It improves the supply diversity to all substations, due to the fact that the Mt Maunganui and the Te Matai GXPs will be linked at 33kV and all the relevant zone substations (Te Maunga, Papamoa & Wairakei) can be supplied via two independent routes.
- 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.

A8.1.12 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 is spring/summer peaking.

A number of constraints therefore apply, as follows:

- The single 110kV overhead line affords no security. Lengthy outages are experienced for maintenance or major faults.
- The peak demand on the Hinuera GXP is ≈43MW, which exceeds the N-1 capacity of the existing transformers.
- Even the small amount of load to the north (Waharoa) which can at times be backfed from Piako, does not meet our security criteria, requiring automated transfer in <15 seconds (security class of AA+).
- Maintenance on the 110kV line has been restricted due to constraints on outages. Generation and lengthy backfeeds have been deployed to facilitate line outages with minimal supply disruption, but these have exposed issues with voltage and stability under such extreme operating limits.
- 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. Customer support, as per recent consultation, for our proposals is high.
- Putaruru substation is supplied via a ≈10km, single circuit, 33kV line. There is limited 11kV backup from the adjacent Tirau substation. This single circuit supply network does not meet the requirements of our Security of Supply Standard, which recommends a security class of AA for the Putaruru.
- The peak demand on the Tirau 33/11kV substation is ≈11MVA. It is supplied via a 33kV tee connection onto the Hinuera-Putaruru single 33kV circuit. This arrangement does not meet our security standard.
- The combined 2015 peak demand on the Walton, Waharoa & Browne Street substations was ≈20MVA. The supply from Piako is not adequate for this, which does not meet our security standards.

Options

The following non-network solutions have been considered:

- **Fossil fuelled generation (i.e. diesel or gas)** – this is technically viable, especially in a Cogen context, but we have not yet identified any cost effective opportunities.
- **Renewable generation** – grid scale capacity (> 20MW) is unlikely, as hydro opportunities are already exploited, and solar is yet reach cost parity for central generation. Wind projects are possible, but their location rarely coincides with security constraints.
- **Fuel switching and demand side response (DSR)** – these are considered to be deferment strategies and could potentially “supplement” a network solution. However, the magnitude of the load to be managed/switched is considerable and no viable options have been identified.
- **Energy storage** – this is untested at the scale required for this grid security context. No opportunities exist to date.

The following grid / network options have been considered:

1. Reinforce the existing 33kV network from the adjacent Kinleith and Piako GXPs.
2. Install a new 110/33kV Putaruru GXP supplied from the existing Arapuni to Kinleith 110kV lines (ARI-KIN B).
3. Construct a new 110kV line from the Arapuni power station to a new 110/33kV substation at Putaruru.
4. Construct a second 110kV line from Karapiro to Hinuera.

Preferred Option

Over the last two years, since securing access to the Kinleith – Arapuni B 110kV circuit, we have been pursuing the option to construct a new GXP at Putaruru (option 2). This option was confirmed through the GRS process (as per the EIPC code) and ensuing public consultation confirmed support for the proposal.

The alternate 110kV upgrades (options 3 & 4) were both assessed as being more expensive. Land access and consenting also presented greater risks. The 33kV upgrades (option 1) would also have ultimately cost more to provide the full degree of security mandated by our security standards.

The proposed solution involves a new 110/33kV substation, to be incorporated within our existing 33/11kV Putaruru site. The 110kV Arapuni – Kinleith B line will be diverted into a new switching station (GXP) to be constructed by Transpower. A new 110kV underground cable will supply Putaruru from this new grid offtake.

This new Putaruru GXP would be used to supply the existing Putaruru and Tirau 33/11kV substations and also to backup a significant portion of the Hinuera load further north. Other projects are planned to enable this increased backfeed. These other projects include:

- Kereone-Walton Upgrade (refer to Section A8.1.13)
- Putaruru-Tirau Upgrade (refer to Section A8.1.14)

As at the time of compiling this AMP, changes were proposed to thermal generation which have cast doubt over the viability of the proposed new GXP, and prompted a review of all possible options.

A8.1.13 KEREONE – WALTON

KEREONE-WALTON UPGRADE

Constraint

As noted in section A8.1.12 (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 Putaruru GXP, as proposed in section A8.1.12, 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 & 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% p.a. Waharoa has seen particularly rapid expansion and growth is forecast to continue at over 2% p.a. and this does not include an existing upgrade to accommodate expansion for Open Country Dairy Ltd.

Options

The following non-network solutions have been considered:

- **Fossil fuelled generation** – Cogen, in conjunction with industrial expansions offers the most viable option here, but no commercially viable opportunities have been determined.
- **Renewable generation** – no viable options exist for the scale and security required, especially for the industrial loads.
- **Energy storage and demand side response (DSR)** – these would not be suitable strategies for what is essentially an N security GXP, with minimal backup to a very large load, much of which has a flat daytime load profile.
- **Alternate fuels** – as noted above, the industrial load base makes Cogen a realistic possibility, especially with gas transmission available nearby. However, the feasibility depends on synergistic development of customer heat plants coordinated with electrical network development. To date, it has not been possible to locate any opportunities of appropriate scale.

The following network solutions have 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 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 backfeed Browne St in Matamata, when supply from Hinuera is unavailable.

Alternative options 1 and 2 require costly upgrade work to the existing Kereone-Walton line, and still impose severe capacity limitations on backfeed. 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.

A8.1.14 PUTARURU – TIRAU

PUTARURU – TIRAU UPGRADE

Constraint

Section A8.1.12 (Putaruru GXP) and section A8.1.13 (Kereone – Walton), set out the overall network development strategy to address the N security at Hinuera GXP. Section A8.1.13 details how the Kereone – Walton upgrade will provide adequate support for Browne St substation from Piako GXP. Section A8.1.12 details how the proposed Putaruru GXP secures substations south of Hinuera. With these projects completed, only Tower Rd 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 backfed 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 11.1.10.

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.

A8.1.15 BAIRD – MARAETAI 33KV RING

BAIRD – MARAETAI 33KV CABLE RING

Constraint

The two substations supplying Tokoroa (Baird Rd and Maraetai Rd) are currently supplied by a single 33kV circuit each – hence only have N security. Any outage of these circuits results in an immediate loss of supply to the respective substation. There is some 11kV backfeed 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 itself, and transit traffic on SH-1. The security of the electrical supply considering this load base is not optimal.

Options

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.

Preferred Option

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 2nd 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.

A8.1.16 HUIRANGI – BELL BLOCK

HUIRANGI GXP – BELL BLOCK 33KV

Constraint

The Bell Block and Katere substations are fed by two 33kV circuits from Carrington St GXP. The N-1 capacity of these circuits has been exceeded, and no longer meets our security criteria. Both substations require full no break N-1 security (class AAA).

Parts of the 33kV circuits cross over residential properties and buildings. This limits access for maintenance and inspection, fault isolation and repair. It also increases the risk profile in terms of overloading of the circuits or potential breakage of conductors.

An alternate low capacity 33kV supply from Huirangi GXP can feed part of Bell Block's load, but this switched arrangement does not meet our security criteria, and is not appropriate for industrial and commercial load.

The industrial and residential developments served by the Bell Block and Katere substations have been growing steadily and urban zoning plus available land indicates substantial demand growth can be expected in this area for some time. This will only exacerbate the existing overloading.

Options

The following possible solutions were considered:

1. SPS scheme or dynamic rating to manage the overload on the existing lines from Carrington St GXP, by switching to Huirangi GXP.
2. Upgrading of the existing 33kV lines from Carrington St GXP.
3. Construct new dual circuit 33kV line from Huirangi GXP to Bell Block substation (in place of the existing single low capacity 33kV circuit). Upgrade Huirangi GXP capacity in conjunction with Transpower renewals.
4. As for option 3 but construct a separate single 33kV circuit from Huirangi GXP to Bell Block substation and operate in parallel with the existing one.

Preferred Option

Option 4 was initially preferred, due to perceived lower cost. However, route negotiations for a new separate line ultimately failed, and a review of options led to option 3 being adopted. We have now completed route negotiations, consenting, design and are in the latter stages of construction of a new dual circuit in place of the existing line from Huirangi to Bell Block. Transpower have upgraded the Huirangi GXP transformers and 33kV switchgear in readiness for the new 33kV feeders.

Alternate option 2 was not preferable as would continue our reliance on these high risk and inaccessible circuits, and it would only defer more substantial upgrades. Similarly option 1 would provide limited additional capacity against a backdrop of strong growth and increased risk, and would also introduce non-standard network configuration and operational protocols.

A8.1.17 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, and Transpower are 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 Transpower are therefore investigating the economics of disestablishing the whole site, and supplying Moturoa by some alternative means.

