POWERco

Electricity Asset Management Plan 2021

Cover: Powerco Lights Up the Night at iconic Taranaki event, TSB Festival of Lights. The striking photography in this Asset Management Plan (AMP) captures some of the impressive light installations on display at this annual community event, which Powerco sponsors. **Photos:** Charlotte Curd.

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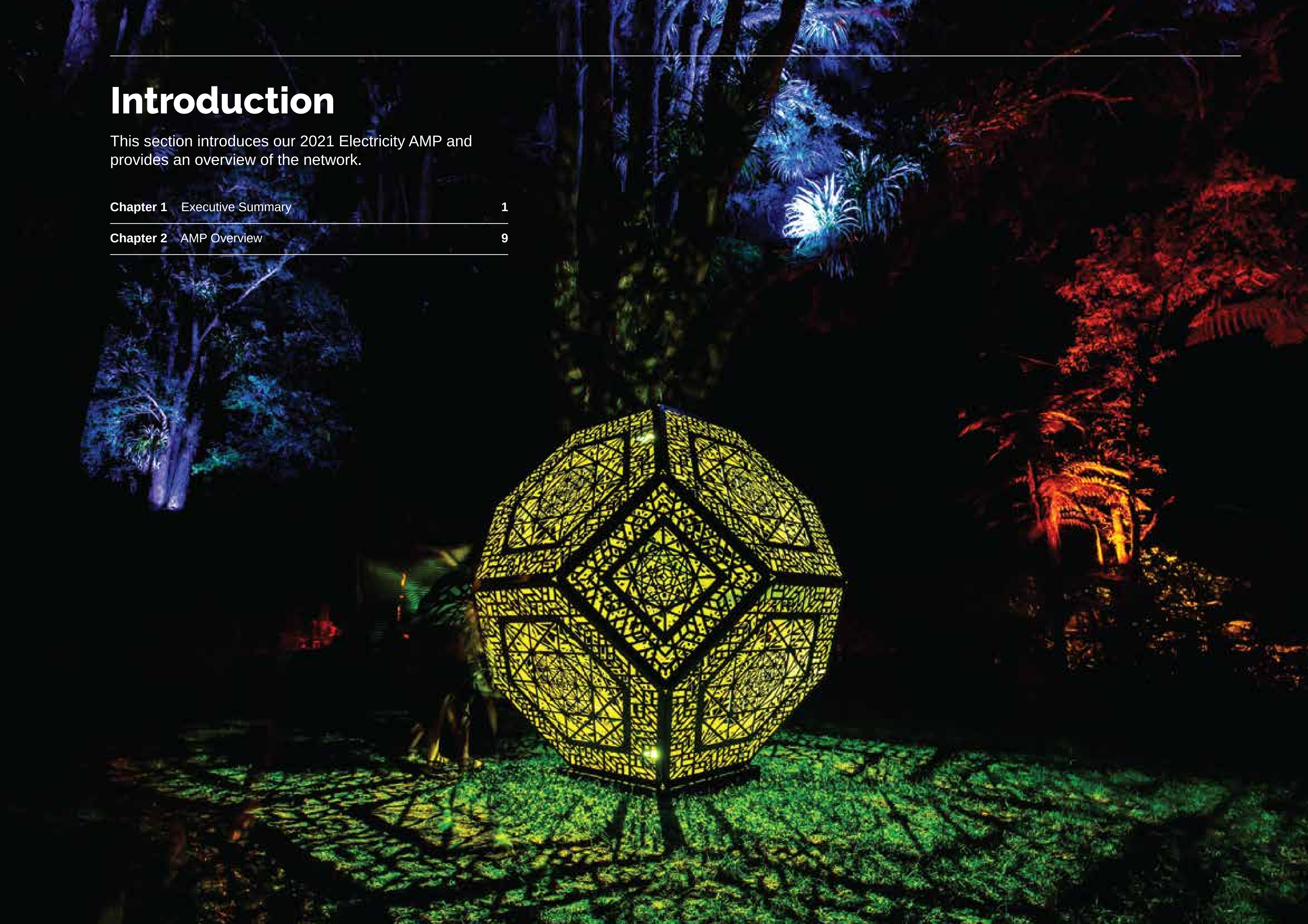


Introduction

This section introduces our 2021 Electricity AMP and provides an overview of the network.

1 EXECUTIVE SUMMARY

1.1 INTRODUCING OUR 2021 ASSET MANAGEMENT PLAN

The year 2020 proved to be extraordinary, opening our eyes in many ways to risks and opportunities we had never before contemplated. Electricity asset management was no exception.

The COVID-19 pandemic starkly underlined how important a secure electricity supply is to our modern society. Maintaining supply to essential services, such as communications networks and water treatment plants, and to our business and industrial customers, has always been front of mind. Working-from-home during the lockdowns showed just how vital supply security can be for our residential areas as well. The obvious corollary for us is that we have to consider these residential networks akin to our commercial ones. This has major implications on how we manage our low voltage (LV) networks, the “forgotten child” of distribution networks.

Even before COVID-19 put its mark on 2020, we had already kicked off a programme to have a fresh look at many of our established network practices. As we contemplate what follows when we move off our current customised price-quality path (CPP), it is essential that we consider the future needs of our customers and network. This relates to the potential impact of network and customer technology changes, and is also an opportunity to reflect on the efficiency of our core network practices and how these should evolve. We are acutely aware that in the longer term, the sustainability of our business will depend on us continuing to provide the best value to our customers, even as alternative energy choices open up to them.

In 2020 we also had an election, resulting in quite resounding support for a Government that has already indicated an acceleration in reducing New Zealand’s carbon emissions. This is alongside its natural strong focus on addressing community disparities – with energy affordability increasingly becoming a major social issue.

Even more recently, the Climate Change Commission (CCC) published its draft advice on the Government’s first set of emissions budgets to 2035 and the policy guidance to achieve them[1]. We expect the Government’s policy response to the finalised advice will lean heavily on the electricity sector. This will have a material impact on the way we build and manage our networks, as well as the timing and magnitude of our investment in them.

Our Asset Management Plan (AMP) outlines our plans for our electricity network for the next 10 years[2]. What we learned from the pandemic, the new network strategies we are developing, and considering how best to respond to expected Government and social directions, are important inputs into this year’s AMP. This is reflected in a number of material changes from our earlier plans.

At the same time, we recognise that electricity use patterns on our network are still mostly very stable. And with electricity a key enabler for economic prosperity and a modern lifestyle, our prime responsibility remains to supply our customers safely, reliably and efficiently. As such, it is essential that we continue to invest in our conventional assets to ensure they remain in appropriate condition and of sufficient capacity. Our traditional network investments for growth, renewal and reliability, therefore, remain the bulk of what we do, and this is reflected in the AMP.

They are also at the heart of our CPP programme. Delivering this successfully remains one of Powerco’s main Corporate Objectives. Our new AMP continues to build on the work we undertook in 2017 in preparing the CPP application, and our subsequent activities to fulfil our commitment to our customers to deliver to our plan.

Another main theme of the AMP is our ongoing commitment to helping New Zealand achieve its carbon reduction targets, agreed to in terms of the Paris Agreement (2015). We discuss how we will help meet the Government’s updated target of a 100% renewable electricity supply by 2030.[3] This means acting in an environmentally responsible manner in all our investment decisions and operational practices, as reflected in our environmental policy and our newly issued 2020 sustainability report.[4]

We are fully aware and excited about the significant potential for our network to help our customers reduce their carbon emissions – to create, use and save energy as efficiently as possible. We see as key to supporting New Zealand’s carbon reduction targets, our running of the network to open-access principles, offering maximum flexibility to customers with opportunity to innovate, connect to, and transact over our network with little impediment.

While future energy market arrangements are still being developed, we will ensure that the network remains safe, stable and provides sufficient capacity under any reasonable energy use scenario. The rate at which our network will transform will, ultimately, be dictated by our customers and their uptake of distributed energy generation or new devices connected to the network.

1.2 THE CPP PROGRAMME – ON THE HOME STRAIGHT

There are two years left of our CPP programme. During the first three years we have successfully ramped up delivery of the planned network projects, achieving or closely tracking our planned delivery targets. Our delivery processes are now well streamlined to continue work at current levels, and our planned asset management improvements have also progressed well.

However, considerable commitments remain for the last phase. Construction work will continue at unprecedented levels, particularly on major growth projects. In

[1] Climate Change Commission, “2021 Draft Advice for Consultation”, 31 January 2021

[2] The AMP planning period runs from 1 April 2021 to 31 March 2031.

[3] Under normal hydrological conditions.

[4] Powerco report, “Sustainability at Powerco”, located on https://www.powerco.co.nz/publications/sustainability-at-powerco/

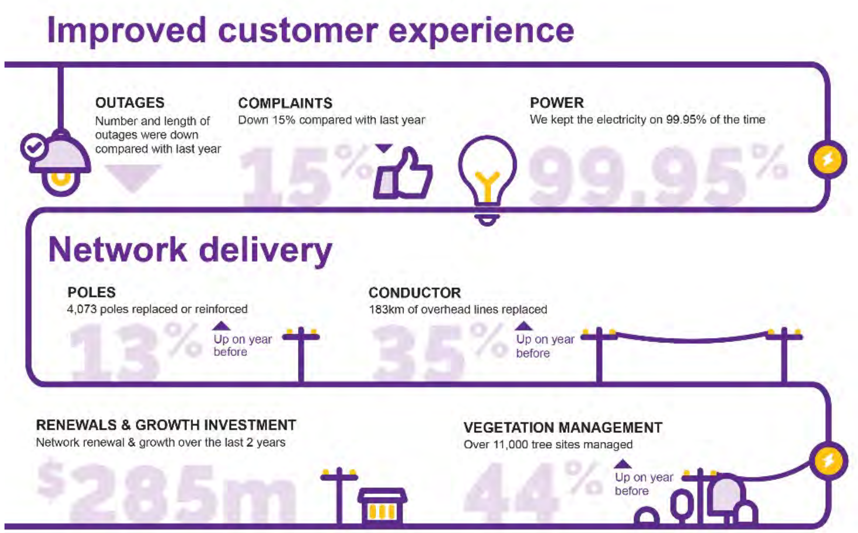
addition, we still have work to do to fully embed some of the new systems, tools and processes we have recently implemented.

1.2.1 WHAT WE HAVE ACHIEVED TO DATE

In terms of the Commerce Commission's final determination on our CPP application, we have to provide an Annual Delivery Report that provides extensive information on our delivery to date against the approved programme.[5]

Key high level delivery results to date are presented in Figure 1.1.

Figure 1.1: CPP delivery achievements for FY20

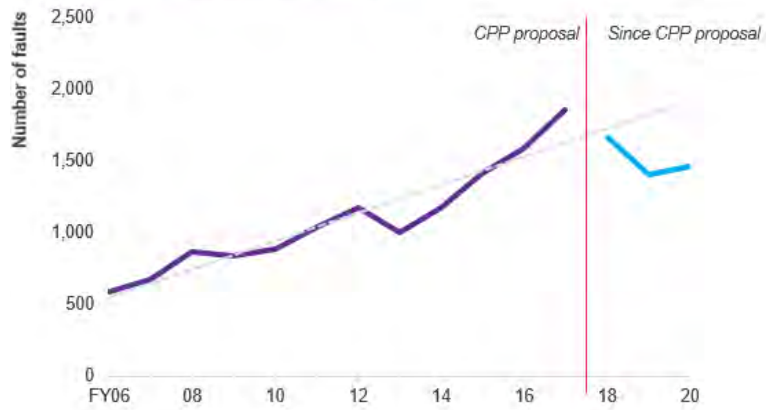


In looking at our network and asset performance in Figure 1.2, early indications suggest[6] stabilising outcomes – reflecting the increased focus on network renewals and defect management since 2017. We are cautiously optimistic that these trends will persist as we improve even larger parts of the network.

As part of the CPP application, we committed to a number of asset management improvement initiatives. This has progressed well, as witnessed by the following achievements of the past two years:

- Implementation of a new Enterprise Resource Planning (ERP) system which provides a modern, systematic foundation for our business, and importantly, a trusted time series of data for all our asset management decisions.
- Implementation of the Copperleaf C55 investment prioritisation tool.
- Development of effective Geographical Information System-based (GIS) overhead renewals planning tools.
- Development of condition-based risk models for several asset fleets.
- Good progress towards ISO 55001 certification (planned for mid-2021).
- Initiated several data quality improvement projects.

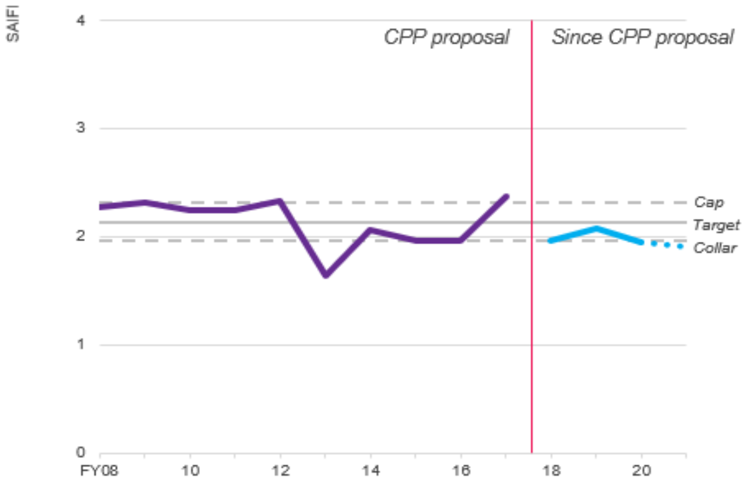
Figure 1.2: Improved network outcomes during the past three years – defective equipment faults



5 Copies of the ADR are available on https://www.powerco.co.nz/publications/disclosures/electricity/

6 While the early results are promising, network and asset performance are highly subject to external influences that vary greatly between years, such as extreme weather events. We would, therefore, not draw far-reaching conclusions from this limited data series.

Figure 1.3: Improved network outcomes during the past three years – unplanned SAIFI (normalised)



1.2.2 CHALLENGES REMAINING AHEAD

The full programme is not delivered yet. The last two years of the CPP still pose some big challenges.

We have a substantial project delivery schedule ahead, with major projects (individual value >$5 million), especially those to meet demand growth, making up two thirds of this. While planning and design of these works have progressed well, there are delivery risks, particularly around finalising the necessary line routes, property rights and resource consents.

Our renewal project volumes are not anticipated to grow further, but it remains challenging to deliver these projects within the constraints posed by the planned outage limits set under the CPP, particularly for planned SAIFI[7]. Changing work methodologies since 2017, particularly reducing live-line work, has meant substantial increases in SAIFI figures[8].

We have been expanding our assessment of network defects, for example through more inspections and our aerial pole-top photography and LIDAR[9] surveys. This gives us a much better view of asset condition, and enables us to prioritise our work with greater accuracy, which will, over time, result in fewer faults. The flip-side of this, however, is that in the short term, the list of known defects becomes larger, despite our extra effort.

Our new enterprise resource planning system (SAP) went live in late 2019. While this is providing valuable support in many areas, considerable work remains to fully integrate this with parts of the business and reach its full potential.

Addressing these challenges will be a major focus for the next two years and is reflected in the AMP.

1.3 LOOKING BEYOND THE CPP PERIOD

1.3.1 BUSINESS AS USUAL

A large majority of our customers continue to use centrally generated electricity as their key energy source. We do not predict this changing significantly in the foreseeable future. Importantly, our networks provide the “last mile” connection to customers. Even when renewable generation or grid-connected energy storage becomes much more widespread, it would not reduce customers’ reliance on our networks to access these. Likewise, to fully realise the potential benefit of locally generated electricity, customers will still need the distribution network to export their excess electricity, or to import at lean times.

Therefore, it would be imprudent to materially adjust investment and asset management plans now to make provision for uncertain needs that may arise in future. For the AMP planning period, we see most of our network expenditure remaining on conventional electricity network assets and practices.

Accordingly, we will continue to keep a strong focus on the health, capacity and operation of our existing network, as well as expand the network to meet the increased demand of new – and existing – customers. In terms of this AMP, it means that investment on asset renewal, maintenance and growth of conventional network assets will also remain paramount post our CPP period.

As recognised in our CPP application, a large proportion of our assets are reaching end-of-life – a situation we have started to address under the CPP programme. This trend will persist, and our data shows that for the foreseeable future, renewal expenditure will have to remain at current (CPP) levels in order to ensure stable health and reliability of our network.

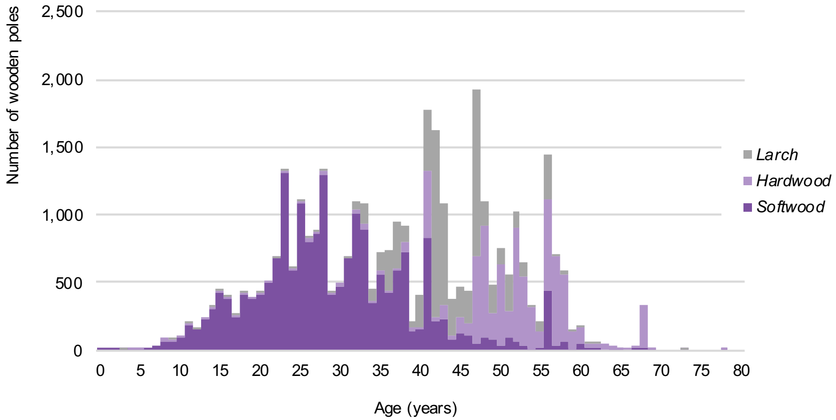
As an example, the age profiles for our wooden pole fleet is shown in Figure 1.4, and for our distribution conductors in Figure 1.5. With an average expected asset life of 45 years for wooden poles and 50-60 years for conductors, the extent of required future renewals is evident.

7 System average frequency duration index – a measure of the number of outages an average customer experiences per year.

8 This is compounded by the measures we are taking to reduce the length of outages during construction. For example, we have to measure a SAIFI incident both when we disconnect supply to allow for generation, and then again when we reconnect.

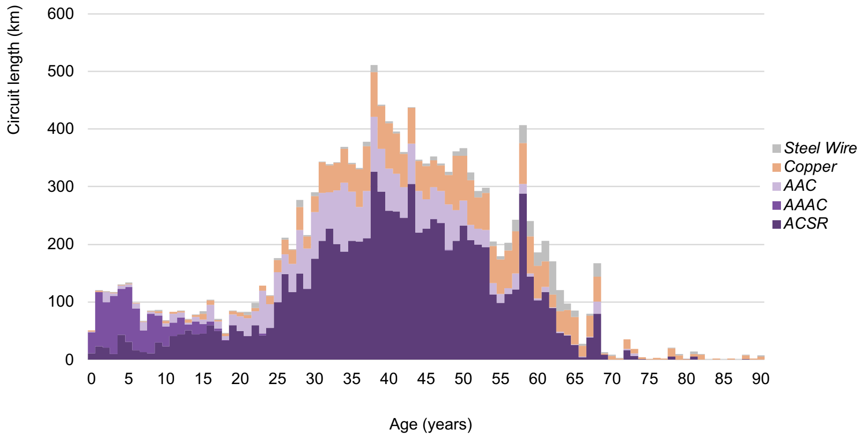
9 LIDAR is a method for measuring distances (ranging) by illuminating the target with laser light and measuring the reflection with a sensor.

Figure 1.4: Wooden poles age profile



Similarly, forecasts are for continued population and demand growth on large parts of our network. We will continue to expand and reinforce the network to cater for the needs of these new customers.

Figure 1.5: Distribution conductors age profile



1.3.2 EXTERNAL FORCES SHAPING OUR NETWORK

With base expenditure levels expected to remain largely at current CPP levels, our focus turned to what will likely change in the future. We do not underestimate the potential impact of longer term changes to our operating environment and in customers' energy use. Some of these important changes are discussed in Chapter 3, chief among which are:

- Ongoing, slow, organic network demand growth in populated areas.
- The ongoing need to reduce our environmental impact and to support our customers in this.
- Potential upcoming legislation or incentives to reduce New Zealand's carbon footprint.
- Electrification of New Zealand's transport fleet.
- Increasing distributed generation (particularly solar panels).
- Conversion of industrial processes, particularly heating, to low carbon energy sources. Much of the larger conversions will bypass distribution networks, but there are significant numbers of smaller, lower heat processes that will require additional demand from our networks.
- Changes in land use in rural areas, further reducing electricity demand – particularly in remote areas
- Energy poverty is emerging as a major issue for a significant part of our customer base.
- The (slow) evolution towards a distribution system operator (DSO).
- Changes in customer technology and how they manage their energy use, including the impact of the so-called 3Ds – decarbonisation, digitisation and decentralisation.
- Changes in network technology and the opportunities this provides.
- The risks posed by cyber attacks.
- The lingering impact of COVID-19 on our network and workforce. The associated increase in working from home has material implications for the value we place on the reliability of LV networks.
- Network resilience and sustaining supply in the face of climate change impacts.

These factors have been driving changes to our Asset Management Strategies, as described in Chapter 6. The impact is also reflected in our network development and renewal plans.

1.3.3 WORKING TOWARDS AN OPEN-ACCESS NETWORK

While many factors could change our future operating environments, of particular importance is the way our customers will use, generate and manage energy in the future. (After all, we exist because we deliver a product that our customers require!) Our evolving approach to understanding and addressing changing customer requirements and energy use patterns is outlined in our network evolution strategy in Chapter 6.2.

These changes on the customer side will likely be driven by a combination of factors, including the increased use of new technology (including own generation, electric vehicles and new types of appliances), increasing efforts to reduce carbon emissions, and an ongoing drive to reduce energy costs.

We have a responsibility to help facilitate these changes, allowing our customers to achieve their goals. One of the main contributions we can make is through effectively planning and operating the electricity distribution network in an open-access arrangement. This will allow customers and energy providers to connect their devices and easily conduct energy transactions over our networks with minimum restrictions. In turn, this will encourage renewable generation with associated carbon benefits.

Additionally, effective demand management, energy storage and tariff incentives will help maximise the utilisation of existing energy infrastructure and defer or minimise future investment. Electricity should also offset other, less environmentally friendly, forms of energy, and the network should facilitate this, for example electric vehicles offsetting the demand for petroleum.

Intense debates about how such open-access networks would look and be operated are under way around the world. New Zealand is still some way behind, but we are closely monitoring developments, particularly in Australia and the United Kingdom. We are committed to working towards providing a completely open-access network, which we see as an essential enabler for any likely future DSO, or similar arrangement.

Transitioning to an open-access network will require considerable effort and investment in providing the required visibility, controllability, flexibility and stability of all parts of the network – particularly in LV networks where the needs and impacts will be most severe. However, the timing at which this investment will be required is highly uncertain. At current uptake rates, material impacts from edge technology will only happen well beyond our CPP period, possibly even after this AMP planning period. Accordingly, while our AMP expenditure profiles make some provision for trialling technology and starting to improve the visibility and performance of our LV networks, we have omitted any major expenditure on transitioning to an open-access network.

However, we recognise that many factors could accelerate uptake rates – not least of which are those external factors discussed above. Should this occur, we will have to materially amend our future AMPs and consider other funding options.

This investment in preparing for open-access networks is discussed further in Chapter 6.

Why an open-access network?

Our customers are increasingly concerned about the impact of their energy use on the environment. They are interested in how their electricity is generated and how they can use it most efficiently. This local interest is reflected at a national level, with the Government committed to a carbon-neutral electricity supply.

In a fortunate convergence of improving technology and cost efficiency, our customers have:

- More choice and the power to exercise their values.
- An increasing ability to achieve significant reductions in their energy use footprint.

A key contributor is the ability to cost effectively generate on-premise electricity, through renewable methods such as solar panels or small wind generators.

This not only reduces electricity taken from the grid, but also holds potential for exporting excess capacity to other nearby customers, or allowing customers without their own generation to buy renewably created electricity from local suppliers and communities.

Other key factors are efficiency improvements in energy-hungry devices, and the ability to switch to renewable energy sources, particularly related to transport and heating.

The limits of today’s networks

The design of traditional electricity networks, however, limits the extent to which renewable generation, or large variable loads, can be accommodated.

Networks were designed for one-way power flows from large generators to end customers, who used mainly passive appliances. Connecting significant volumes of distributed generation, or large, rapidly varying loads to a network not designed for it, can at times cause serious power quality and network instability issues.

Without substantially changing the nature of distribution networks and how they operate, the only mitigation options for electricity distribution businesses (EDB) are to make major reinforcements to the network or constrain customers in what they can connect and how they can use the network.

Limiting choice is bad for customers.

Conventional network reinforcement is an expensive and, generally, inefficient solution to short-term power fluctuations. Constraining customers in what or how much they can connect to the network will greatly inhibit their ability to manage their use and reduce their electricity carbon footprint – thereby foregoing one of the more important levers New Zealand has to achieve its overall environmental. targets.

Networks of tomorrow
In our view, the best way to achieve customers' goals is by operating an open-access distribution network. This will be achieved by:

– Applying suitable developing technology.
– Much improved visibility of power flows and utilisation.
– Increased network automation.
– Improved data and analytics.

Essentially, this future network would allow customers to be largely unconstrained in what they could connect to the network and how they would use it to support their energy transactions – purchasing and exporting electricity.

Our role will be to ensure that networks have the capacity to cope with our customers' evolving energy needs, while remaining safe, stable and efficient.

1.4 OUR 10-YEAR EXPENDITURE FORECASTS

1.4.1 OVERVIEW

Our expenditure forecasts are based on our best current information regarding network use and performance trends, and a prudent allowance for readying the network for expected future changes. The forecast 10-year expenditure base case trend in Figure 1.6 reflects this view.

However, as we have also noted, there is considerable uncertainty surrounding the future use of electricity. In particular, there is significant potential for higher uptake of distribution edge devices associated with increasing trends to decarbonisation. This would be further accelerated by legislation in response to CCC recommendations. These factors could have a major impact on required network expenditure. However, in light of the timing uncertainty, we have not made material provision for this in our AMP expenditure forecast.

For the AMP base case scenario, we forecast our investment during the planning period to initially remain around current CPP levels, approximately $200 million per annum on capital expenditure and $100 million on operational expenditure. This will allow us to continue to address asset condition and security related issues. It will also help ensure we continue to meet our customers' service expectations and support the growth of the communities we serve.

Reverting to a default price-quality path (DPP) in FY24 will see a stabilisation[10] in our capital expenditure allowance, which is reflected in the AMP forecast.

Expenditure is forecast to grow marginally later in the planning period as we provide for some increased investment, especially on automation, limited LV network improvements, and allowing for small-scale process heat conversion. As these increases will have to be managed within regulatory settings, we will be constrained in what we can accommodate.

1.4.2 CAPITAL EXPENDITURE

Our planned capital investments for the 2022-2031 period are set out in Chapter 28. The initial years reflect a targeted blend of investment across growth and security, asset renewal and non-network categories. This provides for:

- Sustained investment in asset renewals – post CPP expenditure is expected to stay at current CPP levels. We forecast a constant level of expenditure is required to manage the health of our overhead fleets.
- Sustained investment in growth and security – network growth investment is forecast to remain consistent with CPP levels. During the CPP our expenditure predominantly focused on improving breaches in security of supply.
- Modest expenditure on research and development, trials of emerging technology, and starting to improve our LV network visibility and performance.
- Information and communications technology (ICT) and other non-network expenditure are set to remain roughly at current levels as we continue to invest in an Advanced Distribution Management System (ADMS), extend our ERP foundation, and complete a major upgrade to our GIS.

The forecast later in the planning period reflects a sustained investment on the core network areas, with limited allowance for accelerating work on the following:

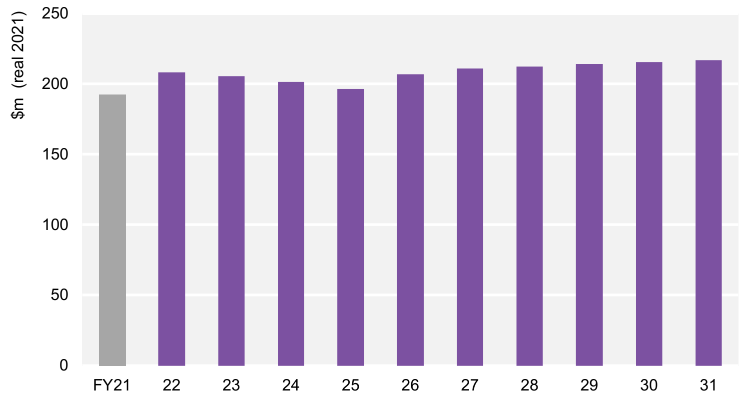
- Improving the visibility and performance of critical LV networks where congestion and/or power quality issues are a factor.
- Increased network automation, to increase the resilience of our network, and the reliability of our worst-served areas. (This is also to avoid or defer conventional network expenditure.)
- A provision for the anticipated acceleration of process heat conversions (smaller scale) and the resulting increased network demand.

Some significant increases in ICT expenditure are foreseen because of further investment in ADMS, ERP and cyber security, and the renewal of the growing number of ICT solutions and their enabling infrastructure. Expenditure during the last two years of the CPP period of the planning window is largely consistent with our CPP allowance – limited increases are foreseen resulting from increasing customer connection activity, and a potential increase in the volume of Transpower

10 Note that at this stage the method by which we will move off our current CPP has not yet been clarified by the Commerce Commission, so this is based on our current understanding of the Input Methodologies.

initiated outdoor-to-indoor switchgear conversion works. Our expected capital investment during the planning period is set out in Figure 1.6.

Figure 1.6: Forecast capital expenditure (AMP base case)



1.4.3 OPERATIONAL EXPENDITURE

The focus for operational expenditure during the planning period is set out in detail in Chapter 28. Our updated operational expenditure for the AMP planning period is in line with our previous AMP and CPP forecasts, and is anticipated to remain stable during the whole planning period.

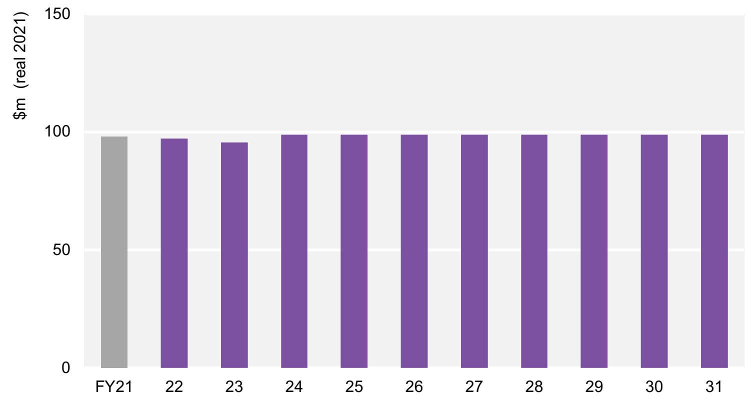
However, we anticipate significant upwards pressure on operating expenses over coming years, resulting mainly from the following:

- The uptake of new digital solutions, including cloud services, with associated higher data network, software maintenance or subscription costs.
- The increasing discovery of asset defects associated with our programme of improved and expanded inspection to improve network safety and reliability.
- Upwards pressure on contracting rates.

Absorbing these increases will require considerable focus on our system operations and network support (SONS) and business support expenditure to achieve business efficiencies. We anticipate that our improving ICT systems, as well as ongoing asset management and process improvements, will allow us to achieve this. We also intend to review our maintenance approach in depth, to ascertain potential for reduced expenditure by adopting improved reliability and criticality centred approaches, without materially increasing the network risk profile.

Our expected operational expenditure during the planning period is set out in Figure 1.7.

Figure 1.7: Forecast operating expenditure



1.5 ACCELERATED DECARBONISATION SCENARIO

Current New Zealand uptake rates of distributed generation, electric vehicles or other new distribution edge devices are still low. However, under the right circumstances this could accelerate significantly. Implementing the recommendations of the CCC could be a catalyst for such change.

To accommodate substantial changes in customer energy use patterns could require substantial network input. In particular, acceleration of the following would lead to increased, or more variable, electricity demand:

- Electrification of process heat.
- Increased use of electric vehicles.
- Increased use of distributed generation, particularly where outputs are highly variable.
- Conversion of household gas use to electricity.

The anticipated impact of this on network demand remains very uncertain. It will depend not only on uptake rates, but also the degree to which we will be able to manage the additional load. The current daily network demand profile includes a prominent early morning and late afternoon/early evening peak. The evening peak, in the winter, represents the overall coincident maximum demand on our network and, therefore, broadly determines the volume of assets required to serve our customers. Any additional demand during the peak periods could require us to invest in additional network capacity.

For example, our modelling indicates that, on the whole, our network should be able to accommodate the CCC's suggested 40% (by 2035) uptake of electric vehicles with relatively little change, as long as these are charged during off-peak periods, between 9pm and 6am. Conversely, with uncontrolled late afternoon/early evening charging, it could add as much as 16% to the network peak demand. To meet this could require additional network reinforcement expenditure in excess of $350 million.

Similarly, should residential gas connections be converted en masse to electricity, it could add significantly to electrical peak demand, particularly for water heating. However, if we are able to reduce the additional demand, as is traditionally done with hot water control systems (for example ripple control), the overall impact should be manageable.[11]

While an allowance is already included in the AMP base case for anticipated smaller scale process heat conversion, should this trend accelerate more rapidly than expected, it will be necessary to bring forward expenditure. (Given the relatively flat and extended load curves, these applications generally offer less possibility for effective demand management.)

As noted in Section 1.3.3, we encourage the connection of distributed generation to our network and our open-access network strategy is predicated on helping facilitate this. However, as also noted, this transition will require network investment to maintain network stability and to effectively balance energy in-and-out flows – primarily on network visibility and metering, automation and power conditioning. Depending on the rate of this transition, and the extent to which we can share infrastructure with others, we estimate this could require additional investment upwards of $120 million over the AMP planning period. This is considerable, but still lower than the alternative of the conventional network reinforcement required to provide the same outcome. Even worse in the long run, would be the cost to society of not investing in our network and thereby having to restrict the potential for major decarbonisation opportunities.

We will continue to monitor emerging trends and legislative changes and adapt our future investment plans – as will be reflected in future AMPs. However, the uncertainty about resulting network impacts, and the timing for this, represents a major risk for a regulated distribution utility operating under a revenue cap set in advance, for five-year periods. We, therefore, believe it is imperative that regulatory rules are reviewed to consider not only how EDB revenue settings could be effectively adjusted within a regulatory period in response to major energy policy changes, but also how to facilitate the availability of network capacity and capability for customers to pursue decarbonisation measures. This may require consideration of expenditure allowance (on enabling infrastructure) in advance of the actual need.

11 Some upgrades of existing hot water control systems may be required, as well as a roll-out of receivers at some homes. The cost for this is anticipated to be substantially lower than reinforcing network capacity. In addition, it should be increasingly feasible to use smart meters, equipped for hot water control, instead of dedicated receivers.

2 AMP OVERVIEW

2.1 CHAPTER OVERVIEW

Powerco is a privately owned utility with two institutional shareholders.[12] We operate the largest network of electricity distribution lines in New Zealand by geographical area and network size, serving about 340,000 connected customers.

This chapter provides the context for our 2021 Asset Management Plan (AMP). It outlines its purpose and objectives, who it is written for and how it is structured. It also introduces our network and provides an overview of the zones, network configurations and assets on our network.

2.2 PURPOSE OF THE AMP

We recognise that the investment decisions we make impact homes and businesses around New Zealand, now and in the future. The purpose of our AMP is twofold:

- Provide our stakeholders a view of our long-term plans, to give them certainty and confidence in how the network is managed and that their expectations will be met, which supports their own longer term energy planning.
- Document and communicate, for internal purposes, our asset management strategies and plans, including our detailed investment and operations plans, which inform our annual Electricity network budgets.

During 2020, we undertook a detailed review of our future network strategies and plans, particularly with an eye on needs following the end of our current Customised Price-quality Path (CPP) period (2024 onwards). In the 2021 AMP we discuss:

- Our view on the future architecture, function and operation of the network.
- Operational and investment needs we foresee after the CPP period to maintain a reliable and safe network.
- Our understanding of the likely future needs of our customers and how we intend to evolve to meet these needs.
- The challenges and opportunities new technology could bring for electricity networks.
- Our response to potential changes in future energy policy and meeting our environmental obligations.

12 Queensland Investment Corporation (58%) and AMP Capital (42%).

2.2.1 AMP OBJECTIVES

The objectives of our 2021 AMP are to:

- Help our stakeholders understand our asset management approach, providing clear descriptions of our assets, key strategies and planned investments.
- Advise interested parties about major network investment plans and the potential opportunities to offer alternatives to these plans. We are committed to considering such offers where these are practical and would provide economically viable, equivalent customer service levels.
- Discuss how we will respond to changes in the electricity distribution environment.
- Explain our Asset Management Objectives and targets, and how we plan to achieve them.

2.2.2 AMP PLANNING PERIOD

Our AMP covers a 10-year planning period, from 1 April 2021 to 31 March 2031.[13] 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 25 March 2021.

2.2.3 OUR STAKEHOLDERS

A key objective of our AMP is to provide information to our stakeholders about how we manage our assets, and where we intend to invest for future network growth or for maintaining the good health of our assets. We explain how our plans and decisions arise and are implemented. Our key stakeholders and their principal interests are summarised in Table 2.1.

13 A brief overview of our longer term, bulk supply planning is also given.

Table 2.1: Key stakeholders and their main interests

STAKEHOLDER	MAIN INTERESTS
Our customers	Service quality and reliability, price, safety, connection agreements, flexibility, ability to innovate in their energy arrangements and use
Communities, iwi, landowners	Public safety, environment, land access and respect for traditional lands
Retailers	Business processes, price, customer service, reliability, connection agreements
Commerce Commission	Pricing levels, effective governance, quality standards, appropriate expenditure, effective asset management, information disclosure
State bodies and other regulators	Safety (WorkSafe), market operation and access (Electricity Authority), environmental performance (Ministry for the Environment)
Employees and contractors	Safe and productive work environment, remuneration, training and development, planning documentation, security of employment, information and tools supporting effective work
Service providers	Safe and productive work environment, consistent workflow, remuneration, training and development, planning documentation, security of employment, information and tools supporting effective work
Transpower	Technical performance, technical compliance, bulk supply planning
Our investors	Efficient management, financial performance, governance, risk management
External energy service providers	Business opportunities, effective network access, ability to transact over the network

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

2.3 STRUCTURE OF THE AMP

The diagram below sets out the structure of the AMP, including the sections (grey boxes) and the chapters within these. Appendix 10 maps the chapters and appendices to relevant Information Disclosure requirements.