While Transpower will ultimately be responsible for maintaining supply to Moturoa, they have engaged with us to consider options, particularly as these relate to the subtransmission configuration.

Options

The magnitude of the existing load and the security required for this largely preclude non-network options in this case.

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 from Carrington GXP to Moturoa and then our City substation.
3. A new 110/33kV GXP at Omata coupled with a 33/11kV substation. Decommission the existing Moturoa substation.
4. 2 x 33kV cables from Carrington to a new substation in Spotswood. Decommission the existing Moturoa substation.

Preferred Option

At this early stage of analysis, option 1 appears the most cost effective. This option would involve two new dedicated 33kV cables from Carrington St GXP to our existing Moturoa substation.

Consideration of options 3 & 4 was prompted by the poor condition and need for 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, which 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 order of cost, but there was insufficient space at City substation for a new 33kV switchboard.

It is to be noted that while this project is signalled in our long-term plans for completeness, the proposals are still in the early stages of investigation. Transpower are presently working through the consultation phase of their consideration of grid options, and these will need to be subject to investment tests and regulatory approval. The final solution, funding, and future ownership demarcations are all still to be determined.

A8.1.18 BRUNSWICK GXP TO PEAT ST

BRUNSWICK GXP TO PEAT ST 2ND CIRCUIT

Constraint

The existing 33kV subtransmission network in Whanganui uses a meshed architecture that relies on switched, cross GXP backfeeds 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:

- 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.
- Switched backup 33kV supply is available from substations fed from Whanganui GXP, but the capacity of this is also constrained.
- 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 backfeed from Peat St substation.
- Kai Iwi substation is fed from Peat St and suffers from the same security issues.
- 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 that while the single, hence N secure, 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, as it is common to all options and cannot be resolved by subtransmission upgrades on the Brunswick side of the city. Somewhat counter-intuitively, 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 (i.e. GXP and transmission) consideration of regional options, in consultation with Transpower.

Options

Both non-network and network options have been considered to manage or resolve the existing constraint(s).

The following non-network options have been considered:

- **Fossil fuelled generation** – network scale diesel or gas generation is considered inappropriate in the context of the urban CBD environment. Customer deployment (e.g. backup generators) is conceptually possible but insufficient viable opportunities currently exist to match the capacity deficit.
- **Renewable generation** – this is not practical in the urban context and distributed solar PV does not assist security.
- **Energy storage** – network storage is unproven at the scale (>10MW) required, and would see very low utilisation.
- **Demand side response (DSR)** – demand side peak reductions, including distributed storage, are conceptually viable, but practical implementation would require a much longer time frame to be coordinated and would be unlikely to reach the capacity required.

The following network options have been considered:

1. Second 33kV circuit from Brunswick to Peat St.
2. New 33kV tie circuit from Peat St to Roberts Ave substation to provide a secure 33kV ring.
3. Additional 11kV backfeeds from neighbouring substations.
4. Additional 33kV circuit(s) from Brunswick into Castlecliff substation.

Preferred Option

The proposed solution is to construct a new 2nd circuit from Brunswick GXP to Peat St (option 1). This will operate in parallel with the existing circuit, and ensure our most important substation in Whanganui is fully secure (no break N-1) in regard to subtransmission contingencies. Security for Kai Iwi and Castlecliff will be similarly improved. Roberts Ave security will be addressed through improved 11kV backfeeds. Further benefits are afforded through increased cross-city backfeed capacity to substations fed off Whanganui GXP (Hatricks wharf, Taupo Quay and Beach Rd).

Of the alternative network options, the 33kV ring with Roberts Ave was the closest in terms of cost, but was rejected due to the need to construct a full 33kV switchboard at Roberts Ave, plus property and consenting for the new 33kV tie would have been challenging given the built up urban route. Increased 11kV backfeed (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.

A8.1.19 PALMERSTON NORTH (FERGUSON SUB)

PALMERSTON NORTH CBD

Constraint

The Palmerston North CBD and commercial / industrial areas are principally supplied by three zone substations (Pascal St, Main St and Keith St). A number of constraints/ issues impact the supply to these important substations:

- 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, the incidence of cable leaks is increasing. They have been de-rated to reduce the thermal cycling stress on the cable joints, and in recognition of 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.
- 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.
- 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.
- 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.
- During 2015 the peak load on the Pascal and Kairanga substations was ≈40MVA and has exceeded the N-1 firm capacity of the 33kV network.
- 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.
- 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. In contrast the Transpower Linton GXP is moderately loaded.

Options

The deployment of non-network strategies has been considered in the context of this project:

- **Fossil fuelled generation or alternate energy sources** – gas is available and feasibility studies have 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, but the intermittent availability of this, without storage, precludes any benefit to security.
- **Storage, efficiency and demand side responses** – widely distributed storage and solar PV could have offered a possible demand side combination, but the flat daytime load profile of the commercial loads makes it ineffective. The magnitude of capacity needed already and the time frame also preclude such options which require complex coordination across multiple parties. Efficiency programmes are possible but would struggle to provide the required magnitude of peak demand reduction. In all instances, these options would only serve to mitigate risk until network solutions could be deployed, or provide some degree of deferral of these network upgrades.

Broadly, the following network options have been considered:

1. Upgrade Linton GXP 33kV subtransmission network, with new 33/11kV, feeder fed transformer, substation.
2. Upgrade Linton GXP 33kV subtransmission network, with new 33/11kV substation supplied via meshed 33kV network.
3. Upgrade Linton GXP 33kV subtransmission network, with new 33/11kV substation supplied via cascaded 33kV network.
4. Upgrade Bunnythorpe 33kV subtransmission network.
5. Construct a new Kairanga GXP and upgrade subtransmission from this into the city.

Preferred Option

Options 4 and 5 above represent a totally different development path for the city and were largely eliminated in high level options analysis at the GXP level. This concluded that the lowest cost long-term strategy would be to develop the subtransmission from Linton, making use of the available capacity at this GXP. Further, more focused, analysis of options for upgrading the subtransmission from Linton concluded that the least cost, and most secure operational configuration was with cascaded 33kV twin circuits feeding firstly Ferguson substation then on to Main St.

For the last two years we have been working towards the option 3 above, which involves:

- The installation of ≈9km of dual circuit, 33kV, underground cable from the Linton GXP to a new 33/11kV substation on Ferguson Rd, including river crossings and access through Massey Farms.
- The upgrade of a ≈3km section of 33kV, underground cable in the existing Linton-Pascal circuit.
- Installation of two 33kV cables from Ferguson to Main St substation.
- Installation of additional 33kV feeder bays at Transpower's Linton GXP.

This option allows the transfer of substantial load from Pascal and Main St onto the new Ferguson St substation, thus restoring security at all CBD substations. 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. The cascaded architecture is preferred over meshed for operational and protection advantages, while it has a distinct cost advantage over the dedicated twin circuits to each substation (option 1).

A8.1.20 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:

- Sanson is supplied by a single 15km long 33kV overhead line, affording only N security.
- The 2015 peak demand on the Sanson substation was ≈9MVA. The 11kV backfeed 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.
- The 2015 peak demand on the Bulls substation was ≈6MVA. Bulls is also supplied from a single 33kVline, 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.
- The Ohakea base security is sub-optimal considering the critical load supported.
- The total demand (of Feilding, Sanson and Kimbolton substations) on the Bunnythorpe – Feilding circuits is approaching their N-1 capacity.

Options

The following non-network strategies have been considered:

- **Fossil fuelled generation (i.e. diesel generation)** – this is technically viable but not preferred primarily due to the cost. A 9MW diesel generator would be needed, and utilisation would be very low.
- **Renewable generation** – there are no viable options that provide the required capacity or security.
- **Energy storage and demand side** – there are possible options, but these would be mainly used as deferral strategies. The magnitude of capacity (or demand peak reduction) required to address the constraints is considerably beyond what has been trialled to date.

The following network solutions have been considered:

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.

Preferred Option

Option 2 is currently preferred. This would establish a 33kV link between Sanson and Bulls substations. The new link would involve the use of an existing ≈3.5km 33kV cable (presently operating at 11kV) from Sanson to Ohakea, plus 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 need to be constructed at Ohakea to supply the existing (and future) air base load.

The cost of this Sanson-Bulls link is estimated to be lower than a 2nd dedicated Feilding-Sanson circuit. Furthermore, the 2nd circuit option would not improve security for Bulls or provide switched capacity to offload the Feilding lines from Bunnythorpe.

A8.1.21 RONGOTEA SUBSTATION

RONGOTEA ZONE SUBSTATION

Constraint

Increased use of irrigation and other agricultural activities is driving demand for electricity to the south-west of Palmerston North. This growth in demand is reflected in the historical and forecast electrical demands on the Kairanga and Sanson substations and the associated feeders. The primary constraints are as follows:

- The Oroua Downs 11kV feeder (supplied from Sanson) is presently voltage constrained during peak network loads, and it is closely followed the Rongatea, Bainesse and Taikorea feeders. Voltage regulators have already been deployed to the extent practical.
- The growth in irrigation load is mostly concentrated in the area supplied by the Oroua Downs feeder. Further irrigation proposals have been signalled, the timing of which is still uncertain.

Options

The following non-network options have been considered:

- **Fossil fuelled generation** – there is some scope to use diesel generators to manage existing daily peaks, but would require close coordination of irrigation developments with network developments, which can be difficult as customer's often have tight timeframes reflecting commercial priorities.
- **Renewable generation** – large scale solar PV generation by the customer would offer obvious synergies with irrigation. Commercial realities may mean this is impractical. No opportunities exist for network scale renewable generation.
- **Demand management (DSM)** – the scale of irrigation indicated precludes this as a long-term solution. As a deferral strategy it would need flexibility in when our customer's irrigation was used, which often requires oversized plant and water offtake rates.
- **Energy storage** – this could be used as a deferral strategy, but would be at a scale that is untested at present.

The following network solutions have been considered:

1. Install 3x11kV voltage regulators on the Oroua Downs, Rongotea and Bainesse feeders.
2. Install additional 11kV feeders from Kairanga or Sanson substations.
3. New Rongatea Substation: Install ≈10km of 33kV overhead line overbuilt on the existing Bainesse 11kV feeder. Install ≈3km of 33kV underground cable. Construct a new 33/11kV substation at Rongatea to offload the existing overloaded 11kV network.

Preferred Option

Rongatea substation is our preferred long-term solution. A staged implementation is proposed whereby the substation can be deferred through use of the 33kV circuit as an extra 11kV feeder initially. The new substation will resolve all feeder capacity and voltage constraints, plus improve reliability by subdividing the existing feeders, reducing the number of customers affected by faults, and the frequency of faults customers see.

Installing further voltage regulators is no longer feasible as coordination becomes unacceptable, and thermal capacity constraints are ultimately worsened. The installation of additional feeders ultimately becomes constrained again, and increases loading on the Sanson and Kairanga substations.

A8.2 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.

A8.2.1 WAIHI BEACH TRANSFORMERS

The Waihi Beach substation contains a single transformer. The peak demand has exceeded the transformer's capacity. There is limited 11kV backfeed, and the substation does not meet our security requirements.

Options considered include:

1. **Increased 11kV backfeed** – 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** – addresses 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 that the capacity and security will provide for the future demand.

A8.2.2 PIAKO GXP (2ND 110/33KV TRANSFORMER)

The new Piako GXP was constructed three years ago to offload Waihou GXP, which was at the time exceeding N capacity and presented a very high risk of extensive and lengthy outages if a transformer failed.

Alternate options considered at the time (and reasoning) were:

1. **Upgrading Waihou GXP** – risk would have been excessive in managing the works at a constrained site and working around live equipment, while maintaining secure supply. Additional 33kV reinforcement would also have been required from Waihou and Piako is a better site to backstop Hinuera.
2. **Construct Piako GXP with full switch-station** – this was the preferred solution originally, but civil cost escalations and consenting / grid interface difficulties ultimately eliminated it. The final solution provides virtually the same security for a much lower cost and complexity.

This project (2nd 110/33kV Piako transformer), involves the final stage of the Piako GXP construction, with the purchase of a 60MVA 110/33kV transformer, as a matching unit for the existing one. The Piako GXP currently has a temporary 40MVA unit as its second transformer – this was to be our system spare, and is needed when the Putaruru GXP project proceeds. In this regard, there are no viable alternatives now to the purchase of the 2nd 60MVA transformer, as it is only a final stage of the overall development path that is Piako GXP.

A8.2.3 MATAMATA (TOWER – BROWNE 33KV CABLE)

The Browne Street and Tower Road 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 backfeed upgrades** – increased 11kV backfeed capacity and automated switching could reduce outages. Against this, the more obvious 11kV backfeeds 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 9.1.12), but ultimately proved too expensive.

The proposed solution is to construct a 33kV underground cable circuit between Tower Road and Browne Street substations. This will create a secure 33kV subtransmission ring serving Matamata, without excessive costs and without undesirable operating configurations.

A8.2.4 HINUERA – TOWER ROAD 33KV LINE UPGRADE

The project detailed in section 9.2.3 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. **2nd circuit from Hinuera to Tower Rd** – this would involve excessive cost excessive cost, plus it would require additional switchgear and added complexity of the protection.
2. **Additional 11kV backfeed** – this cannot meet the no-break N-1 requirement required for appropriate security, and rejected for the same reasons as detailed in section 9.2.3.
3. **SPS to transfer Browne St to Piako** – this is 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 backfeed options and the option does not meet our 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.

A8.2.5 MORRINSVILLE 2ND CIRCUIT

The Morrinsville substation is fed by a single 33kV circuit from the Piako GXP – therefore only providing 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 backfeed 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.

A8.2.6 TOWER RD 2ND TRANSFORMER

Tower Road substation currently has just one 33/11kV transformer. The 11kV backfeed 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 2nd 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.

A8.2.7 LAKE RD 2ND TRANSFORMER

Lake Rd substation currently has just one 33/11kV transformer. Substations which could provide backfeed 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.

A8.2.8 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.

A8.2.9 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 that is the capacity that can be supplied by one transformer plus available 11kV backfeed.

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 backfeed** – the nearest substations are some distance and their capacity is quite limited, meaning this option is not very effective. Breakless supply is not possible.

The preferred solution is to replace the existing transformers with two larger units. The Eltham 33kV is operated with a split bus and hence the transformers are exposed to higher duty more often – i.e. whenever there is a subtransmission fault.

A8.2.10 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 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 backfeed.
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 lien, plus the pending capacity constraint when backfeeding 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 the Hawera – Manaia – Kapuni ring 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.

A8.2.11 TAUPO QUAY 2ND CIRCUIT

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 the 11kV bus. There is insufficient capacity in either circuit to carry the total peak load following a fault on the other circuit.
- 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.
- 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.
- 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 those that came out of these wider analyses, but are options (or components projects of overall development path options) which are particularly pertinent to the Taupo Quay constraints identified above.

1. **2nd Circuit from Whanganui GXP to Taupo Quay** – a 2nd 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. **Upgrade existing Taupo Quay circuit** – to achieve the necessary capacity uplift, this would need to be reconductored with a much larger size, increasing cost and complexity – especially in the river crossing. Property access and consenting are risks where the project could fail or costs escalate.
3. **New circuit from Whanganui GXP into Beach Rd** – this is effectively a variant on option 1, and terminates the new circuit at Beach Rd rather than Taupo Quay, A longer circuit would be needed and additional switchgear at Beach Rd.
4. **New (2nd) circuit into Hatricks Wharf** – this would also require extensive property and consenting cost, which could necessitate an underground cable via the existing road reserve, similar to options 1 and 3 for most of the route. Additional 33kV switchgear and protection would be needed at Hatricks Wharf, which is highly space constrained.

Option 1 is currently preferred. This has flexibility during the planning stages to be changed to option 3, if demand growth patterns favoured Beach Rd, or the switchgear/protection requirements or route negotiations dictate that this is preferred. Estimated costs for option 1 (Taupo Quay) are obviously lower than option 3 (Beach Rd). Terminating a new circuit at Taupo Quay requires upgrade of the substation to allow a new compact switchboard to be fitted. This work is scheduled as replacement and renewal, recognising that the substation itself is very space constrained and in need of reconstruction to meet modern standards of access, clearance and safety.

Option 2 (upgrade of the existing line) is a strategy that is explicitly rejected since the cost could still be substantial, but the option cannot realistically provide sufficient capacity or security in the long-term.

Option 4 is another variant to option 1, and for comparable cost, and better addresses some of the needs associated with Brunswick substations (e.g. backfeeding Peat St for a Brunswick outage). However, constraints associated with Taupo Quay and Beach Rd/Castlecliff are not resolved by this option. Furthermore, Hatricks Wharf is very space constrained and has been rebuilt recently – it could not accommodate the additional switchgear required.

Variations to option 1 are therefore potentially worth exploring further, and will be as more detailed analysis takes place closer to the proposed project implementation. Essentially this project sets our development path for the whole city, by proposing much greater security and capacity into the city from the Whanganui GXP. Brunswick can then remain an N secure GXP without compromising reliability, avoiding very large costs to upgrade Brunswick. Consenting and land acquisition, plus issues with switchgear and protection, may warrant a different final solution in terms of actual project scope.

A8.2.12 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 backfeed** – 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.

A8.2.13 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 backfeed capability from the 11kV distribution network.