INTRODUCTION
This section introduces our 2021 AMP and provides an overview of the network.

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

2 **AMP Overview**
The purpose and structure of our AMP and the footprint and types of customers it applies to.

ASSET MANAGEMENT STRATEGY
The context, objectives and strategies driving our investment. Where we are heading in the future.

3 **External Forces Shaping Our Network**
Provides an overview of the externalities that we consider while developing our AMP.

4 **Asset Management Objectives**
Details the service we plan to deliver for our customers and reviews our performance.

5 **Core Asset Management Strategies**
Our core strategies for achieving our objectives and managing the network.

6 **Evolving Asset Management Strategies**
Where we are today.
The trends impacting us.
What we are aiming for.
The steps we are implementing to get us there.

7 **Network Targets**
Outlines our detailed targets for achieving our Asset Management Objectives.

ASSET MANAGEMENT SYSTEM
How we organise ourselves to deliver our services.

8 **Asset Management System Overview**
Outlines the scope of our Asset Management System (AMS).

9 **Developing Our Strategy**
How we align our Asset Management Plan with the overall organisation's objectives.

10 **Decision-Making**
How decisions are managed at various stages of an asset's lifecycle and at multiple levels of our organisation.

11 **Lifecycle Management**
How we acquire, operate, maintain and dispose our assets.

12 **Risk Management**
How the structure of our AMS enables risk management across the business.

13 **Organisation and People**
How we organise ourselves and coordinate activities across various groups.

14 **Information Management**
How we manage information to enable our asset management process.

NETWORK DEVELOPMENT
Our plans to develop and improve our network's response to customer change.

Growth and Security (15)
Our plans to ensure supply security and a summary of our area development plans.

Reliability and Automation (16)
Explains what we plan to invest in our automation systems to enhance network reliability and performance.

Customer Connections (17)
Explains how much we plan to spend to connect new customers to our network.

FLEET MANAGEMENT
Our plans to manage our existing assets to deliver a safe and reliable service.

- (18) **Overhead Structures**
- (19) **Overhead Conductors**
- (20) **Cables**
- (21) **Zone Substations**
- (22) **Distribution Transformers**
- (23) **Distribution Switchgear**
- (24) **Secondary Systems**
- (25) **Vegetation Management**

For each portfolio we describe:

- High level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition and risks
- Preventive maintenance tasks
- Renewal forecasting

Asset Relocations (26)
Discusses how we facilitate relocations of existing assets for third parties.

Non-Network Assets (27)
Sets the roadmap for our non-network assets and how they will meet the needs of our customers and our business.

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

Expenditure Forecasts (28)
Provides an overview of the Opex and Capex forecasts for the planning period. It explains our inputs, assumptions and cost estimation approach.

2.4 OUR NETWORK

2.4.1 NETWORK CONFIGURATION

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

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

- **Subtransmission** – mostly 33 kilovolt (kV) 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.

We take bulk electricity supply from the Transpower network at several grid exit points (GXPs), generally converted to subtransmission voltage levels. For electricity flowing from a subtransmission circuit to a distribution circuit, it passes through a transformer housed in one of our zone substations. When electrical flow is from a distribution circuit into the LV network, a smaller ground or pole-mounted distribution transformer is used.

2.4.2 TRANSMISSION POINTS OF SUPPLY

Our place in New Zealand's electricity sector is illustrated in Figure 2.1

Figure 2.1: Our place in the electricity sector

Generation	Transmission	Distribution	Retail
Electricity is generated across New Zealand using water (hydro), wind, geothermal, gas and coal stations.[14]	This electricity is transported from generators to distribution networks using the national grid, owned and operated by Transpower.	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.

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

Our network connects to the national grid at voltages of 110kV, 66kV, 33kV and 11kV via 30 points of supply or GXPs. These GXPs are where our network and Transpower meet and interact. The national grid carries electricity from generators throughout New Zealand to distribution networks and large directly connected customers.

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

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

Detail on the GXPs in each zone and associated network maps can be found in Chapter 15.

2.4.3 REGIONAL NETWORKS

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

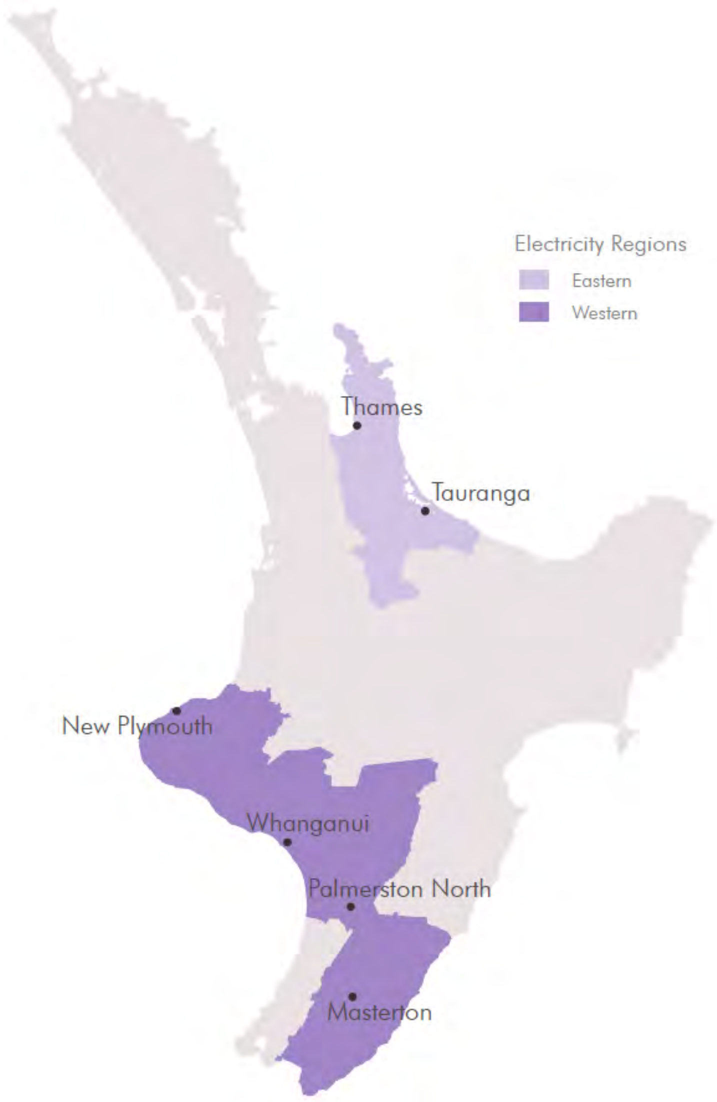
Our development as a utility included several mergers and acquisitions that have led to a wide range of legacy asset types and architecture. This requires an asset management approach that accounts for these differences, while seeking to standardise network equipment over time.

Table 2.2 provides summary statistics relating to our assets in the Eastern and Western regions. Figure 2.2 provides a geographical overlay of these regions.

Table 2.2: Key regional statistics (2020)

MEASURE	EASTERN	WESTERN	COMBINED
Customer connections	163,045	181,139	344,184
Overhead circuit network length (km)	7,143	14,492	21,635
Underground circuit network length (km)	3,631	3,175	6,806
Zone substations	53	69	122
Peak demand (MW)	488	450	923
Energy throughput (GWh)	2,769	2,412	5,181

Figure 2.2: The regions we cover



2.4.4 EASTERN REGION

The Eastern region consists of two zones – Valley and Tauranga – which have differing geographical and economic characteristics presenting diverse asset management challenges.

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

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

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

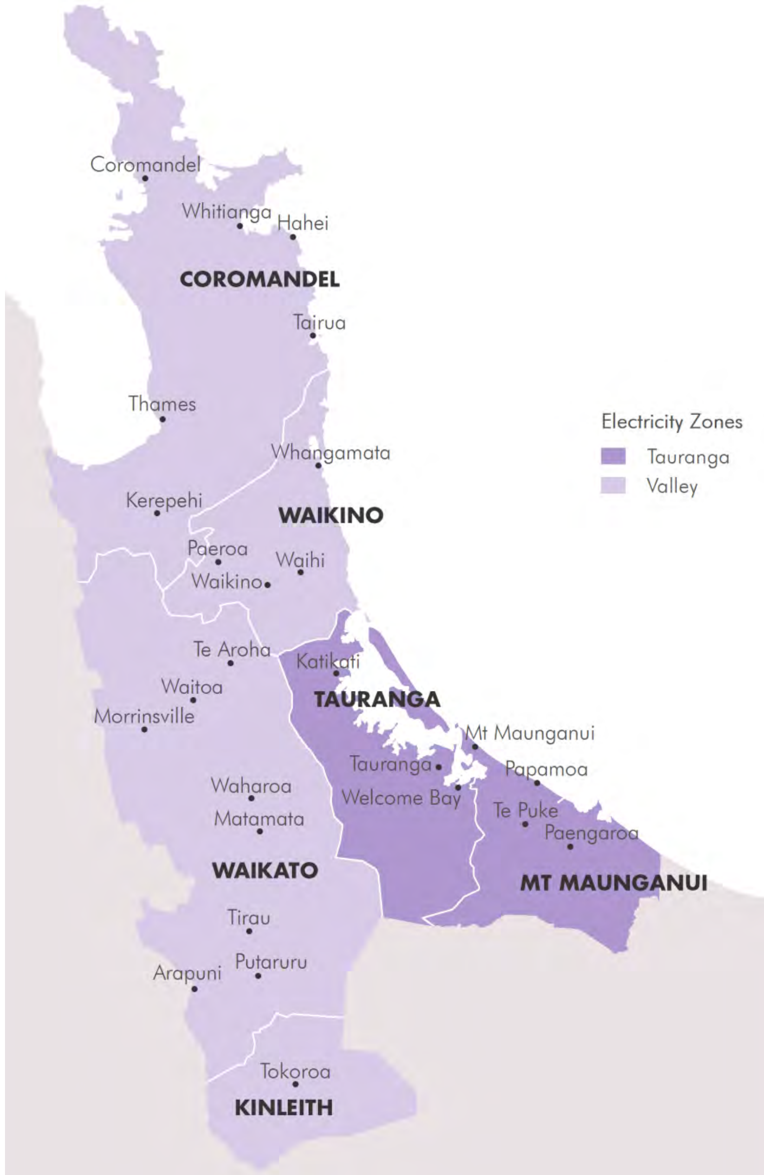
  Investment priorities have focused on improving network security and resilience, and developing better remote control and monitoring facilities.

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

  The principal investment activities in this zone have been associated with accommodating the rapid urban growth in Tauranga, maintaining safe and reliable supplies to the port, supplying new businesses, and supporting the horticultural industry.

The map in Figure 2.3 shows the Eastern region network footprint and planning areas.

Figure 2.3: Eastern network and planning areas



2.4.5 WESTERN REGION

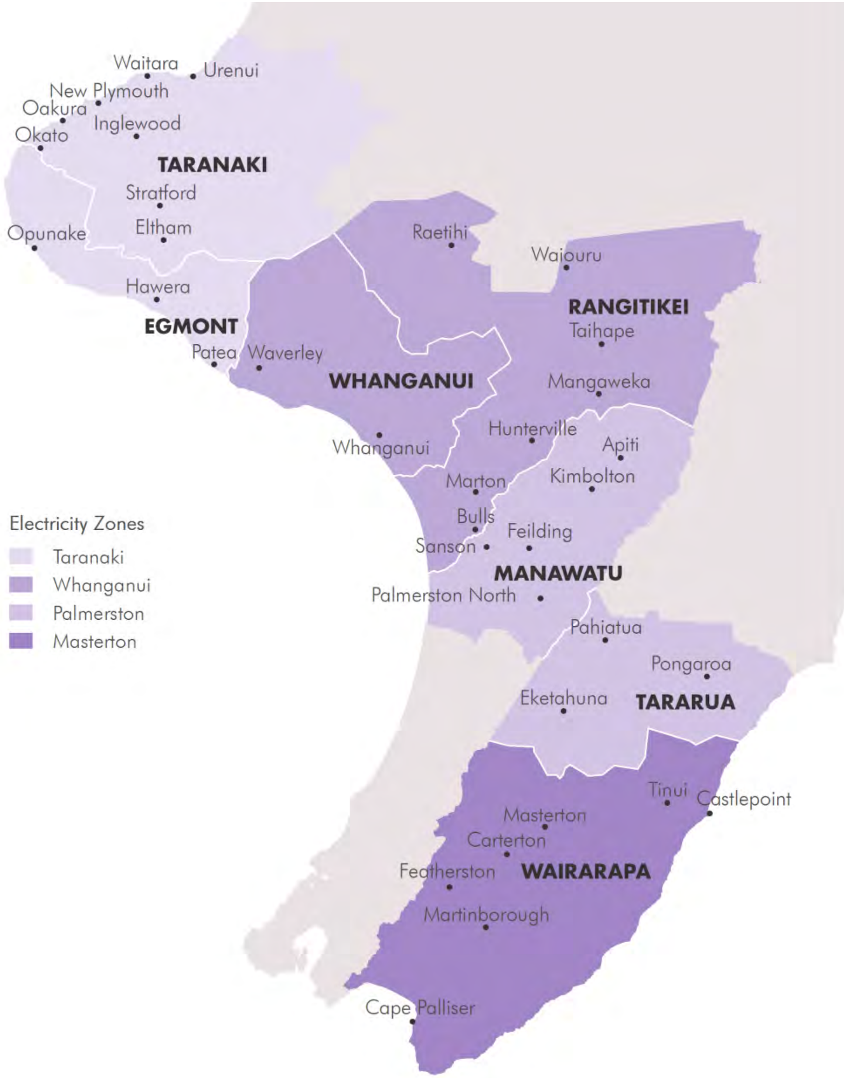
The Western region comprises the four network zones described below. Similar to the Eastern region, these zones have differing geographical and economic characteristics, presenting various asset management challenges. Because of the age of the network and, in particular, the declining asset health of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

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

The investment priorities in these regions are largely to meet growth requirements (mainly around Whanganui, Palmerston North, Wairarapa and New Plymouth) and to renew assets at end-of-life or in poor condition.

The map in Figure 2.4 shows the Western region network footprint and planning areas.

Figure 2.4: Western network and planning areas



2.5 ASSET SUMMARY

2.5.1 OUR ASSET FLEETS

We use the term “asset fleet” to describe a group of assets that share technical characteristics and investment drivers. We categorise our electricity assets into 25 such fleets. These in turn are organised into the seven primary portfolios below.

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

Our approach to managing our asset fleets is explained in Chapter 9.

2.5.2 ASSET POPULATIONS

Table 2.3 gives an overview of our asset populations across our full Electricity network[15]. The large number of assets in certain fleets, eg 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 18 to 24.

Table 2.3: Asset population summary (2020)

ASSET TYPE	POPULATION
Overhead network	
Subtransmission (km)	1,496
Distribution (km)	14,780
LV (km)	5,360
Underground cables	
Subtransmission (km)	245
Distribution (km)	2,142
LV (km)	4,420
Overhead structures	
Poles	264,317
Crossarms	442,115
Zone substations	
Power transformers	216
Indoor switchboards	138
Buildings	154
Distribution assets	
Transformers	36,358
Switchgear	44,861
Secondary systems	
Zone substation protection relays	2,401
Remote terminal units	313

15 Some population quantities in the table vary slightly to Information Disclosure because of the use of different classifications for fleet management planning.

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Asset Management Strategy

The context, objectives and strategies driving our investment.
Where we are heading in the future.

3.1 INTRODUCTION

We build electricity networks to serve our customers' needs. The energy sector sits at the cutting edge of several societal mega-trends, which will likely accelerate change in how our customers use and produce electricity. Potential material changes include:

- **Changes to our customer base** – This pertains to population movements, demographics, changing land-use patterns and increasing energy poverty.
- **Legislative and electricity market changes** – This includes measures to reduce New Zealand's carbon footprint, the evolution of distribution networks to a Distribution System Operator, and other potential regulatory changes.
- **Technological changes** – This includes, changing customer energy technology or devices, new network technology, increasing cyber security risk, and a reduction in grid inertia with associated stability implications.
- **Managing business environmental footprint** – The increased incentives and pressure for businesses to better manage their environmental footprint.
- **Impact of Covid-19** – The potential longer term implications for distribution networks.

To respond appropriately to these changing needs, we have to consider the immediate and potential longer term impact of these large societal changes on our business (our assets are typically expected to perform upwards of 45 years).

In this chapter we explore some of the more important trends we observe that influence our strategies and our network. Our plans to respond to these form the basis of our Asset Management Plan (AMP), as set out in the following chapters.

3.1.1 HISTORICAL ELECTRICITY DEMAND

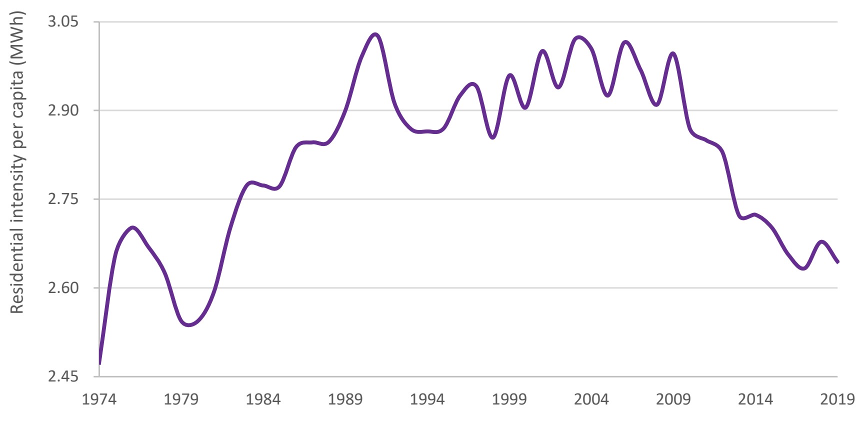
From the early 1900s to 2007, national electricity consumption increased steadily, primarily driven by increased use in the commercial sector and a growing population base. During the past decade, national demand has remained relatively flat, despite continuing population and gross domestic product (GDP) growth. New Zealand's per capita consumption of electricity in the residential sector has decreased by 13% since 2009. This is a trend reflected across many Organisation for Economic Co-operation and Development (OECD) economies.

Increases in residential consumption from the 1970s to the 2000s was primarily attributed to the increase in the range and use of electric household appliances, including the increased use of electricity for heating and hot water. The subsequent decrease in consumption has been attributable to improvements in energy efficiency, eg the increased use of heat pumps instead of resistive heating, LED light bulbs, better home insulation etc. The changing energy use intensity in New Zealand, up to 2019, is shown in Figure 3.1.

From a distribution network perspective, further changes in supplied energy levels (as opposed to consumed energy levels) are expected as the technologies for generating and storing electricity become more affordable and practical. As consumers take a greater part in generating and managing their own electricity, whether this is for environmental, economic or reliability reasons, we expect bigger changes in per capita energy consumption flowing over our network. This is likely to be at least partly offset by increased use of our network to convey excess locally generated supply to other consumers.

Energy consumption and demand on the Powerco network in recent years has not decreased. If anything, average peak demand per connection point has continued to increase during the past decade, while even average energy use has shown a marginal increase, particularly in the past three years. This is illustrated in Figure 3.2: Energy consumption and demand per ICP on our network.

Figure 3.1: New Zealand energy intensity per capita for residential customers 1974 to 2019[16]



[16] Source: Ministry of Business, Innovation & Employment: Energy in New Zealand 19 https://www.mbie.govt.nz/dmsdocument/7040-energy-in-new-zealand-2019

Figure 3.2: Energy consumption and demand per ICP on our network

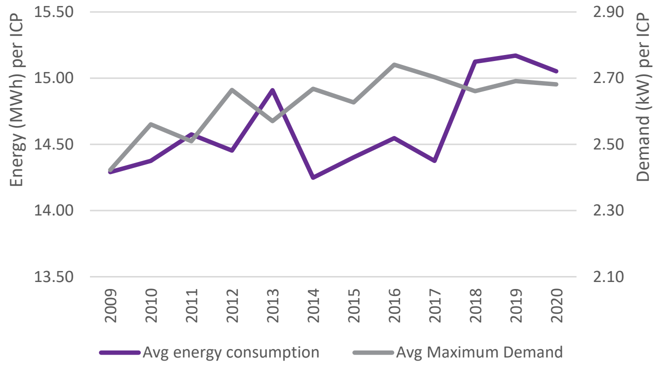
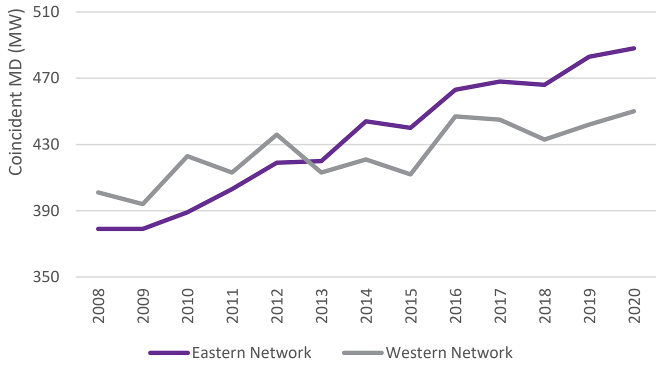


Figure 3.3: Peak demand growth on the Powerco networks East v West



3.2 CHANGES IN OUR CUSTOMER BASE

The size, demographics and primary activities of our customer base have a major influence on electricity consumption on our network. These factors have tended to follow relatively stable trends, which form key inputs in our network planning.

3.2.1 POPULATION MOVEMENTS

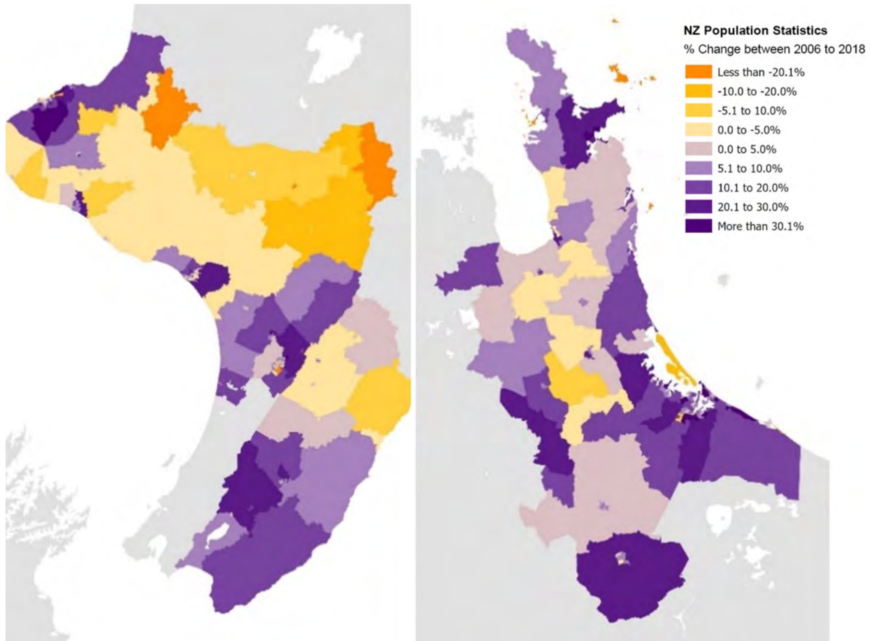
Our distribution networks cover a large part of the North Island, spanning areas with distinctly different population growth trends. While we have experienced overall population growth on the networks, the varying rates at which this is occurring across our regions are illustrated in Figure 3.2. The impact of current restrictions on immigration is uncertain, but we foresee these growth trends broadly persisting throughout the AMP planning period.

As shown in Figure 3.2: Energy consumption and demand per ICP on our network, overall network demand is still growing at a constant
rate, along with increasing customer numbers. But the growth is uneven across the network, with some areas showing materially higher growth than others.

The Tauranga region, in particular, is experiencing ongoing population growth from movement inside New Zealand, with an ongoing demand for new housing. To a somewhat lesser extent, population growth pressure is also being experienced in Whanganui, Wairarapa, and Palmerston North and surrounding areas.

Conversely, the longer term population impact in Taranaki of government decisions to curtail oil and gas exploration is still uncertain. At present, modest growth is persisting.

Figure 3.2: Population growth rates in territorial authority areas between 2006 and 2018[17]



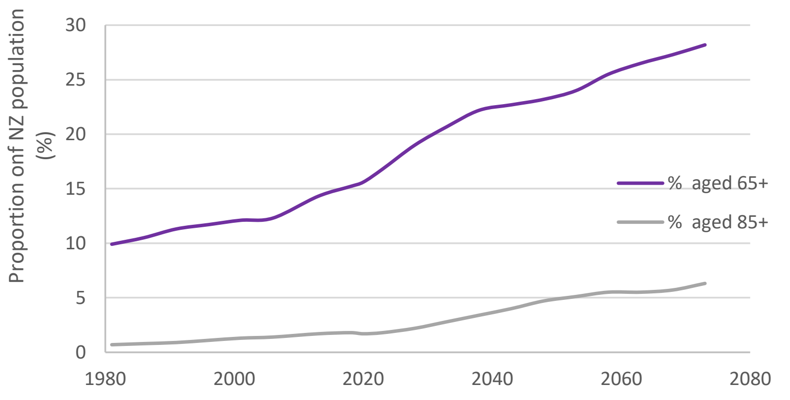
17 Stats NZ Census 2018 information. (Note: chart reflects relative change, not absolute numbers of population)

3.2.2 POPULATION DEMOGRAPHICS

The New Zealand population is ageing and there is a growing proportion of customers forecast to reach retirement during the next decade. (See Figure 3.3.) At present the impact of this trend is not significant from a network development perspective. We will, however, continue to monitor the impact and adjust our future investment plans as necessary.

The ageing population does, however, have a direct impact on our business operations. As a large portion of the workforce retires, it takes with it a generation of acquired knowledge and know-how about our network. How we capture and institutionalise this knowledge, and train the next generation of talent, will be a challenge that will be addressed by new information and knowledge management capabilities and resourcing strategies.

Figure 3.3: Population aged 65+ and 85+ (historic and forecast)[18]



3.2.3 CHANGING LAND-USE PATTERNS

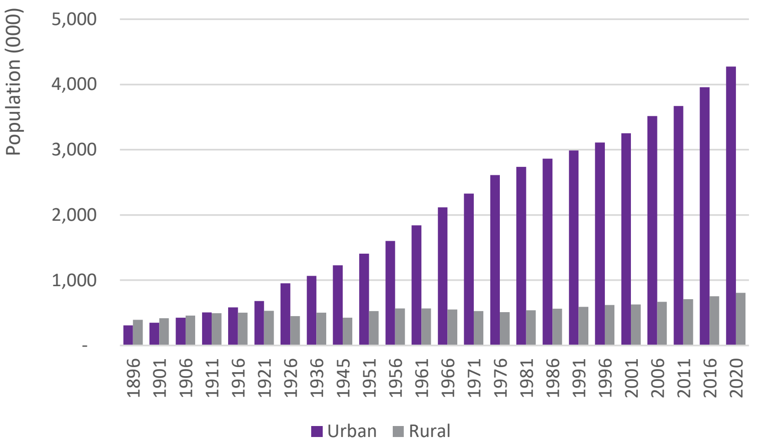
Most of our customers are urban-based, with a concentration in Tauranga, Palmerston North, New Plymouth, Whanganui and a number of medium-sized regional centres. In our urban areas, energy demand growth is largely driven by population movements and associated commercial activities. However, given the large size of many industrial plants, the opening or closure of any of these can also have a material impact on regional electricity demand.

Outside the development of new residential areas to meet population growth requirements, the primary land-use trend we observe in urban areas is the increasing densification of residential areas. As yet we have not reached a clear conclusion on material differences in individual household consumption patterns between traditional and more dense urban areas.

While the volume of electricity consumption on our rural networks is generally much lower (than suburban or urban), these make up the bulk of our assets. As the nature of farming changes, electricity consumption changes accordingly. Many of these trends are still developing, and we will continue to monitor long-term changes in land-use and plan for the likely impact. Based on our observations to date, the following trends will likely have a material impact on our network and how we meet their demands.

- In recent decades, land conversion to dairy farming has caused additional energy demand on parts of our network. This trend now appears to have slowed down, with demand stabilising.

Figure 3.4 : Urban v rural population growth 1896-2020[19]



- Over time, we have observed a decline in sheep farming in many parts of the network. This was partly driven by dairy conversions, but much of the land is also being repurposed for forestry. Energy consumption at sheep farms is generally low, but consumption in forestry-dominated areas is much lower still.
- More recently, there appears to be an increase in bee farming in rural parts of our network. There is increasing evidence of forestry areas and traditional farms being converted for this purpose. Energy consumption on bee farms is generally very low, especially if these are not permanently inhabited.

18 Source: Combined datasets from https://www.ehinz.ac.nz/indicators/population-vulnerability/age-profile/ (historic) & Stats NZ (forecast)

19 Source: Combined datasets from https://teara.govt.nz/en/graph/25294/urban-and-rural-populations-1891-1976 & Stats NZ

- On parts of our network, particularly in the Bay of Plenty, the horticultural industry is thriving, with associated growing energy demand. Kiwifruit farming, in particular, is adding additional load on these rural networks, such as for cold storage etc.

The historical trend of growing urbanisation and a relatively stagnant rural population is expected to continue into the future. As the network features and associated cost varies materially between urban and rural networks, this will have longer term implications for the electricity quality/cost trade-off and economically efficient electricity pricing. This will be reflected in varying service levels and pricing structures.

These trends will make it ever more important for us to segment our approach to network planning to meet our customers' needs.

3.2.4 ENERGY POVERTY

Energy poverty is a complex issue that requires a system-wide approach. There is increasing evidence that a significant proportion of our customers struggle to meet their basic energy needs. In addition to the impact of generally rising energy costs, this situation could be exacerbated by a number of other factors:

- Uneven access to customer-side energy technology. For example, parts of the population can afford electricity generation, eg solar PV, and storage which may reduce the overall grid-sourced electricity they require. However, as most network costs are fixed and are generally recovered through overall energy sales, this may increase the network cost to customers without their own generation.
- Distribution electricity pricing is generally relatively evenly applied to mass market customers, despite significant differences in the actual cost of supply. Besides the intrinsic economic inefficiency this entrenches, it inhibits effective consideration of customers' price/quality trade-off preferences. In addition, it inhibits the uptake of new technology or non-network solutions – where individualised pricing (or some form of incentive) are generally important for these to succeed.

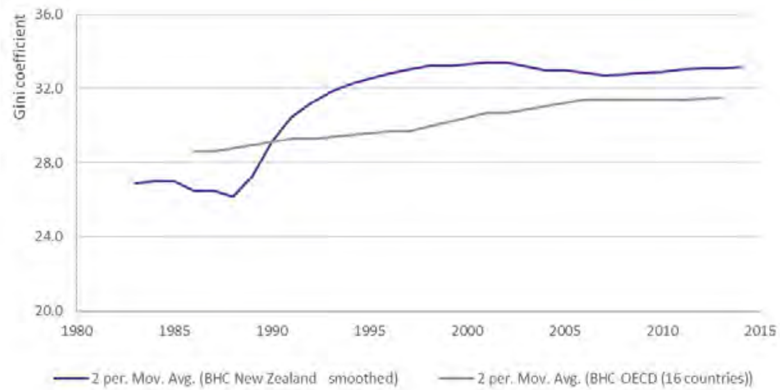
  It is therefore desirable that we transition, over time, to a more cost-reflective distribution pricing basis that can be better tailored to customers' individual preferences and network impacts. Managing this change will involve communicating with retailers and customer groups so that change can be managed and assistance can be targeted effectively eg Powerco is supporting the EnergyMate programme[20].
- Effective management of energy use through, for example, more efficient housing insulation and implements, or controlling consumption during peak-demand periods, are useful means of reducing energy cost. However, it is generally the higher socio-economic groups that are more able to achieve this.

The most obvious response for a distribution utility to help mitigate against energy poverty is to minimise its cost to customers by delivering as effective a service as possible. Within the bounds of practicality, we also have to ensure that we deliver to customers' price/quality trade-off preferences. These are also the underpinnings of good asset management, with its drivers of seeking optimal investment solutions, maximising the utilisation of assets (conversely, minimising the extent of assets required) and ongoing improvements in operational efficiency.

In addition, we will increasingly work with our customers to encourage improvements in efficient energy use, and to seek opportunities to lower the cost of their supply. Emerging technology, with its associated opportunities, is likely to play a large part in this.

How we bring the customer along this journey, and the decisions we make, will evolve. Our customer engagement strategy outlines how we plan to involve our customers, retailers, iwi, third-party service providers and other interested stakeholders in our key decisions.

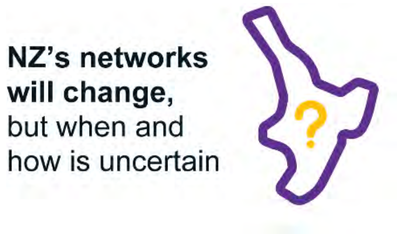
Figure 3.5: Inequality in New Zealand and the OECD using the Gini coefficient, 1982-2014[21]



20 https://www.powerco.co.nz/about-us/community-support/energymate/

21 Source: Perry (2015a), Ministry of Social Development, using data from Statistics New Zealand's Household Economic Survey, OECD

3.3 LEGISLATIVE AND ELECTRICITY MARKET CHANGES



The energy policy and market environment are adapting to improve the interface between technology, infrastructure, and sustainability drivers. Outcomes include relatively rapid shifts in electricity consumption and investment decisions, as well as the direct and indirect costs of providing services to customers. While the timing and extent is difficult to predict, we foresee the following changes as a reasonably high likelihood during the AMP planning period.

3.3.1 REDUCING NEW ZEALAND'S CARBON FOOTPRINT

The Climate Change Commission is consulting on New Zealand's emissions budgets to 2035, along with the plans to achieve them. Net-zero carbon emissions in electricity generation is a stated government goal, with a now-accelerated target of 2030 to achieve this. Achieving this will require a number of actions and incentives, with those most likely to materially impact the distribution sector being:

- Facilitating the uptake of solar PV generation (with or without associated energy storage).
- Increased support and regulations for energy efficiency measures.
- Increased incentives for electric vehicles (EV), while phasing out the petrol vehicle fleet.
- Increased focus on hydrogen as an alternative fuel source.
- Increased use of electricity for industrial processes as an alternative to energy sources with higher carbon emissions.

We support these measures, which are for the greater good of our society. While there will be network implications, we are planning on how to manage this effectively. Our planned response is set out in Chapter 6.

3.3.1.1 PROCESS HEAT ELECTRIFICATION

One of the main focus areas for reducing New Zealand's carbon footprint is the decarbonisation of process heat. Industrial processes and waste represent about 11% of New Zealand's carbon emissions.

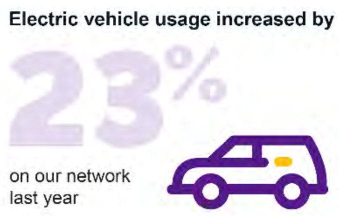
Conversion of large industrial processes is unlikely to directly impact electricity distribution networks. Current indications from the major industries are that, in order to reduce carbon emissions, they are more likely to convert their plants to run on biomass than on electricity. This is partly driven by energy costs, but also by the limitations of using electricity to effectively drive high-temperature heat processes (as required, for example, for steam boilers). In addition, the sheer extent of the energy required for these large processes is mostly beyond the capacity of distribution networks to supply.[22] Where large processes are electrified, we therefore foresee that these will be directly connected to the transmission grid.

However, there are still significant numbers of smaller industrial and commercial heat processes, such as heating for hospitals and schools, operating at lower temperature levels, where converting to electricity from current carbon-based heat sources is viable. At least part of the additional electricity capacity required to achieve this will be drawn from distribution networks.

As the pressure on business and other entities to reduce emissions increases, we see potential for significantly higher electricity demand associated with process heat conversion. We conservatively estimate that this can increase peak loading by as much as 11% on our overall network. This impact can be even more substantial on those parts of our network where heat loads are concentrated.

Chapter 15 outlines our plan to meet this growing demand.

3.3.1.2 ELECTRIFICATION OF THE VEHICLE FLEET



Road transport accounts for about 17% of carbon emissions in New Zealand. The electrification of these fleets, starting with passenger vehicles, is therefore another obvious focus area to reduce emissions in New Zealand. While current uptake of EVs is relatively low, we expect it to accelerate, especially if more government incentives emerge to support this.

The impact of increasing numbers of EVs on electricity demand is highly uncertain, as it is subject to multiple factors such as:

- Number of EVs in a network area.
- Average distance travelled per day (and hence energy required to recharge).
- Use of charging infrastructure structure (public infrastructure v residential charging).

[22] When point demands start to exceed about 30MVA, it becomes generally impractical or uneconomic to connect to distribution networks, even at 33kV. Direct grid connections are generally necessary, even where these may still be provided by distribution utilities.

- Time of charging (off-peak charging will have little impact, but should it coincide with the early evening demand peak, it will add to total network demand).
- Energy required by the type of vehicle.
- Rate of charging.

Based on a relatively aggressive assumption of a 60% uptake by the end of the AMP planning period, we estimate that with uncontrolled charging, EVs can add about 9% additional peak demand on our network. This figure will likely vary greatly across the network, as a result of clustering of EVs in particular areas.

The expected demand increase can be largely avoided if we can encourage charging during off-peak hours. Various means of achieving this are being investigated.

3.3.2 DISTRIBUTION SYSTEM OPERATOR

To encourage the uptake of local, particularly renewable, generation, advanced economies are realising the importance of creating an electricity market at distribution network levels. While the debate in New Zealand on what form such a market and its operator may take is still in its relative infancy, we expect much more action on this during the AMP planning period. The outcome from these decisions may have a major impact on our business.

In anticipation of some form of distribution system operator and distribution electricity market in New Zealand, we are looking to ensure that the essential (distribution network) enablers for this are being developed. This is discussed in Chapter 6.