Options considered include:

1. **Increased 11kV backfeed** – Sanson is quite remote from other substations, and due to the N security 33kV subtransmission, most practical 11kV backfeed 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.

A8.2.14 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 backfeed** – 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 3rd 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.

A8.2.15 FEILDING TRANSFORMERS

The Feilding substation supplies the town of 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 backfeed 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, which could be eroded by growth relatively quickly. 30MVA units are also feasible, but again create a non-standard configuration, and mean that fault levels can be hard to manage.
3. **Install a 3rd transformer** – this would be a non-standard substation configuration, which we would prefer to avoid and due to 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.

A9.1 APPENDIX OVERVIEW

The projects detailed in this section are those that are substantially driven by renewal need, which are in progress or commencing in the next financial year. Only zone substation and subtransmission projects are included, which have costs that are expected to exceed $500k.

A9.1.1 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. Factory overflow has recently contaminated the site.

The transformer is due for replacement in the next 10 years and a number of auxiliary assets are also deteriorated and in poor condition.

In considering major refurbishment and renewal, the alternate option to relocate the substation was considered. The option to construct a new Mokoia substation nearer the load centre has been shown to be cost effective and will improve future maintenance and operation. The capacity of the new transformer will be determined to allow for existing demand and future growth.

MOKOIA SUBSTATION (EX-WHAREROA SUBSTATION, $000, 2016 REAL)

Estimated Total Project Cost	$5,305
Expected Project Timing	2017-2018

A9.1.2 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, 33/6.6kV 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, and the back supplies are not rated for the morning and evening peak times.

The project is to replace the existing transformer, with a 33/11/6.6kV, 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	$680
Expected Project Timing	2017

A9.1.3 WAIHI 11KV INDOOR SWITCHBOARD REPLACEMENT

The Waihi 11kV switchboard consists of ten Reyrolle Pacific - LMT oil filled circuit breaker panels. The switchboard was built in 1965 and the arc flash hazard level is 11.54cal/cm2 which is above our limit. The switchroom building has had a seismic study completed by engineering consultants and the building was rated at 30% New Building Standard (NBS). This is well below the set threshold zone substation buildings (67% NBS) as defined by the New Zealand Building Code. A switchboard failure will cause an extended outage which will have significant financial impact on the nearby gold mine and cause loss of supply to the Waihi township. There is limited backup feeds from adjacent substations and full restoration will require switchboard replacement.

A conceptual design has been completed and the existing switchboard will be replaced with a three incomer, 2 bus coupler, and seven feeder panel switchboard and associated equipment such as cables, seismic strengthening and protection relays.

WAIHI 11KV INDOOR SWITCHBOARD REPLACEMENT ($000, 2016 REAL)

Estimated Total Project Cost	$1,095
Expected Project Timing	2017

A9.1.4 KINLEITH LOAD CONTROL PLANT REPLACEMENT

The existing 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 manufacturers of the existing plant ceased trading in New Zealand in the 1980s.

This project is to replace the existing plant with a new ripple injection 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	$876
Expected Project Timing	2017

A9.1.5 PUTARURU 11KV SWITCHBOARD REPLACEMENT

The 11kV switchboard at Putaruru was commissioned in 1962 and is one of the oldest switchboards on our network. It consists of ten Reyrolle Pacific – LMT oil filled circuit breaker panels. The switchroom building has been assessed by engineering consultants and the building has only achieved 19% NBS, well below the set threshold of 67%. A switchboard failure will cause an extended outage to the Putaruru township and nearby farms.

We are currently in the design phase of the project. The project scope at this stage consists of constructing a new switchroom building to house the new 11kV switchboard with an allowance for future growth.

PUTARURU 11KV SWITCHBOARD REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$1,336
Expected Project Timing	2016-2017

A9.1.6 MOBILE SUBSTATION

Many of our rural zone substations have only a single power transformer supply (i.e. 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. Investigations are currently underway to determine the best configuration of the mobile substation.

MOBILE SUBSTATION ($000, 2016 REAL)	
Estimated Total Project Cost	$1,643
Expected Project Timing	2017-2018

A9.1.7 GILLESPIE OIL FILLED CABLE REPLACEMENT

There are six oil filled cable segments in Palmerston North that are approximately 50 years of age. They are typically three copper or aluminium cores, with paper insulation and oil insulation fluid maintained at a pressure above atmospheric The outer sheaths are either corrugated aluminium or lead. These cables require frequent top ups of oil due to leaks from joints and possibly cracks in the sheath. It is suspected that thermal cycling, cables laid on slopes, ground movement (earthquakes, traffic vibration) and third party damage are the primary factors causing the leaks. The cables have been de-rated to reduce thermal cycling. The Gillespie segment (comprising a cable pair named Gillespies 1 and Gillespies 2) began leaking badly last year. The worst of the two leaking cables (Gillespies 2) has now been shut down due to environmental and failure concerns. Gillespies 1 remains in service and is being closely supervised. This has resulted in the Palmerston North area now operating under reduced security until the cables are replaced.

This project will replace the Gillespie oil filled cables including the installation of new fibre communications cable and two spare distribution ducts in the same trench. The existing oil filled cables and associated oil equipment will be evacuated of oil and abandoned.

GILLESPIE OIL FILLED CABLE REPLACEMENT ($000, 2016 REAL)	
Estimated Total Project Cost	$1,523
Expected Project Timing	2017

A9.1.8 ALFREDTON – 33 KV LINE RECONSTRUCTION

The Alfredton-Pongaroa 33kV subtransmission line is part of the 33kV ring that supplies Parkville, Pongaroa and Alfredton zone substations.

In the past 12 months the line has had 15 unplanned outages recorded against it, making it the worst performing subtransmission line on our network. The fault causes have been attributed to defective equipment, foreign interference and other unknown faults. A significant portion of the line is supported by aged hardwood poles, which are decaying and in poor condition. The line crosses rugged terrain, requiring helicopter access to some areas, making the line inaccessible during winter months. While some short sections of the line have been rebuilt in more recent times, the majority of the conductor is Dog ACSR installed in the 1960s, making the conductor around 50 years old.

ALFREDTON – 33 KV LINE RECONSTRUCTION ($000, 2016 REAL)	
Estimated Total Project Cost	$561
Expected Project Timing	2017

A9.1.9 BROOKLANDS 5 RECONSTRUCTION

The Brooklands 5 feeder has 1224 ICPs and is has a feeder security rating of F4.

The feeder is listed as the fourth worst distribution feeder on the Western network with 15 unplanned outages due to equipment failures. We have received a number of customer complaints regarding the number of outages experienced. One fault mechanism identified is failing 812b insulators, which have been shown to corrode at the pin, causing cracking of the sheds. These have so far been replaced reactively. The sections of network where the insulators have been identified will have their crossarm assemblies replaced.

The conductor on this circuit includes a mixture of light conductors including 16mm^2 copper and namu AAC, both types of conductors targeted for replacement due to high numbers of failures. As part of the project, the lighter poles on circuit will be replaced with stronger poles in preparation for a future upgrade of the line capacity.

BROOKLANDS 5 RECONSTRUCTION ($000, 2016 REAL)	
Estimated Total Project Cost	$602
Expected Project Timing	2017

A9.1.10 KAPONGA 33 KV LINE RECONSTRUCTION AND CARDIFF 33 KV LINE RECONSTRUCTION

The Kaponga and Cardiff subtransmission lines form a circuit which supplies Cardiff and Kaponga zone substations. These zone substations supply 1450 ICPs. These projects are part of the overall works to renew the Stratford subtransmission network.

The subtransmission lines have had several recent faults, including conductor failure. The lines have NZI 4490 two piece insulators which have been known to fail. The lines also have old hardwood poles with wraps on the bases which are difficult to test the condition of. In 2015 a pole failed which caused outages to the Cardiff and Kaponga zone substations. These lines consist of 7/.104in copper conductor installed in 1941 and now require replacement. It is planned to replace this conductor with iodine AAAC, which will require associated pole replacements due to the heavier conductor.

Overhead conductor and insulator failure is a safety risk. Consequences of such failures in areas where distribution and low voltages networks are underbuilt include damaged electrical and telecom equipment, and building fires.

KAPONGA 33 KV LINE RECONSTRUCTION ($000, 2016 REAL)	
Estimated Total Project Cost	$635
Expected Project Timing	2017

CARDIFF 33 KV LINE RECONSTRUCTION ($000, 2016 REAL)	
Estimated Total Project Cost	$767
Expected Project Timing	2017

A9.2 MAJOR RENEWAL PROJECTS PLANNED 2018-2021 ($000, 2016 REAL)

PROJECT NAME	DESCRIPTION	PLANNING AREA	2018	2019	2020	2021
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	-	-	-	2,798
Alfredton – Outdoor to Indoor Conversion	Poor outdoor switchgear and transformer asset health, inadequate switching capability and inadequate fencing. The project will include building a new switchyard, switchroom building, new power cables, new power transformer, indoor 33 kV and 11 kV switchgear.	Wairarapa	-	3,134	-	-
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	-	1,193	-	-
Feilding – 11kV Switchboard Replacement	Poor asset health, oil type switchgear and high arc flash incident energy. This project will replace the existing switchgear.	Manawatu	-	1,061	-	-
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	-	-	-	1,787
Greerton – Outdoor to Indoor Conversion	Poor outdoor switchgear asset health and the site is critical to the supply of the Tauranga region. This project will convert the existing outdoor switchgear and associated structures into an indoor 33kV switchboard including a new building, civil works, power cables and associated secondary systems.	Tauranga	-	-	4,606	-
Hawera – 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.	Egmont	-	-	850	-
Kai Iwi – W27 Power Transformer Replacement	Poor asset health and current bunding uses a petrol plug which is inadequate. This transformer will be replaced with a new 5MVA unit together with an oil separator system.	Whanganui	-	-	-	948
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	-	-	2,226	-
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	-	-	820	-
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	-	-	-	850
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	-	-	-	1,788
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	650	-	-	-
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	-	-	-	850
Matua – 11kV Switchboard Replacement	Poor asset health and is an oil type switchgear. This project will replace the existing switchboard.	Tauranga	-	-	657	-

PROJECT NAME	DESCRIPTION	PLANNING AREA	2018	2019	2020	2021
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	984	-	-	-
Moturoa – 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.	Taranaki	-	-	-	1,032
Paeroa – 11kV Switchboard Replacement	Existing switchgear is one of the oldest switchboards in our network and is an oil type switchgear. The project will replace the existing switchboard.	Coromandel	701	-	-	-
Paeroa – T1 and T2 Power Transformer Replacement	Poor asset health and inadequate oil buding and oil containment. This project will replace the existing transformers as well as installing new oil containment system and associated cables.	Coromandel	-	1,993	-	-
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	-	1,026	-	-
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	911	-	-	-
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	-	-	421	816
Tatua – T1 Power Transformer Replacement	Poor asset health. This project will replace the existing unit on the existing bunded area.	Waikato	-	-	1,125	-
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	-	-	-	960
Triton – Outdoor to Indoor Conversion	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	-	-	-	2,969
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	-	-	1,334	-
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	-	-	1,478	-
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	562	-	-	-

A10.1 APPENDIX OVERVIEW

This appendix sets out forecast scheduled maintenance expenditure ($000, real 2016) by asset category over the planning period.

ASSET CATEGORY	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Zone Substations											
Routine scheduled maintenance and inspection	2,726	3,353	3,046	3,361	3,485	3,209	3,698	3,937	3,962	3,931	3,817
Subtransmission Lines and Cables											
Routine scheduled maintenance and inspection	330	285	323	311	303	328	261	291	295	299	303
Distribution and LV Lines											
Routine scheduled maintenance and inspection	1,069	1,064	1,747	1,495	1,251	1,713	1,493	1,371	1,359	1,332	1,244
Distribution Transformers											
Routine scheduled maintenance and inspection	841	699	705	790	754	838	695	621	800	768	721
Distribution Switchgear											
Routine scheduled maintenance and inspection	1,787	1,150	1,155	1,208	2,100	2,301	1,988	1,719	1,312	1,494	1,835
Other Network Assets											
Routine scheduled maintenance and inspection	389	744	949	1,004	1,198	1,265	844	840	844	849	329
General Maintenance											
Other corrective work	6,819	7,768	8,049	7,356	9,141	10,591	11,611	11,323	11,023	10,023	9,499
Defects	2,936	3,437	3,437	4,637	5,837	5,837	5,837	5,837	4,637	3,437	3,437
Third party damage repair	761	891	891	891	891	891	891	891	891	891	891
Total ARR and RMI expenditure	**17,658**	**19,390**	**20,301**	**21,052**	**24,959**	**26,973**	**27,318**	**26,830**	**25,124**	**23,024**	**22,076**

A11.1 APPENDIX OVERVIEW

This appendix discusses the performance of our poorer performing feeders. For some of these feeders we explain the reasons for poor performance 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 2015 calendar year.

The analysis is broken down by feeder class.[126] Each distribution feeder is assigned a class that best encompasses the types of consumers connected to the feeder.

A11.2 FEEDER CLASS F1

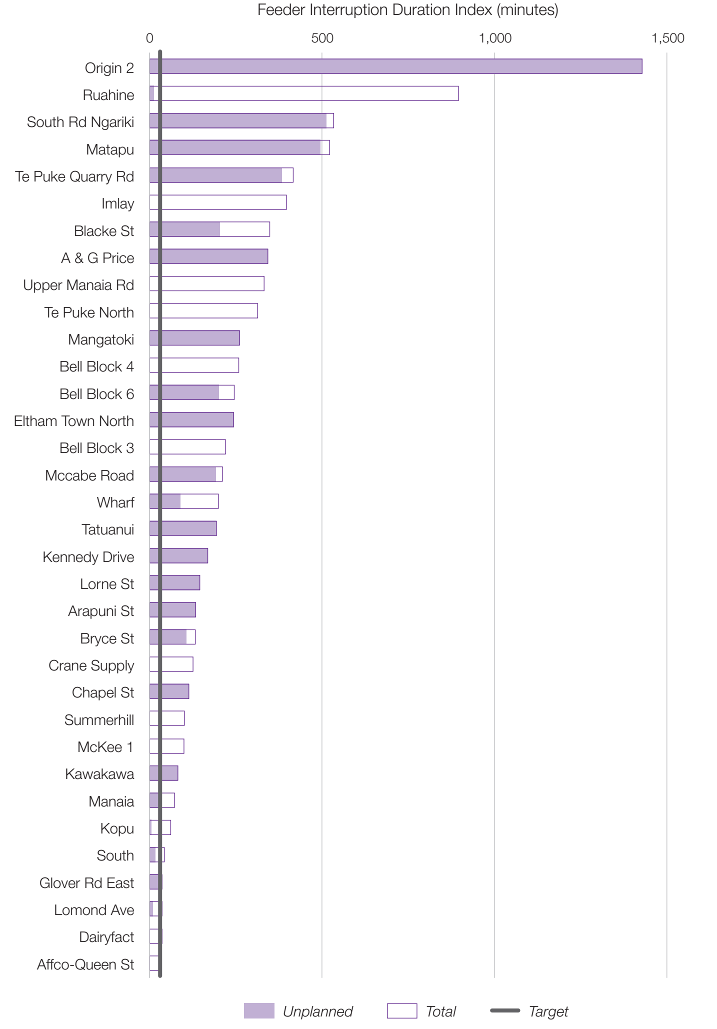
Origin 2, Taranaki – One outage occurred. A lightning strike damaged the two transformers on site which required total replacement. A generator was connected to the customer's supply until transformer replacement was carried out. No further work is planned.

Ruahine, Manawatu – Five planned shutdowns occurred for capital works where one was to make urgent repairs to the 400 volt network. No further work is planned on the feeder.

T**e Puke Quarry Rd, Mt Maunganui** – Eleven outages occurred with four planned shutdowns, two outages from defective equipment accounting, and five unknown outages recorded against the feeder. This feeder has a F1/F4 security rating with most faults occurring on the F4 section. A new 11kV overhead link and tie point switch is currently being installed.

Imlay, Whanganui – One planned outage on the feeder. The outage was to repair an oil leak on a distribution transformer. No further work is planned.

Feeder class F1 – worst performing feeders



[126] 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

Waterworks Rd, Whanganui – A total of 28 outages occurred however only one unplanned outage disrupted supply to the F2 section of the network, due to a lightning strike. All other unplanned outage occurred on the F5 section of the network. Planned works included tree trimming and pole replacement.

Katere 10, Taranaki – A total of 21 outages occurred, including two minor unplanned outages with transformer fuses replaced. All other outages were due to planned works for pole and conductor replacement.