3.3.3 ELECTRICITY REGULATION

Electricity distribution in New Zealand is regulated by two entities:

- The Commerce Commission is the competition regulator. We are a monopoly and the Commission determines the maximum revenue we are allowed to earn as well as the minimum quality of supply for the delivery of electricity. It also manages an Information Disclosure regime, requiring us to publish annually a number of key statistics about our business, asset and network performance, as well as our plans for the network, changes to our pricing, and policies for sharing the costs of new connections.
- The Electricity Authority (EA) is the market regulator, which sets and oversees the rules for participating in the New Zealand Electricity Market. Some of the key touchpoints for us are our commercial arrangements with other market participants (including data access), commercial and technical requirements for connecting new technologies to the network, and access and use of consumer data. The EA's powers also include guidelines, compliance, and reporting requirements relating to our pricing and equipment connected to the grid.

Any material change to electricity or market regulation could have a significant impact on our business, ranging from additional revenue or operational limitations, to additional reporting requirements. Performance targets can also affect the way we have to run our operations.

At present, we foresee potential changes in the following areas of regulation:

- The Information Disclosure regime is due for an update. In particular, the Commission has indicated its intent to require more extensive reliability of supply reporting, and the introduction of customer service measures. These are positive steps from a consumer perspective, and we support them, but they will likely bring about additional requirements for measurement, record-keeping and reporting.
- The Input Methodologies are due for review. We expect a focus to be on how flexibility is handled in distribution planning to both minimise costs and leverage alternative technologies. This will overlap with the EA's role in managing market arrangements for energy services.
- The EA is pursuing the implementation of open-access networks, which are an essential precursor to a Distribution System Operator or distribution network electricity market. Again, we support this direction, but note that its implementation will require additional (likely significant) investment in monitoring and metering equipment, information systems and reporting.
- Pricing reform continues to evolve. The EA is planning to approve a new transmission pricing regime applied by Transpower, coming into effect in 2023. These costs are a significant proportion of our network charges – equivalent to almost half of our distribution charges – so the level and form of these prices will affect our prices and, potentially, an indirect impact on our network depending on the response from commercial customers. We anticipate the removal of the low-fixed charge regulations will be complete during the AMP period, enabling significant improvement to the alignment of network costs and revenues.

3.4 TECHNOLOGICAL CHANGES

Energy technology, including communications networks and the ability to remotely monitor and control devices, is improving at a rapid rate. This brings about amazing opportunities for electricity customers and utilities to improve flexibility, reliability, efficiency and safety in the delivery and use of electricity, with associated cost benefits. However, along with this comes increased complexity of operations and the potential for network disturbances or instability, which we will have to manage to ensure the benefits from new technology can be fully realised.

3.4.1 CUSTOMER ENERGY TECHNOLOGY

Emerging technology is creating increasing energy opportunities for customers. This includes possibilities for self-generation, energy storage, demand management, improved energy efficiency and the like. With a functional distribution market, it will also become easier to sell excess generation directly to other consumers or aggregators (or back to suppliers) – using the distribution network as the platform for these transactions.

However, the ability of distribution networks to integrate customer technology, especially local generation or additional high-demand equipment, such as EVs, is finite. Should the network capacity be exceeded, this can not only cause the network to be overloaded, but can also give rise to system instability. The latter can lead to large voltage swings, signal distortion and, in serious cases, even the total collapse of a network requiring a shutdown and re-livening.

It is therefore essential that distribution businesses work closely with customers to ensure that the network has adequate capacity to manage new connected devices, or to agree on mutually acceptable measures to reduce the impact of the new devices during periods of network constraint.

Our approach to managing the impact of new customer technology is discussed in Chapter 6.

3.4.2 NETWORK TECHNOLOGY

With emerging technology, distribution utilities also have an expanding scope to improve the service they provide, or lower supply costs. Solutions include novel distributed generation solutions, demand management, remote monitoring and control, automated self-restoring networks, energy storage and much more.

Our Network Evolution strategy, described in Chapter 6 is largely aimed at keeping abreast with emerging technology, testing this and supporting the roll-out of new solutions where these are safe, reliable and technically and economically feasible.

It is our intent to operate an open access network, allowing our customers maximum flexibility without compromising the stability and safety of the existing electricity supply. We see this as an essential enabler for an effective distribution market, which in turn is a pre-requisite to allowing customers to fully realise the benefits of emerging technology on their side.

Such an open network and distribution energy market will play an essential role in supporting customers to reduce carbon emissions, by facilitating and encouraging local, particularly renewable, generation, with the associated ability to buy or sell excess local capacity with minimum constraints.

3.4.3 CYBER-SECURITY

As our reliance on connected digital devices increase, so does our vulnerability to cyber-attacks. This is true for our normal business operations, as well as for the network operations – where devices are increasingly remotely monitored and controlled. The number of cased reported where electricity utilities are subject to cyber-attacks is rapidly increasing, with New Zealand no exception.

To address this, we have a dedicated cyber security team and a well-established programme to continually upgrade our protection. Plans are also in place to react should our cyber defences be breached. Our cyber security strategy is described in Chapter 5.

3.4.4 REDUCTION IN GRID INERTIA

As technology changes from traditional large generators, to smaller renewable sources, an inevitable loss in system inertia follows. Traditional spinning machines have considerable momentum, with associated ability to ride through short-term system fluctuations and ensure stable system operation.

Most new renewable generation has little to no intrinsic inertia, particularly smaller scale local generation. In addition, the devices are connected to the grid through electric inverters. Absent substantial permanently connected energy storage devices to create artificial inertia, the ability of new generation to ride through system disturbances, is limited. This holds substantial potential for system collapse following a significant event, which is further exacerbated by the fact that individual equipment controllers often do not synchronise well, which can further contribute to instability.

Grid stability is currently mainly a system operator function. However, as we move to more reliance on small scale generation, connected to distribution networks, close coordination between distribution network operators and the system operator will become imperative.

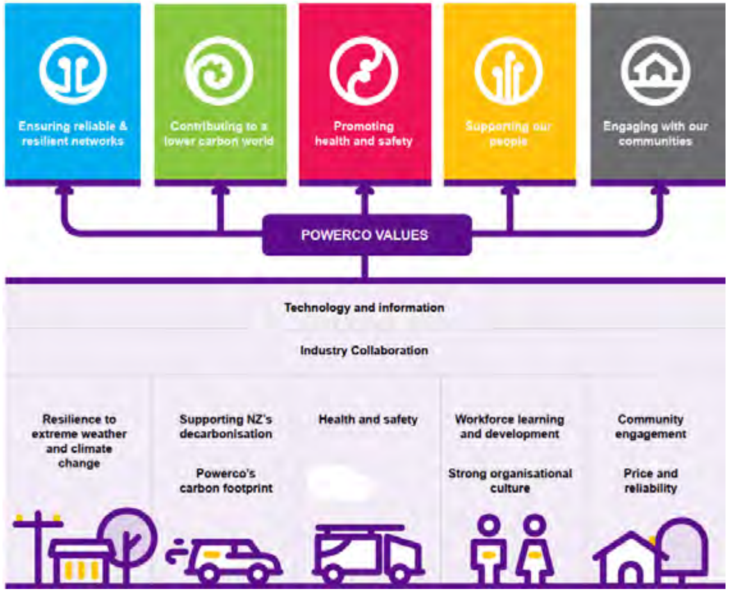
We continue to monitor the uptake of small scale generation on our network. Timely steps will be taken to ensure that we understand and manage the system impact of individual devices and work closely with the system operator in this regard.

3.5 MANAGING OUR ENVIRONMENTAL IMPACT

The New Zealand Productivity Commission's "Low-emissions economy" report details pathways for New Zealand to reduce its carbon emissions, in line with meeting the targets of the Paris Accord. We are committed to supporting this. In our Sustainability Report[23] we set out our plans and goals for a sustainable business, from an environment, as well as people and operations perspective. Our main sustainability pillars are shown in Figure 3.6. Key asset management themes from this document are summarised below.

The Climate Change Commission, the Crown entity charged by legislation to build and recommend to Government the pathway to achieve the targets of the Zero-Carbon Act, has issued its draft recommendation on the 31st of January 2021. While we see the recommendations as largely positive, we assessing the impact of its recommendations on our network, and will provide formal feedback to the commission.

Figure 3.6: Powerco's pillars for a sustainable business



As an electricity distribution utility, we realise that out environmental footprint is actually small compared with that of the users of the electricity we convey.

Accordingly, the largest positive environmental impact we can have is to enable and encourage efficient energy use and carbon reduction initiatives for our end-users and electricity generators. This is at the heart of our Network Evolution strategy. [24]

But there are also direct ways by which we can reduce our impact on the environment. Therefore, we continually review the environmental impact of our internal operations, our assets and our network, to reduce our environmental impact over time. Our roadmap to achieve this and its associated goals is presented in Figure 3.7.

Figure 3.7: Our roadmap to carbon reduction

POU TAIAO

Contributing to a lower carbon world

SHORT TERM (FY21)	MEDIUM TERM (1-3 YEARS)	LONG TERM (3+ YEARS)
Develop a roadmap for our 2030 net-zero target	Deliver the roadmap for meeting our net-zero at 2030 target during FY21	Deliver the roadmap for meeting our net-zero at 2030 target during FY21
Measure and reduce Scope 1 and 2 emissions (excluding line losses) and the most material Scope 3 emission activities (currently flights and contractor mileage)	Prepare for Zero Carbon Amendment Act and Taskforce for Climate Related Financial Disclosures (TCFD) requirements	Achieve our net zero emissions target through the reduction of emissions and by offsetting any unavoidable emissions (e.g. via forestry)
Develop low carbon transition strategy for the gas network	Support distributed and renewable generation by enabling our customers' use of solar panels, batteries, and electric vehicles (EVs)	Continue to evolve electricity network to support customer driven renewable generation and energy trading
	Collaborate with industry peers and customers on reducing line losses	Prepare our gas network assets and trial biomethane (biogas) and hydrogen substitution
	Plan to enable our gas network assets to convey biomethane (biogas) and hydrogen	
	Trial zero carbon gas (or blend) on our gas network	
	Test options for our gas customers to offset their emissions through a voluntary scheme (e.g. forestry)	

Some of the direct improvements Powerco is working on to reduce its emissions, include the following:

- Reducing travel and increasingly relying on remote meeting facilities.
- Reducing electricity use at our substations and office facilities.

[23] Sustainability at Powerco – December 2020 https://indd.adobe.com/view/6b1d988f-ddc6-4e53-83cf-5a25a1bb1ae3

[24] The increased use of localised distributed energy could further support decarbonisation through reduction in lines losses and increased efficiencies.

- Ensuring we source our assets from responsible suppliers, using sustainably sourced materials.
- Improving our understanding of the embedded carbon in our network and maximising the knowledge gained. Carbon embedded in the materials used to build (eg concrete v wood poles) and operate (eg ester v mineral oils) our network has an impact on our footprint.
- Increasing automation and remote fault indication on our network, thereby reducing the travel required for switching, fault-finding and repairs

Current New Zealand practice is to exclude line losses from distribution utilities' Scope 2[25] activities. By ensuring that our networks operate within regulated voltage limits, we ensure that line losses do not exceed industry acceptable levels. However, we appreciate that line losses can still be a major contributor to emissions and that this is a factor we can influence. Accordingly, we will be increasing our monitoring of losses (largely LV-related) and working on cost-effective means to reduce this.

3.6 IMPACT OF COVID-19 ON OUR NETWORK

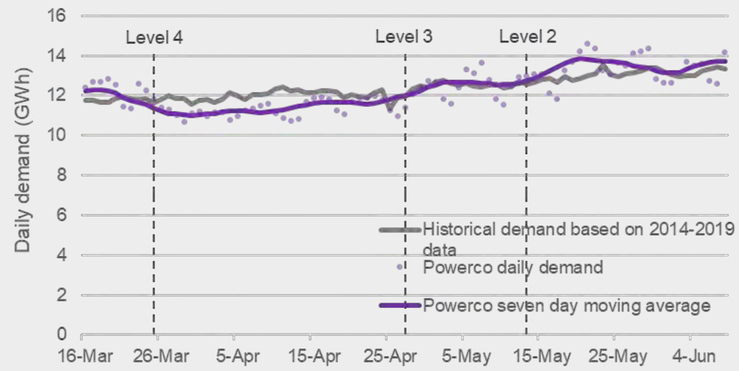
3.6.1 IMPACT ON DEMAND DURING COVID-19 LOCKDOWNS

The COVID-19 lockdown provided utilities an opportunity to understand the drivers for demand on their network. The closure of entire sectors of the economy provided the ideal control to experiment and verify our demand forecasts. The key trends that we saw were:

- During Level 4 restrictions, there was an 8% reduction in energy consumption compared with previous years. This was primarily driven by the shutdown of commercial, and some industrial, operations.
- Overall network demand approximated normal residential load curves, with flatter and more drawn-out morning peaks and more pronounced evening peaks. Distinguishing between weekend and weekday demand became difficult.
- Demand quickly returned to pre-lockdown levels as restrictions were eased. Increased working from home has not made a discernible difference to network demand.

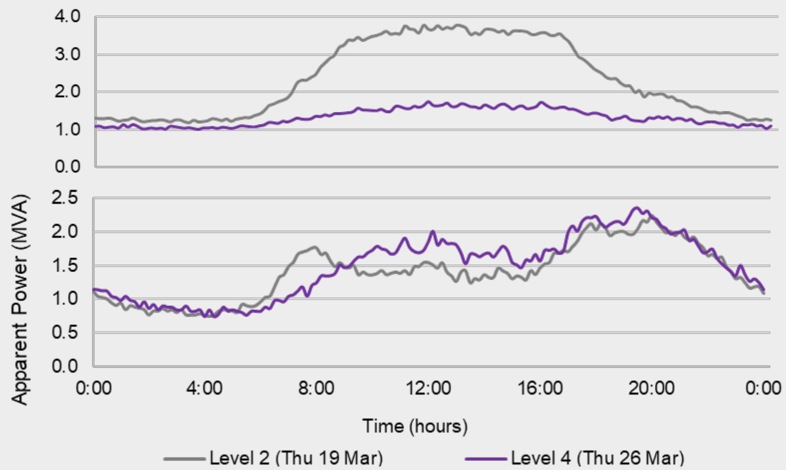
Impact of the COVID-19 lockdown on our network

We saw a slight decrease in energy consumption during the COVID-19 lockdown.



Reduction in commercial activity was the primary driver for a drop in demand. However, this was partially offset by an increase in residential loading.

Figure 3.8: Change in daily profiles during COVID-19 lockdown (commercial – top, residential – bottom)



25 We measure emissions in terms of the internationally accepted Greenhouse Gas Protocol. Scope 2 losses refer to indirect emissions.

3.6.2 LASTING IMPACT OF COVID-19

The lasting impact of COVID-19 will be seen in how it shapes behaviours.

The closure of economies across the globe highlighted the interdependency and the inter-connectivity of global supply chains. The pandemic emphasised the need for resilience and re-localisation of our energy systems.

During the lockdown period, when most people who were able to work had to work from home, residential electricity supply quality was paramount. Not only was electricity essential to enable most work operations to continue, but it was also essential for keeping communication networks running. A reliable residential supply is, therefore, vital in helping provide societal resilience to pandemics. And, of course, we cannot discount the possibility of further COVID-19 related lockdowns, or future pandemics.

This is causing a rethink of the importance of residential, generally LV networks – an area that has traditionally not received the same attention as higher voltage network parts and where, accordingly, reliability has often been quite poor. LV network outages are not counted for quality-of-supply regulation and this has contributed to the reduced focus.

4 ASSET MANAGEMENT OBJECTIVES

4.1 INTRODUCTION

Powerco's business is to deliver electricity to its customers, and to do so safely, reliably and efficiently, while also ensuring that its shareholders earn an acceptable return on their investment.

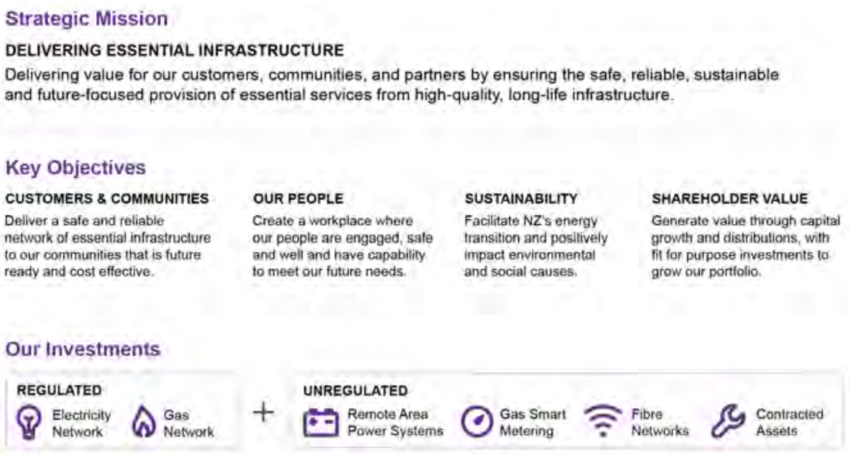
The essential nature of having efficient and affordable electricity available for modern society to thrive is well understood. We take the responsibility to deliver this very seriously – it lies at the very heart of our business. The COVID-19 crisis has again underscored the importance of electricity security, with a robust, reliable electricity supply a key precondition for the functioning of the healthcare system, maintenance of social welfare, and facilitation of online economic and social activity.

Our Corporate Objectives and supporting Asset Management Objectives have been formulated to achieve this central business goal and to effectively discharge our responsibility as an essential service provider.

4.2 CORPORATE OBJECTIVES

Powerco Ltd and its parent Powerco New Zealand Holdings Ltd are leading energy infrastructure asset managers. Figure 4.1 shows our corporate mission and objectives.

Figure 4.1: Powerco's mission and corporate objectives



4.2.1 CORPORATE VALUES

Our corporate values define us: Who we are and what we stand for. They describe the behaviours we expect from our employees and service providers. These are summarised in Table 4.1.

These values define the way we go about our work and what we expect in our relationships with each other. 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 as to how 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 delivers to the evolving needs of our customers.
– Supporting environmentally sustainable and ethical practice, through the selection and lifecycle management of our assets.
– Delivering a cost effective service by optimising asset cost, risk and performance.
– Being proactive, transparent, and authentic in our interactions with our stakeholders.
– Meeting all statutory and regulatory obligations.

We will achieve these asset management outcomes by:

– Developing and maintaining an Asset Management System (AMS) for each of our electricity and gas networks, integrated with Powerco's existing management systems.
– Preparing and delivering to our plans set out in our Asset Management Plan.
– Obtaining ISO 55001 certification by the end of CY 2021.
– Managing data as an important asset and implementing a data management governance framework that supports asset management decisions.
– Continually enhancing our asset management capability and skills over time.
– Recognising the importance of our people and their development.

Members of the Executive Management Team are accountable for resourcing, and delivering the outcomes of this policy as follows:

– As representatives of the Asset Owner, the Asset Management Steering Committee is responsible for setting the Asset Management Policy.
– The Asset Strategy and Investment General Manager shall own the Electricity AMS and, alongside the Service Delivery and Systems Operations General Manager, shall be jointly responsible for delivering the outcomes of this policy in the Electricity division.
– The General Manager (Gas) shall own the Gas AMS and shall be responsible to deliver the outcomes of this policy in the Gas division.
– Further roles and responsibilities will be documented in the respective Asset Management System.

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.

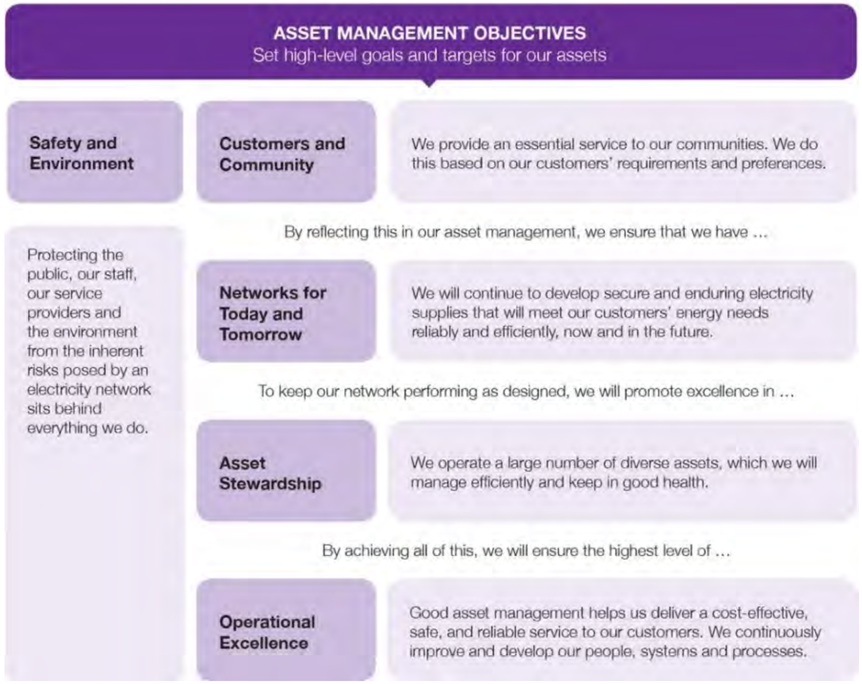
4.4 ASSET MANAGEMENT OBJECTIVES

Our Asset Management Objectives set the direction for managing our electricity network assets. They have 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.
- Ensure our asset management practices deliver the Corporate Objectives.

Five Asset Management Objectives are at the heart of how we manage our assets. They reflect our lifecycle asset management approach, which considers all aspects of asset decision-making and activities from inception to decommissioning. These Asset Management Objectives are illustrated in Figure 4.2.

Figure 4.2: Our Asset Management Objectives



In the sections below, we discuss the five asset management objectives in more detail, along with the goals and targets we have for each. We also illustrate some key performance indicators for each objective to illustrate how we are performing against them. More performance indicators are given in Chapter 7.

4.5 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 to minimise harm.

We see ourselves as responsible custodians of our environment. To support this we encourage the efficient use of energy, ensure sustainable business practices (also for our suppliers), strive to minimise our carbon footprint, and help our customers achieve the same. Our electricity assets and our operations are designed to minimise the potential for environmental damage.

Safety and Environment: Overall objectives

Our overall safety objectives are to safeguard the public from any harm from our assets and to ensure an injury free workplace.

Our overall environmental objectives are to cause no lasting harm to the environment and to reduce our carbon footprint to net-zero by 2030.

4.5.1 CONTEXT

The Safety and Environment context that our assets operate under can be broadly categorised into three parts:

- Public safety
- Lifecycle environmental stewardship
- Worker safety

It is also usually shaped by broader societal factors, such as legislation and public perception. The strategies for this objective, therefore, must constantly monitor external factors to ensure they are meeting their goals.

Public safety

On a societal level, electricity networks are inherently safe when compared to other societal risks eg transport, healthcare etc. But there is significant effort required to keep it that way, which may not always be apparent to the general public.

As society has grown around our assets, there is also a shift in expectations from managing these risks in absolute terms (such as Electrical Codes of Practice terms and conditions) to a more balanced assessment of risk to encompass more than physical harm, but also considering other factors such as ethical, economic and social considerations (concepts such as Tolerability of Risk – TOR).

When commissioning assets, work practices have also evolved to better manage public safety during construction and maintenance.

Lifecycle environmental stewardship

There has been a significant lift in environmental awareness in the second half of the 20th century. New networks are designed and built with the aim to minimise any potential environmental harm. However, as we have substantial legacy networks where the environment was not so carefully considered, we have to be extra vigilant about managing any potential impact of these older assets.

Organisations and asset owners across the world also have a growing expectation that equipment suppliers and service providers be held to a higher standard. This has meant we have had to take a more active role in monitoring the work practices and manufacturing practices of our key suppliers – ensuring that we obtain material from sustainable sources and from suppliers who are ethically and environmentally responsible in their manufacturing and workforce practices.

Worker safety

There has been substantial reform in health and safety in New Zealand, with the introduction of the Health and Safety Reform Bill enacted at the end of 2015. The Reform Bill put a strong emphasis on prevention and accountability. It followed on from other reforms in the health and safety arena, such as the introduction of WorkSafe New Zealand, a health and safety regulator, and the adoption of a proactive approach to enforcement.

This has made it even more important for asset owners to take steps to ensure health and safety systems are appropriate. It requires robust steps, including reviewing and updating existing internal policies and processes, and considering whether the business is doing all it should with respect to work travel.

4.5.2 SAFETY AND ENVIRONMENT GOALS

We have developed a set of goals to help us achieve our Safety and Environment objectives and to monitor our performance. These are set out in Table 4.2 and Table 4.3.

Table 4.2: Safety goals

GOAL	SUPPORTING INITIATIVES
Zero fatalities to staff and contractors	Develop and implement plans to manage critical risk areas for Powerco staff and ensure contractors have similar plans in place for their own staff working on our assets.
	Enhance contractor approval and work monitoring processes to ensure we utilise the right delivery partners.
	Mitigate arc flash hazards for high-risk assets.
Minimising lost time injuries to staff and contractors	Ongoing development of safety culture maturity with our service providers, including recording, analysis and reporting of safety-related issues.
10% year-on-year reduction in Lost Time Injury (LTI) frequency rate	Review effectiveness of contractor works manual to communicate critical information.
	Evolve contractor approval process to include design capability assessment.
	Develop leading and lagging performance metrics for contractor and subcontractor performance.
	Phasing out assets that no longer meet modern safety standards or have known operations restrictions in place.
Zero public harm incidents resulting from our network	Regular public safety communication with our customers, communities, emergency services and professional bodies. Remove defective assets, especially those in areas of high public safety risk.
	Targeted renewal programmes to ensure appropriate levels of asset health.
Reducing public safety risks	Engaging the public about the dangers of copper theft.
	‘Look Up’: A comprehensive lines safety campaign across multiple digital, print and radio platforms.
	Raising awareness for tree management and safety through online and newspaper media.

Table 4.3: Environment goals

GOAL	SUPPORTING INITIATIVES
Net zero carbon emissions by 2030	Develop and commence implementation of the net-zero carbon roadmap.
	Support distributed and renewable generation by enabling our customers’ use of solar panels, batteries, and electric vehicles.
	Collaborate with peers and customers on reducing line losses.
Zero significant, avoidable environmental incidents caused by our assets or work practices	Development and implementation of sustainable environmental management principles to employees and contractors.
	Identification of environmental critical risks and associated mitigation measures for communication to all stakeholders.
	Work with our contractors to ensure reporting, containment and rehabilitation of environmental incidents caused by our assets.
	Environmental management planning is core to any project initiation process.
All environmental incidents reported in time	Continual improvement in measuring and reporting incidents that have a real or potential environmental impact.

GOAL	SUPPORTING INITIATIVES
	Development of systems to better enable contractors and employees to manage environmental incident reporting.
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.
	New materials approved for use on the network are subjected to rigorous MECO[26] analysis process for whole-of-life impact assessment.
Full compliance with the Resource Management Act 1991 and any other non-legally binding stakeholder agreements	Conduct planning reviews to ensure assets in environmentally sensitive areas are appropriately selected and installed.
	Implement system to ensure compliance obligations are well managed.
Continued certification with ISO 14001:2015	Ongoing target to meet all requirements of ISO 14001:2015 to continue to hold certification.
	Continual self-assessment of systems and procedures, with ongoing improvements where the need is identified.

4.6 CUSTOMERS AND COMMUNITY

Our core business is to ensure that electricity is delivered to our customers safely, reliably, efficiently and sustainably. Our customers' priorities guide our investments.

Achieving this requires balancing:

- Investment in the network to ensure it remains in an appropriate condition, has sufficient capacity and functionality to meet customers' current and future needs, with
- Customers' individual experiences in the short-term as we deliver our investment programme and service their day-to-day needs.

Our Customers and Community objective is one of a number of objectives that sets the direction of how we deliver our Customer Commitment, the policy detailing the high-level principles that reflect our corporate vision, mission and values.

Customers and Community: Overall objective

Ensure customer and community preferences are reflected in the provision of a safe and reliable electricity network that meets their service level expectations, is future ready, and cost effective.

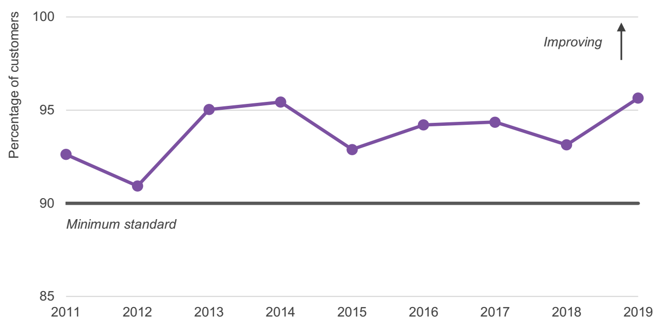
[26] Materials, Energy, Chemicals, Other lifecycle considerations

4.6.1 CONTEXT

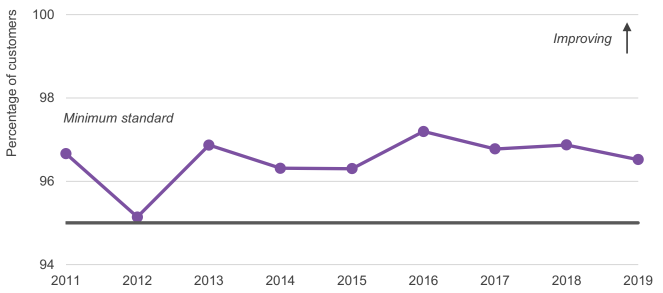
We have historically surveyed our customers to test their perception of supply quality and reliability, and the score is both high and stable as shown in Figure 4.3. By ensuring customer preferences are reflected in our investment decisions, we are striving to maintain strong customer ratings.

Figure 4.3: Customer satisfaction ratings for electricity delivery

Percentage of customers rating their electricity supply reliability as acceptable or better



Percentage of customers rating overall electricity supply quality as meeting expectations



Evolving customer expectations

Customer expectations are increasing – people want to have instant information at their fingertips, a seamless customer service experience, and the ability to influence decision-making across all aspects of their life. For the electricity industry, this means we need to engage with customers and communities on topics ranging from how we design our networks to the individualised information customers can access about outages.

Our ability to understand changes in customer preferences and appropriately respond relies on comprehensive customer insights. We strive to generate quality insights through:

- Targeted engagement with individuals and communities on topics relevant to them, in an appropriate manner, and at the right time.
- Providing positive day-to-day experiences across all customer touch points.

Achieving this ensures our asset management decisions are based on the level of service customers desire, at a cost they find appropriate, and that we have a clear understanding of the needs and timing of future network investments.

Effective customer engagement requires positive customer experiences. Customers' willingness to engage on matters beyond pricing, outages and land access is inherently difficult, and even more so if a foundation of positive experiences has not been established.

A number of indicators provide an outcome view of performance against our Customers and Community Asset Management Objective.

4.6.2 CUSTOMERS AND COMMUNITY GOALS

We have developed a set of goals and targets to help achieve our Customers and Community Asset Management Objective and to monitor our performance. These are set out in Table 4.4.

Table 4.4: Customers and Community goals

GOAL	SUPPORTING INITIATIVES
Meaningful customer engagement on price and service quality levels	Maintain and implement an annual customer and community research programme designed to deliver insights to support network planning and investment optimisation.
Network-related complaints reducing	Understanding our customer journeys, touch points and their specific pain points, and working in partnership with our delivery partners and the wider supply chain to improve their experience.
All major projects (>$5m) developed with customer/community consultation	Community engagement and relationship management programme to ensure customer and community preferences and priorities are reflected in our investment decisions.
Network enables customers' future energy choices	Monitoring and analysis of local and international customer trends and preferences.
	Provide insights from our customers into changing usage patterns and trends related to future usage requirements.
Investment programme enabled by full community, landowner and other stakeholder support	Community engagement and relationship management programme to create partnerships that support the efficient delivery of our works programme.

4.7 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.

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

Maintaining stable asset health is a key focus. To stabilise and reverse deteriorating performance trends we have accelerated investment in asset renewal and on our maintenance programmes. We are also improving our asset management support systems and processes to ensure we get the benefits of modern information technology to optimise asset investments.

Asset Stewardship: Overall objective

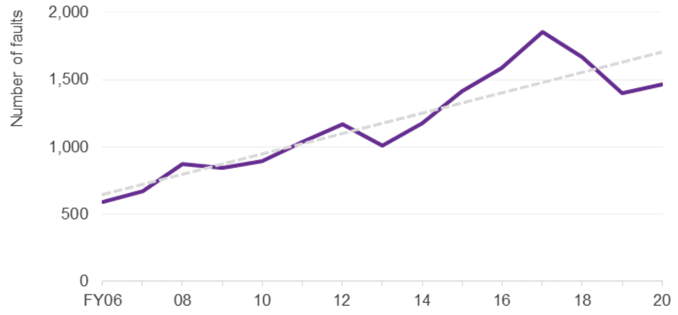
Through effective management and operation, our assets deliver a safe and reliable supply to customers in a cost effective manner over the full expected asset life.

4.7.1 CONTEXT

Defective equipment

Asset deterioration over time results in poor network performance and potentially puts the public and workers at risk. Therefore, maintaining stable asset performance is one of Powerco's main objectives. Arresting the declining asset performance trend associated with an aged asset fleet was a fundamental reason for our Customised Price-quality Path (CPP) application in 2018. A key indicator of the condition of our assets is the number of assets that fail in service, illustrated in Figure 4.4.

Figure 4.4: Defective equipment fault trend[27]



From this figure our earlier concern about the long-term deterioration of our assets is clear. However, more recently the trend appears to have stabilised – albeit based on limited observation data points. This coincides with the substantial uplift in our renewal programme since FY18.

4.7.2 ASSET STEWARDSHIP GOALS

We have developed a set of goals to help achieve our Asset Stewardship objective and to monitor our performance. These are set out in Table 4.5.

Table 4.5: Asset Stewardship goals

GOAL	SUPPORTING INITIATIVES
Our assets perform at their designed capacity over their expected lives	Continue to develop our holistic fleet management approach to asset maintenance and renewal.
	Expand our preventive maintenance programme for each asset fleet, including collecting expanded asset health assessments and defect records.
Well targeted asset renewal plans to cost effectively ensure safe and reliable performance of our network, also reflecting the needs of the future network	Enable advanced information-driven maintenance and asset renewal decisions.
	Use diagnostic testing tools, such as acoustic testing of wood poles, expanding the application of Condition-Based Risk Management (CBRM), Reliability Centred Maintenance (RCM) and further development of Asset Health Indices (AHI).
Effective vegetation management around our networks, with the support of private landowners, councils and roading authorities	Adoption of full cyclical vegetation management.
	Implement a catch-up programme of work for sections of the network that were previously not part of a cyclical programme.
Increasing asset standardisation, supported by a group of specifications and guidelines that ensure optimal asset lifecycle performance	Continue to standardise the minimum number of assets required to ensure the cost effective, safe and reliable operation of our networks, and maintain appropriate commercial tension between suppliers.
	Maintain a comprehensive set of high-quality asset standards and guidelines for all asset classes on the network.

[27] Equipment faults that led to outages longer than one minute are included in the trend. These are the outages that contribute to SAIDI and SAIFI.

4.8 OPERATIONAL EXCELLENCE

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

- Putting in place the skills, capacity and supporting systems needed 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.
- Achieving internal cost efficiencies and ongoing improvements.
- 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.
- The efficiency of our service provider management.

Operational Excellence: Overall objective

Ensure we have the skills, capacity, systems, and processes in place to cost effectively and reliably deliver to our broad Asset Management Strategy.

4.8.1 CONTEXT

There are several drivers to us continually improving our operational practices.

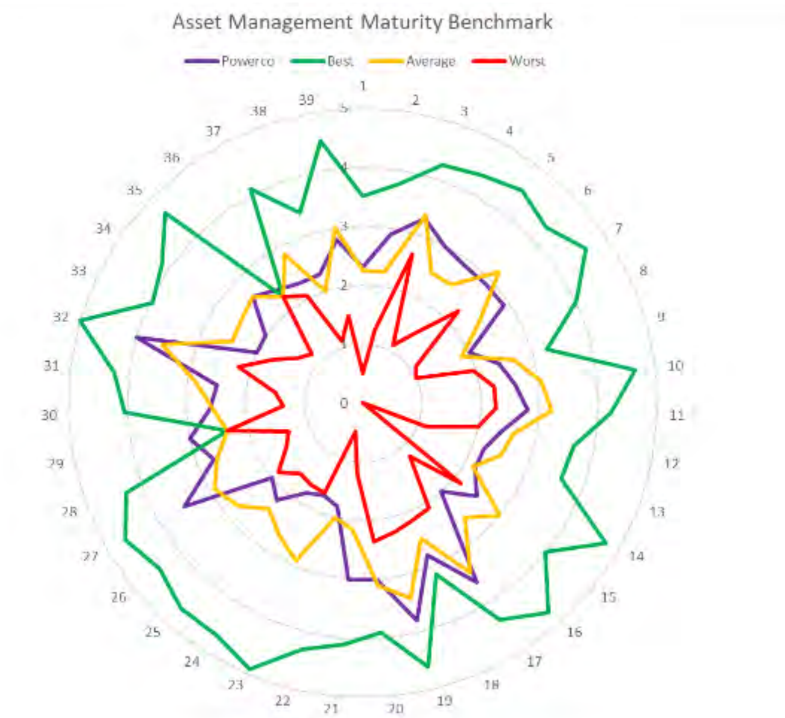
The regulatory price quality paths are frequently re-evaluated, and targets are ratcheted down every regulatory period. This market design mechanism ensures that we constantly strive to outperform ourselves. Paired with this is our current period of uplift in expenditure. The increased expenditure means that an incremental saving, because of operational efficiency, gets amplified significantly more.

We have been assessing ourselves against the structure of the Asset Management Maturity Assessment Tool (AMMAT) since 2013. This is a self-assessment required by the regulator.[28]

To get a more in-depth understanding of our asset management maturity, we conducted independent assessments in 2018. This allowed us to compare our practices across the requirements of the internationally recognised asset management standard, ISO 55001, and Global Forum on Maintenance & Asset Management (GFMAM). This allows us to benchmark ourselves against other utilities in Australia and New Zealand.

The results of the assessment lead us to alter our AMMAT scores across a range of categories. In Figure 4.5, we show the scores grouped by assessment areas of GFMAM. We re-assessed ourselves as improving markedly in asset strategy and delivery, marginally declining in the area of communication and participation.