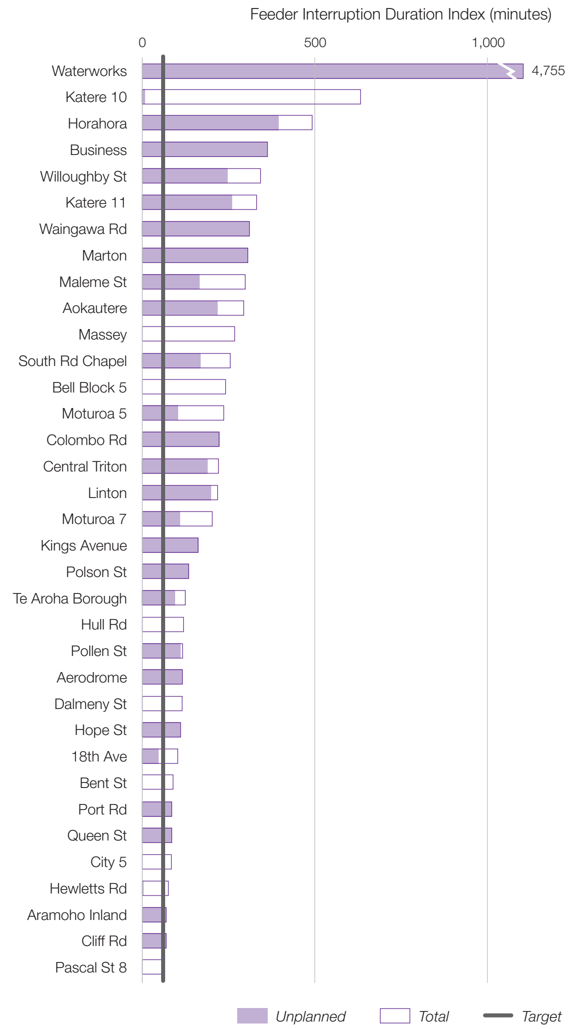
Business, Manawatu – One unplanned outage which was due to a failed insulator (replaced reactively). There is no further work planned for the feeder.

Willoughby St, Waikino – Three outages occurred comprising two planned shutdowns and one outage due to a cable fault accounting for 62% of the FIDI minutes recorded against the feeder. A new recloser and tie point switch is being installed in FY16.

Katere 11, Taranaki – Two shutdowns occurred, both planned for line upgrades.

Marton, Rangitikei – A total of six outages occurred. One outage was due to a car versus pole incident that accounted for 60% of the FIDI minutes recorded against the feeder. There are no further works planned for the feeder.

Feeder Class F2 FIDI



A11.4 FEEDER CLASS F3

Marangai, Whanganui – There were a total of nine outages. Four of these were unplanned outages which occurred during adverse weather conditions, including the Whanganui floods in June 2015. There were long restoration times because of poor access to the affected assets. Planned work included moving sections of the network away from slippage zones.

Thames Coast, Coromandel – In total there were 14 outages recorded. Two unplanned outages were from vegetation encroachment and four unplanned outages from defective equipment, the largest being a broken 11kV pole. This feeder has a F3/F4 security rating with planned projects to install new 11kV cable/ line to segment customers.

Hunterville 22kV, Rangitikei – A total of 28 outages occurred. Eight unplanned outages were due to defective equipment, the remaining outages due to vegetation and foreign interference. Line reconstruction work is planned for the feeder FY17.

Kuaotunu, Coromandel – A total of 20 outages occurred with 13 planned shutdowns accounting for 86% of FIDI minutes recorded against the feeder. This feeder has a F3/ F4 security rating with planned projects to reconstruct the 11kV lines.

Oakura, Taranaki – A total of 19 outages occurred. 16 outages were due to planned works on the feeder. Work carried out included pole, crossarm and conductor replacement. No further work is planned.

Somerset Rd, Wairarapa – A total of 11 outages occurred. Eight outages were due to planned shutdowns accounting for 60% of the FIDI minutes on this feeder. Other outages included car versus pole. No further works are planned for the feeder.

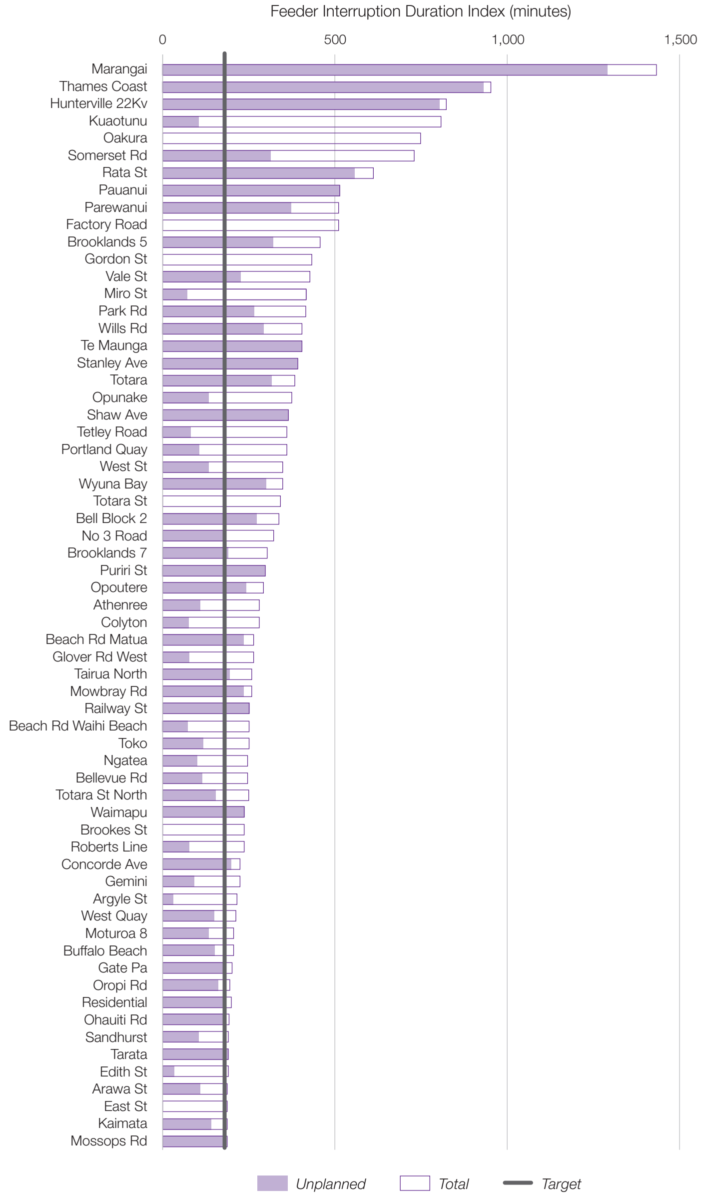
Rata St, Taranaki – A total of seven outages occurred on the feeder. Four outages were for planned works which included pole, transformer and cable replacement. Two outages were due to car versus poles and accounted for 90% of the FIDI minutes recorded against the feeder. No further work is planned.

Pauanui, Coromandel – A total of two outages occurred on the feeder. One unplanned outage for a failed cable accounted for 99% of the FIDI minutes recorded against the feeder. No further work is planned for the feeder.

Parewanui, Rangitikei – A total of 17 outages occurred on the feeder. Three planned outages were for pole and conductor replacement. Fourteen unplanned outages were due to mainly defective equipment on the F4 section of the feeder. Planned works for FY17 include conductor, crossarm and pole replacement on the feeder.

Factory Rd, Waikato – Two outages were recorded against the feeder. Both outages were for planned work to replace poles and crossarms. No further work is planned for the feeder.

Feeder Class F3 FIDI



A11.5 FEEDER CLASS F4

Brooklands, Tararua – Eight outages occurred on the feeder. Two planned shutdowns were for crossarm and transformer replacements. The six unplanned outages were due to vegetation and defective equipment. All defects have been repaired. No further work is planned on the feeder.

Te Poi, Waikato – A total of 34 outages occurred with 17 planned shutdowns accounting for 42% FIDI minutes, and one outage from loss of bulk supply accounting for 51% FIDI minutes recorded against the feeder. 11kV pole renewals are planned.

Horoeka, Tararua – A total of 37 outages occurred on the feeder. The unplanned outages were due to adverse weather conditions and defective equipment. Planned work has included pole, crossarm and conductor replacement.

Strathmore, Taranaki – A total 54 outages have occurred on the feeder. 46 of which were unplanned. The feeder has been patrolled to identify fault mechanisms. Defect repairs and replacements are planned to improve feeder performance. Tree trimming is also being carried out on the feeder.

Waitotara, Whanganui – A total of 54 outages occurred on the feeder. 40 unplanned outages occurred during adverse weather conditions, including the Whanganui floods in June 2015. Long restoration times were due to poor access to the affected assets. RAPS were installed for customers on lines damaged by floods. We are currently investigating rerouting lines away from flood prone areas. Line reconstruction work is planned for FY17.

Lockington, Tauranga – A total of 19 outages occurred on the feeder. Twelve were planned outages for pole and crossarm replacements. No further work is planned on the feeder.