Figure 4.5: Benchmarking of asset management maturity against other utilities in Australia and NZ

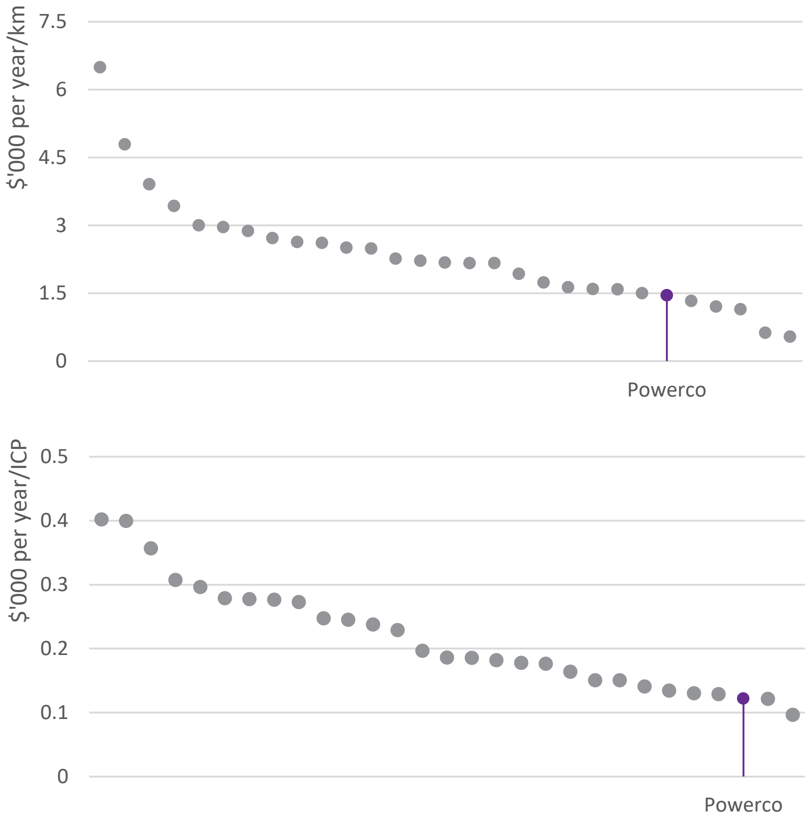


Further details about our improvements in our asset management maturity over the years can be found in Chapter 7.

Another important measure of operational excellence is the efficiency of our expenditure on internal support compared with the network we operate. Figure 4.6 compares our costs, normalised to network line length and to number of customers, with the rest of New Zealand's electricity distribution businesses (EDBs). Our non-network expenditure is low when compared with other EDBs in NZ.

[28] As it is a regulatory requirement, our AMMAT assessment for the 2021 AMP is once again provided, in Appendix 02

Figure 4.6: System Operations and Network Support (SONS) and Business Support expenditure by network length (top) and per Installation Control Point (below) (Average FY15-19)



4.8.2 OPERATIONAL EXCELLENCE GOALS

We have developed a set of goals to help achieve our Operational Excellence objective and to monitor our performance. These are set out in Table 4.6.

Table 4.6: Operational Excellence goals

GOAL	SUPPORTING INITIATIVES
Implement leading asset management information practices	Improve data reliability by streamlining processes, providing new tools to report on quality of data, and investing in new field mobility tools for asset data collection.
	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.
	Combine data from engineering, operations and network performance to support intelligent decision-making.
Ensure cost efficient, valuable services to our customers	Enforce a transparent, commercially competitive approach to all our procurement and contract activities, adhering to best industry practice.
	Automate manual processes to increase worker efficiency.
Our electricity network and databases are secure against cyber attacks	Improve the security of our databases, 'intelligent' assets, and Supervisory Control and Data Acquisition (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.
	Supplement our risk framework to better quantify risk and ensure an appropriate balance between mitigation and cost.
Employ motivated, competent technical staff to look after our assets	Encourage a culture of continuous learning and innovation.
Achieve ISO 55001 certification	Undertake ISO 55001 gap analysis.
	Identify and address the necessary steps to achieve, at least, level three maturity on all measures by end-of-year 2021.
	Develop skills for ISO 55001 and evolve organisational structures to better align network development, fleet management, analytics and future networks.

4.9 NETWORKS FOR TODAY AND TOMORROW

Our networks provide a lifeline service to communities. Safe, resilient and reliable electricity is essential, and we will maintain this supply now and in the future.

For today's network it means we must provide electricity supply at a level of service that balances customers' quality requirements with their willingness to pay for this. Looking forward, this means ensuring that we can support those customers who choose to utilise new energy solutions, such as rooftop photovoltaics (PV) and energy storage, as well as those who wish to continue taking electricity supplies from our network.

In addition, overseas and local studies have shown that effective planning and application of appropriate emerging technologies is essential to realising the opportunities these bring for improved services and cost efficiency, or to moderate the cost of accommodating new distributed energy solutions. This topic is further discussed in Chapter 6**.**

Networks for Today and Tomorrow: Overall objective

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

4.9.1 CONTEXT

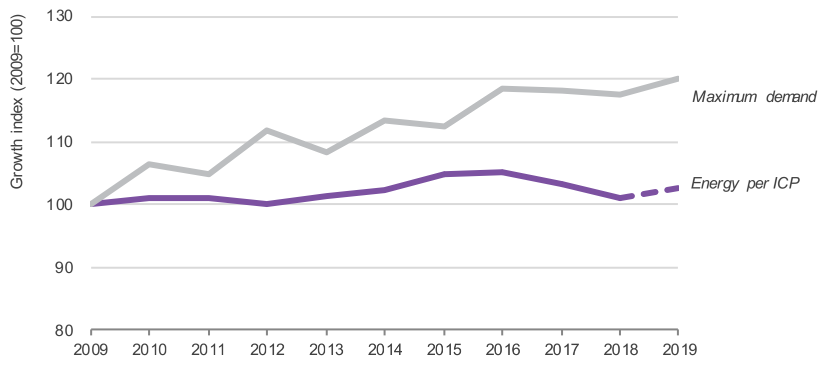
After almost a century, the way electricity is delivered to customers is starting to change. In a legacy system, such as New Zealand's, the flow of electricity has been almost exclusively from large generators, through transmission and distribution networks, to end customers.

Most smaller customers have essentially been considered as quality takers – the service they have received has been determined by their position on a network, and they have had only limited ability to influence it. This is the reason why electricity networks have evolved and been configured to meet peak demand, offering a one-size-fits all approach to passive or disengaged customers.

New technology in generation and consumption is slowly challenging this model and will eventually lead to more stress on the network during peak hours. At present, we are still experiencing a steady increase in demand taken from our network, as illustrated in Figure 4.7. This suggests that the average consumption pattern for our customers has not materially changed during the past decade – and we have no reason to expect this to change substantially during the AMP planning period. Accordingly, our primary asset management focus remains on conventional electricity networks – meeting the needs of today's customers.

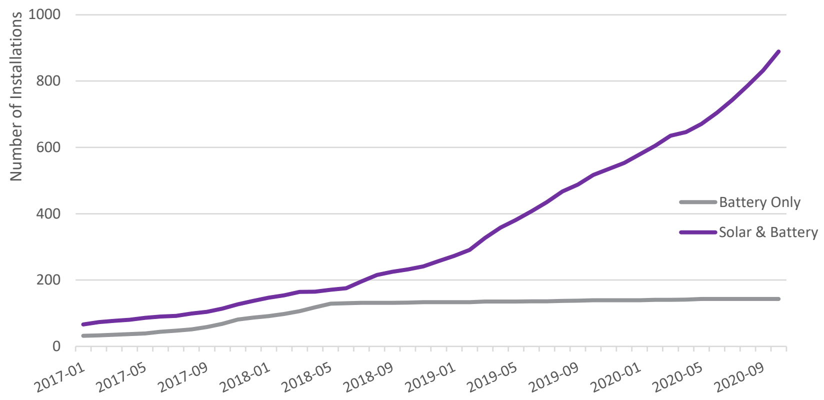
However, there is a slowly increasing uptake of solar PV generation and energy storage in our network area, as shown in Figure 4.8. Over time, this number will increase and, as we plan networks with long-life assets, it is essential that we keep a close watch on the uptake and associated impact on network stability and act early when required.

Figure 4.7: Average electricity consumption and demand on our network



Note: The figures are based on electricity drawn from grid exit points (GXPs) and do not include the impact of distributed generation. The 2019 consumption is a projection of expected consumption.

Figure 4.8: Increase in solar PV and battery storage on our network footprint



4.9.2 NETWORKS FOR TODAY AND TOMORROW GOALS

We have developed a set of goals to help achieve our Networks for Today and Tomorrow objective and to monitor our performance. These are set out in Table 4.7Table 4.7.

Table 4.7: Networks for Today and Tomorrow goals

GOAL	SUPPORTING INITIATIVES
At least maintain overall and disaggregated network reliability at historical levels[29] (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, considering 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.
	Developing our networks to open-access principles that will allow our customers maximum flexibility to achieve their energy requirements.
Encourage innovative fresh approaches to traditional issues	Expand our capability and incentives for innovation, including encouraging innovation from staff.
Adopt prudent asset investment approaches given uncertain future energy demand patterns	Improve our demand forecasting approach to better reflect demographic, weather and economic trends, and the likely increased complexity of future networks.
	Review our network architecture based on detailed scenario analysis and adopt the least-regret outcome.
Ongoing improvement in network resilience, reflecting changing community needs	Enhance our networks and communications infrastructure to support future network resilience.
Off-gridding of uneconomic supply areas	Identify parts of the network where it would be more cost effective to provide off-grid electricity solutions, based on lifecycle considerations, than maintain the grid. Work with customers on implementing such schemes.

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

5 CORE ASSET MANAGEMENT STRATEGIES

5.1 INTRODUCTION

In the previous sections we set out a number of external factors we have to consider in evolving our asset management approach. We also discussed our core company and the supporting Asset Management Objectives. In this chapter, and the next, we describe our evolving Asset Management Strategies – our plans to continue a stable core business where appropriate, but also to prepare for the changes in our environment and to meet our objectives, supporting the long-term sustainability of our business.

Continually evolving Asset Management Strategies is important. However, these should be evaluated against the backdrop of a core business – electricity distribution – which remains overwhelmingly stable and is unlikely to change dramatically in the near to medium future. Accordingly, our traditional, core Asset Management Strategies remain the most influential drivers for how we invest in and operate our networks.

As the bulk of the Asset Management Plan (AMP) is dedicated to the implementation of these core Asset Management Strategies, only a brief overview of these is provided below. In the following chapter, more detail is provided of the areas where we intend to make material changes to our historical asset management practices.

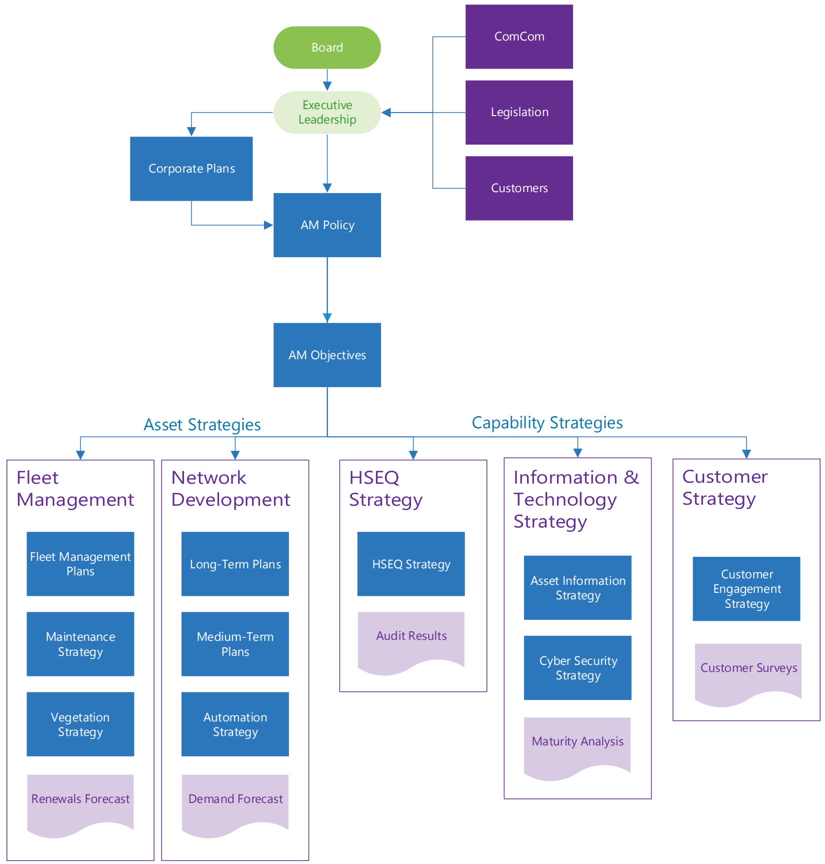
5.1.1 CORE ASSET MANAGEMENT STRATEGIES

Our core Asset Management Strategies have been developed to help deliver our Corporate and Asset Management Objectives. They form the basis of our long-term customer service plans, risk mitigation plans and provide direction for various parts of our organisation and our service providers. Our Asset Management Strategies can be broken into two broad categories:

- **Asset strategies:** These are broadly our Network Development and Fleet Management strategies.
- **Capability strategies:** These are our Customer, Information and Technology (I&T) and Health, Safety, Environment and Quality (HSEQ) strategies.

Figure 5.1 illustrates how our Corporate Objectives, Asset Management Policy and Asset Management Objectives feed into our various strategies. This AMP collates the forecasts as a result of these strategies to develop our 10-year plan.

Figure 5.1: Line of sight from our objectives to individual strategies



5.2 ASSET STRATEGY: FLEET MANAGEMENT

The Fleet Management Strategies ensure that we deliver on our promise to act as good stewards for our assets throughout their lifecycle.

The Fleet Management Strategies include our plans to replace and renew the existing network as it approaches the end of its functional life. Replacement and renewal represent the largest component of our capital expenditure, and these strategies carefully consider how best to deploy it. We generally base our renewal decisions on asset condition and health, known type issues, asset criticality and obsolescence.

These strategies also include our inspection and maintenance approaches for our asset fleets. The objective of these strategies is to ensure that our fleets reach the end of their expected asset life in a controlled manner. Maintenance, therefore, includes planning interventions on the physical assets to keep them serviceable, as well as management of hazards, such as vegetation, on the network. Key to this is the condition assessment data we collect during inspections, which inform our decision-making for asset replacement or repair.

In order to minimise the likelihood of failures, the fleet strategies also include our plans for managing failures caused by third-party interference and natural hazards.

5.2.1 ASSET RENEWAL STRATEGY

Renewing our asset fleets is essential to maintaining the overall health and condition of our network. Deteriorating condition increases safety and reliability risks because of the higher likelihood of asset failure. The primary purpose of our asset renewal strategies is to inform our approaches to replacing our existing assets in order to meet our safety and reliability objectives, while minimising costs.

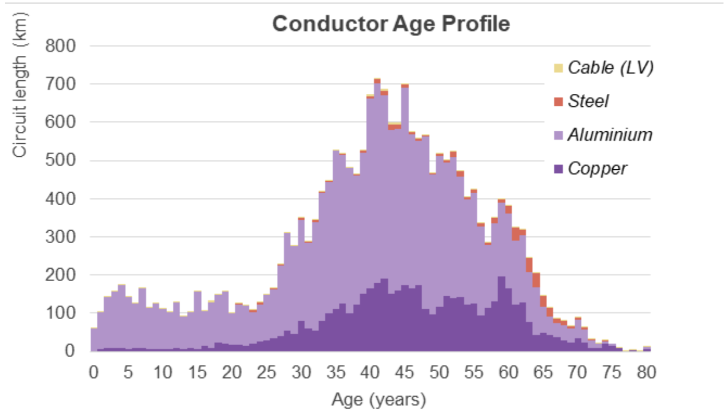
During the past five years we have significantly increased our asset renewal investment. This was in response to asset renewal-related trends such as:

- Increasing number of equipment failure related network faults.
- Unsustainable levels of asset defects.
- Poor asset health.
- Increasing numbers of poor performing feeders.
- Poor unplanned System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) benchmarking (when considering customer density).

Most of our distribution network was constructed from the 1960s to the 1980s. Asset age is a useful indicator of asset replacement needs, although actual replacements are triggered using other factors. Asset service life varies by fleet, but distribution assets typically have a service life of 40 to 70 years. This means a large amount of our legacy network is becoming due for replacement.

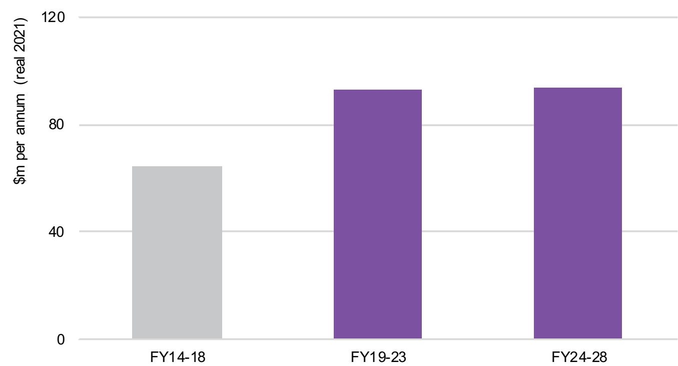
As an example, Figure 5.2 shows our overhead conductor age profile. Most of our overhead conductor fleet is 30 to 65 years of age, and large quantities of this will require replacement during the next several decades. We have now increased replacement to approximately 200km per year. During the upcoming planning period we aim to replace more than 300km per year.

Figure 5.2: Overhead conductor age profile



Our increase in renewal investment during the past five years has bought us up to a sustainable level of asset replacement. We now must continue this level of investment for the foreseeable future to continue to manage the asset health and risk of our network. Figure 5.3 shows our historical, current and future levels of renewal investment. We increased our renewal investment by 45% in order to stabilise related safety and reliability trends. In order to stay on top of these risks, our future renewal investment level is broadly similar to that of today.

Figure 5.3: Renewals Capex investment levels



Since establishing a new level of renewal investment, our focus has moved to how we best optimise our asset replacement programmes. During the past two years we have improved our knowledge of asset condition and developed tools that use this knowledge to inform our short-term renewal priorities. We have:

- Introduced new condition assessment approaches, such as pole-top photography and increased partial discharge testing.
- More systematically identified and managed asset type issue programmes, such as servicing oil-filled ring main units (RMU).
- Developed a greater suite of condition-based risk management (CBRM) models for some of our key asset fleets.
- Developed a geographical information system-based (GIS) overhead renewals planning tool, allowing greatly improved identification and prioritisation of overhead line replacement projects.
- Recently introduced Copperleaf C55, which will allow for cross-portfolio optimisation of renewal investments.

Extending on these capabilities will continue to be a focus. Our maintenance strategy (discussed below) will continue to expand our inspection processes and data collection, from which we will be able to improve our asset replacement decision-making.

An area of increased focus for us in coming years is the design and material specification of our modern equivalent assets that we are currently installing. Our standards and specifications have a large bearing on our replacement costs, and these decisions made upfront have a critical impact on the overall lifecycle cost of the asset. Electricity networks are also faced with increased uncertainty about how they will be used and operated in the future, with disruptive technologies likely to impact how distribution networks are designed, and continued changes in rural land use, eg increased forestry development. We intend to improve our lifecycle cost analysis and use this to update our design and material specification standards. Areas of investigation will include lower construction standards for remote rural areas of our overhead network, and challenging cost-benefit assumptions for how we design and configure our zone substations. This work is part of our wider Network Architecture strategy, discussed in Chapter 6.

5.2.2 VEGETATION STRATEGY

Vegetation is a key risk to our overhead assets, with the potential for unplanned outages or fires. Although we don't own the vegetation, as a network operator we have obligations to manage vegetation near our powerlines, as prescribed in the Tree Regulations.

Known vegetation-related faults during the past eight years contributed 16% of our total unplanned SAIDI. Therefore, our vegetation management approach can have a large bearing on the overall reliability of our network and impact customer experience.

From FY19 we approximately doubled our vegetation management Opex, bringing us to industry average levels per kilometre of line. At the same time, we have developed a full cyclical trimming programme for all distribution feeders, adding to existing cyclical programmes for subtransmission and high-risk urban networks. The cyclical programme requires that all the network is surveyed within a defined time period and a tree trimming plan implemented. Cycle times vary, based on network environment and criticality.

Our cyclical strategy is consistent with good practice and aims to maximise the length of powerlines that are compliant with minimum clearance zone requirements. However, developments in Lidar surveying, vegetation analytics and risk-based planning may provide opportunities to improve the safety, performance and cost effectiveness of our vegetation management activities. After a Light Detection and Ranging (LIDAR) trial during early 2019, we have now commenced a full LIDAR survey of our network. From this, we will have a complete record of the vegetation in close proximity to our powerlines and, during 2021, we will develop new vegetation analytics to allow us to greatly improve our understanding of vegetation risks.

This updated knowledge will be used to develop an updated vegetation strategy that is intended to move us to a more efficient programme – one that achieves compliance while reducing long-term costs. It will also support improving reliability through the targeted removal of out-of-profile vegetation in critical sections of the network. (The optimal long-term strategy may require a short-term increase in expenditure to realise the longer term sustainable minimum.)

5.2.3 MAINTENANCE STRATEGY

The objective of our Fleet Maintenance Strategy is to minimise asset lifecycle costs while ensuring safe and reliable performance.

The current maintenance regimes are a combination of time-based asset inspections, coupled with time or operation-based preventive maintenance. The time-based asset inspections identify any reactive maintenance requirements (ie defects) on the network. The routine preventive maintenance keeps assets operating optimally and reliably.

The next phase in our maintenance strategy is focused on transitioning to reliability centred maintenance.

Currently the maintenance regimes are applied uniformly across entire fleets. Reliability centred maintenance would include optimising maintenance regimes and task intervals at individual asset levels. This is achieved by tailoring tasks for specific equipment types and scheduling maintenance based on the operating contexts and criticality of these assets. This includes adjusting maintenance frequencies for each asset based on their operation count, criticality, site specific environmental factors and rate of deterioration.

We are tailoring tasks for specific equipment types by introducing detailed maintenance procedures for use in the field and training field staff in their use. Initially, we are rolling out these maintenance procedures on our high-volume and high-risk assets, with the intent to eventually extend them to our entire fleet. This is increasingly important with the uptake of new technology on our network.

Since 2019, we have introduced several new inspection and maintenance programmes. These programmes are intended to:

- Lead to an optimisation of expenditure and maintenance activities.
- Improve the performance of assets on our network in the medium to long term.
- Implement new maintenance, condition monitoring or test techniques to better understand asset condition and inform renewal plans.
- Extend the service life of assets.

Examples of these programmes include enhancing the performance of our overhead networks through rapid line inspections of the worst performing feeders and undertaking periodic pole-top photography to better understand the condition of this fleet. We are also now undertaking major oil RMU maintenance to ensure the assets can operate safely and reliably until the end of their planned life.

A shift to specialist service providers will see us increase maintenance investment in critical assets, such as power transformer tap changers and partial discharge measurement on 33kV indoor switchboards. This shift is predominantly driven by the limited knowledge of older assets among service providers and the ability to maintain working knowledge as new technology increases periods between maintenance.

5.2.4 DEFECTS STRATEGY

The primary objective of the defects strategy is to manage and reduce the defect backlog to prudent levels. The defects strategy is closely aligned with the introduction and training around the maintenance procedures, and the introduction of non-intrusive inspection techniques to drive consistency.

Our defects process can be broken into three main segments:

- Identification
- Prioritisation
- Remediation

The defect identification process can be subjective, resulting in inconsistencies in how defects are classified. This makes it difficult to efficiently prioritise defects. We are working on improving this capability by:

- Developing defect classification catalogues for our high-volume assets.
- Automating inspection processes through means such as our pole-top photography programme.

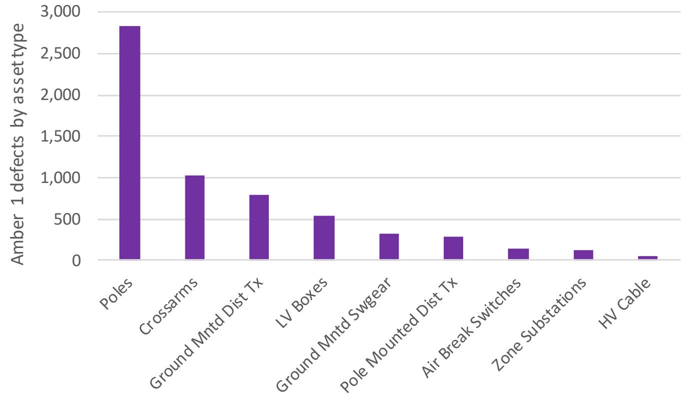
Better identification allows us to improve defect prioritisation by gathering consistent information to make decisions. We prioritise defects against time-mandated rectification intervals, such as hazardous (red), unserviceable (amber 1) and conditionally serviceable (amber 2) categories, which have a strong focus on safety. Our next step will include developing risk-based failure trees for our most common defects. This will provide us better resolution about specifically which defects in the backlog pose the highest risk and will allow us to prioritise works accordingly.

Lastly, we are focusing on improving our works packaging processes. The implementation of SAP has enabled a step change in sharing information across all layers of our asset management. It allows everyone, from people in the field to planners forecasting long-term trends, to understand the defects logged against individual assets.

This creates opportunities for us to better package defects into the primary planned capital works programme, focusing remedial defect work on a smaller portion of the defect backlog, and allowing field staff to make decisions about what on-spot fixes they can carry out.

Figure 5.4 shows a breakdown of our current Amber 1 defect backlog and how the defects are distributed across different asset types. The overhead network fleet accounts for most of the defect pool as it is our biggest fleet.

Figure 5.4: Amber 1 defect backlog by asset type



The incremental improvements in defect identification, prioritisation and remediation will allow us to reign in and eventually reduce our defects backlog.

5.3 ASSET STRATEGY: NETWORK DEVELOPMENT

Our Network Development Strategy captures our plans for the capacity and functionality of our network.

Capacity of the network includes determining the number and types of subtransmission and distribution feeders and the size of the substations we install on the network. The capacity grows to meet customer demand. But as capacity grows, we also need to safeguard the network from the impact of any single failure. This includes ensuring adequate back-up capacity to compensate for failures at critical nodes. It also includes ensuring that the segmentation of our network minimises the impact of outages on our feeders.

The functionality of the network is dependent on the non-network alternatives and switching capability deployed on the network. Judiciously applying the appropriate mix of distributed generation and automation equipment on our network helps to defer expensive capacity development projects.

The Network Development Strategy also ensures that we maintain an appropriate quality of supply on the network. Going beyond managing fault statistics, it extends to voltage disturbances, brownouts, and the harmonics performance of our network. These qualities require us to carefully track and pre-empt the impact of customer demand.

5.3.1 SECURITY OF SUPPLY

We use security standards to define what level of redundancy our zone substations should have and the acceptable duration of outages. They include both the size and type of load, to reflect the consequence of an outage. These standards act as a ‘starting point’ for further investment analysis and aren’t used to mandate investments. They are discussed in more depth in Chapter 10.

Our security standards have traditionally been mainly deterministic in nature, but we are in the process of moving to a probabilistic approach. (See Chapter 6 for a discussion.) The latter will be implemented during the next three years, and our current security of supply approach is described below.

After identifying non-conformances with our security standards, we undertake further analysis, including evaluating the economic cost of supply loss, as well as a full options analysis of potential supply solutions, or other means, to mitigate the downside of an asset-related failure while avoiding major investment. From here, we can develop a prioritised works plan that aims to reduce the load at risk while staying within our capital budgets.

Historically, because of capital constraints, we had to defer larger subtransmission projects that required significant investment and prioritise smaller tactical subtransmission solutions and other distribution investments to manage load at risk. With continuing growth in our network, this necessitated a catch-up on a suite of major subtransmission projects that we have either recently completed or are in the process of executing. This has led to a material increase in Network Development expenditure during the past three years.

Compliance with our security standards had been deteriorating up until FY17-19, when we began substantially increasing investment. By the end of the customised price-quality path (CPP) period we plan to have reversed the legacy deterioration in security standard compliance.

We also intentionally have not targeted full compliance with our security standards, as we have been willing to judiciously accept more to avoid potentially uneconomic investment[30]. It is also a reflection that deterministic security criteria are comparatively simple, coarse and conservative, and ignore important elements of Network Development planning, such as demand profiles, circuit failure rates, the value of lost load and mixed load types.

By using the security standards as a first past ‘trigger’, followed by economic analysis, we have already been moving away from the pure deterministic standards for some time. As noted, we are now formally embarking on replacing our legacy security standards with an updated probabilistic approach. This is intended to include elements such as different growth scenarios, failure rates reflecting specific asset performance and consideration of a wider set of options. The standards will

30. We have previously had our security standards independently assessed, and they were found to be “middle of the road” for New Zealand electricity distribution businesses.

use value of lost load (VoLL) inputs to calculate monetised risk and be compatible with our overall Value Framework.

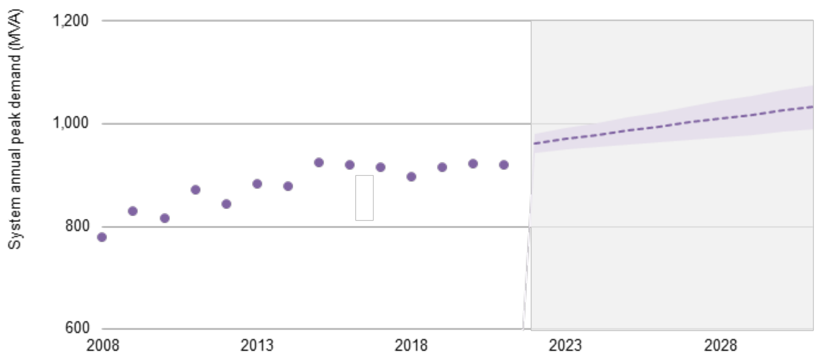
As we are just commencing work on this new approach, our Network Development plan in this AMP (as shown in Chapter 15) has been prepared using our legacy approach. However, we have included a top down moderation to these investment forecasts to reflect that we expect to be able to reduce the level of this investment in the future from an improved probabilistic approach. This is most likely to materialise in deferred investments for existing N-1 substations where, considering demand profiles and capacity, the risk of loss of supply is generally low.

5.3.2 DEMAND GROWTH

Electricity demand growth continues to be a main driver of investment in our network. New subdivisions and property developments because of population growth, or increasing economic activity, are the main factors contributing to the increase in electricity demand. To ensure our network can safely and reliably facilitate these growth factors we need to invest in more capacity or seek ways to reduce the impact of increased demand.

As discussed in Chapter 3, unlike much of New Zealand, we are experiencing continued growth on much of our network and expect this to continue. Figure 5.5 shows our overall system demand trend and forecast.

Figure 5.5: System demand trend and forecast



At a subtransmission level, our demand forecasts are an input into our security analysis that will identify potential future areas requiring investment (as discussed above). Feeder level demand forecasts are used at distribution level to identify future required reinforcements or greenfield installations. Over a shorter horizon, investments will often occur when we are aware of a specific customer need and have worked with them to ensure an appropriate solution is designed. The majority of our investments are only committed when demand requirements are relatively certain, so our demand forecasts are put in our long-term plans rather than lead directly to committed works.

We are also embarking on improvements in our demand forecasting approach, linked to our transition to probabilistic planning. This will involve forecasting at a much more disaggregated network level than what we do today, and will require much improved data on individual customer demand. Initially, we will use this for improved upper and lower demand scenarios, but ultimately we will seek to transition to full probability distributions. Linked with our improved security standards, this will allow for a more refined approach to assessing load at risk and the optimal investments to manage this.

5.3.3 RELIABILITY

Powerco's overall network reliability objective is to ensure that we meet our customers' reasonable expectations regarding the quality at which we deliver their electricity, and the price they are willing to pay for this.

To achieve this, we focus on three key areas:

- At an aggregated network level, we will maintain reliability of supply at historical performance levels. Regular customer feedback confirms that there is no general desire for improved reliability, particularly if that would affect the cost of electricity. While we will ensure that network and asset performance do not deteriorate, we will also not deliberately invest to improve overall performance.
- We may, however, decide to improve[31] the quality of supply to individual or smaller groups of customers. This decision will be driven by factors such as meeting customers' specific quality requirements, or where we assess that supply quality falls short of what customers should reasonably expect in terms of good industry practice.
- We will continuously improve the measurement of network performance to better inform our management and investment decisions. This includes greater disaggregation of reliability reporting, recording incidents on all parts of our network, and improving outage root cause analysis.

Our primary reliability measures are SAIDI and SAIFI, broken down into unplanned and planned outages. These measures are also what we report to the Commerce Commission to meet quality of supply regulation obligations. However, these are aggregate network measures only, and therefore we also track performance at

[31] In rare cases, we may also decide to allow quality of supply to deteriorate if our customers indicate their preference for this, or supply quality is inappropriately high.

feeder and distribution transformer level to identify poor performing parts of our network.

Many investments contribute to the reliability of our networks. Asset renewal, maintenance and defect works address reliability concerns of our older assets, while Network Development projects help enhance reliability by providing alternative options for supply. Vegetation management is also a key tool in keeping our network reliable. Our operations have a key role in managing the reliability impacts of outages, such as through outage response times, contingency planning and spares management.

Specific reliability focused investments have traditionally been centred on the deployment of automated distribution switches and fault indicators. For our radial feeders we typically use reclosers and sectionalisers. These devices enable the faulted section of circuit to be isolated while maintaining supply to the customers upstream of the fault. We will continue to seek out further opportunities to install these devices during the planning period.

We are now beginning to expand our automation strategy beyond this legacy approach. With an increased likelihood of two-way power flows and considerable distributed energy resources on our network, the ability to monitor the network and react to the changes becomes essential. This will mean a greater focus on measuring and monitoring the state of the network and adding increased remote-control capability. This new automation strategy is discussed in Chapter 6.

5.3.4 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

Operating the distribution network is becoming more complex and dynamic, with growing numbers of backfeeds, switching points and automation devices. This is leading to a major increase in the volume of information that operators contend with, and the complexity of switching plans. The anticipated future growth of distributed energy resources (DER) technology will further add to the complexity of operations.

We intend to address this growing complexity by improving the capability of our operations centre through the application of an Advanced Distribution Management System. Our ADMS strategy is to simplify and streamline control room operations by using platform-based software solutions to support operational decisions – leading to increased operational efficiency, service provider safety, and network reliability. These platforms will allow us to integrate data between asset management, control room and field staff by using historical, real-time and forecast data for real-time operations. Examples of such applications to support decisions in the operation room include:

- Fault Location, Isolation, and Service Restoration (FLISR)
- Realtime Distribution Power Flow analysis(DPF)
- Switch Order Management (SOM)

We see this as one of our key initiatives for improving customer service and the effectiveness and safety of our operation. While the focus will initially be on our subtransmission and distribution networks, it is intended that, over time, the Low Voltage (LV) network will be introduced into the system as well as we roll out more monitoring, automation and switching capability on this part of the network.

5.4 CAPABILITY STRATEGY: CUSTOMER

We know New Zealand’s electricity networks will change because of customer needs and demands. However, the ‘when’ and ‘how’ is uncertain. Our Customer Strategy supports the delivery of our Customer Commitment to provide a safe and reliable electricity network that meets their service level expectations, is future ready and cost effective. Successfully delivering on our Customer Strategy lays the platform for achieving our Customer and Community Asset Management Objective.

In the past three years, we have focused on improving the experience of customers and communities when interacting with us. This provides the foundation to meaningful and constructive community discussions and is achieved in partnership with the wider supply chain.

We operate an interposed contractual model with retailers. As a result, customers interact with us directly or through their retailer. In either case, we know the customer’s experience is heavily dictated by the information they receive and the ease of communication. For us this means that regardless of who the customer is interacting with, they should experience seamless access to consistent and accurate information. This is a core principle of our Customer Commitment.

Our Customer Strategy sets a path to ensure we have the processes, systems and people to deliver this experience. In recent years, this has included evolving our customer-facing digital platforms to provide individualised access to information on planned outages, and the ability to directly log network faults with Powerco. Additionally, we now have greater capability to engage with customers and communities on work that could or does affect them at a more individual level.

5.4.1 WHERE WE ARE HEADING

Our Customer Strategy is broadly focused on delivering outcomes driven by our Customer Commitment, these include:

- Minimising the disruption caused by our work programme or loss of supply.
- Growing a customer-centric mindset throughout the entire business.
- Building relationships with our customer base so that engagement delivers the information and intelligence required to ensure optimal network investment decisions.
- Providing public-facing digital platforms that support engagement through access to information and two-way communication.

Our Customer Strategy primarily focuses on five key service dimensions developed through engagement with customers, our delivery partners, and the wider industry. The five dimensions drive initiatives that support our Customer Commitment and associated objectives.

5.4.1.1 CUSTOMER SERVICE DIMENSIONS

Customer experience (information and works delivery): Our customers value timely and accurate information about their electricity supply and information to mitigate the impact of a loss of supply or the impact of physical work carried out in their communities. Advances in mobile technology and social media have created an expectation that information should be readily available through a number of communication channels. The most important information for residential customers is communication about power cuts, why they are occurring, changes to planned outages and other disruptions, such as traffic movement restrictions or access to private land.

Responsiveness to unplanned loss of supply: Unplanned outages occur for a variety of reasons. Some of these are within our control, such as equipment failures. Others are beyond our control, such as lightning strikes or vehicles hitting poles. The outages that are within our control are easier to foresee and prevent, and we do everything we reasonably can to eliminate them. When an unplanned outage does occur, our customers expect us to respond quickly to reduce the impact and potential safety risks.

Reliability and continuity of supply: Customers generally place a high value on reducing or avoiding outages. But this varies for different groups, and our approach to asset management is to better understand these differences so we can align our investment plans. Resilience is similarly important, as our customers expect our network to be able to withstand storms and for supply to be restored within a reasonable period. This will become a growing challenge as climate change impacts our largely rural and often remote network.

Cost effectiveness: While our customers recognise the importance of investing in the network to ensure that it is safe and reliable, they are also concerned about the price of electricity. Delivering efficient and effective value, and having control over our costs is paramount at Powerco.

Choice of energy options: Increasingly, customers are wanting more flexibility and choice in the way they interact with the network. New technology offerings, combined with an increasing customer willingness to take more control of their energy options, is leading to a change in the way energy markets operate. This means we must learn about these new technologies and new energy solutions to enable our networks to support and accommodate the future choices of our customers.

5.4.2 HOW WE WILL GET THERE

Delivering our investment programme on time and within budget while minimising the disruption to our customers and communities, creates the need for trade-offs. Our Customer Strategy endeavours to achieve the optimal balance between delivering our works programme and meeting the customer expectations embodied in the customer service dimensions. We continue to review and prioritise Customer Strategy initiatives to ensure they are supporting customer preferences and expectations. The key short to medium term initiatives of the Customer Strategy are detailed in the following sections.

5.4.2.1 CUSTOMER RESEARCH AND INSIGHT PROGRAMME

The Customer Research and Insight Programme ensures the customer intelligence needs of the business are met. The programme covers the collection of data used to inform long-term asset management decisions through to development of digital communication tools.

5.4.2.2 COMMUNITY ENGAGEMENT AND RELATIONSHIP MANAGEMENT PROGRAMME

The Community Engagement and Relationship Management Programme provides a framework to support the efficient delivery of our works programme by creating partnerships that support our ‘social licence to operate’ and the necessary access to land and other resources.

5.4.2.3 CUSTOMER SERVICE DEVELOPMENT

Continued development of our customer service experience is important to enable us to engage with our customers to access insights and priorities that influence network design and enable us to minimise the disruption as a result of our work.

This initiative focuses on understanding our customer journeys, touch points and their specific pain points, and work in partnership with our delivery partners and the wider supply chain to improve customers’ experience.

5.4.2.4 CUSTOMER-FACING DIGITAL ENGAGEMENT INITIATIVE

Keeping pace with social changes and expectations around access and customisation of information drives continued innovation of our communication channels. The Customer-Facing Digital Engagement Initiative utilises customer insights and internal needs to guide the design and implementation of solutions.

5.5 CAPABILITY STRATEGY: INFORMATION AND TECHNOLOGY

Our Information and Technology (I&T) Strategy is a key component of our capability development. The I&T Strategy is designed to reduce technology risk and increase business resilience and efficiency through the delivery of foundational business practices and technology. It also addresses the new skills and ways of working that we must adopt in order to be successful.

The I&T Strategy outlines our plans to improve our asset management processes and systems, and prepare for our operational transition to a secure, intelligent and open-access grid. Information and technology improvements will make our business operations more secure and resilient, our employees more productive, and help them make better decisions. Our plans also include connecting with our customers meaningfully in the digital world and providing assurances about how any customer data is managed now and into the future.

5.5.1 WHERE WE ARE NOW

Earlier I&T strategies were based upon a "best of breed N-tier architecture", in which Powerco built or acquired point solutions to meet particular business needs and managed the integration itself.

This resulted in an IT system architecture that was overly complex, difficult to support, expensive to maintain and difficult to change to satisfy new business needs.

Our CPP investment case for information and technology was primarily based on growth projects to mitigate these technology risks with a focus on:

- Field communications
- Legacy applications
- Multiple data repositories

Investments to improve the resilience of our IT infrastructure were already well under way and have now been completed.

Our plans required a significant increase in the number and complexity of information and communications technology (ICT) projects. We have upgraded our field communications networks, including the introduction of a new digital mobile radio network, and also completed a number of application upgrade and replacement projects. The most complex of these is our Enterprise Resourcing Planning (ERP) programme. The first and largest phase of this multi-phase programme went live in 2019.

While we had started to develop our cyber security capability in order to protect both our networks and corporate information, our cyber security risk level was high. Since that time we have significantly increased the resources dedicated to cyber security, created a Cyber Security Strategy and delivered upon that roadmap. With strong support from the Powerco Board and Executive, we have seen our cyber risk reduce to medium. However, given the dynamic and growing cyber threats, this continues to be an area of focus.

At the same time, we have been working to standardise our ICT environment in order to simplify operations, contain costs and enable business agility. We are doing this by reducing the number of configurations, customisations, products and suppliers we support. Standardisation, together with automation and the adoption of cloud services, will increase the reliability of ICT services as well as the efficiency of the Information Service department.

Unfortunately, due largely to significant delays to the first phase of the ERP programme and increased expenditure on cyber security, ICT capital expenditure has exceeded the forecast proposed in our CPP investment case. This additional expenditure has resulted in us delaying certain projects until we have satisfactorily embedded the ERP.

The increased rate of ICT investments has accelerated changes to business processes, systems, roles and data impacting employees, service providers and business partners. We have learned that successful people change management is essential to realising the benefits of our information and technology improvements. We have increased our people change maturity, but it is still taking longer than anticipated to embed the changes for Powerco employees and our business partners.

An aspect of digital transformation that is frequently overlooked is that of data. All digital opportunities depend upon access to a sufficient volume of quality data. Historically, our approach to data acquisition has been piecemeal and uncoordinated, resulting in data silos and reliability and accuracy issues. We are adopting new tools and practices to help Powerco improve its data management maturity.

A final consideration is the new skills and ways of working that we must adopt as our business environment becomes increasingly digital. We need to attract and retain digital talent, while also upskilling existing staff. Our employees and service providers need to embrace relevant technologies, improve how they read, work with and analyse data, and adopt a culture of continuous learning – both formal and self-directed.

5.5.2 WHERE WE ARE HEADING

Our I&T Strategy has three high-level goals, to ensure that:

- Our customers get the information they need, wherever they are, whenever they want it.
- Our people (employees, service providers and contractors) have the right tools and best practice processes to do their jobs efficiently, anywhere, anytime.
- Our people are able to make insightful, informed and fact-based decisions with confidence.

To achieve these goals, we need to focus on three areas:

- Reducing cyber security and technology risk and increasing business resilience.
- Increasing business efficiency through the delivery of foundational business practices and technology.
- Developing new skills and adopting new ways of working in order to be successful with technology.

5.5.3 HOW WE WILL GET THERE

We will deliver our I&T Strategy through seven strategic programmes, as outlined below. These programmes are the result of a detailed I&T needs analysis covering the planning period and incorporates lessons learned and new technology trends.

All new technology capabilities, across all programmes, are designed to be secure and resilient.

5.5.3.1 DIGITAL WORKPLACE PROGRAMME

The purpose of the Digital Workplace Programme is to enhance employee productivity and organisational agility. Business growth and an ageing workforce mean dilution of Powerco "know-how" and culture that is critical to sustaining our leadership position in the energy industry. Easy-to-use collaboration and information management technologies will help to leverage our existing know-how, create greater connectivity across operating locations, enable remote working, and decrease non-essential travel. This programme also includes developing the digital skills mindsets and practices required to get the most benefit from technology.

5.5.3.2 CONNECTING WITH CUSTOMERS PROGRAMME

The purpose of this programme is to use digital channels to improve customer experience and make it easy to do business with Powerco.

Our customers want timely and accurate information about faults, outages and new service connections and expect data privacy to be maintained.

A focus on customer experience regarding planned and unplanned outages will improve engagement satisfaction and provide new sources of customer intelligence.

Changing energy demand will require greater understanding of customer preferences. Data and analytics services that protect customer privacy will enable demand-side research to help us better align pricing, tariffs and customer contributions with evolving customer and market needs.

5.5.3.3 NEW FOUNDATIONS ERP PROGRAMME

Our New Foundations ERP Programme is about adopting industry best practice financial and asset management processes and systems to provide a modern business foundation.

Our new ERP platform brings industry standard business processes and more automation to the planning, delivery and management of the works programme, property and consents, and financial management capabilities. This will increase the volume of work per employee and improve contract performance through robust works planning and scheduling, and enables the capture of a consistent time series of asset data upon which to base future asset management and operational decisions.

To advance health, safety and environment (HSE) performance in response to regulatory changes and increasing work volumes, we need to improve HSE competency management processes, risk and incident management (getting HSE data and real-time network status information in the field) as well as analysis and reporting.

In future phases, we will adopt new consumption management and billing capability to enable a transition from grid exit point (GXP) to installation control point (ICP)-based billing and future tariff models that encourage the efficient use of our network as well as the potential for direct customer billing and dynamic tariffs.

We will also introduce multi-channel customer service and new works management systems to streamline business processes to support growth while reducing cost of service.

ERP will also automate HR business processes to scale-up recruitment and onboarding and help build a high-performance workplace through improved learning, leadership and talent development processes, workforce planning and employee analytics.

5.5.3.4 ADMS PROGRAMME

The Advanced Distribution Management System (ADMS) Programme (see section 5.3.4) will extend existing systems with the data, processes and technology required to operate an intelligent, open-access grid.

The new digital mobile radio system and voice communications consoles have already improved our ability to communicate with the field.

The next step is to scale Network Operations by extending tools that help manage network access and availability as well as provide new tools to manage operational risk, such as switch order management.

Powerco's vision of an open-access network requires new capabilities to operate distributed energy resources. Our smart grid will use an ADMS and intelligent assets, such as automated switches and control relays to manage power flows in all directions across both high and low voltage networks. This will require accurate network information, including LV, and investment in an Internet of Things

(IoT[32]) platform comprising scalable communications, layered cyber security and the ability to discover, manage and analyse data from the field in real-time for business purposes, such as the calculation of dynamic tariffs.

5.5.3.5 DATA AND ANALYTICS PROGRAMME

The Data and Analytics Programme provides the technology and practices to access and analyse data, and measure and improve its quality, essential to moving to a data driven organisation.

The transition to an intelligent grid, including improved management of the LV network, is entirely dependent on access to accurate asset and network information. Legislative requirements, both existing and new, also emphasise the need for mature data management practices as well as reporting transparency.

We have developed a new Asset Information Strategy which outlines how we will use data governance, combined with new data standards and management tools, to streamline network information management business processes and improve data quality and timeliness.

On the technology front, flexible and scalable reporting and advanced analytics services are needed to improve the repeatability of regulatory reporting and drive a performance culture to support new data sources (eg LIDAR, sensor data), and to provide easy to use tools that aid high quality options analysis. For example, consistent identification of the most cost effective, long-term investments, or combine network asset performance, customer and market data to inform the future network architecture.

5.5.3.6 CYBER SECURITY PROGRAMME

Cyber risk is one of Powerco's more significant risks and our business strategy to transition to an intelligent, open-access grid will increase our risk. Some of the particular threats facing the energy industry include:

- Digitisation of the energy supply chain creates networks that are more dependent on digital technologies and increases the risk of cyber threats
- The desire to optimise asset lifecycles leads to increasing deployment of IoT sensors and wireless technology, increasing the risks to safety and of business disruption
- Influences such as the organic growth of technology networks, the speed of digital change and increasing fiscal constraints can create conditions where information systems are more susceptible to compromise
- Increased data sharing with partners and third parties leads to increased risks of data compromise
- Many threat actors including organised crime, nation states, insiders and hacktivists are motivated to attack the energy sector
- Energy companies are a key component of critical national infrastructure, making them an attractive target for attackers seeking to disrupt or sabotage a nation state
- Attacks on the energy sector are becoming more frequent and more sophisticated

We have developed a Cyber Security Strategy and roadmap to reduce cyber risks and manage business continuity, while also opening the pathway for intelligent devices that improve network control and capture asset performance data.

Our goal is to reduce the likelihood and impact of a cyber attack on continuity of service to our customers, and to ensure our business is prepared and resilient when under attack. We take a risk based approach prioritising Powerco's core function (delivering electricity) over its other business functions should other layers of control fail. One of the key aspects is enhancement of our operational technology, including SCADA systems and field devices. We measure and actively seek to improve Powerco's cyber security maturity and will also undertake ISO 27001 certification for the management of sensitive customer information.

5.5.3.7 IT TRANSFORMATION PROGRAMME

This programme includes the modernisation of legacy IT systems, ICT cost optimisation, as well as the new IT capabilities, competencies and practices required to enable digital transformation. This includes speeding up the delivery of new information and technology services by adopting a platform architecture approach, cloud services and Agile methodology.

5.6 CAPABILITY STRATEGY: HEALTH AND SAFETY

Powerco is committed to keeping people safe – the public, our staff and our service providers. The Health and Safety Strategy enables us to deliver on our health and safety objectives, business commitments and to improve our systems. Initiatives in this strategy are broadly categorised into public safety and worker safety, with an underlying focus on critical risks.

Driving simplicity and proportional risk management is at the core of our systems and our strategy. It includes defining, monitoring and improving the processes used to manage risks that are presented during the delivery of our network and fleet strategies. It also builds on our advisory capability for our staff and contractors.

The use of our assets improves the lives of our customers. It also presents risks that need to be managed. The strategy outlines the way we manage those asset

[32] The Internet of Things (IoT) is the network of physical objects that contain embedded technology to communicate, sense, or interact with their internal states or the external environment.

related risks and of our role as a person conducting a business or undertaking (PCBU).

The Health and Safety Strategy also helps ensure that we have appropriate resources to monitor the quality of works on our network. This provides for good oversight throughout our supply chain, from equipment suppliers, to internal staff and contractors in the field. The strategy is built around three pillars:

- Critical Risks
- Public Safety
- Safety as Usual

Each of Powerco's health and safety initiatives are targeted towards supporting at least one of the three strategic pillars.

5.6.1 KEY CRITICAL RISK INITIATIVES

5.6.1.1 TRAFFIC MANAGEMENT

One of the main health and safety risks involves working in local council and New Zealand Transport Agency (NZTA) roading corridors, which leaves workers exposed to traffic. There have been a number of traffic management incidents in the wider construction and roading industry, as well as during work carried out by Powerco.

We are engaging with and encouraging contractors to implement more robust traffic management controls focused on worker safety. Powerco, along with the Electricity Engineers Association (EEA), has representation on the NZTA's Road Work Site Health and Safety Improvement Programme (stakeholder group meeting).

NZTA is undertaking a review of the Code of Practice for Temporary Traffic Management (CoPTTM). It is expected this will lead to increased focus on the hierarchy of controls and greater use of road closures and technology solutions. It will mean an increase in traffic management training requirements for our service providers working on the NZTA roading corridor.

WorkSafe is releasing its Good Practice Guide for Road Worksite Safety in 2021. This will introduce additional legal requirements that Powerco and our service providers must meet.

The effectiveness of traffic management is included in our field auditing programme. This helps ensure that all work carried out in the roading corridor has an approved traffic management plan in place to keep workers and the public safe, and that the traffic management on site is in compliance with this plan.

5.6.1.2 HIGH VOLTAGE LIVE LINE WORKING

Live line working has long been an important part of how we minimise customer disruption when we build or maintain assets. While there have been very few safety incidents related to this practice, it has become somewhat controversial, with questions asked about whether the intrinsic risks it may pose warrants its use.

We believe that live line working can be safe in many situations, provided it is appropriately managed. Accordingly, we have been working with our live line service providers to develop a common industry set of procedures for (safe) live line glove and barrier working.

We have also developed and are implementing a decision-making tool to assist with understanding where live line work can be safely undertaken. The purpose of developing this tool is to carry out realistic assessments of where live work on our network can be completed safely, thereby reducing the impact of outages on our customers.

Critical risk controls to manage live line working were identified as part of the assessment process. An assurance programme for live line working risk controls will be included in the wider audit and assurance programme in FY22.

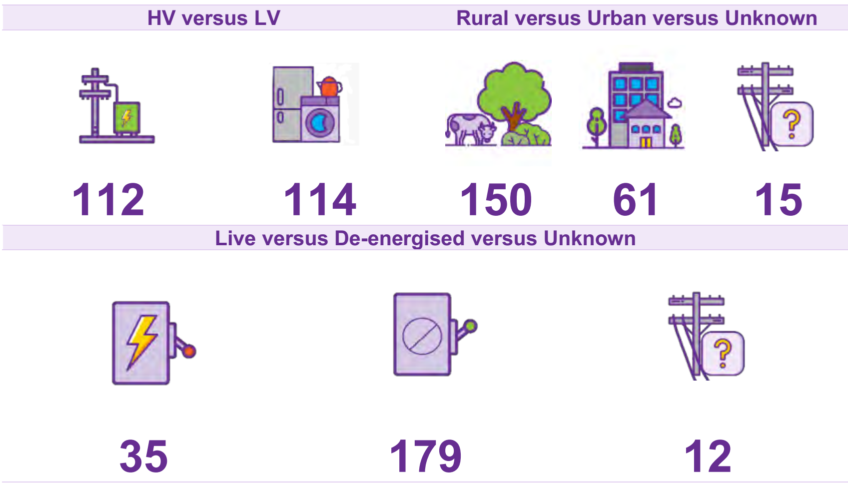
5.6.1.3 COMPETENCY DATABASE UPGRADE

The Powerco Contractor Competency Database will be transitioned from a Microsoft Access platform and incorporated into ISNetworld's wider contractor management offering. This will align the Powerco Contractor Approval process and the Powerco Contractor Management process, and allow service providers to manage their own employee competencies.

5.6.2 KEY PUBLIC SAFETY INITIATIVE

Downed power lines that remain live present a significant risk to the public, as shown in Figure 5.6. Lines are brought down for a number of reasons, including falling vegetation, wind, asset failure and car v pole incidents. We track and report monthly to our Board the number of lines that remain live when downed.

Figure 5.6: Lines down data across the Powerco network



To reduce the risk to the public, our current standard is for all new LV conductors to be covered with insulating material. This safety mechanism is necessary as it is impossible, with existing protection devices and low levels of LV network monitoring, to ensure that all downed conductors will be de-energised. Given the large volume of legacy assets on our networks, a substantial portion of LV conductors are bare. Chapter 19 contains further details on the LV bare conductor renewal programme.

We have a Learning Team that examines live lines down incidents to improve understanding of root causes and the actions that we can take to reduce the number and impact.

Projects are under way to increase the sensitivity of sensitive earth fault protection schemes in 32 substations. This will increase detection rates of downed lines.

Powerco runs several public safety campaigns each year to educate our communities on how to keep themselves safe around our network assets. Steps to take to stay safe in the event of a line coming down are included in these campaigns.

5.6.3 KEY SAFETY AS USUAL INITIATIVE

Our Safety as Usual initiative has the goal of building closer collaboration and understanding between us and our service providers. The planned outcome is to achieve broad understanding across the wider business of how each role contributes to the safety of staff, contractors and the public.

5.6.3.1 LEARNING TEAMS

An initiative involving Powerco and service providers is under way to encourage the sharing of knowledge on safety related events and asset performance. This allows improvements to be identified and for us to build on what is already going well.

Learning Teams have been implemented to better understand:

- Rotten wooden assets
- Live lines down
- Worksite safety interactions

The outcome of the Learning Teams will be an improved understanding of what is really happening out in the field. Based on this knowledge, improvement options can be identified and implemented.

5.6.4 AUDIT AND ASSURANCE PROGRAMME

Our Audit and Assurance Programme is delivered by an external provider. It covers:

- Worker safety in the field
- Quality of workmanship
- Work planning
- Documentation and record keeping
- Assurance of critical work and public safety controls

The audit programme provides our managers and senior leadership with oversight of the performance of service providers doing our work, as well as the quality of work done for customers who engage Powerco-approved contractors.

In FY22, the audit programme will continue to grow to include auditing of:

- Our capital works projects process
- Traffic management for our works
- Assurance of internal and service provider critical risk controls

We utilise the data gathered through the Audit and Assurance Programme to identify safety and quality trends. Positive trends are reinforced, while improvement action may be indicated by negative trends..

6 EVOLVING ASSET MANAGEMENT STRATEGIES

6.1 INTRODUCTION

In Chapter 5 we described the core asset management strategies that help us deliver our corporate and asset management objectives. While the way we build and operate our electricity network is generally very stable, we also continually look for ways to improve and adapt to material changes in our operating environment. In this chapter we describe the significant changes planned in our asset management during this AMP planning period.

Our evolving strategies are mainly centred on three aspects, which overlap to a considerable degree:

- Adapting to changes in network and customer technology.
- Adapting to a changing operating environment, driven by changing customer needs as well as environmental and legislative changes.
- New ways of thinking about traditional asset management approaches.

Developing and implementing the emerging strategies discussed below have been factored into our AMP expenditure forecasts. Our general intent is to embed successful outcomes from new strategies into our core business as usual practices. Where appropriate, our network development and fleet management plans have already been expanded to reflect some of this.

6.1.1 DRIVERS FOR CHANGING ASSET MANAGEMENT STRATEGIES

The overall drivers for the continuous evolution of our asset management is to ensure that our services remain relevant to our customers and represent best value when they make energy choices. This, in turn, will support the long-term profitability and sustainability of our business. Several factors require us to review our practices, chief among which are the following.

Cost efficiency of electricity distribution

We have a responsibility to our customers to distribute electricity at the lowest reasonable cost, while still ensuring they receive a safe, reliable service that reflects their preferences and requirements. The importance of keeping distribution services affordable is further underlined by the very real pressures many of our customers face in meeting their basic energy needs.

Optimal lifecycle investment decisions have been a core plank of our asset management for a long time. However, we continually look for further improvement opportunities, particularly in ways that we can enhance network performance or improve asset utilisation at the lowest cost, without taking on unacceptable risk.

Network resilience

A combination of increasingly unstable environmental conditions, from climate change or other factors, and customers' increasing reliance on electricity to sustain their lifestyles has brought network resilience into strong focus. Accordingly, we are developing strategies to ensure the appropriate resilience of our networks.

We are looking at how we can avoid outages from major events or, when these do cause outages, how to restore supplies in reasonable time, and how we can efficiently recover following major events.

Emerging technology

Emerging technology offers huge opportunity to benefit customers as well as networks. From a network perspective, we are researching and conducting trials, and implementing new technology where it is found to be practical and cost-effective.

Increased customer-side use of edge devices can have a destabilising impact on network operations. Since we do not want to inhibit customers from seeking out new applications, we see it as our responsibility to manage network stability (within practical bounds). This requires us to evolve the network alongside customers' changing requirements.

Improving customer understanding

It is fundamental to good asset management that we develop solutions that meet our customers' needs in an optimal way. Traditionally, customer requirements have remained relatively static and predictable. However, customer requirements are changing, and the rate of change will accelerate. Understanding existing and changing customer requirements is an important pillar of network planning and investment.

Network reliability

Customer reliability requirements change over time. This has to be reflected in changing network architecture, security standards and designs.

In addition, we have to continually upgrade our network to ensure acceptable supply quality to all our customers. Finding cost effective ways to achieve this is imperative if we are to avoid potentially substantial associated price increases.

Environmental change

Protecting the environment against adverse impact from our assets has long underpinned our asset management decisions. In support of international and country-wide drives to reduce greenhouse gas emissions, we have also adopted stringent emission reduction goals. This requires a further filter on our investment and operating decisions.

In addition, we anticipate significant government regulations and/or incentives to reduce New Zealand's carbon emissions. These will no doubt impact the manner in which electricity is used and we therefore have to be ready to adapt.

6.2 NETWORK EVOLUTION: EMERGING TECHNOLOGY

Our Network Evolution strategy maps out how we intend to benefit from, or will manage the potential adverse impact of, emerging technology.

Understanding and responding in good time to emerging customer energy trends is a key part of our Network Evolution strategy, as is the research into and testing of the impact of new customer or network technology. This allows us to not only understand the technical features and how to integrate new equipment, but also the behavioural aspects of how this influences customers' energy use patterns and overall network performance.

6.2.1 NETWORK EVOLUTION: WHERE WE ARE NOW

In our previous AMPs we described how three mega-trends in the energy industry drove the evolution of our network – the so-called 3Ds of decarbonisation, decentralisation and digitalisation. These are still the key drivers.

6.2.1.1 DECARBONISATION

Decarbonisation is the challenge to reduce carbon dioxide (CO_2) emissions.

The New Zealand Productivity Commission's "Low-emissions economy" report details pathways for New Zealand to reduce carbon emissions, in line with its Paris Accord targets. It highlights the electricity sector as one of the main impacted sectors. While electricity supply is a major contributor of CO_2 (through thermal generation for example), the industry can be an enabler for the decarbonisation of more carbon-intensive sectors, for example by substituting petrol cars with electric vehicles.

Our general strategy for adapting to climate change and meeting our targets is set out in Section 6.6 of this chapter. Our climate change strategy recognises technology-driven solutions as an important feature. In this it integrates closely with our Network Evolution strategy.

Most electricity distribution utilities do not generate significant electricity and are not themselves large electricity users. Therefore, our direct impact on carbon emissions is relatively minor, and we see our main contribution as encouraging and accommodating carbon reduction initiatives for our end-users and generators. We will provide the enabling network solutions and services to achieve this. In particular, we will plan and operate our network as an open-access platform, which will allow customers to connect devices to it as desired, including renewable generation and energy storage devices. They will be able to conduct largely unconstrained energy transactions over our network, while we continue to ensure a stable and safe electricity supply.

6.2.1.2 DECENTRALISATION

Decentralisation is the shift from centrally generated, large scale electricity production to distributed, or scattered smaller scale devices that can often generate, store or consume electricity.

This could be a challenge for us in terms of both policy and technical aspects.

Customers expect the unfettered ability to use distributed generation or energy storage devices to offset or manage their own electricity consumption, or to sell surplus electricity. At the same time, most want to maintain a connection to our network to cover the times that their devices cannot generate electricity, such as at night. The network also provides the connection to others, to allow energy transactions.

This requires us to maintain electricity connections at full peak demand capacity, even if average consumption levels reduce. Since the bulk of our revenue is traditionally derived from the quantum of electricity delivered, this makes network capital cost recovery increasingly difficult. It will require us to consider alternative pricing structures in future, particularly if we are to avoid charging other, non-generating, customers more as a result.

Concentrated clusters of new distribution edge devices[33], such as solar photovoltaic (PV) generators or electric vehicles (EV), can also cause voltage stability or other power quality issues. Older networks, in particular, which were not designed for potential two-way power-flows or rapidly changing, high-peak demands, will need intervention, otherwise we will have to limit the connection of such devices. Such limits would be a last resort and an undesirable situation, as it would not only inhibit customer flexibility, but would also run counter to achieving carbon reduction targets.

6.2.1.3 DIGITALISATION

Digitalisation is the substantial and sustained increase in the numbers of digitally enabled and connected equipment available to customers, market participants and asset owners, along with data, analysis, monitoring and control applications.

It is a key part of future automation and distributed network control systems. In addition, it will be essential to help ourselves and our stakeholders to understand and manage energy demand and generation profiles, allowing energy transactions over our network.

[33] Distribution edge devices are new types of end-customer loads connected to the distribution network that were not traditionally prevalent and have characteristics that can cause power signal distortion in different ways to traditional, mainly resistive, customer loads. It includes local generation, particularly PV, electric vehicles, energy storage devices, and the like.

The cost of data capture, storage and communication continues to decrease. Low-cost sensors and communication mediums, for example Long Range Wide Area Network (LoRaWAN), are becoming mainstream. With it, artificial intelligence, blockchain, and other capabilities have become more prominent as computing processing power increases.

For asset managers, this trend offers major opportunities to efficiently increase visibility of network condition, utilisation and operational conditions. It will allow us to enhance our service offering, improve network utilisation and reduce potential instability issues that could arise from connecting edge devices. This all would contribute to more efficient and stable network utilisation and support cost effective delivery.

6.2.2 OUR CURRENT OBSERVATIONS OF ENERGY TRENDS ON OUR NETWORK

6.2.2.1 BASE CONSUMPTION TRENDS

In Chapter 3 we demonstrated the historical energy use and maximum demand trends on our networks. As noted, peak demand per connection point has continued to increase during the past decade, while even energy use has shown a marginal increase. Overall demand has grown on both our Eastern and Western networks.

While the impact of COVID-19 on longer-term population growth is uncertain, current projections are for continued growth, particularly on our Eastern network. From this, we conclude that core network demand will continue to grow at recent rates for the foreseeable future – including most of this AMP planning period.

However, in the longer term, energy use patterns are expected to change, along with the increased adoption of distribution edge devices. For example, factors such as increased use of EVs may cause sharp, short-term demand increases, whereas increased use of energy storage devices may assist to reduce demand peaks.

While the timing for the uptake of material volumes of edge devices is uncertain, even if we allow, for example, a 10 years lag, we have to consider the long lifecycle of an electricity network when we invest. This means that investment decisions we make today have to consider the potential energy use scenarios 20 to 40 years from now. It is therefore essential we understand and prepare for the eventuality of material changes in electricity use, to ensure our networks can accommodate the impact.

We will therefore continue to monitor emerging international and local trends, to ensure 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 they value.

[34] International Energy Agency, "Global Energy Review 2020".

6.2.2.2 SOLAR PHOTOVOLTAIC GENERATION

Residential PV generation is growing rapidly across the world. The uptake rate between countries varies, but it has been particularly pronounced in Germany, parts of Australia, the United Kingdom, 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 customers. Regardless of the initial driver, the scale of uptake has supported large scale manufacture and resulted in reduced costs.

Rooftop solar is becoming available at prices that can, in many instances, 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.

The International Energy Agency[34] reports that PV electricity production has grown from 4TWh in 2005 to 720TWh in 2019, with the trend accelerating.

Internationally, it is reported that 3% of electricity consumed globally in 2019 was produced by PV installations.[34]

By contrast, the uptake of PV in New Zealand, while growing materially on an annual basis, is still at a much lower level. The Electricity Authority (EA) reported that as of 30 November 2020, New Zealand had 30,000 residential customers with installed solar generation, representing a total of about 139MW[35]. This represents a 22% increase in capacity over the November 2019 figure published by the EA of 114MW[35].

PV uptake on our network is shown in Figure 6.1 and Figure 6.2[35]. At the end of December 2020, the total PV connection proportion on our network was 1.5% (5,700 Installation Control Points – ICPs). The total number of PV connections on our network is 43% higher than December 2018.

[35] Electricity Authority, "Installed distributed generation trends, November 2020".

Figure 6.1: PV uptake on our network (percentage of ICPs)

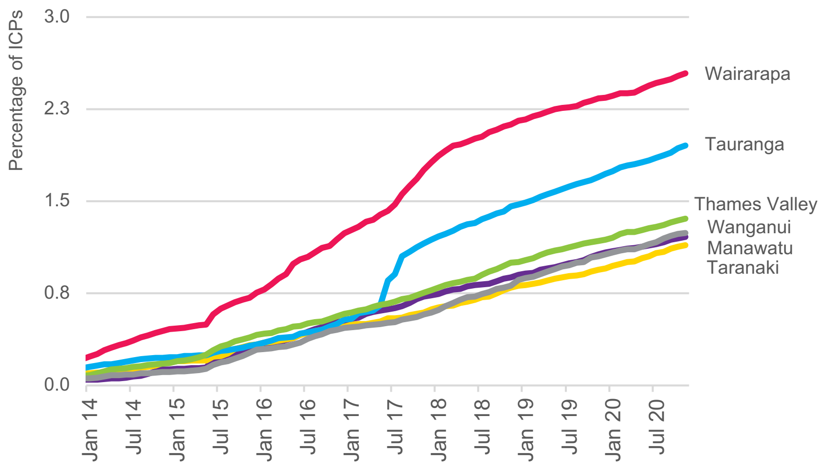
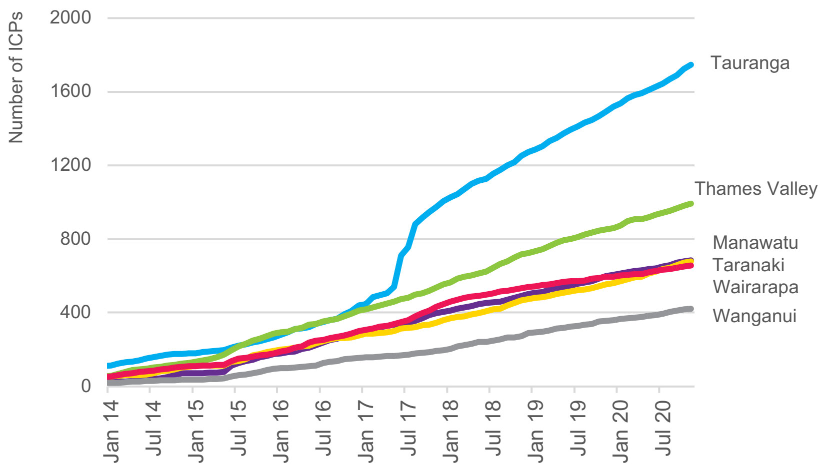


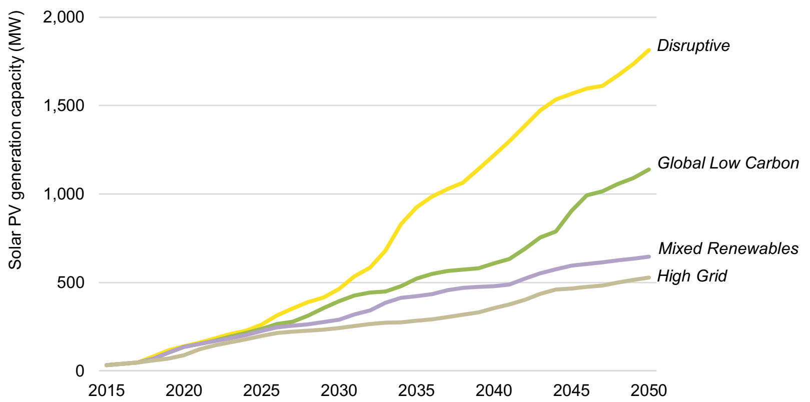
Figure 6.2: PV uptake on our network (number of ICPs)



The rate of PV uptake has remained steady since 2018, with an average monthly increase of 75 installations. International literature suggests that when PV penetration reaches about 10% on a network, issues associated with the variability of its output could become material, requiring some form of network investment[36]. At current growth rates, this still appears to be some distance off on our network, although localised clusters of high PV penetration rates would have to be closely monitored.

In August 2016, MBIE provided an updated Electricity Demand and Supply Generation Scenarios (EDGS) model, which included forecasts for the anticipated growth of solar PV generation in New Zealand under various scenarios. In Figure 6.3, the 'disruptive' scenario suggests that PV generation could approach 10% of (current) installed New Zealand generation capacity by about 2035.

Figure 6.3: Forecast growth of PV installations in New Zealand[37]



6.2.2.3 ELECTRIC VEHICLES

The use of EVs (full electric or plug-in hybrid) is still relatively low in New Zealand, with a total of 23,600 vehicles registered at the end of November 2020. The uptake rate of EVs has remained relatively flat since 2018. There is also wide recognition 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, which may provide further impetus for the uptake of EVs.

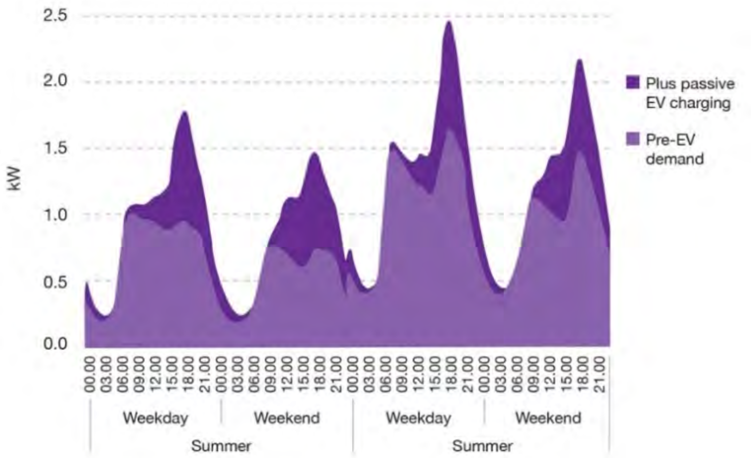
We do not see a material network impact from EVs in the short term. However, as penetration numbers rise, the potential for localised power quality issues increases

[36] 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.

[37] Source: MBIE, "Electricity Demand and Supply Generation Scenarios 2016", http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016.

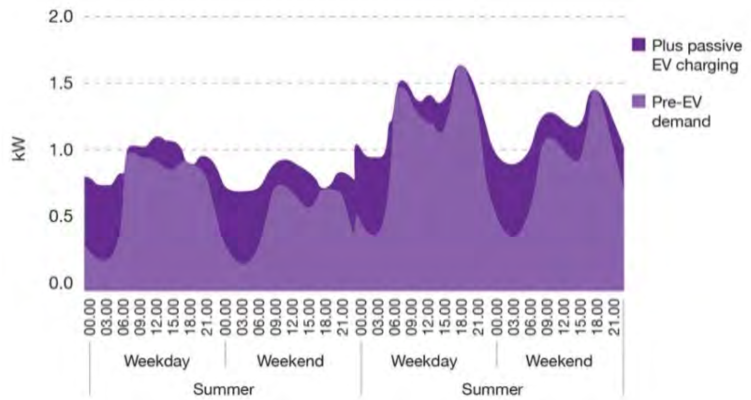
within the Low Voltage (LV) network. To facilitate EV charging, particularly at peak demand times and with fast chargers, could require substantial network reinforcement. In 2018, we commissioned a study in collaboration with Unison and Orion to model the impact of EV charging on residential ICP demand [38]. It showed that, without any form of control, the demand could increase significantly, as shown in Figure 6.4.

Figure 6.4: Impact of EV charging on an average household demand profile



The study suggested that this increase in demand can be mitigated by the introduction of smart charging. Figure 6.5 shows how smart EV charging can influence the demand profile.

Figure 6.5: Impact of smart EV charging on an average household demand profile



EV uptake and demand response capability at a household level is hard to assess as customers are not currently required to notify the network operator when they have purchased an EV or installed non-significant chargers, ie those that do not require a change in their electricity supply. This lack of visibility has an impact on the efficacy of network investment and reinforcement to accommodate the capacity and quality challenges introduced through EV charging. We are working with wider industry groups to both address the lack of visibility and to improve our ability to monitor and predict EV uptake increases.

6.2.2.4 ENERGY STORAGE

Energy storage continues to be a major topic of discussion in the industry, with a rapidly escalating range of market offerings at both the domestic and utility scale. While there are more than 1,100 battery installations on the Powerco network alone (a 440% increase since November 2018), this remains a small percentage of our overall customer base.

While internationally the 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. Grid scale energy storage systems usually only impact the distribution network in certain specific circumstances.

Worldwide, the installation of battery storage capacity is increasing at a significant rate – mainly in utility scale applications, typically in the range of 0.5 to 10MW/MWh,

[38] For example, “Electric Vehicles in New Zealand: From Passenger to Driver”, published by Dr Allan Miller and Scott Lemon, EPECentre, University of Canterbury.

although larger units are increasingly frequent. These are mainly installed by electricity utilities for peak demand management, network stability, standby capacity, 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 expanding rapidly, 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. Residential scale battery installations are likely to have a greater impact on distribution networks than grid scale battery installations.