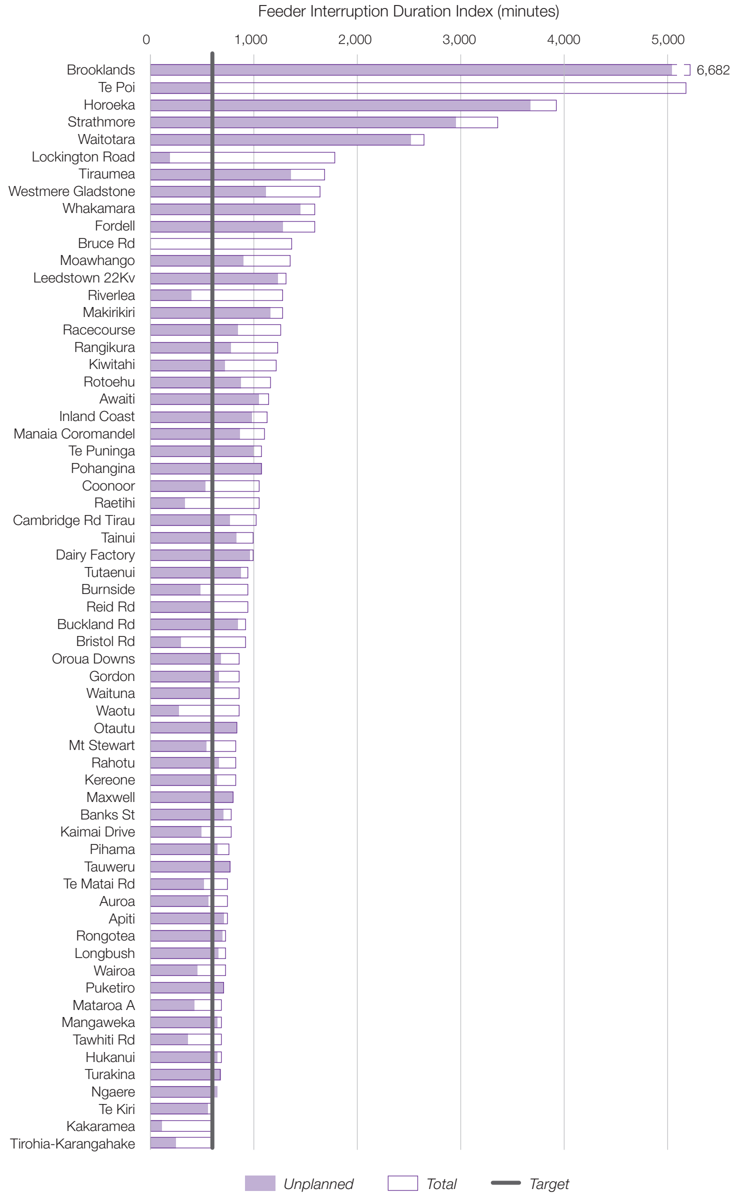
Tiraumea, Tararua – A total of 26 outages have occurred on the feeder. Of these 14 were planned outages for line reconstruction that has been carried out this year. Adverse weather and defective equipment have been the main fault mechanisms for the remaining outages. Construction has been completed and no further work is planned.

Westmere Gladstone, Wairarapa – 31 outages occurred on the feeder. The main fault mechanism has been vegetation encroachment. The feeder has been targeted for tree clearance. Line reconstruction work is also planned.

Whakamara, Egmont – A total of 31 outages occurred on the feeder, including nine planned shutdowns for tree trimming, and pole and crossarm replacement. Unplanned outages include foreign interference, defective equipment and unknown faults. Further reconstruction work on the feeder is planned.

Fordell, Whanganui – A total of 35 outages occurred on the feeder. 14 planned outages were for tree trimming, and pole and crossarm replacement. Unplanned outages include foreign interference, defective equipment and unknown faults. No further work is planned.

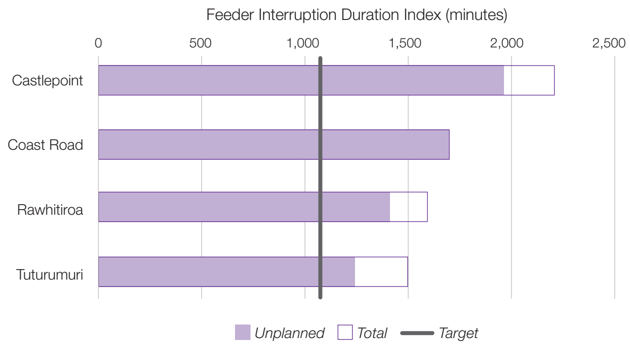
Feeder Class F4 FIDI



A11.6 FEEDER CLASS F5

Castlepoint, Wairarapa – A total of 19 unplanned outages occurred on the feeder. The main fault mechanism has been vegetation issues. The feeder has been targeted for tree clearance.

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
- 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 IC 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 supports 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 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. 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.

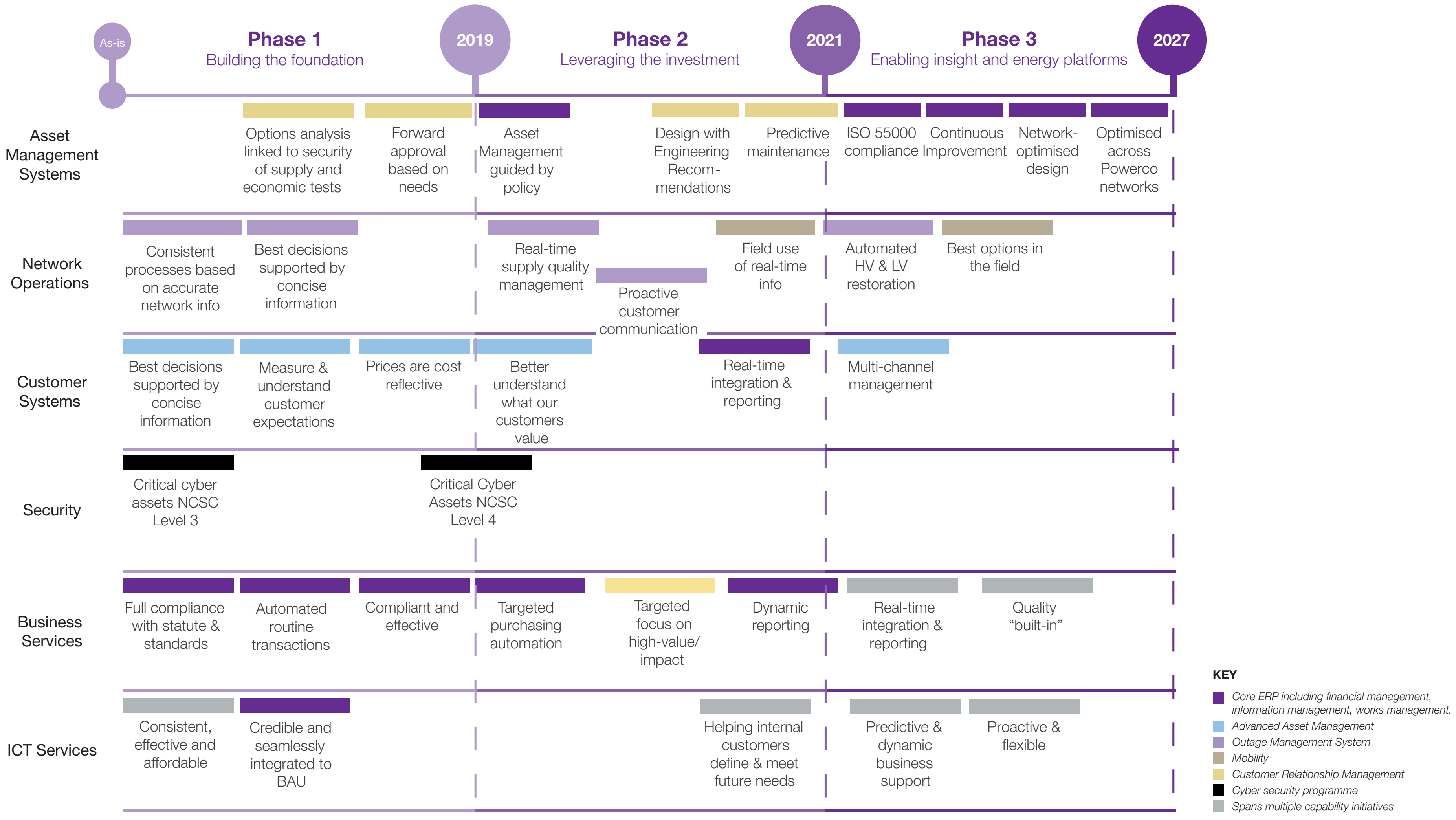
A12.3.3 LIMITATIONS OF DATA AND INITIATIVES TO IMPROVE DATA

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 22.

A12.4 ROADMAP FOR NON-NETWORK ASSETS AND ACTIVITIES OVER THE PLANNING PERIOD



A13.1 APPENDIX OVERVIEW

This appendix provides further details on the future network initiatives discussed in Chapter 11.