In New Zealand, the uptake of battery storage and other new forms of energy storage is still in its infancy, with only a few major installations in place, although many trials are under way. This situation is expected to change during the planning period, although we still don't foresee a major proportion of energy supply assisted from storage devices.

Although the cost of battery storage systems has reduced substantially in recent years and is anticipated to decline further in the foreseeable future, for the vast majority of individual customers 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 offers 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 do not believe that battery storage will lead to meaningful levels of grid defection or have a substantial impact on how 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 in which we intend to increase our focus, increasingly incorporating storage solutions where these provide economic or reliability benefits to our customers.

6.2.2.5 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 under way 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 customers.

With improving communications systems and more intelligent home devices, new opportunities are opening up for demand management on the customer side of the electricity meter. While it is not our intent to become involved in customer 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 customers 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. There is increasing opportunity to roll out 'intelligent' devices on the network. These allow more visibility, remote communication, and use of computers to optimise power flows. A better understanding is gained of the real-time performance of the network, increasing the ability to take effective action based on data available. Ultimately, this allows networks to be 'run harder', and for electricity demand to be spread more evenly over the day without compromising reliability. This will increase utilisation levels and reduce investment needs.

6.2.3 POWERCO'S CURRENT INITIATIVES TO ADAPT TO THE NEW ENERGY FUTURE

While we have always been a leader in developing and adopting conventional network solutions and assets, in recent years we have stepped up our focus on non-network solutions and emerging technology. A dedicated Network Evolution team, with the support of Powerco's other teams, has been set up to monitor energy trends, research and test new technology and the customer impact of these, and to develop new solutions to network requirements. Current and recent activities include:

- Monitoring and analysing trends on our network, as well as nationally and internationally, of customers' technology changes, focusing on EVs, PV panels and domestic batteries. Providing insights to the rest of the business, based on this analysis.

  This activity is further supported by projects to work with customers to install new edge devices on parts of our network and use the information gained to better inform our strategy.
- Installation of our first grid scale Battery Energy Storage System (BESS) in Whangamata (a 2MW, 2MWh unit that automatically islands the central distribution network following a bulk supply outage).
- Deploying various types of monitoring and communication devices across our network to ascertain performance and ease of integration, thereby laying the foundations for more automation and asset utilisation optimisation.

- Enabling new entrants to develop new services on our network.
- Testing various forms of LV network monitoring devices, to inform our future investment in this important area.
- Continuously use the learnings from these activities to define our Network Evolution strategy.

6.2.4 NETWORK EVOLUTION: WHERE ARE WE GOING?

While we know that the 3Ds are fundamentally changing the industry, the speed of the change in New Zealand energy use patterns is still uncertain – current uptake rates of edge technology are very low by developed world standards.

6.2.4.1 DEALING WITH AN UNCERTAIN FUTURE

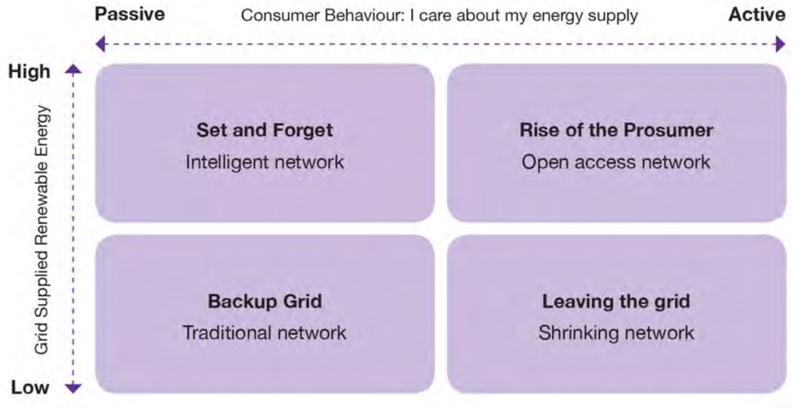
The future nature of electricity distribution networks is being widely debated around the world. We subscribe to the New Zealand-specific Network Transformation Roadmap developed by the Electricity Network Association (ENA)[39]. It is backed up by international research in similar jurisdictions, particularly Australia and the United Kingdom.

As described in the ENA's study, we recognise that the network of the future will be influenced by two main factors:

- Customer behaviour – how engaged are customers with their energy supply?
- Technology – how much renewable electricity, and associated edge devices, are connected to the grid?

Using these primary dimensions, four future scenarios were created, shown in Figure 6.6. These purposely extreme scenarios are intended to support clarity in thinking and assessment – it is unlikely that any of these will arise by themselves. A more feasible outcome, however, will be a mix of customer outcomes, possibly leaning more in one direction. To respond to these scenarios, we have devised four possible evolution pathways that can meet each of the challenges and requirements.

Figure 6.6 : Network transformation scenarios adapted from ENA with evolution pathways



A. Backup grid scenario: Traditional network

This is largely the distribution network that we are accustomed to:

- It relies on physical assets to convey electricity from bulk electricity supply points[40] to customers.
- The large majority of customers remain generally passive, not taking much interest in changing their behaviour or interest in their energy supply or how this is provided – price and reliability are their major considerations.
- Other than electricity conveyance, distribution utilities do not participate in energy markets and limit their activities to 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 provides acceptable levels of reliability. Even if all communications to control centres are lost, these networks will largely keep operating as normal for extended periods.
- Assets are generally sized for the peak demand they are anticipated to experience, which is predetermined at the design stage. Actual measurement of peak power flows in assets is limited.
- Localised concentrations of customers wanting to connect EV and PV can compromise system stability.

[39] Source: ENA, "Network Transformation Roadmap", https://www.ena.org.nz/dmsdocument/403, 2018

[40] These are generally points of connection to the transmission grid, but can be direct connections to generators.

B. Set and forget scenario: Intelligent network

This is the often-touted 'smart grid', which is based on the traditional network with extended capabilities for monitoring, measurement, control, reconfiguration 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 largely on physical assets to convey electricity from bulk electricity supply points to customers, although local generation and energy storage can be encouraged.
- The large majority of customers remain generally passive, not taking much interest in changing their behaviour or in their energy supply or how this is provided – price and reliability are their major considerations. However, the uptake of renewable generation and storage – mainly as a mechanism to avoid potential price increases, rather than active energy market participation – is likely to increase.
- Distribution utilities do not participate in energy markets, other than providing electricity conveyance. They are compensated for the assets they provide and operate as well as for, in many instances, the reliability of service and for energy efficiency improvements[41].
- 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 allow a significant reduction in the degree of asset redundancy required (to achieve the same or improved network outcomes).
- Traditional deterministic planning and operational approaches are increasingly substituted with a probabilistic approach – this allows distributed energy devices to be appropriately considered in reliability planning, as well as supports better informed risk/cost trade-off decisions.
- Customers can generally connect their EV and PV, however, technical network limitations may restrict their ability to fully utilise them.

C. Rise of the prosumer scenario: Open-access network

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 customers, as well as from customer to customer, or customer to bulk supply point.
- In this scenario, customers are actively involved in their energy acquisition, generation, and consumption management.
- 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.
- As in the past, revenue is earned through providing electricity conveyance, 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 the 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.
- Customers can connect their EV and PV and maximise their utilisation.

[41] This is to ensure that incentives exist to find optimally efficient solutions, rather than stick to traditional network investment solutions.

D. Leaving the grid scenario: Shrinking network

The shrinking network describes a situation where it makes economic sense for a customer's primary electricity supply to be derived from sources other than the grid – mass defection will then occur. The level of investment on the core network would then likely drop to a minimum as it would be economically impossible to maintain anything other than an adequate level of safety and meet our minimum legal obligations.

We are not aware of examples in New Zealand of large scale grid defection. However, it may become increasingly feasible in remote areas, where grid supply is expensive, eventually spreading to larger parts of networks. For example, we already facilitate decommissioning long rural feeders supplying isolated loads through the use of the Base Power alternative, albeit only for individual or very small groups of customers.

6.2.4.2 DEVELOPING THE OPEN-ACCESS NETWORK

Internationally, there is much activity on the development of the concept of open-access networks. This is done in conjunction with the development of the distribution system operator (DSO) concept – open-access networks are an essential enabler. In New Zealand, the EA is supporting this concept, but there has been little progress on discussing how it may be achieved.

6.2.5 NETWORK EVOLUTION: HOW WILL WE GET THERE?

6.2.5.1 OVERVIEW

At the moment, our network finds itself somewhere between the traditional and intelligent network stages as we have many of the initial features of an intelligent network already in place. This includes:

- Modern Supervisory Control and Data Acquisition (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 Outage Management System (OMS).
- Extensive automation devices spread across the network.

Our network is not homogeneous. It covers large areas of rural land, coastal township, dense cities, Department of Conservation-protected and iwi-owned areas. We do not believe that a one-size-fits-all approach is right for our customers, with many stark differences in customer consumption patterns and network characteristics, especially between the higher density, more urban network areas, and the low density rural network areas.

Therefore, we expect the four scenarios described above will have different likelihoods and outcomes in different parts of our network. For example, it is more feasible – technically and economically – for a small cluster of rural customers at the end of a very long spur line to accept non-traditional electricity supply solutions and go off-grid, than for higher density parts of the network.

In a city such as Tauranga, the nature and density of load is more likely to make the development of a smart grid necessary.

In our previous AMP, we stated:

> Our goal during the planning period is to evolve to an open-access network. This will include the building and operation of a fully functional intelligent network.

We still believe this will bring the most value to our customers over the long term, particularly as this will provide the flexibility required to underpin efficient, low-carbon energy options. However, we also recognise the uncertainty around the nature of future energy requirements, technology developments, and the rate at which these will manifest on our network.

Our Network Evolution strategy, therefore, in the short term focuses on a least regret research and investment approach, focusing on maximising flexibility and technology that is likely to be useful under a wide range of future possible demand scenarios. By adopting this approach, we can continue to expand our knowledge base and identify – and implement – valuable new network solutions, without having to substantially lock ourselves into a particular scenario or network configuration.

We have identified four key themes of work that will enable us to better understand the uncertainties, while creating value for our customers and our network. They are:

- Improved visibility
- Future energy consumers
- Modernising the grid edge
- Enhanced network response

Each theme and their indicative investment programmes are described below.

It must be noted that most of these initiatives are in the domain of research and development, with the objective of validating the benefits of a technical solution before a potential network-wide rollout. If a solution is proven to be technically successful, we will then consider the best way to obtain a similar outcome, in line with our normal investment decision processes and tests.

In parallel, we continue to develop non-network solutions, such as the Base Power solution, which we are implementing at reasonable scale. It is a more cost effective and better power quality solution for remote rural customers, as we avoid having to renew uneconomic and unreliable existing (pre-1992) overhead lines. (Refer to Section 6.3.3.1.)

Base Power is a fully autonomous, self-healing off-grid power solution for homes, lodges, hill-country farms and communications sites. It typically uses renewable PV generation and energy storage to meet customer needs, supplemented by a diesel generator when necessary.

Networks of tomorrow

In our view, the best way to maximise flexibility to our customers in how they can use and manage their energy needs is by operating an open-access distribution network. This will be supported by:

- Applying suitable technology to ensure network capacity and stability.
- Much improved visibility of power flows and network utilisation.
- Increased network automation.
- Improved data and analytics.

Essentially this future network would allow customers to be largely unconstrained in what they can connect to the network and how they would use it to support their energy transactions – purchasing and exporting electricity.

Our role will be to ensure that networks have the capacity to cope with our customers' evolving energy needs, while remaining safe, stable and efficient.

6.2.5.2 IMPROVED NETWORK VISIBILITY

A high level of real-time to semi real-time visibility on network performance, current flows, quality of supply and asset utilisation is an essential enabler to run a truly open-access network. At present, this visibility is patchy across the higher voltage networks, and largely lacking on our LV networks. We therefore need to increase monitoring across our network and customers' installations.

This programme will involve:

- Greatly increase monitoring throughout the network.
- Change our approach to how we monitor the HV network, specifically focusing on the versatility of monitoring technology available.
- Dramatically increase the amount of available data related to utilisation, current flows, quality of supply and asset performance on the LV network.
- Enhance communication and information technology to support the increasing volumes of information collected in the field.

Intended stakeholder benefits from this programme are:

- Enabling the open-access network, which in turn will allow an effective DSO.
- Reducing the time to locate and respond to network faults, thereby improving general network reliability. This will include LV outages, where our fault response now largely relies on being notified about outages by the customers.
- Safety enhancements – being able to recognise potential issues more accurately and more effectively.
- Improved ability to predict and prepare for network congestion because of changes in customer energy profiles and distributed energy resources (DER) penetration.
- Improved asset management and network operations enabled through better insight into the condition of our assets and how they perform their service on the network.
- Greater efficiency in monitoring and managing the network and assets.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to support improved network visibility.

- **LV network monitoring** – a tiered approach to monitoring the utilisation of LV feeders, transformers, switches and other LV assets throughout the Powerco network. This is an essential programme that will inform future investment plans, provide inputs for automation schemes, and help ensure network stability in the face of increased use of distribution edge devices. Over time, we intend to expand visibility further down into the networks – typically to include feeder endpoints and T-offs.

  The programme will also look at the integration of other available monitoring devices on the network – for example customers' inverters (for PV), smart meters etc.
- **Enhanced network condition and utilisation monitoring** – incorporating new and different network condition detection methods through expanded sensor types, external sources of network specific data, and improved back office capability.
- **Interfacing with DER resources on the LV network** – developing methods to provide network relevant data to DER resources (and their management interface) and obtain data from these sources. This will include developing methods of exchanging information with local generation, storage and discretionary loads, such as EVs.
- **Expanded communications and information systems** – as described in section 6.8.4.3

Note, that as part of our network development expenditure forecast, described in Chapter 15, we make provision for the early stages of a systematic rollout of network monitoring devices across the whole network. The learning from early years will inform the technology choices and business case for the eventual proposed comprehensive rollout. We will also identify potential opportunities to share infrastructure with other providers, for example, should the required network insights be available from retailers' smart meters, it may obviate the need for our own investment.

6.2.5.3 FUTURE ENERGY CONSUMERS

The Future Energy Consumers programme revolves around developing a deeper understanding of changing customer energy preferences, emerging technologies and energy market products, and integrating this into our network planning and operations.

This extends to:

- Collaborating with customers, retailers, and third-party service providers to understand the changes in their expectations from distribution services.
- Testing beyond-the-meter assets to understand how these interact with network operations and changes in customer preference.[42]
- Exploring the potential to obtain and integrate external sources of data that help us improve demand and customer profiling.

Our stakeholders will benefit from this programme through our:

- Enhanced ability to accommodate increasing use of distribution edge devices.
- Improved ability to respond to specific customer needs.
- Ability to anticipate customer demand trends and maintain a safe, stable supply in the face of this.
- Better targeted network design standards based around customers' actual consumption patterns rather than generic designs.
- Sufficient lead time to prepare our network and services to meet changing market environments.

Why an open-access network?

Our customers are increasingly concerned about the impact of their energy use on the environment. They are interested in how their electricity is generated and how they can use it most efficiently. This local interest is reflected at a national level, with one of the government's key commitments being a goal of a carbon-neutral electricity supply.

In a fortunate convergence of improving technology and cost-efficiency, our customers have:

- More choice and the power to exercise their values.
- An increasing ability to achieve significant reductions in their energy use footprint.

A key contributor is the ability to cost effectively generate on-premise electricity, through renewable methods such as solar panels or small wind generators.

This not only reduces electricity taken from the grid, but also holds potential for exporting excess capacity to other nearby customers, or allowing customers without their own generation to buy renewably created electricity from local suppliers and communities.

Other key factors are efficiency improvements in energy-hungry devices, and the ability to switch to renewable energy sources, particularly related to transport and heating.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to develop our understanding of future energy consumers.

- **Customer and retailer collaboration** – actively seek opportunities to collaborate with customers or retailers on specific initiatives to pilot new market products that could influence customer expectation and/or utilisation of the network.
- **Researching demand-side energy technologies** – procure, implement and test demand-side DER assets, to test the impact of these on the network.
- **Obtaining, analysing and integrating external sources of demand data** – procure/obtain customer Advance Metering Information (AMI) data as well as other sources of data to develop new segmentation techniques.

[42] Note, we have little appetite to own beyond-the-meter assets – instead preferring to work with customers or suppliers who own these to better understand the network implications. We also wish to understand how we may develop incentives to obtain network benefits or avoid negative impact on our operations. To aid our research projects we will look at ways to encourage accelerated take-up of customer devices, in limited areas.

- **In-depth measuring and analysis of customer trends and patterns** – enhancing our understanding of what our customers desire and to optimise our response to this.

6.2.5.4 MODERNISING THE GRID EDGE

We define modernising the grid edge as enhancing our network operations and increasing asset utilisation through the application of new technology.

This extends to:

- Enhancing real-time monitoring of asset and network condition. For example, remotely operated inspection drones or remote asset monitoring.
- Increasing asset and network utilisation. For example, applying real-time asset ratings.
- Advanced automation and protection solutions to enable networks to self-heal and minimise interruptions.
- Network energy storage solutions, for demand management and stand-by capability.
- Expanding use of demand-side participation, such as load control, to improve network utilisation, deferring reinforcements.

Our stakeholders will benefit from this programme through:

- Improved reliability of the network.
- Enhanced network utilisation, with associated cost efficiency gains.
- Improved response ability.
- Improved power quality.
- Reduced callouts for investigations on fault causes.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to enhance our grid edge modernisation programme.

- **Real-time asset ratings** – monitoring the utilisation, temperature and other operating parameters of key assets, particularly where these constrain delivery capacity, in real-time. By understanding the actual operating condition, it is often possible to increase asset utilisation over pre-defined limits, while still running assets safely. (For passive networks, we have to build in conservative safety factors in operating allowances, to avoid asset damage under worst-case operating scenarios.) Real-time capacity monitoring can also inform automation schemes, allowing power flows to be redirected to less constrained areas.
- **Self-healing networks** – by combining appropriate network monitoring, assets with intelligent or remote operating ability, and a solid communication system, it is often possible to develop networks that can automatically self-restore following an outage.
- **Enhanced fault response** – by automatically providing information to the Network Operations Centre (NOC) on the occurrence and location of an outage, quicker fault response and location times are achievable.
- **Energy storage** – effective energy storage can have multiple network benefits, ranging from the ability to reduce peak demands and provide standby capacity, through to providing voltage or frequency support. At present, distribution scale energy storage focuses on utility or household scale battery systems, although alternative technologies, such as large flywheels, will also be evaluated.[43]

6.2.5.5 ENHANCED NETWORK RESPONSE

The Enhanced Network Response programme relates to our ability to maintain stable network operation in the face of increased use of distribution edge devices that can interfere with power quality. In particular, we have to ensure voltage levels, frequency and signal distortion can be maintained within prescribed regulatory limits. This can be challenging when distributed generation, non-linear devices or equipment with large, rapidly changing load profiles become abundant on the network.

This programme extends to:

- Expanding voltage and frequency control applications.
- Working with customers to expand the use of demand-side management, such as load control, to mitigate against excessive demand peaks.
- Testing design and stable operation of microgrids within our network.
- Designing, implementing and testing automated LV network architecture models to support stable network operations.
- Rethinking our approach to remote rural and/or uneconomic networks and expanding Base Power-type, off-grid solutions.

[43] We are also looking into strategically situated generators on the network – refer to Section 6.7. This will complement energy storage.

Our stakeholders will benefit from this programme through our:

- Enabling the open-access network, which in turn will allow an effective DSO.
- Quality of supply and network stability being maintained, despite increased variability in demand and distributed generation, and increasing two-way power flows.
- Reduced impact from planned/unplanned outages.
- Greater certainty around demand response incentives for future DSO markets.

The limits of today's networks

The design of traditional electricity networks limits the extent to which renewable generation, or large variable loads, can be accommodated.

Networks were designed for one-way power flows from large generators to end customers, who used mainly passive appliances. Connecting significant volumes of distributed generation, or large, rapidly varying loads to a network not designed for it, can, at times, cause serious power quality and network instability issues.

Without substantially changing the nature of distribution networks and how they operate, the only mitigation options for electricity distribution businesses (EDB) are to make major reinforcements to the network or constrain customers in what they can connect and how they can use the network.

Limiting choice is bad for customers.

Conventional network reinforcement is an expensive and, generally, inefficient solution to short-term power fluctuations. Constraining customers in what or how much they can connect to the network will greatly inhibit their ability to manage their usage and reduce their electricity carbon footprint – thereby foregoing one of the more important levers New Zealand has to achieve its overall environmental targets.

Indicative investment programmes

The following outlines the types of investments targeted within the planning period to support our Enhanced Network Response programme.

- **Energy communities** – testing new forms of network architecture designs, for example microgrids and LV meshing, which enable new methods of distribution service offerings and network operations.
- **Base Power, and other distributed assets** – investigating new methods to respond to changing demand patterns through the network, which include assets that can dynamically respond to network conditions to maintain quality of supply. Examples include variable tap changing transformers and taking customers off-grid at times.
- **Innovative network design** – develop new methods of designing networks to improve quality of supply potential through planned and unplanned events, for example loop automation and improved sectionalisation.
- **Monitoring and automatic response to power quality issues** – monitoring the impact of customer devices on network stability and power quality, and developing various solutions to cost effectively ensure the ongoing stability of the network.

6.3 NETWORK ARCHITECTURE

Network architecture largely sets out the blueprint for how we plan, build and operate our networks. Architecture decisions have a major bearing on the cost of distribution, network utilisation, the resilience and the reliability of electricity supply.

While legacy networks have a major influence on our network architecture, new installations and replacements are built to standards that have not been materially reviewed in the past 15 years. By reviewing the network architecture, we see opportunity for cost reduction without sacrificing safety or quality of supply.

6.3.1 NETWORK ARCHITECTURE: WHERE ARE WE NOW

Traditional network architecture

Network architecture generally refers to the fundamental design elements of a network. These include:

- Feeder configuration and interconnection of feeders, substations etc.
- Standard sizes/capacities for backbone, spur lines etc.
- Allowed nominal lengths and connection numbers on feeders or circuit sections.
- Size and configuration of substation bays and busses.
- Protection and communication design.
- Type and density of switching devices.

Drivers of architecture are:

- Required service and capacity levels.
- Load and, in future, DER, density.
- Network location.
- Asset costs, particularly as a function of size.
- Reliability and security requirements.
- Operational requirements.
- Technology developments and costs.

Design and asset standards generally follows architecture, which sets the all-encompassing framework for the network.

Powerco is an amalgamation of many historical networks and, as such, has inherited some significant variation in architectural elements across its footprint. Notwithstanding this, the New Zealand industry has traditionally adopted some very similar architecture features. It is particularly common to have quite different architectures for urban networks and rural networks.

It is this point of difference between urban and rural networks that sits at the heart of our network architecture review. We refer to our situation as a "tale of two networks" – with the major differences detailed in Table 6.1.

Table 6.1: Comparison of rural and urban network features

	URBAN	RURAL
Load density	High	Low (except for some primary industry)
Topology	Predominantly underground; some overhead. Moderate length HV circuits	Almost exclusively overhead. Long lines, low capacity.
Interconnection	Large capacity backbone feeders; some sub-rings. High degree of interconnectivity and backfeed capability.	Medium capacity backbones, large number of long spurs with minimal interconnection.
Capacity constraints	Mainly thermal, and generally only under contingent events.	Mainly voltage, sometimes even in normal configuration.
Protection	Substation CB and fused distribution transformers.	Substation CB, some line, spur and group fuses.
Automation	Minimal or no automatic reclosing.	Line reclosers and sectionalisers widely used.
Isolation	Feeders regularly segmented by ring main units or air-break switches (ABSs).	Widely spaced ABSs.
LV	Large capacity. Multiple connections per feeder. High diversity of load.	Low capacity and often long. Single or few connections.
Switching	Increasing levels of automation (including loop).	Some automation; mostly sectionalisation.
Fault finding	High degree of isolation points. Some fault passage indicators.	Minimal fault indicators. Reliance on line surveys.

The above also leads to two contrasting price/quality outcomes:

1. The cost per connection for rural customers is generally substantially higher than urban.
2. Long exposed rural lines are more exposed to interference from vegetation and weather and environmental factors than urban feeders. Therefore, they do not perform as well, and it takes longer to find and repair faults. Rural supply quality is generally intrinsically lower than in urban areas.

6.3.1.1 URBAN NETWORK ARCHITECTURE

By virtue of the network density and resulting architecture, our urban networks are generally better utilised and more reliable than the rural networks. The average cost per connection is substantially lower. They are also generally better suited to accommodate technology improvements such as automation, fault restoration or load shifting.

Most of the potential gains from reviewing our architecture will, therefore, come from the rural areas. However, it is recognised that the urban networks, particularly the LV side, also need review.

At the distribution voltage level, capacity is generally sufficient to absorb a substantial volume of new customer devices, such as solar PV, batteries and EVs, before capacity or stability issues may pose a challenge.

This will likely be different on the LV side, where the immediate impact of new consumer devices will be directly experienced, and where there is generally less capacity and load diversity to accommodate the associated load increases or fluctuations.

We have several programmes of work under our Network Evolution strategy to understand and respond to the impact of new technologies on urban networks. refer to section 6.2.5. A review of our LV networks and increased levels of monitoring and automation is also beginning, see section 6.8.

6.3.1.2 RURAL NETWORK ARCHITECTURE

Note: For the following discussion, we are generalising "rural" networks. While the assumptions mostly hold true, there are a number of rural areas with considerable economic or high density farming activity and associated high energy use. The supply economics for these areas is markedly different from the low consumption rural areas. Reflecting customer requirements, the supply quality in these areas is, mostly, much better than in the general rural areas.

As noted above, the cost to supply rural connections is generally substantially higher than in urban areas, even if supply reliability is generally lower – and this differential is likely to increase as urban customers have more opportunities to adopt technology and change their energy use patterns. Pricing differentials for distribution services cannot realistically reflect these urban/rural cost differences, unless we are prepared to entertain significant price-shocks with associated upheaval in rural areas, which is unlikely to be politically palatable (or to us) and may not ultimately be beneficial to any part of our customer base.

This requires us to look more deeply into rural architecture and the ensuing price/quality implications. At the same time, there are a number of changing dynamics that also necessitate a re-think about the make-up of rural networks:

- Continued urban drift and changing land use, leading to flat or negative demand growth[44]. This means low and reducing asset utilisation.
- Ageing rural infrastructure, commonly built from the late 1950s to early 1970s.
- The move towards more cost reflective pricing and open-access networks where tailored energy solutions and applications will be supported.
- Reducing costs of off-grid and network alternatives and, therefore, more opportunity for beyond-the-meter services and solutions.
- The need to use more sustainable construction materials and techniques, with less impact on the environment.
- A challenging framework for effectively managing vegetation issues.
- The need for networks to be more resilient and designed to more onerous criteria in the future.
- Sustained pressure on costs from the need to keep electricity affordable.
- Safety issues, especially around downed conductors.
- Potential for large scale renewable generation located in rural areas.
- The increased availability of remote monitoring and communications, plus improved protection and switching capability.

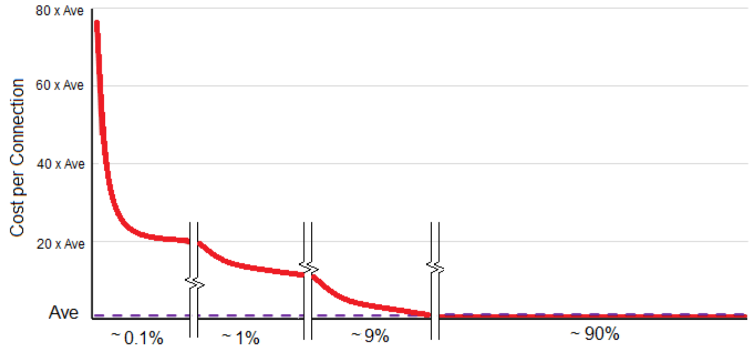
The combination of these factors poses some serious challenges. On the one hand, lower consumption and network utilisation makes it imperative to reduce the cost for providing rural supplies – or accept an even greater wealth transfer from urban to rural customers. Conversely, rural networks are facing a pending tsunami of renewal needs (the “wall of wire”) in the next decade or so. Much of the rural network will need to be totally rebuilt. At the same time, rural customers still rely on reliable electricity to support their lifestyle and economic activity.

Emerging technology will likely provide part of the solution. Opportunity now exists for much greater customer participation in providing their own energy, in full or in part. We also have increasing ability to use technology to reduce the operating cost of networks, through improved automation and remote fault-finding.

Before any large scale rebuilds, we will have to resolve the ideal network architecture as well as engage with rural customers on possible alternative electricity supply arrangements. This engagement has to be transparent, particularly in presenting the price/quality options that exist, and the extent of cross subsidisation already in place.

Figure 6.7 shows the extent of the cost imbalance for different parts of our customer base – this is directly correlated to the degree of remoteness from our core network. While this presentation is stylised (of necessity to visualise the sharply hyperbolic nature of the relationship), the underlying numbers are based on real network data.

Figure 6.7: Comparison of connection costs for different customer proportions



- Network supply to a very small (~0.1%) portion of the most remote customers costs up to 80 times the average cost per connection; the supply economics of which should pose very obvious questions about remaining on-grid.
- Approximately 1% of customers cost up to 20 times the average to service. The economics of remaining on grid is still questionable, but will be a function of costs (driven by network architecture) and the alternatives (new technology).
- A further 9% of customers could still be classified as semi-remote, in that service costs can be up to 10 times average. Network connections are likely to remain more economic than alternatives, but we need to consider supply quality trade-offs.
- For the remaining 90% of mass market customers, mostly urban, network supply remains the obvious most economic choice.

44 For example, a general shift from sheep farming to forestry on large parts of our footprint led to substantial load reductions. This trend now appears to be continuing with conversions from forestry to bee farming.

6.3.2 NETWORK ARCHITECTURE: WHERE ARE WE GOING?

Our approach to re-architecting the rural network starts with better understanding the different nature, needs and costs of our customers on the various parts of the network. The biggest cost differentiator is remoteness, which could be measured by the allocated share of supply assets to serve a customer.

Our rural architecture review is initially focusing on three tactics.

- **Off-gridding of remote connections – remote area power supplies (RAPS)**: This is already the economic supply solution for the most remote connections (~0.1% of our customers). Should we be able to obtain lower cost RAPS units, the number of viable off-grid supplies could increase to about 1% of our connections.
- **Alternative build/design for overhead line assets**: We are working on lower cost designs for rural lines with low demand. These serve about ~10% of our network connections.
- **Use of generation to improve reliability (and resilience) on remote feeders**: By judicious use of remote generation, we foresee that we will be able to defer major line rebuilds on a substantial portion of our rural network.

Our ultimate vision is for a rural network architecture that is more cost effective and to ultimately strive for actual cost reflectivity.

A cost effective network will mean capacity and quality of supply are finely tuned to the future needs of customers. As this is uncertain, there is value in deferring major rebuilding of existing network assets until there is greater certainty about future consumption patterns, or to allow for more cost effective solutions to emerge.

Accepting the uncertainty, our view of the future rural network is that it will comprise the following:

- The most remote customers will be supplied by off-grid systems.
- Pockets of clustered remote customers will be operated on an off-grid micro-grid.
- Remote customers still connected to the network should be able to cost effectively deploy DER, both supplemented by and supporting the network.
- Network lines will be built small, light and at low cost – sufficient for the expected load, but with a shortened life expectancy. The network may be supported by distributed DER.
- More use is made of single phase and single wire earth return lines (SWER).
- Applying real-time monitoring and asset ratings, along with smart protection systems, will allow lines to operate beyond traditional capacity or performance limits. Downed lines will be quickly detected, remotely isolated and made safe.
- Monitoring and fault indicators will provide rapid isolation and fault location.
- Networks will be constructed using sustainable materials and construction techniques that are also resilient to changing climate effects.
- An appropriate mix of underground cable, covered aerial conductor and improved vegetation management will be applied in critical areas to minimise tree interference. New protection systems could detect tree contact before faults become permanent.
- EVs or farm implements in rural areas will be accommodated. Local storage and smart charging regimes will be applied to overcome capacity and voltage constraints.
- Over time we may switch to higher distribution voltages to provide additional capacity with smaller sized assets.

6.3.3 NETWORK ARCHITECTURE: HOW WILL WE GET THERE?

Our planned implementation of the three core architecture change strategies is discussed below. A key goal is also to defer major network reconstruction as long as possible, to allow more certainty before committing to specific fixed solutions.

6.3.3.1 OFF-GRIDDING

The most remote and costly connections will be considered for off-gridding when local spur lines become due for renewal. For some of these, off-gridding is already an economic option with lower lifecycle cost than rebuilding the lines. This is essentially a continuation of our current Base Power RAPS deployment programme.

We are investigating ways to reduce RAPS costs and to extend the range of options in terms of capacity and reliability. In particular, a lower cost, simpler unit may be appropriate for very low energy users. Ideally, a contestable market will develop that will allow customers a choice of supplier and products, and therefore let them refine their price/quality options to individual preference.

With lower off-gridding cost, more remote connections will become viable to off-grid. Our financial forecasts for the AMP period make some modest assumptions around these cost reductions. Timing may become critical, as renewal of poor quality lines cannot be deferred indefinitely.

Off-gridding requires agreement of the affected customer (or small cluster of customers). This often involves lengthy negotiations and measures to put customers at ease that the reliability of their electricity supply will not deteriorate.[45]

Micro-grids are a potential solution for a cluster of customers situated relatively close to each other, at the end of a long rural line. Aged and poorly preforming sections of line would be removed, and facilities installed so that downstream customers could operate within an isolated network of their own. While this appears to be an economic solution, implementation faces considerable operational, legal (electricity market) and logistic obstacles.

6.3.3.2 ALTERNATIVE LINE BUILD

Alternative line build essentially involves a strategy to trade off initial construction cost against service capability, and to some extent asset life. Presently, our standard is to construct three-phase lines using concrete poles for all installations. Smaller, lighter lines utilising softwood poles will still serve current needs but should materially reduce immediate costs. From a lifecycle perspective, indications are that such an approach will still be most cost effective, even if assets reach end-of-life at an earlier point. In addition, lower upfront cost solutions can defer major investment until there is greater surety about long-term electricity needs.

We are, therefore, reviewing our line design and construction standards for rural areas, in particular to accommodate softwood poles and lighter conductors. Softwood poles are lower cost, locally sourced, environmentally beneficial and, most of all, are light weight and materially reduce transport and construction costs for lines that are commonly built in hard to access backcountry areas.

While the softwood poles have lower crossline strength than pre-stressed I-section poles, their superior downline strength is more important to long span rural construction, especially in backcountry areas with significant snow loading.

The intent is to complement the lighter strength poles with smaller conductors. This could constrain future capacity, but the risk is low with most rural lines very lightly loaded and there being negligible demand growth. Possible future thermal capacity constraints may be manageable through distributed energy resource (DER) or demand side response (DSR) alternatives. New technologies are allowing more dynamic rating of lines, leveraging additional latent capacity.

Given modern treatment standards, the durability of softwood poles has improved markedly. Notwithstanding this, the economic life of these poles may be restricted by standards of safety related to the surety of pole integrity before climbing. We are conducting tests to ascertain the pole strength and will continue this over time to ensure full understanding of the lifecycle performance of poles. Even if pole integrity cannot be guaranteed for the whole expected lifetime (45 years), replacing poles after 30 years is still economic given the early installation savings.

As part of the alternative build, we are also investigating expanded use of SWER lines or single phase lines. These are very cost effective for backcountry areas with long spans across deep valleys. There may be some capacity constraints, and options for more than single phase supply will need to be investigated.

6.3.3.3 RELIABILITY OPTIONS

Off-grid and alternative build options are only useful as a counter-factual to the default choice of replacing lines with like-for-like at the end of their life. The timing of a line renewal is never a clear binary decision; instead it is a risk trade-off balancing declining asset and network performance against investment timing.

Strategies to defer major line renewal are, therefore, valuable to allow greater certainty of future requirements before investing.

Strategies to manage declining network performance or extend capacity includes the use of DERs on the customer and network side. There are options for generation solutions, potentially supplemented by energy storage. Located near the end of long lines, these can drastically improve overall power quality, both in terms of reduced outages and providing voltage support. Refer to Section 6.7 on our generation and storage strategy for more details.

6.4 PROBABILISTIC PLANNING

We intend to change from our mainly deterministic-based network planning approach to progressively introduce more probabilistic elements. This is expected to lead to material cost-savings in new network investments (growth and renewal), as the approach intrinsically leads to optimally efficient solutions, while being very transparent about the risk involved.

In addition, this planning approach will become essential as we see more renewable generation on the network, or intermittent demand. Current planning methods cannot accommodate this so cannot reflect any network benefit from, for example, wind generation connected to the network.

6.4.1 PROBABILISTIC PLANNING: WHERE ARE WE NOW?

The electricity distribution industry has traditionally used deterministic approaches to plan network investment, particularly in regard to security of supply or network reliability. This was a pragmatic approach, which was appropriate given limited past data and analytic capabilities, and also well suited to less volatile and more predictable growth trends, particularly in high growth scenarios.

[45] Given the relatively poor performance of many long rural feeders, supply reliability actually improves materially with a RAPS unit.

Analysis and network modelling capabilities have greatly increased, allowing disaggregation of data to low levels, potentially even individual customers. Multiple uncertain planning dimensions can also be analysed simultaneously using a risk-based or probabilistic approach to better understand the economic and risk trade-offs for network solutions.

The following drivers necessitate a different approach to network planning:

- Changing patterns of electricity use, particularly where these are more variable.
- Emerging technology, particularly where these represent intermittent generation and/or demand features, such as energy storage, solar PV, and EVs.
- Customer participation in providing network services, or selling excess energy.
- More volatile economic, demographic and industry factors.
- Smart grid solutions: Variable asset ratings, automation and network reconfiguration, Advanced Distribution Management Systems (ADMS).
- Pressure on affordability of utility services.
- Risk-based and value-based investment frameworks.

Faced with these drivers and changes, retaining a planning deterministic approach limits our ability to optimise network investment decisions. Problems with a deterministic approach include that it:

- Considers only the maximum demand (MD); not the demand profiles, or the potential future changes to these profiles.
- Does not reflect circuit failure rates, asset age/condition or circuit length.
- Assigns a single capacity to assets, despite the fact this changes with time or seasons.
- Cannot reflect the reliability benefits from intermittent connected generation, eg wind generation.
- Is biased towards traditional supply side (poles and wires) solutions.
- Uses a very subjective and generic (class-based) approach to risk management, and customer criticality.
- Does not support value-based investment frameworks, or ensuing pricing signals.
- Does not reflect the actual cost of an outage to customers, which are much higher for some than others. Optimal cost reflective solutions are therefore not possible.

Deterministic approaches set security criteria to cater for the lowest common denominator in the security class, assuming the worst-case peak demand. This leads to conservative planning decisions, particularly where network redundancy or alternative supply arrangements exist – as is often the case in urban networks.

The main dimension in which our current deterministic standards vary across classes is in terms of the switching response speed – the time taken to reconfigure the network and establish alternative feeds where possible. This was appropriate given the traditional and stable network architecture in the past, but will again struggle to cope with a future where network configuration is more varied, operations more automated, and customer side solutions more common.

The existing deterministic approach does not support monetised risk, which is foundational to our recently introduced value framework for investment decisions.

Finally, the move from deterministic to probabilistic is predicated on the increased future uncertainty that impacts so many investment drivers. As its name implies, a probabilistic approach is required to assess and manage uncertainty. The deterministic approach cannot assess the impact of alternative demand scenarios such as can arise from electrification, customer technology uptake etc. The future open-access network will be a platform for trading energy transport, meaning network export capability may be just as important as serving loads. A new approach is needed that can assess the value an investment returns in regard to any network service.

6.4.2 PROBABILISTIC PLANNING: WHERE ARE WE GOING?

In principle, a probabilistic approach analyses the uncertainty or variation in any input driver/parameter of a planning decision and produces a statistical distribution of out-turn costs, risks or benefits. This is in contrast to a deterministic approach that takes a single representative value for each input variable, which may be a percentile or mean, and produces a single output value.

The term “probabilistic approach” is often more simply interpreted as the application of:

- Generic circuit failure rates.
- Value of lost load (VoLL), associated with likely customer outages.

This is largely the extent of “probabilistic planning” as defined in the “EEA Guide to Security of Supply”. These two aspects have already been introduced to our network planning process.

A full probabilistic approach should also contain the following elements:

- Load profiles and different future growth scenarios.
- Forecast changes because of technology uptake and changing customer use patterns, or political drivers, eg electrification.
- Failure rates reflecting specific asset performance, and future interventions.
- Consideration of smart grid solutions: Automation, dynamic rating, intermittent generation.
- Consistent comparison of non-network solutions alongside network solutions.

- A monetised risk approach supporting future value-based investment frameworks and pricing regimes.
- An assessment of variance (risk) in regard to the out-turn variables, such as costs, benefits, value and pricing.

Ultimately, a Monte Carlo-type analysis is envisaged to assess the complex interactions of multiple random distributed variables. The analytic platforms, data integration and user applications required to support this will need significant work, but the rapidly changing world of digital technology makes this possible.

Security criteria

The broad security classes within which the deterministic approach groups assets and loads often lead to sub-optimal investment decisions. The probabilistic approach obviates the need to use prescribed security classes or criteria, as the analysis takes place at a very granular level. Needs, options and solutions are tailored to the specifics for each case.

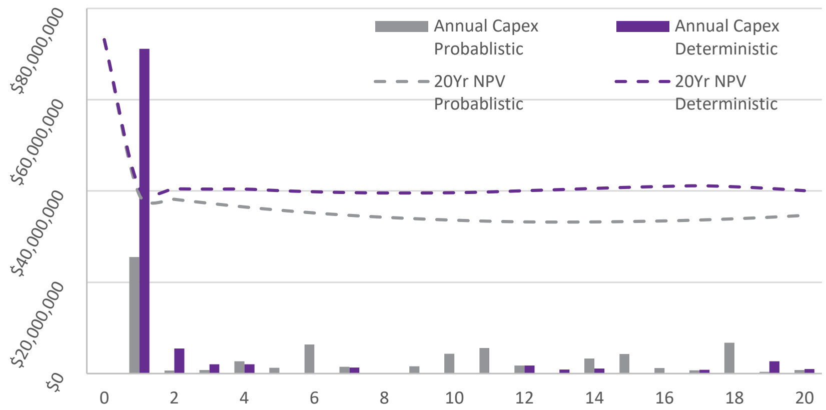
This was already reflected in a new approach introduced for our Customised Price-quality Path (CPP) application. The entire network was analysed against a single contingent event criteria, with the resulting constraint costs ranked by order of risk exposed. This allowed planning to focus on high-risk areas. The planning process then considered options, evaluating the final costs and benefits of the optimum solution (which can be "do nothing", if the value of the problem being resolved exceeds the cost to do so).

While this detailed bespoke solutioning was practical for large investments and high-risk situations, it has not, to date, been implementable at lower investment levels.

Investment and risk impacts

Our preliminary analysis suggests the shift from deterministic to probabilistic planning will see a significant reduction in investment, or deferral, for a similar or even improved level of risk. Figure 6.8 demonstrates the outcome of a theoretical application of strict deterministic versus probabilistic approaches to the zone substation power transformers.

Figure 6.8: Potential investment savings from adopting a probabilistic planning approach



Both the approaches reduce risk to a sustainable level with modest subsequent investment to counter growth beyond Year 1. More detailed analysis revealed there were two aspects to the reduced investment under the probabilistic approach:

- Drastically reduced (or deferred) upgrades for "N-1 secured" substations (those previously requiring full redundant backup under the deterministic criteria).
- Increased investment for "N secured" substations (ie those with nominally one primary circuit; and limited backup), which previously would not have attracted any consideration as they nominally complied with the deterministic criteria.

Value and risk basis

The probabilistic planning strategy is required to support our investment value framework and our strategy to apply more risk-based asset management. It is also a necessary step on the way DSO capability.

Our new investment optimisation system requires that the benefits of any investment, on multiple dimensions, are evaluated in equivalent dollar terms for optimisation purposes. For network security investments, VoLL benefits from reduced outages are generally the dominant project benefit. A deterministic approach could not evaluate monetised value.

A further example of the better risk-based outcomes is where a high criticality load might be more cost effectively secured through a targeted smart grid or customer side solution than a network investment. The value of this can be readily assessed under a probabilistic approach, but not under a deterministic approach.

The capabilities required by a DSO are still being defined, but the monetised constraint costs directly support a marginal pricing system, which is not achievable under the deterministic approach.

6.4.3 PROBABILISTIC PLANNING: HOW WILL WE GET THERE?

6.4.3.1 ANALYSIS AND DECISION-MAKING

We have already introduced the “probability of failure” and “value of lost load” concepts into our planning approach. These are foundational to the value framework now being introduced for investment optimisation.

The longer term analytic platform and user interfaces (tools, visualisations) we intend to use for our probabilistic modelling and planning are still being evaluated. There is no single off-the-shelf software platform that satisfies all the requirements (power flow analysis, statistical forecasting and Monte Carlo analysis). We therefore plan to develop our own prototypes, but will continue to monitor the software landscape and adopt good products as these become available.

Prototype tools have already been developed to jointly consider asset lifecycle renewal alongside network augmentation. The goal is to develop an integrated modelling platform for both asset fleet management and network development.

6.4.3.2 DATA MODELS

A probabilistic approach requires considerably greater volumes of data and analysis than our current needs. In future, network performance will need to be modelled over a range of possible demand scenarios and profiles (a time series of demand), to be assessed for every circuit section in a feeder. Modelling the frequency and location of outages needs to be expanded. In addition, the models will need to reflect the operational response to events (protection systems and operator driven). In addition, the models need to reflect the customers’ sensitivity to outages; requiring VoLL or value of customer reliability (VCR) data and load profiles specific to each customer type.

Our plan is to progressively improve the underlying data driving the models. In the interim we will use generalised assumptions, based on our best knowledge to date.

6.4.4 DEMAND FORECAST METHODOLOGY

We intend to transition our demand forecasting to a probabilistic basis in the near future, as well as forecasting at a much more disaggregated network level (both in time and spatially). To fully implement this will necessitate historical customer demand data, reconciled against normalised network historical load data. These forecast profiles will also be needed for our ADMS system.

We will initially simplify our assumptions, using scenarios to set realistic demand limits at load points. Ultimately we will seek to transition to full demand probability distributions at these points. We will also seek to integrate the expected changing future demand trends and profiles into our models.

6.4.4.1 VALUE OF CUSTOMER RELIABILITY (VCR)

VCR or VoLL is one of the most important variables used in probabilistic planning. It is also dynamic in nature, changing with time of day, load type, and outage duration. As it is a somewhat abstract concept, it is also one of the hardest parameters to quantify – requiring extensive customer intelligence.

Obtaining quantified data for VoLL/VCR rates should ideally be a cross-industry initiative. We continue to monitor international and national research in this regard, but will append to this surveys of our customers.

Depending on how the DSO concept and distribution pricing models evolve, there may ultimately be a market to directly inform VoLL rates, but this is likely to be some time away.

6.4.4.2 NEW CUSTOMER TECHNOLOGY UPTAKE AND DISTRIBUTED ENERGY RESOURCES

Understanding the nature and impact of new technology uptake or customer side investment on demand profiles is important for probabilistic network planning. We will continue our research into this – it is also a key part of our network evolution strategy, described in section 6.2.

Having access to good information on the cost of implementing non-traditional network solutions on the network and customer side, is also essential to inform the assessment of investment solutions. Research on this is also ongoing.

6.4.4.3 MODEL AND BUSINESS INTEGRATION

An early required initiative will be to align and integrate our asset and network models.

Asset lifecycle models are effectively probabilistic in nature, using condition and health data to forecast probability of failure. As networks are made up of individual assets, these forecasts ultimately determine the likely availability of supply.

We have already started to build out a full suite of asset renewal models and plan to integrate these with our enterprise data systems as well as our investment optimisation platform. As we do this, we will look to expand this into our network model, vegetation management and operational models. Effective integration of our models will allow information sharing and support ever more comprehensive assessments to inform our probabilistic network planning.

Finally, implementing a probabilistic approach will require coordination with a number of other strategic developments across the business:

- Automation, generation, and energy storage.
- Network Evolution strategy.
- Network visibility (ie data and monitoring, Internet of Things – IoT), especially at LV.

- Open-access networks and cost reflective pricing.
- Regulatory and political initiatives (electrification, affordability).
- IS, data governance and digital strategies.
- ADMS programme.
- Investment value framework and optimisation platform.
- Criticality framework and asset model development.

6.5 NETWORK AUTOMATION

One of the major benefits associated with developing technology, is our increased ability to automate the network. The scope for real-time monitoring and the ability to remotely control “intelligent” network devices is rapidly expanding – facilitated by ever-improving communication networks, metering and monitoring devices and the capability of the network assets themselves.

With distributed intelligence and local control, it is also increasingly possible to build autonomous applications on the network – allowing, for example, automatic fault isolation, network islanding, self-restoration, or synchronising adjacent devices to minimise the extent of outages.

All of this can contribute greatly to improved reliability of supply, the effective integration of distributed generation, and improved network and asset utilisation – often in more cost effective ways than building conventional network extensions.

6.5.1 NETWORK AUTOMATION: WHERE ARE WE NOW?

6.5.1.1 OUR CURRENT NETWORK AUTOMATION STATUS

Automation schemes on our network have been a major contributor to keeping network reliability under control in recent years, in spite of increasing asset failure rates. System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) trends are, therefore, better than asset performance trends would suggest. It is one of the most cost effective ways of managing reliability.

To date, our automation programme has focused mainly on the deployment of automated distribution switches and fault indicators. For our radial feeders, which is the bulk of our network, we typically use automatic reclosers and sectionalisers that can isolate a faulted circuit section while maintaining supply to upstream customers. Reclosers briefly interrupt supply to enable downstream sectionalisers to open and isolate a faulted line section, before restoring upstream supply.

Once the protection devices have isolated a faulted area, service crews will typically manually operate switches in the field to restore supply to as many customers as possible, switching around faulted sections, where possible.

These devices have been complemented with fault passage indication, to reduce the time service providers need to locate network faults. Devices placed at nodal points (from which more than one line radiate) on the network give a visual indication of which spur experienced a fault. For longer circuits, we use fault indicators along the circuit to help pin-point fault location. In limited cases, we have fault passage indicators that provide remote indication – allowing our controllers to advise service providers of the likely fault location as they are dispatched.

In the more interconnected (meshed) areas of our network, we have applied a small number of automated restoration schemes (loop automation schemes). This is to provide rapid reconfiguration of the network around faulted sections, maximising the use of available backfeeds. Typically, these schemes consist of a remote operated switch at the interconnection point and reclosers at feeder mid-points. If a fault is detected in a portion of a feeder, the schemes isolate that section and backfeed the remainder of the feeder. These schemes use a mix of centralised SCADA control and distributed intelligence using the on-board functionality of the switching devices themselves. To date, the performance of these schemes has been somewhat problematic, as the additional complexity can result in maloperation and misunderstanding of the reasons for operations. This has resulted in trust issues for our NOC staff.

Another focus has been on improving the visibility and operation of expulsion drop out (EDO) fuse operation by the application of ‘fuse saver’ devices, designed to clear transient faults. These have proven difficult to deploy in remote rural areas, where fault levels often tend to be too low for the devices to operate effectively.

6.5.1.2 LIMITATIONS AND DRAWBACKS OF OUR CURRENT AUTOMATION

There are a number of areas where we need to improve network automation.

- A major shortfall of our current automation is that it is essentially static. It cannot adequately deal with changing network needs and the challenge of future emerging technologies, such as distributed generation and storage, PV and EV uptake (which includes the possibility of two-way power flows).
- Opportunities for further deployment of reclosers and sectionalisers on our network is limited. As we attempt to split feeders into even smaller sections, using the protection functions associated with these devices, we encounter issues with protection grading on circuits. On many feeders we have effectively reached a limit to the effective number of these devices.
- In evaluating the cost-benefit of automation schemes, we traditionally take a pure SAIDI approach to determining the benefits, based on our deterministic performance targets for various customer groups. This does not accurately reflect the real value of load at risk and, therefore, compromises investment decisions. In addition, faults on LV networks are not factored in at all.

- Manual field-switching exposes our service crews to risks arising from human error, equipment failure during operation, and general environmental impact associated with working during poor weather.

We have been updating our automation strategy to address these shortcomings. In addition, anticipating a changing future, we have undertaken a number of trials, covering distribution transformer monitoring, power quality monitoring, remote fault location, communications and equipment trials. These studies have helped shape our thinking on our future automation plans.

6.5.2 NETWORK AUTOMATION: WHERE ARE WE GOING?

Our Network Evolution roadmap suggests that we will ultimately move to a Distribution Service Operator (DSO) future, where two-way power flows and the extensive deployment of DER will be the norm. Under these conditions, to keep network operation stable while avoiding excessive reinforcement costs, the ability to closely monitor power flows and performance and to react effectively to rapid changes in demand and generation will be essential. This reaction can include automatic voltage and reactive power management, constraining or enabling energy sources and load, demand management, and the dynamic reconfiguration of the network through remote control.

To meet these challenges, we have taken a wider view of automation, to consider the elements it will take to efficiently and safely manage the network of the future. Generally, it means a greater focus on measuring and monitoring the state of the network and adding increased remote control capability – centrally controlled or through distributed automation. The main directions we will pursue are summarised below.

- We still have opportunities to expand our current approach to keep improving network reliability and will continue to seek out opportunities for further sectionalisers and reclosers. However, we intend to continually increase our ability to remotely operate isolation points, moving away from field-staff intensive operations, initially to a centralised network configuration management. In future, we see increased uptake of distributed automation schemes, requiring no operator intervention.
- An interesting avenue we are pursuing is the detection of pre-fault conditions using sensors on our network to pre-empt outages. This development is another key component in addressing network performance.
- With increased network operations visibility and remote operability, we see the use of an ADMS system as crucial to our ability to manage our network effectively. As network complexity increases, response requirements will be well beyond the capability of human intervention. Our automation rollout, therefore, needs to align closely with our ADMS pathway.
- In addition to the ongoing focus on reliability, we need to consider power quality. As the number of distributed generation sites increases, we expect to see more reactive power flows and excessive voltage excursions on our network. While it is expected that in the main, at least initially, this will impact the LV networks in urban areas, there will likely be larger installations on our rural networks that could also impact our medium voltage (MV) network
- We intend to increasingly use our LV network for outage support and to reduce loading constraints – this will reduce the need for augmentation on MV networks. Ultimately, we will require control of voltages and reactive power flow on the LV network. That may be through Volt/VAR support, directly or through the control of third-party inverters. Where loading constraints begin to surface through the increased use of, for example EV charging, demand side management may be required to ensure peaks are effectively minimised. Monitoring, communication systems, data processing and remote controllable device systems on the LV networks will be essential to achieve this.
- To better serve our customers and optimise our investment benefits, a shift from our current pure deterministic-based assessment to a VoLL-based (probabilistic) approach will be necessary. To inform and prioritise our automation investments we intend to look more closely at the risk associated with various segments in the network, determining the probability and consequence of failure, and also considering the availability of alternative feeds, distributed generation, energy storage and the like.

6.5.3 NETWORK AUTOMATION: HOW WILL WE GET THERE?

We consider the creation of an open-access network as an essential enabler for a DSO future. To provide as much flexibility as possible to customers to manage their energy use or to trade energy over the network, we will have to ensure that network capacity and stability is well managed. This will require increased visibility and operability, particularly on the LV networks.

To make the desired improvements, we initially intend to focus more on remote control operation and monitoring, developing tools to determine the optimal network segregation, understand the real-time state of the network, and to remotely reconfigure it. Over the longer term, we will move to increased use of decentralised control systems, truly automating the network.

6.5.3.1 REMOTE CONTROL

Initially targeting existing network intertie points, we propose to significantly increase the number of remote operable switches on the network – overhead and underground. We will initially focus on locations where the value of load at risk is high and traditional response times are lengthy. Over time we will expand on this by creating additional remote control points across the network – where cost-benefit analysis supports this.

To support this, we intend to develop assessment tools to better understand the reach, benefit and cost of improvements.

6.5.3.2 URBAN NETWORKS

For our denser urban and suburban networks, we intend to add sectionalisation through retrofits to our existing distribution overhead and ground-mounted switchgear. This will allow for both remote operation and increased fault passage indication, with the goal to restore supply around a faulted section within one minute. We will initially target existing tie points and strategic nodes in the network, moving to increased sectionalisation through additional control points over time.

For our urban LV networks, we will initially continue to focus on monitoring as a means to understanding the impact of emerging energy use patterns. Over time we will expand our automation portfolio to include automated Volt/VAR control and remote switching capability. The intent is to be able to manage quality and performance on our LV network as we would for our MV network.

6.5.3.3 RURAL NETWORKS

Our rural networks are a mixture of mesh and radial configurations. For these feeders we will prioritise automation of locations that deliver the highest value outcomes based on the value of load at risk and the probability of faults occurring. For the meshed sections, we will supplement the remote control with voltage and current monitoring, allowing us to safely maximise backfeed potential. For radial feeders, we will look to increase visibility of the operation of protective devices, using a combination of end-of-line voltage monitoring, fault passage indication and replacing fuses with electronic equivalents where practical.

6.5.3.4 REMOTE RURAL NETWORKS

For our more remote fringe networks, which tend to consist predominantly of radial feeders, monitoring and fault location will be the main automation focus. For these areas we will apply additional remote-readable fault passage indication and end-of-line monitoring, along with additional protection devices to better detect high impedance faults. For isolated communities, we plan to improve resilience and reliability through remote generation and storage options – refer to the generation and energy storage strategy discussed in Section 6.7.

6.5.3.5 DYNAMIC ASSET RATINGS

In areas of our networks where load growth is uncertain or very low, or where network capacity is generally sufficient other than following low probability contingent events that create short-term excessive peaks, network upgrades are difficult to economically justify. In these situations, it is valuable to extract as much capacity from existing assets as possible – balancing this with the risk implications. An often effective means to increase available asset capacity is by using dynamic asset ratings. This generally means that actual operating and asset status conditions are considered to determine the actual asset capacity in real time, rather than creating operating limits based on capacity determined for generalised, worst-case assumed operating conditions.

To apply dynamic ratings, we need to be able to monitor real-time conditions, such as temperature, windspeed, voltages and currents. To achieve this, we intend installing additional remote monitors and weather stations, integrating these with our remote control switching devices where possible.

6.5.3.6 FAULT ANTICIPATION

Preventing faults from occurring in the first place is the key to long-term reliability and customer satisfaction. Many faults, such as failed insulators or vegetation faults, tend to manifest over time, starting out as a power quality issue before developing into a hard fault that activates protection devices and results in an outage. By analysing the voltage and current waveforms, it is often possible to detect fault signatures, and address the issue ahead of a loss of supply. Part of our strategy is to implement pre-fault monitoring at our substations.

We are trialling both generic power quality monitoring as well as AI-based systems that utilise a multi-user database to match waveform abnormalities to known fault causes and indicate probable fault types and probable location. We also want to leverage off the pre-fault information collected from our existing protection relays to detect issues worthy of further investigation.

6.5.3.7 DEMAND SIDE MANAGEMENT

As we see increased uptake of distributed generation and EV charging, we expect to see an increase in network constraints. Although our initial focus will be on monitoring power quality, augmenting network capacity or curtailing load or generation will likely become ultimately necessary. Managed curtailment[46] can be the most economic solution, as long as the probability and extent of this is transparent and pre-agreed with customers, who can then choose to accept this or contribute to the cost to augment the network.

Besides working with customers on optimal solutions, we intend to work with industry to ensure that new energy resources are capable of reacting to constraint signals issued by networks.

[46] Network capacity is often only insufficient for a small proportion of the time, so the need for curtailment is often very limited.

6.5.3.8 DATA SUPPORT AND ANALYSIS

Our future automation approach will require intensive data analysis, based on a comprehensive network model.

We intend to apply solutions based on feeder topography, tailoring solutions to match the interconnectivity of the feeders and the value of load at risk. We will use a common criticality framework to enable us to consistently evaluate automation responses in comparison with other capital works solutions. This will be integrated with our Copperleaf investment optimisation tool, to direct our spend to the optimal projects and enable us to more accurately predict the benefits of an individual automation project.

Over time, we will continue to improve our network model and asset information. An important part of this will be to compare the actual out-turn results of investments with the initial planning assumptions and using this feedback to tune our approach.

We also intend to integrate all the available information from around the network to present a more holistic view of what is happening and improve our modelling with this information.

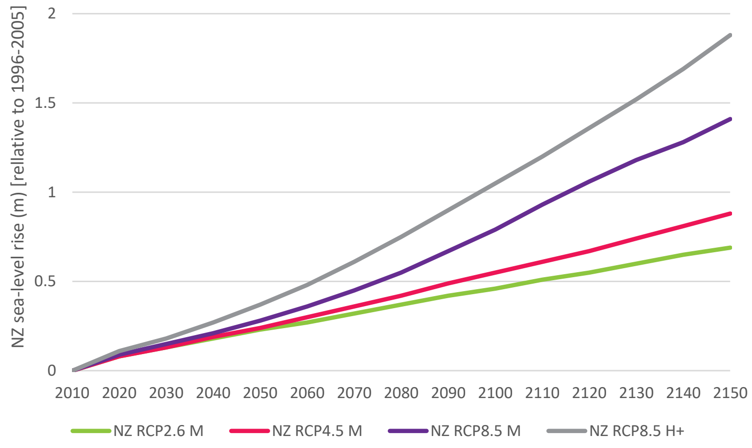
6.6 ADAPTING THE NETWORK FOR CLIMATE CHANGE

6.6.1 OVERVIEW

Increasing levels of greenhouse gases in the atmosphere are changing the climate and, with it, the conditions in which our assets operate. While year-on-year change is relatively small, electricity distribution assets have long lives, making cumulative changes potentially significant to an asset's fitness for purpose over its lifecycle. We must therefore ensure that the potential effects of climate change are considered for both existing and planned assets to ensure that our electricity distribution infrastructure continues to operate safely, reliably and cost effectively.

Based on the information at our disposal, the climate change variable with the most damaging potential to our network is sea level rise. Sea levels are projected to increase by between 0.4m and 0.9m by 2090 (depending on the climate scenario). Sea level rise will cause increased coastal erosion, potentially requiring the relocation of assets, and water inundation in low lying coastal areas (highest during storms and high tides).

Figure 6.9: Projections for sea level rise in New Zealand for four Representative Concentration Pathway (RCP) scenarios[47]



The NZ RCP8.5H+ represents a high scenario currently recommended for infrastructure planning decisions.

Other climate variables of interest from a network perspective are:

- Increased periods of low rainfall leading to excessive drought and fire risk.
- Increases in extreme winds and storms, which can cause network damage and customer interruptions.
- General air temperature rise.

At this time, however, there is significant uncertainty in climate projections related to these variables – see Table 6.2. The projected impact does not warrant material changes to our asset or network standards or investment, which already provide for considerable safety margins. The impact of general air temperature rise has been evaluated and is considered to be, by and large, immaterial to the performance of assets over the time horizon considered.

[47] Source 'Preparing for Coastal Change – A summary of coastal hazards and climate change guidance for local government'. Ministry of the Environment 2017.

Table 6.2: Projected changes to climate variables affecting Powerco electricity network assets in 2040 (unless otherwise stated)[48]

CLIMATE VARIABLE	DIRECTION OF CHANGE	MAGNITUDE OF CHANGE	NOTE
Drought	Increase in severity and frequency.	By 2090 [8.5], up to 50mm or more PED[49] increase per year.	Increases most marked in already dry areas. (Less so in Taranaki and Manawatu).
Extreme wind speeds	Increase	Up to 10% or more.	Most robust increases occur in southern half of North Island, and throughout the South Island.
Storms	Likely poleward shift of mid-latitude cyclones and possibly also a small reduction in frequency.	More analysis needed.	High uncertainty.

6.6.2 NETWORK CLIMATE CHANGE RESPONSE: WHERE ARE WE NOW?

Our asset and design standards are based on our historical experience of climatic events on the various parts of our network. While these include significant safety margins, they are based on an assumption that climate patterns will remain constant.

This situation is being reviewed to reflect evidence and forecasts from emerging climate science.

6.6.3 NETWORK CLIMATE CHANGE RESPONSE: WHERE ARE WE GOING?

In 2020, Powerco engaged specialist climate change consultants Tonkin and Taylor to conduct a climate change vulnerability assessment. This work considered a range of potential climate scenarios based on the IPCC RCP[50] scenarios. Maps of projected climate change hazards, such as coastal inundation and coastal erosion, caused by sea level rise were overlaid on maps of Powerco assets to determine the type and number of assets exposed to each hazard. Exposed assets were then assessed to determine their vulnerability, and where necessary the most appropriate adaptation strategy. An example is shown in Figure 6.10.

Figure 6.10: Visualisation of Powerco asset exposure to coastal inundation and coastal edge proximity hazards in Coromandel

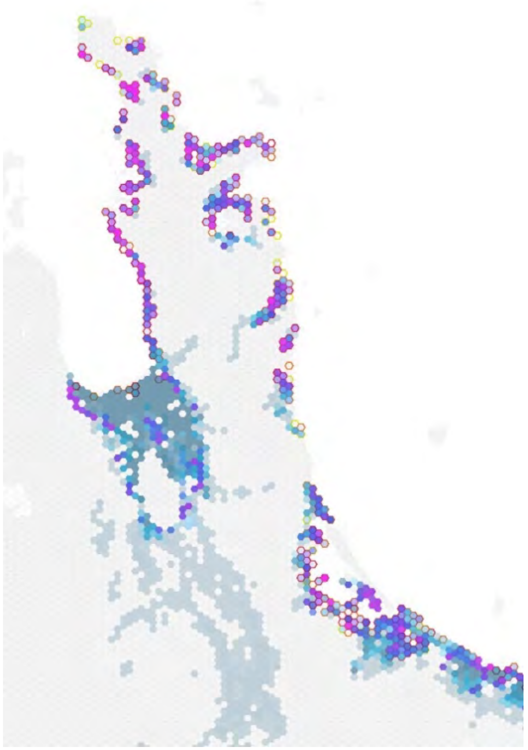


Table 6.3 shows the adaptation strategies considered by Powerco. These range from 'do nothing' for assets that are not materially affected by climate change, to proactive intervention where action is required now. In general, however, because of the slow year-on-year impact of climate change, coupled with the expected asset life and current age profile, few if any assets will require immediate intervention to remain fit for purpose. By and large, the most applicable adaptation strategy is organic adaptation where assets are replaced when at the end of their current useful life with alternatives that have designs and specifications adapted to cater for changing climate and environment.

[48] Based on simulations undertaken for the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment 2nd edition. National Institute of Water and Atmospheric research.

[49] Potential evapotranspiration deficit – the difference between how much water could potentially be lost from the soil through evapotranspiration and how much is actually available.

[50] Representative Concentration Pathways – carbon emission scenarios.

Table 6.3: Powerco's climate change adaptation strategies

STRATEGY	DESCRIPTION
Do nothing	Climate change is not considered a threat to this asset class.
Organic	The rate of renewal through age or condition is sufficient to allow adaptation with minor evolutionary changes to asset specifications that marginally affect costs.
Proactive	Climate change-related threats require proactive action in the near-term future.
Remediation	The asset is at risk. Improvements can be justified against current climate conditions.
Redevelopment	While climate change drivers may not render the asset unsuitable, land use or other public infrastructure changes may drive the need to replace the asset. For example, road raising or relocation works to allow for adaptation to sea level rise.

Our assessment is that organic adaptation strategies will, in general, require some changes in equipment specifications – see Figure 6.11 as an example. This could result in a modest increase in asset replacement costs (<10%). In some cases, new assets may need to be relocated resulting in significantly higher renewal costs. We will continue to liaise with other infrastructure providers so as to ensure that our work is coordinated with other climate-related infrastructure investment.

Figure 6.11: Example of organic adaptation. Standard LV pillars (left) are vulnerable to coastal inundation as they are not waterproof. A newer submersible design (shown right).

6.6.4 NETWORK CLIMATE CHANGE RESPONSE: HOW WE WILL GET THERE?

As noted above, we do not foresee that material network changes will be required during the AMP planning period to prepare for potential climate change impacts. During this period, we plan to undertake the following actions:

- Further develop our climate change hazard maps based on consensus projections of climate change variables. This will be used to identify potential asset exposure as part of the asset planning process. Exposure maps will enable also exposed and vulnerable assets to be identified for interventions.
- Progressively review and, where necessary, revise equipment specifications, standards and designs to accommodate projected climate change impacts.
- Utilise new equipment specifications, standards and designs in capital and maintenance works processes

6.7 GENERATION AND ENERGY STORAGE

6.7.1 WHERE ARE WE NOW?

Our traditional deterministic planning approach tends to result in black and white outcomes – we either meet our deterministic threshold or we don't. If it is the latter, we look at long-term solutions to achieve the threshold and rank those based on the benefits they deliver for the cost incurred. Partial solutions, or solutions that target high-value load over low value are not effectively considered.

Traditionally, we build and upgrade lines or substations to meet growth and security requirements. Where capacity is constrained, we revert to bigger or more wires and cables. This is a long-term, costly solution with a risk of at least initial under-utilisation, which in situations with peaky loads may persist into the future. Assets could become stranded when demand growth does not eventuate or reduces, or where energy use patterns change.

In addition, land/route acquisition and consenting can take several years, which does not support meeting more rapidly changing customer needs.

While conventional network solutions are still appropriate for most required network augmentations or renewals, particularly on the more energy-dense part of our networks, there are many cases where the construction of new circuits is prohibitively expensive, not economically viable based on lifecycle considerations, or where there is too much uncertainty to support major long-term investments. This is especially the case for remote communities, supplied by single circuits over long distances in often rugged terrain or ecologically sensitive areas. Areas with highly peaky loads, where we have to provide capacity that may be required only for short periods during the year, also pose economic challenges.

For these areas, generation and energy storage can provide viable alternatives – not only being more cost effective, but also providing options for future redeployment or scaling. This allows (expensive) permanent solutions to be deferred until we have more certainty that energy demand would justify these.

We have trialled this approach in areas such as Whangamata, focusing on maintaining supply to the town's commercial hub through a hybrid Battery Energy Storage System and traditional generation.

6.7.2 GENERATION AND ENERGY STORAGE: WHERE ARE WE GOING?

Those parts of our network where upgrades by conventional network means are uneconomic, or where we have significant uncertainty of future energy demand, often lend themselves to generation and storage options. The ability for periodical peak lopping, is often sufficient to avoid other upgrades, or to defer these for extended periods[51].

We propose to apply more non-network solutions, particularly large generation – with or without storage – to these areas. Benefits include:

- **Modular rollout** – the solution can be sized to match the immediate problem.
- **Faster response** – reduced property and consenting delays compared with new line and substation builds.
- **Relocatable** – we are able to uplift and redeploy assets if demand patterns change again.
- **Economic** – these solutions generally provide a lower up-front cost option.
- **Scalable** – we can add or subtract generation and storage to match changes in loads, resulting in minimal stranded assets.

Short-term solutions provide future option values, allowing us more time to better understand and influence longer term customer behaviour before committing to major investments. This will support initiatives such as demand side management, incentivising beyond-the-meter energy storage or generation, energy efficiency drives etc to offset demand growth.

Storage and generation can be applied modularly to match the ongoing shortfall increases. Where growth continues, this allows time to implement more traditional network enhancement, and to redeploy generators/storage elsewhere.

We expect that some demand management will occur naturally on the customer side, as battery and PV costs decline, and energy efficiency is better managed. We could support or accelerate this through cost-reflective pricing signals, or through directly supporting demand side management solutions.

Ultimately, as large-scale energy storage costs reduce, the focus could be on replacing generation with storage.

[51] Note that generation or storage solutions are generally not well suited to applications with extended peak demand periods.

6.7.3 GENERATION AND ENERGY STORAGE: HOW WILL WE GET THERE?

We intend to increase the application of generation and storage solutions, making these part of our inventory of network solutions. With the intended introduction of probabilistically planning assessments in future, using VoLL as the key measure of consequence, such non-conventional solutions can be appropriately evaluated alongside our more traditional approaches.

These solutions will be especially targeted at areas of our network where an alternative supply either cannot be economically justified, or where unserved demand peaks only persist for short periods. We will also target areas where longer term future growth is uncertain, and peak loads cannot be met without costly upgrades. In these cases, we will use generation and storage as a deferral to traditional upgrades, providing time to gain certainty of growth or to give us time to plan our traditional upgrades. This will include areas where we have previously considered traditional solutions to be uneconomic and not worthy of further investigation, such as remote rural and beachside communities at the end of lengthy subtransmission and distribution lines.

Generation is initially likely predominantly diesel-based – this is by far the most reliable and cheapest option available. However, as renewable energy technology improves and battery storage costs decline, we will progressively work to replace diesel generation with greener alternatives. In the interim, to mitigate the environmental impact of diesel generation, we are investigating options for bio-fuel. We also note that the intended use of these devices is for short periods only – often as a stand-in in case of primary network outages. This means that overall emissions will mostly be very low, especially when compared with that of manufacturing and building lines and substations.

In the longer term, we will look to encourage load management schemes and beyond-the-meter (customer owned) energy solutions to reduce demand to within current network capabilities, ultimately negating the need for generation altogether.

To assist us in choosing the appropriate areas to target, we are developing spatial analytics tools to help bring those opportunities to the fore.

Table 6.4: Generation and storage use cases

USE CASE	CUSTOMER/NETWORK BENEFIT	APPLICABLE SITUATIONS
Peak lopping	Reduce peaks to remove thermal capacity constraints on existing network assets; avoid or defer expensive network asset upgrades. Immediate reliability and resilience benefits.	Infrequent short duration peak loads exceed network capability. Could be on subtransmission or the distribution networks.
Peak lopping (abnormal state)	Reducing peaks to remove thermal capacity constraints when the network is reconfigured following a fault. Avoids expensive network upgrades.	Where subtransmission and/or zone substation security of supply criteria is exceeded or where distribution backfeed is insufficient.
Voltage support (steady state)	Reduce peaks to ensure regulatory voltage levels are met. Avoid expensive network upgrades.	Infrequent short duration peak loads exceed network capability. Could be on subtransmission or the distribution networks.
Voltage support (abnormal state)	Providing voltage support when the network is reconfigured to support a faulted section. Avoids expensive network asset upgrades.	Infrequent short duration peak loads exceed network capability. Could be on subtransmission or the distribution networks.
Islanding	Creating an independent island supplied from distributed generation enables restoration of supply to remote parts of the network while the upstream fault is repaired. Also enables upstream assets to be isolated for renewals or maintenance with minimal interruption.	Areas where the ICP clusters are reasonably condensed, at the ends of long overhead lines, vulnerable to outages with little or no alternative supply.
Maintenance support	Enabling the connection of generation to support the network while undertaking maintenance activities reduces the impact of planned outages on our customers.	Locations where regular out-of-service maintenance is required on assets where alternative supply is unavailable or limited. For example, single bank substations.

6.8 LV TRANSFORMATION OVERVIEW

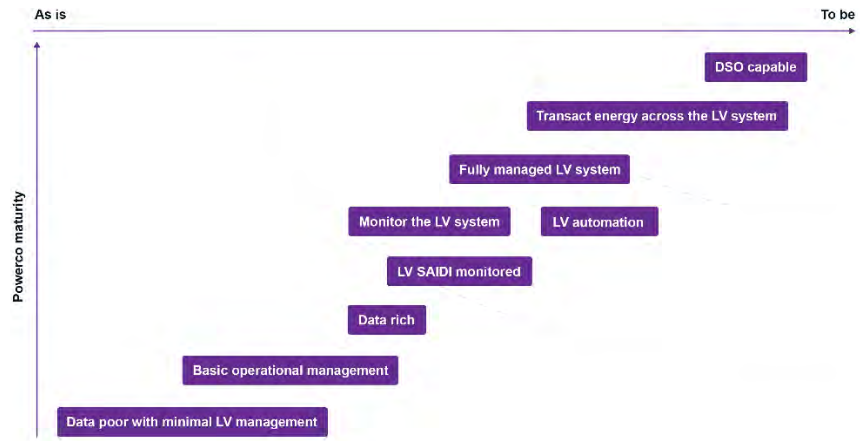
6.8.1 OVERVIEW

Our LV network is a key component for meeting the needs of the changing energy environment and our aim of achieving an open-access network. However, if we are to realise our vision of being fully DSO, we must be able to administer, monitor and operate in real time, the entire distribution network, including the LV system.