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.[127]

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.

[127] Under current regulatory settings, reliability is measured on higher voltage networks only.

- Supporting environmental programmes, by improving the utilisation 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.[128]

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.[129] 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.

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.

[128] At current price levels, permanent battery storage installations are generally not economical as network reinforcement solutions.
[129] Cable temperature is of course proportional to the current it carries, but several factors can influence the actual level.

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 – both in 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.[130]

[130] 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).

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,[131] 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 that 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 that 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 that 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.

[131] 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 exist.

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 (for example, 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 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.

A13.4.3 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,[132] 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.

A13.4.4 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.
- 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.

[132] 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.

A13.4.5 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 SECTION 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 the second paragraph of Section 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 2.6.5 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 Section 23.5.
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; and (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): In line with our asset management improvement programme we have: restructured the AMP to streamline and enhance its usability. This is described in Section 2.5; moved detailed factual information to appendices; a glossary is provided in Appendix 1 to assist understanding; and (3): Risk is discussed in Section 5.10 and Appendix 6. High Impact Low Probability (HILP) events are specifically addressed in Section 5.10.4.
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 5 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 5 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 2016.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION 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 7 outlines service objectives and measuring network performance. 1.2: Chapter 23 outlines AMMAT results and improvement plan. 1.3: Chapters 4 & 5 describes the alignment. 1.4: Chapters 4 & 5 describes the strategies while Chapter 7 describes network targets. 1.5: Chapter 5 describes accountabilities across all levels of the organisation. 1.6: Chapter 3 provides a high-level overview of our assets. Chapters 14 – 20 provide details on location and condition information for each asset class. 1.7: Section 7.5.1 & 7.5.2 discuss asset utilisation and asset performance. 1.8: This is outlined in Section 5.6. Additionally, Chapter 12 outlines our approach to asset management lifecycle and fleet management. 1.9: Section 8.4.7 discusses non-network solutions.
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. 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 Section 23.5.1. 2.4: Our new service objectives are discussed in Section 7. 2.5: Section 5.10 discusses overall risk while Chapter 8 details how we address growth and security risks. Chapters 14-20 provide details on condition information for each asset 2.6: Section 5.8 details approach, including tendered work (Section 5.8.3). 2.7: is discussed in Chapter 5. 2.8: is discussed in Section 23.4.2. 2.9: Chapter 11 provides an overview of the network and service offerings we are planning for. Chapter 22 provides commentary on our systems, IT capabilities and plans. 2.10: We have used terminology in line with this Appendix, and also provided a glossary in Appendix 1. 2.11: Chapter 5 outlines how we manage our network, while Chapter 7 details the networks targets we aim to achieve. Chapter 23 provides improvement initiatives for our asset management capability.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION 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.
	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, 3, 4, and 5. This describes the context in which we operate. The objectives of our asset management and planning process is provided in Chapter 7.
	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 Section 2.2. 3.3.2: Our corporate vision, mission and values and their relationship with the AM process is discussed in Section 4.2. 3.3.3: See Chapter 5.7. 3.3.4: See Chapter 5.3. 3.3.5: This is described in Section 5.2.
	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 5 years of the AMP planning period need not be presented in the same detail as the first 5 years.	Our AMP planning period is from 1 April 2016 to 31 March 2026, as described in Chapter 2.
	3.5 The date that it was approved by the directors	The AMP was approved on the 17 March 2016.
	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 Section 2.4. A more detailed description of each main stakeholder's interests, how these are identified and accommodated in the asset management is in Appendix 3.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION 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 Section 5.4.1. 3.7.2: Refer to Sections 5.4.2 3.7.2: Section 5.8 discusses 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 24 provides key assumptions an uncertainty in the development of the AMP. 3.8.3: Chapter 13. 3.8.5: Section 24.3.2 describes how we developed the escalators we used to inflate our forecasts into nominal New Zealand dollars in schedules 11a and 11b.
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 Section 24.4.
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 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 and explains how we plan and deliver investments.
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; and • the extent to which these systems, processes and controls are integrated.	Chapter 22 provides information on systems and information management data, specifically 22.7.1 discusses processes to identify data. In addition, Appendix 12 details systems and controls to ensure the quality and accuracy of asset management information.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION 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	Limitations and incentives are described in Section 22.7.2 and Appendix 12.
3.13	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. 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 Chapter 13. 3.13.2: Refer Chapter 8 3.13.3: Refer Section 7.4.1
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; and (v) audit or review procedures undertaken in respect of the asset management system.	Chapter 5 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 Section 2.4 and Chapter 23.
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	All figures are reported in constant 2016 dollars.
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.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION 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 Section 3.3. The extent to which these are interlinked is in Section 3.2. 4.1.2: Large consumers are described in Appendix 4. 4.1.3: Load characteristics for our two network regions is described in Chapter 3, and for each of our planning areas throughout Chapter 8. Detailed demand forecasts are included in Appendix 7. 4.1.4: This is in 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; and 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 Chapter 8. 4.2.2: The subtransmission system is referred to in Section 3.3 and maps are provided throughout Chapter 8. The information required on zone substation capacity is provided in Schedule 12b of Appendix 2. 4.2.3: The distribution system at a high level in Chapter 3, along with the extent to which it is underground. Chapters 8 and 14-20 describe the distribution system in more detail. 4.2.4: Refer Chapter 18. 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 14-20 describe the low voltage system in more detail. 4.2.6: Refer Chapter 20. 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.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
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; and 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.	Chapters 14 to 20 are fleet plans that contain each asset category information.
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; and 4.5.11 other generation plant owned by the EDB.	4.5.1- 4.5.8: Refer to Chapters 14 to 20 4.5.9: GXP meters are discussed in Chapter 20 and section 8.6 4.5.10: N/A 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 Chapter 15.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
	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 7 including Section 7.7 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.
6.	Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next 5 disclosure years.	Section 7.4.1 and table in 7.7. Schedule 12d in Appendix 2 provides this information.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
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 7. 7.1: Section 7.4.2 provides customer-orientated indicators. 7.2: Chapter 7 discusses our network targets, for example, Section 7.5.1 describes our asset capacity and utilisation targets. Section 7.7 provides a summary of all these measures.
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 7.
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	Chapter 7 provides historic 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 Sections 7.7.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
	Network Development Planning	
11.	AMPs must provide a detailed description of network development plans, including -	Network development planning is discussed in Chapter 8.
	11.1 A description of the planning criteria and assumptions for network development;	The criteria are discussed in Sections 7.2 to 7.4.
	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 Section 8.4.1.1.
	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 is discussed throughout Chapters 14-20.
	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 14-20 which are disaggregated to individual asset categorises.
	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 Section 11.5.
	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 Section 8.1.2.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
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.	Section 8.2 provides detail of how network development is prioritised and Chapter 4 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; and 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 Chapter 8. 11.8.1: The methodology is provided in Section 8.4.1. 11.8.2: Forecasts at zone substation level, constraints and the impact of distributed generation are provided in Section 8.5 Area Plans.
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.	Section 8.5 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: Section 11.4 illustrates our current innovation programme.

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
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); and 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.	Section 8.5 summarises our Area Plans and describes all significant network developments. Appendix 8 discusses all network and non-network options considered for major projects.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
	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 8 describes how we treat distributed generation in our demand forecasts which informs network development plans.
	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; and 11.12.2 the potential for non-network solutions to address network problems or constraints.	Refer to Section 8.4.7
	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 12.
	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; and 12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	Our maintenance strategy is discussed in Section 6.14 and forecasts in Appendix 9. 12.2.1 & 12.2.2: Each asset class fleet plan in Chapters 14 to 20 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); and 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 14-20 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, 14 and 15.
	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 plans are detailed by fleet in Chapters 14 - 20.

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
	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 describes 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 22.7.3, 22.8.1.
	3.4	a description of material maintenance and renewal projects (where known) planned for the next five years.	The major projects are included in Section 22.7.3
	Risk management		
14.	AMPs must provide details of risk policies, assessment, and mitigation, including -		Section 5.10 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 Section 5.10. The details of risks are provided in Appendix 8.
	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 Section 5.10.4.
	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 Section 5.10
	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 Section 5.10.5

	ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
	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 7. 15.1.i - iii): Project and expenditures variances are described in Appendix 5. Additional material is provided throughout Chapter 13 – 20.
	15.2	An evaluation and comparison of actual service level performance against targeted performance; i) 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 7 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 Chapter 23 and Schedule 13 (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 7 describes our initiatives for each category of network targets.
	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;	Chapter 5 describes 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 5 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 Laughlin and Michael Bessell, 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

17/3/16

Date

17.3.16

Date

POWERco