Our vision to get the best out of the LV distribution network will require us to move to a fully administered LV system. The journey will mean waves of change and investment over at least a 10-year period. The transformation will need to encompass an operational strategy and a monitoring strategy that works in tandem to enable us to reach our LV vision.

A synopsis of LV change for the next 10 years can be seen in Figure 6.12.

Figure 6.12: 10-year LV network evolution roadmap



6.8.2 LV NETWORKS: WHERE ARE WE NOW?

Background

The LV network is also our immediate interface with customers. Overall customer experience can be heavily influenced by the LV network, and the customers are indifferent to whether an outage is because of an HV or LV asset.

However, the industry regulatory framework measures network outage at the subtransmission and HV levels. This encourages investment and operational improvements on higher voltage assets. LV networks across the industry have consequently been reactively managed and organically planned. This has resulted in a deterioration of LV asset information over time, which results in further reactive management of the LV system.

The lack of LV performance monitoring limited drivers to utilise the LV network to improve network operations. Parts of our LV networks may have been constructed with interconnectivity to enable isolation and backfeeding around faulted sections. However, these were not designed with rapid response, or safe operation in mind. Many areas were simple bolted connections, which are unsafe to operate by today's standards. This has reduced our reliance on using these interconnections, leading to a deterioration in the condition, operational capability and network knowledge of these connection and isolation points.

LV records have further deteriorated, as we have lost the direct interface with our customers after the Electricity Industry Reforms Act of 1998. Our lack of a perceived need for the information meant a steady decline of accurate records and knowledge.

Operations

The LV network comprises about 38% of the entire electricity network – a complex interconnected component of the distribution system that is designed to provide high levels of supply security to commercial and residential areas. Parts of the urban LV distribution system have been designed in a similar manner to the HV system, where supply can be maintained by the operation of switches and links between differing supplying circuits.

The LV system was designed with consideration of known appliances for the time before DER were practical options. Widespread uptake of high capacity EV chargers, PV or energy storage would impose possible load constraints or imbalance.

Currently our ICP connectivity stops at the distribution transformer, a significant limitation when thinking of facilitating customer management for outages. Management of LV does not employ a systematic criticality approach, largely because of the incomplete connection data. While past information systems could not manage the volume of data for LV reliability measurement, modern systems should be able to overcome these limitations.

Monitoring

We expect some early signs of stress within parts of the LV network to occur soon. However, at present we rely on thermal maximum demand indicator (MDI) reading or loading calculation around the number of connected ICPs. This has, on occasion, led to solar (voltage) or loading violation, which we have had to reactively manage.

The LV system has little or no real-time monitoring. Network operations and investment planning are both blind to possible latent voltage and capacity issues in the LV system, being only able to reactively respond to customer complaints.

The lack of monitoring means it is suspected there are occasions when LV voltage limits are being exceeded which, while not causing issues for customers, is outside legislative voltage criteria.

6.8.3 LV NETWORKS: WHERE ARE WE GOING?

The industry and regulator are both working towards including LV reliability in the compliance terms. This reflects growing awareness that the LV system is the essential interface with the customer and also that customers do not differentiate between outages arising from higher or lower voltage networks.

A fully transparent and managed LV system is a key requirement for our transition to a DSO future. The LV network will take on an increased importance as our customers connect new devices and interact with a more open energy market future.

We anticipate EV or solar growth will occur in urban clusters and require attention within a few years, followed by an uptake across most of the urban network. Monitoring will be a key capability if we are to actively manage PV/EV issues. However, it is going to take several years to prepare the network to be fully monitored and capable of managing load and quality to ICP level. We are expecting to target investment to enable monitoring to the highest-risk parts of the network first.

We want to ensure that our operations and planning align with our customer needs. This means taking account of outages and performance on our LV network in the same way we would our HV networks. This would also require a better understanding of our LV system to proactively plan and invest in the LV network.

In short, we want to get back to operating our LV as a network.

As a principle, Powerco is seeking to make best use of LV assets through operation and monitoring of the LV network. This can be interpreted as:

- Making use of LV distribution to provide continuity of supply for customers during planned or unplanned outages.
- Configuring the LV distribution system to maintain supply quality.
- Facilitating PV owner connection and EV connection without undue cost, yet allowing customers to reach the potential of their connected assets.
- Enabling the distribution system for future evolution by installing end-of-line LV monitoring to fully administer the last mile of LV distribution.
- Real-time management of power flow through the LV system.
- Optimised, both in scale and timing, LV network investment, balancing costs against future service level expectations.
- Identifying high-value distribution transformer assets that supply dense ICP locations or high-value CBD load.

- Measuring each LV circuit load, power quality and voltages at chosen transformer locations.
- Measuring mid and end point circuit load, power quality and voltages for each LV (monitored) circuit.
- Working to obtain customer metering (AMI) data.
- Developing an analytics capability that can identify LV network congestion, imbalance and power quality violations.
- Real-time management of power quality.
- Enhancing our customer provision by maximising asset utilisation.
- Preparing for active load and DER management.
- Monitoring LV SAIDI.

6.8.4 LV NETWORKS: HOW WILL WE GET THERE?

6.8.4.1 BETTER MONITORING

We have installed about 65 monitoring devices to a broad cross-section of overhead and ground-mounted distribution transformers, monitoring the transformer LV terminals only.

We are planning to deploy a further 430 multi-channel monitors to the LV distribution frames of our larger residential or commercial transformers in the New Plymouth, Tauranga and Palmerston CBDs. This will provide us with a good sample understanding of what load and power quality we have at an individual LV feeder level.

This will help us understand load density, congestion and imbalance to the lowest level of our network. Deployment of monitoring will be prioritised by ICP density and commercial loading. In general, we will build out monitoring capability as follows:

Urban network

- We will monitor all LV circuits at transformer sites larger than 200kVA.
- We will deploy monitoring at mid and end points of each LV circuit.
- We will seek to obtain customer metering data.

Rural network

- We will deploy monitoring along the main HV lines at periodic transformers, monitoring the transformer bushings only.
- We will deploy monitoring at the end transformer of extended HV spur lines, monitoring the transformer bushings only.

6.8.4.2 BETTER INFORMATION MANAGEMENT

We have started a programme of data gathering and labelling of LV assets. To date, 60% of all LV assets have been surveyed and labelled. We anticipate the remaining programme of work to take a further 3-4 years, which will provide us with a detailed LV connectivity model that allows a full understanding of the LV distribution system. Further work is required during this programme to assign ICPs to the lowest labelled LV asset that allows tracing from any ICP through the connected assets.

To properly administer the network, we will need to develop new tools and systems to support field staff and engineering staff to get the best out of the LV distribution system. This means:

- Accelerate the existing programme of LV asset labelling and circuit tracing to update our Geographical Information System (GIS) records and provide a reference and connectivity view of the LV reticulation system.
- We will need to develop modelling and analytical capability to analyse the large amounts of information that monitoring and AMI sources will produce. This will be an essential tool for management of congestion.
- We will develop our SCADA and connectivity models that identify each component of the LV distribution system. This will be an essential tool for field and engineering staff to plan and manage the LV asset.
- In developing our SCADA system, it is also essential that we create a mobility function so that field staff can utilise the information in real time. This will be a component part of our ADMS project.
- Data for these devices will be replicated within our historian systems for analysis. While our historian provides good representation of power flow, the level of available information will increase through time as more data streams into our system.
- We will automate analytics to review LV data and alerted us of any quality of supply issues. Currently this can only be done manually.

6.8.4.3 BETTER COMMUNICATION SYSTEMS

Monitoring has been achieved by utilising cellular communication systems to recover the information. This limits monitoring of the LV distribution system where there is reasonable cellular coverage. This is appropriate for higher population areas or CBD locations.

However, as we extend monitoring of the LV system, we intend to use LoRaWAN technology for communications. Therefore, we plan to develop a network of LoRaWAN gateways around our Packet Transfer Network system. This provides us with an opportunity to determine what communication system best suits the Powerco network and our unique topology.

A secondary benefit being explored is whether we are able to use the same monitoring technology to detect HV lines down, so moving to a long range communication system will enable more rural deployment and increase our capability to detect lines down across the network.

6.8.4.4 BETTER ASSET PLANNING

Increased visibility will enable us to see where we are lacking, help us get ahead of problems as they manifest and, ultimately, provide a basis for accurate forward planning.

We will improve the quality and safety of our interconnection points. We will support this with new procedures and improved records to ensure we can operate safely and efficiently. Over time, we will add more operable connection points to facilitate more granular sectionalising and load transfer, ultimately automating these points and integrating them into an ADMS system.

We will carry out LV upgrades, initially to ensure we meet appropriate quality thresholds, but over time our upgrades will be needed to cope with the additional impacts of distributed generation and EV on the network. This will include upgrading cables as well as adding new technology, such as voltage and reactive power control to address the additional issues arising from distributed generation and storage.

We are establishing an investment strategy that accelerates key LV investment to facilitate increased operation of the LV distribution network. Such as:

- A programme of replacing underground link box equipment.
- A programme of replacing J-type fuse installations.
- A programme of replacing older street link/switch equipment.
- A programme of adding operable link and switch equipment to the overhead LV network.

Some preliminary analysis of LV monitoring data and circuit connectivity indicates that a targeted approach of investment is required where high impact, lost load and high ICP density can benefit from LV investment strategies.

A shift in focus of our network development expenditure allowance from HV to LV assets will be reactive initially but, in future, will be informed by detailed forecasting and analysis.

7 NETWORK TARGETS

7.1 CHAPTER OVERVIEW

This chapter sets out our Network Targets for the planning period, as well as our historical performance against these targets. We use these to gauge our performance in delivering our Asset Management Objectives.

We have designed our targets framework to drive improvement in the way we run our business, our networks, and the services we provide to our customers. It also serves to provide an early indication of areas requiring intervention.

Our plans and strategies outlined in this Asset Management Plan (AMP) are focused to help deliver and achieve these targets.

7.2 SAFETY AND ENVIRONMENT

7.2.1 OVERVIEW

This section sets out the specific targets we have set for Safety and the Environment during the planning period. We also consider the basis for these targets and our historical performance against these targets.

7.2.2 TARGETS

Table 7.1 lists the targets we have set ourselves to monitor performance for Safety and Environment objectives. Table 7.2 outlines the rationale behind the targets.

Table 7.1: Safety and Environment targets

INDICATOR	FY19		FY20		FY21 FY22 FY23
Safety	**Target**	**Actual**	**Target**	**Actual**	**Target**
TRIFR (Total Recordable Incident Frequency Rate) per million hours worked	15.43	16.74	12.33	11.24	12.33 (FY21), TBA (FY22-FY23)
HPI (High Potential Incidents) containment actions completed in 7 days	n/a		n/a		100%
Response time to emergency electrical calls – arrive on site within 60 minutes	90%	86.85%	90%		90%
Learning teams initiated	n/a		n/a		3
Environment	**FY19 Actual**		**FY20 Actual**		**Target**
Major or higher consequence environmental incidents investigated using Incident Cause Analysis Method (ICAM)	No major or higher consequence incidents occurred in period		No major or higher consequence incidents occurred in period		100%
IS0 14001:2015	Certified		Certification withdrawn [52]		Certification by FY22
Environmental programme delivery	86% achieved		82% achieved		
SF_6 (sulphur hexafluoride) leak rate (% of stock)	0.13%		0.01%		<2%
New Target – Net-Zero carbon emissions at 2030	886.83tCO_{2e}		855.09tCO_{2e}		Net zero at 2030
Legislative compliance	**FY19 Actual**		**FY20 Actual**		**Target**
Legislative non-conformances	n/a		n/a		0

[52] Certification audit is booked for FY22

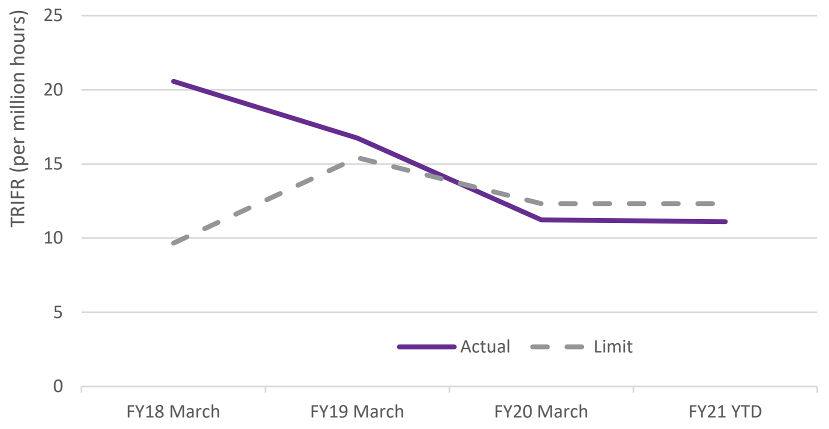
Table 7.2: Safety and Environment target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
SAFETY	
Our targets have been set to reflect progressive reduction of harm over time and to measure the processes that drive harm reduction. We aim to create an environment where we learn from our success in order to replicate it, and act quickly to prevent incidents from occurring or reoccurring to protect workers and the public. Swift completion of incident actions and consistent emergency response time allow Powerco to ensure we create a safe operating environment.	TRIFR is our primary lagging indicator. Section 7.2.3 outlines our improving trend in this area. We have also recently created a series of leading indicators (ie HPI, response times and learning teams), and made improvements to our safety processes during past years. We will continue to track these new initiatives and metrics, to improve our safety metrics.
ENVIRONMENT	
We have set targets that seek to decrease our environmental footprint and that align with the material sustainability issues identified by our stakeholders. We have publicly reported on our greenhouse gas emissions for the first time in FY20 and this is available on our website[53]. We have set a Net-Zero at 2030 emissions target for scope one and two emission sources[54]. Our net-zero road map is currently under development.	In FY20, a small number of issues relating to compliance obligations and document management were identified during an ISO 14001 audit. We were, therefore, unable to maintain certification in FY20 and this is reflected in our environmental programme delivery being below 90% for FY19 and FY20. We are targeting recertification in FY22. Our SF6 losses remain well below 1% of total holdings.
LEGISLATIVE COMPLIANCE	
We undertake a legal compliance programme to assure we are meeting our legal obligations. We are committed to: – Identifying our legal obligations and risks. – Ensuring our people are clear about what the law requires. – Tracking compliance against obligations and resolving outstanding risks.	In 2020, we trialled an online legal compliance survey tool as part of our legal compliance programme. This was rolled out across the business in 2021. The survey tool helps us better understand, monitor, and report on our legal compliance obligations and risks, and track the resolution of those risks.

7.2.3 HISTORICAL TRENDS

The TRIFR per million hours worked is a standardised measure of the rate of health and safety incidents occurring as a result of work completed on the Powerco network. The initiatives implemented during the past five years have resulted in a steady rate of decline from FY18 to FY20. The rate of decline has plateaued through FY21 and the initiatives outlined in Chapter 5 of this AMP have been designed to further reduce this measure.

Figure 7.1: Total recordable incident frequency rate (TRIFR) for Powerco YTD



[53] Sustainability at Powerco – December 2020 https://indd.adobe.com/view/6b1d988f-ddc6-4e53-83cf-5a25a1bb1ae3

[54] Excluding emissions associated with network line and pipe losses.

7.3 CUSTOMERS AND COMMUNITY

7.3.1 OVERVIEW

The customer and community targets are measures aligned with our Customers and Community Asset Management Objective outlined in Chapter 4. They demonstrate our focus on ensuring the customer voice is heard in our planning and delivery processes.

As part of our Customised Price-quality Path (CPP) determination, our quality path measure of System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) is now assessed as planned and unplanned rather than an aggregated measure. The separation is to ensure our planned work programme isn't constrained by a quality path that can be influenced by unplanned network events.

This section sets out the specific targets we have set ourselves for customers and communities during the planning period, and the CPP quality path targets set by the Commerce Commission. We also consider the basis for these targets and our historical performance against these targets.

7.3.2 TARGETS

Table 7.3 lists the targets we monitor when assessing how well we are serving our customers and communities. (Note that the SAIDI/SAIFI targets are as set by the Commission in their CPP decision.) Table 7.4 outlines the rationale behind the targets.

Table 7.3: Customers and Community targets

INDICATOR	FY19		FY20		FY21	FY22	FY23
Customer engagement	**Target**	**Actual**	**Target**	**Actual**		**Target**	
Number of network related complaints	836	615	881	549	819	781	729
Percentage of major projects ($5m>) (in)developed with community consultation	N/A	55%	N/A	60%	80%	100%	100%
Number of formal community group engagements	N/A	N/A	N/A	22	>30	>40	>40
Unplanned SAIDI							
Cap	191.4		187.4		183.5	179.7	175.9
Target	169.5	**197.3**	166.0	**181.0**	162.5	159.1	155.8
Collar	147.6		144.6		141.6	138.6	135.7
Unplanned SAIFI							
Cap	2.28		2.26		2.24	2.22	2.19
Target	2.12	**2.03**	2.09	**1.92**	2.07	2.05	2.03
Collar	1.95		1.93		1.91	1.89	1.87

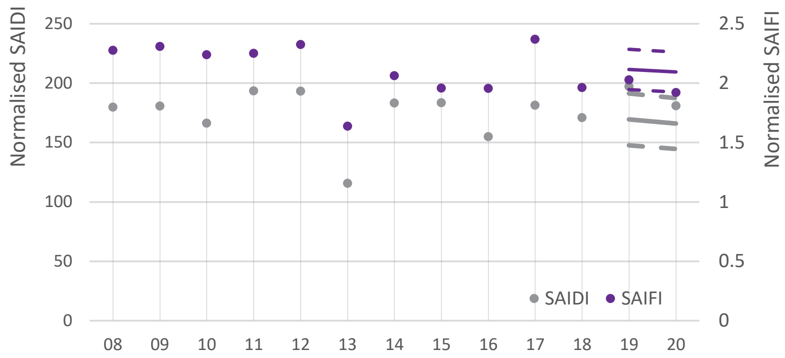
Table 7.4: Customers and Community target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Customer engagement	
Network related customer-initiated complaints help us to understand customer satisfaction of network performance beyond the duration frequency of outages. Community engagement for major projects has planning and implementation benefits for both communities and Powerco. Understanding the needs and expectations of communities is an essential input for network planning and the delivery of our work.	Despite annually increasing Installation Control Point (ICP) numbers and improved complaint capture channels, complaints have decreased. Engagement was targeted at projects identified as having high implementation impacts on communities. Seeking broader input on project planning and delivery is driving an increase in engagement. Engagement that influences network decision-making has not been previously tracked as a subset of our overall engagement.
Unplanned reliability	
Our unplanned SAIDI and SAIFI performance metrics help ensure that the works we undertake provide a better outcome for our customers.	Details of our unplanned reliability performance can are outlined in Section 7.3.3

7.3.3 HISTORICAL TRENDS

Our CPP unplanned reliability targets for the five-year period are shown in Table 7.3 and Figure 7.2, alongside our actual results for FY19 and FY20. The targets were set based on a 10-year historical period from 2008-2017 and include a 10% and 5% reduction in SAIDI and SAIFI respectively by the end of the CPP period. Normalisation using a boundary value is included.

Figure 7.2: Unplanned SAIDI and SAIFI performance

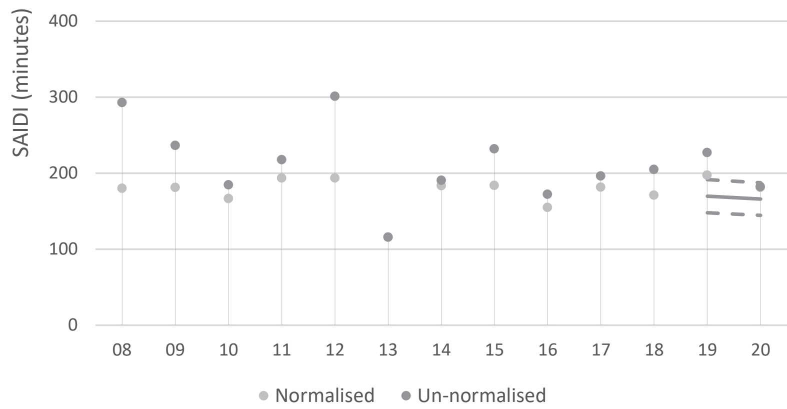


As seen in Figure 7.2, in FY19 we exceeded our regulatory cap for unplanned SAIDI, but returned to within regulatory limits for FY20. We continue to closely monitor our unplanned SAIDI performance, have strong governance in place, and are progressing multiple work programmes in order to manage performance (through our asset renewal, defect, vegetation and automation programmes).

Although our performance is judged on the normalised SAIDI/SAIFI values, the un-normalised SAIDI/SAIFI provides a better reflection of our customers' experience. While we exceeded our regulatory limits in 2019, the customer experience has been steadily improving as demonstrated in Figure 7.3, by the steady reduction in variance between normalised and un-normalised SAIDI.

Our unplanned SAIFI performance during the CPP period has been better than targeted. We aim to remain within regulatory quality limits.

Figure 7.3: SAIDI performance, normalised v un-normalised



Schedule 12D in Appendix 2 shows our unplanned SAIDI and SAIFI forecasts for the planning period. We use a separate model to forecast unplanned SAIDI and SAIFI. It is based on modelling our historical fault data, and the interactions with our planned work that impact reliability, such as asset renewal, vegetation management and automation investment. As the forecast is based on historical fault trends across different fault types, the forecast is not normalised and is therefore not directly comparable with the CPP targets from above.

Our FY21 forecast is based on an in-year projection of unplanned SAIDI and SAIFI. So far during FY21 we have had few large unplanned outage events on our network (typically from storm activity), resulting in a low unplanned SAIDI and SAIFI projection. Our longer term unplanned SAIDI and SAIFI forecast reflects our focus on arresting deterioration and maintaining network reliability at current levels.

7.4 NETWORKS FOR TODAY AND TOMORROW

7.4.1 OVERVIEW

This section outlines the specific targets we have set to demonstrate that our networks are suitable for today's needs while being ready to meet the needs of tomorrow. We consider current and future network reliability, and the work we are doing to prepare our network for societal changes in energy use.

Our feeder performance metrics help us identify parts of the network that may not be performing to their expected service levels. This allows us to better plan for future improvements.

To prepare our network for tomorrow, we have outlined our new Network Evolution strategy described in Chapter 6. The strategy focuses on four principal themes:

- **Improving visibility** – increasing the level of monitoring on our network, to assess real-time performance.
- **Future energy consumers** – developing a deeper understanding of changes in customer energy preferences, emerging technologies and energy market products, and integrating this into our network planning and operations.
- **Modernising the grid edge** – enhancing our network operations through the application of new technology.
- **Enhancing response** – improving our network's ability to deal with emerging customer applications, changing consumption and generation patterns, and two-way power flows.

The following sections provide more detail on the targets relating to these four themes. They also provide further detail on our unplanned and planned network reliability targets, and also discuss our feeder reliability targets.

7.4.2 TARGETS

The tables below set out our targets for Networks for Today and Tomorrow and the rationale behind them.

Table 7.5: Networks for Today and Tomorrow targets[55]

INDICATOR	TARGET			FY19	FY20
Feeder performance					
	FEEDER CLASS	TARGET	CONSUMER TYPE	NUMBER OF FEEDERS EXCEEDING TARGET	
Feeder Interruption Duration Index (FIDI) targets	F1	30	Large Industrial	41	33
	F2	60	Commercial	57	54
	F3	180	Urban	82	69
	F4	600	Rural	73	69
	F5	1080	Remote Rural	10	10
Feeder Interruption Frequency Index (FIFI) targets	F1	0.5	Large Industrial	44	36
	F2	1.0	Commercial	51	48
	F3	1.5	Urban	99	89
	F4	4.0	Rural	100	88
	F5	6.0	Remote Rural	14	16

Table 7.6: Networks for Today and Tomorrow target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Feeder performance	
We analyse our feeder performance using FIDI and FIFI targets. FIDI represents the average number of minutes per year that a customer on a particular feeder is without supply. FIFI represents the average number of times per year that a customer is without supply on a particular feeder.	Our feeders are performing better in FY20 when compared with FY19. This is because of the increased governance around network performance, and the completion of multiple work programmes targeted at underperforming feeders.

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

7.5 ASSET STEWARDSHIP

7.5.1 OVERVIEW

This section outlines the specific targets we have set for Asset Stewardship during the planning period. We also consider the basis for these targets and our historical performance against these targets.

7.5.2 TARGETS

Table 7.7 lists our Asset Stewardship targets and performance, while Table 7.8 explains the rationale behind them.

Table 7.7: Asset Stewardship targets

INDICATOR	TARGET	FY19	FY20
Asset failure rates (Faults/interruptions per 100km)			
6.6, 11, 22kV overhead lines	<16 faults	30.30	28.17
	<10 interruptions	21.61	18.97
6.6, 11, 22kV underground cables	<4 faults	4.35	5.62
	<4 interruptions	4.35	5.53
33, 66kV overhead lines	<9 faults	14.22	10.80
	<5 interruptions	6.68	5.43
33, 66kV underground cables	<1.7 faults	0.00	0.82
	<1.5 interruptions	0.00	0.82
Asset utilisation (%)			
Distribution transformer utilisation	30%	28.6	28.7
Network energy losses versus energy entering network	6%	5.0	5.3
Vegetation management			
Cyclical trimming programme (cumulative)	Trimming of trees to regulatory limits complete once for 100% of the network during the CPP period.	22%	45%

Table 7.8: Asset Stewardship target commentary

FOCUS AREA	INITIATIVE
Asset failure rates	
Fault and interruption rates are a useful indicator of the effectiveness of our renewal plans. We have set our targets to reflect levels typically considered good practice within the industry. The selected fault rates also reflect, on average, performance achieved by similar networks in NZ.	The following section contains figures showing how our failure rates compare with other electricity distribution businesses (EDBs). The failure rates of our overhead network are higher than most other EDBs. Our cable failure rates, however, are comparable with the industry average. Section 7.5.3.1 discusses our failure rates and benchmarks our performance against other utilities.
Asset utilisation	
Asset utilisation provides useful top-level indicators of the balance between network security and asset use. Our targets are set to reflect the midpoint of the accepted good practice range in the industry, noting all network development projects are subject to project-by-project scrutiny.	Our distribution transformer utilisation is 28% against a target of 30%. Figure 7.11 shows how this compares with the industry averages. Our energy loss has been measured at 5.3%, near our target of 6%.
Vegetation management	
Tree regulations require us to ensure appropriate vegetation clearances from lines. Our target of moving to a full cycle across our network is based on us cyclical trimming regime, which is designed to ensure full compliance.	The first cycle to bring back the vegetation corridors to regulatory limits requires additional resources. Subsequent cycles will require fewer resources to help maintain the clearances along the corridor.

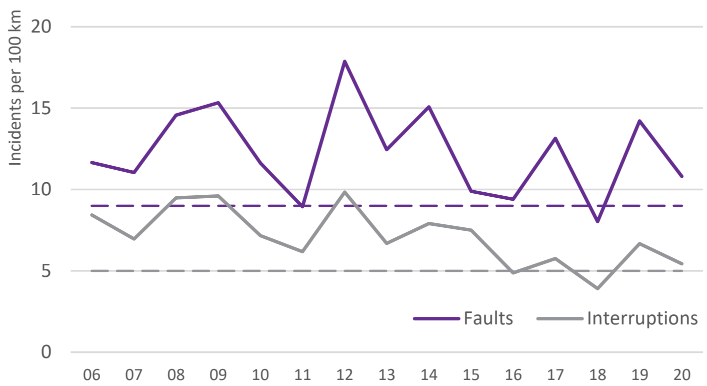
7.5.3 HISTORICAL TRENDS AND BENCHMARKS

7.5.3.1 ASSET FAILURE RATES

Failure trends

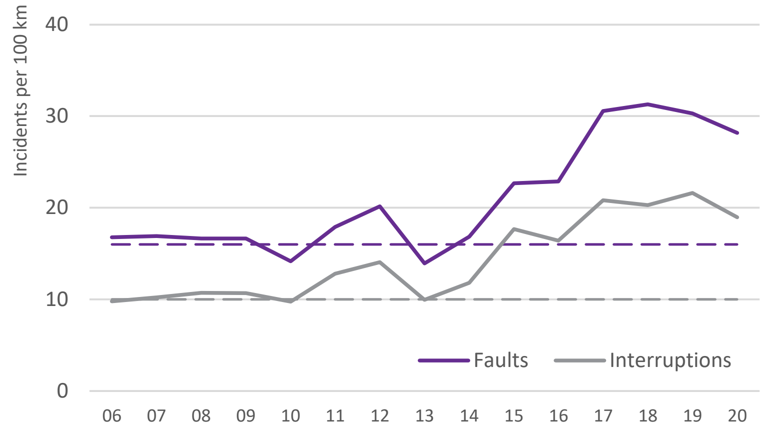
The figures below show our historical fault and interruption performance on our subtransmission and distribution system asset fleets.

Figure 7.4: Subtransmission overhead faults and interruptions per 100km



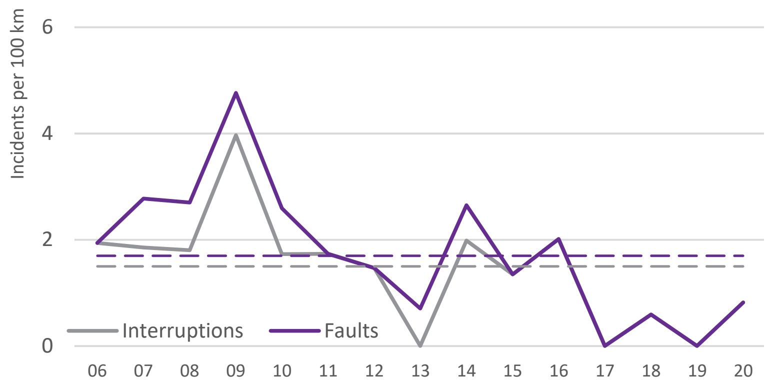
As shown in Figure 7.4, subtransmission overhead faults and interruptions have consistently been above target during the past decade. The irregular shape of the trend line reflects inclement weather conditions from year to year. Our targets are designed to improve asset health and decrease the number of subtransmission overhead faults we are experiencing.

Figure 7.5: Distribution overhead faults and interruptions per 100km



As shown in Figure 7.5, the number of distribution overhead line faults has significantly increased during the past five to seven years, indicating deteriorating asset health and high levels of vegetation-related faults during storm activity. Our CPP programme has targets designed to improve health, reduce the number of defects and reduce failure rates. This has started to show gradual improvements in the performance of our network.

Figure 7.6: Subtransmission underground faults and interruptions per 100km



As indicated in Figure 7.6, the performance of our underground subtransmission circuits is satisfactory.

Figure 7.7: Distribution underground faults and interruptions per 100km

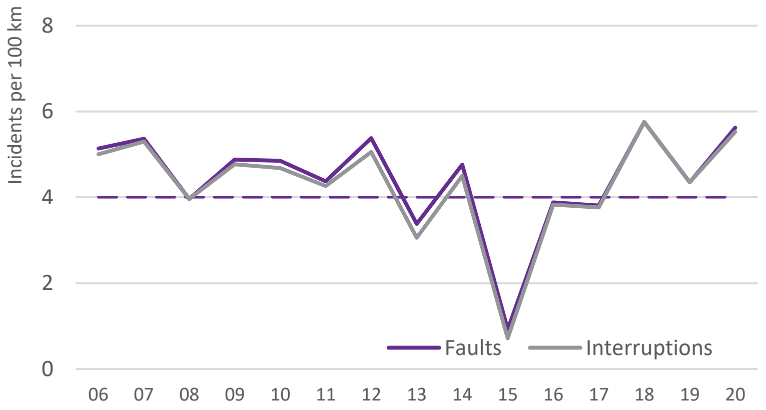
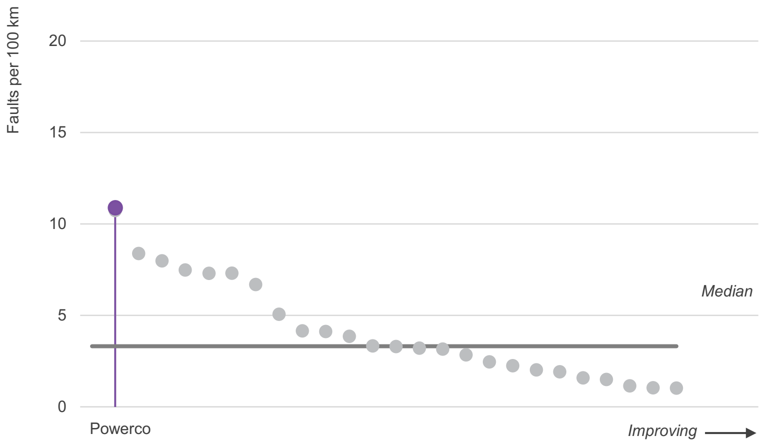


Figure 7.7 shows that we experienced a higher than average number of distribution cable failures.

Benchmarking

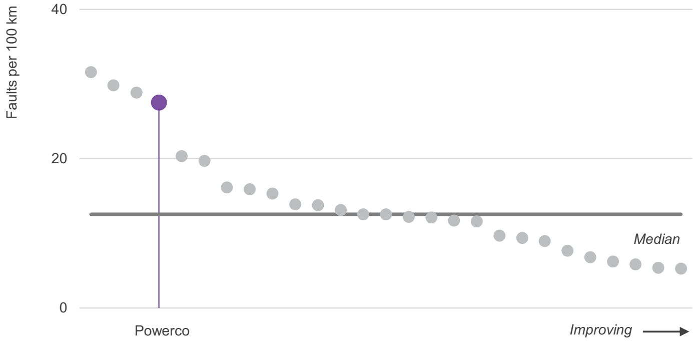
The following graphs show where we sit among our peers in terms of faults per unit length of circuit.

Figure 7.8: Subtransmission overhead line benchmarking



As shown in Figure 7.8, the frequency of faults on our subtransmission lines is more than double the industry median. Our performance in this area has been poor for some time. Our targets are designed to reduce the number and duration of overhead line faults.

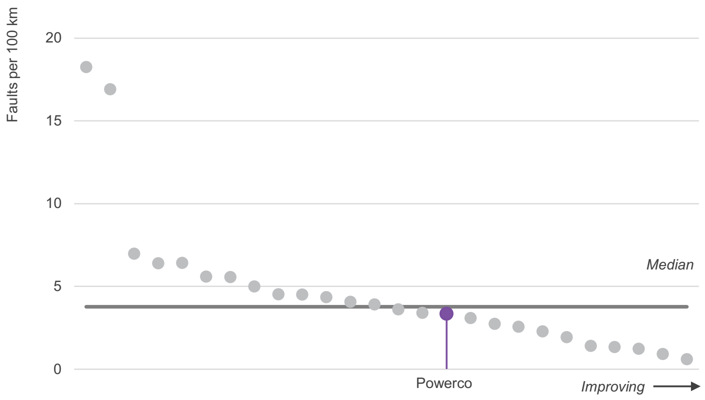
Figure 7.9: Distribution overhead line benchmarking



As shown in Figure 7.9, the frequency of faults on our distribution overhead lines is almost double the industry median. Our performance has substantially deteriorated during the past five years. Our targets are designed to reduce the number and duration of these types of faults.

As shown in Figure 7.10, we sit at industry median with respect to faults on distribution cable networks.

Figure 7.10: Distribution cable benchmarking

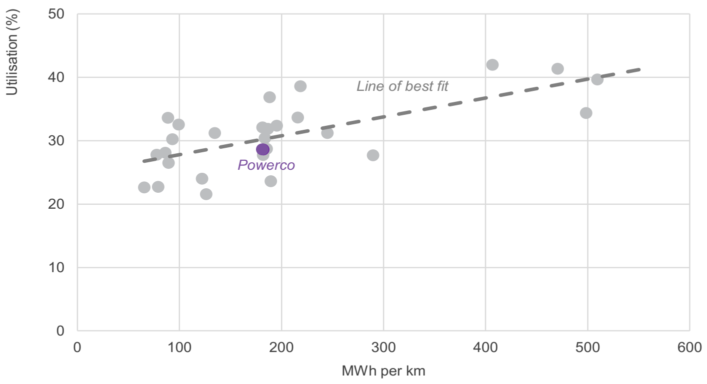


7.5.3.2 ASSET UTILISATION

Distribution transformer utilisation

Figure 7.11 shows our distribution transformer utilisation against network load density.

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

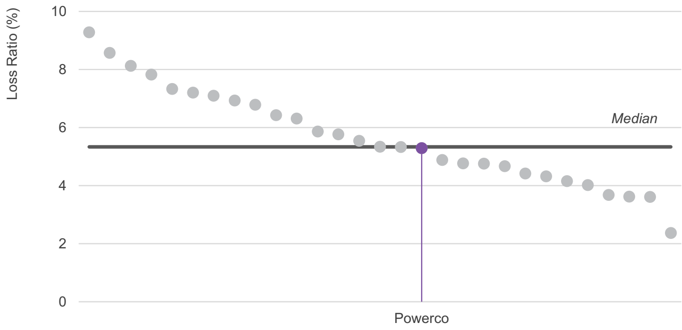


We sit close to the line of best fit for us. We use this relationship to inform our distribution transformer utilisation target of 30%.

Network losses

Figure 7.12 shows our network loss ratio compared with that of other EDBs.

Figure 7.12: Benchmarking of average network loss ratio (2015-2019)



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

7.6 OPERATIONAL EXCELLENCE

7.6.1 OVERVIEW

This section outlines the specific targets we have set for Operational Excellence during the planning period. We also consider the basis for these targets and our historical performance against these targets.

Increased levels of investment on our network require an increase in the number of planned outages in the short term to ensure stable unplanned outage performance in the longer term.

To incentivise our works programme, we proposed a new quality path as part of our CPP application that removed the planned outage component, and re-baselined the unplanned component on our performance in the past 10 years. In the final determination, this proposal was adjusted to include a separate planned quality path, and to include a reducing unplanned quality target.

This section outlines how we plan to monitor the performance our network, and our organisation to deliver the optimal outcomes for our customers.

7.6.2 TARGETS

Significant improvements are needed in the way we plan, engineer and deliver projects and run our network to deliver our CPP commitments. Improvements being implemented include:

- A strong focus on minimising the impact of planned outages.
- Alignment with and certification to Asset Management Standard ISO 55001.
- Development of a Data Quality Framework.
- New Foundations – a programme of activities that will improve our business performance, reduce the number of manual tasks over time, and reset our core software-based processes and systems.

Table 7.9 lists the targets we intend to achieve and our performance against them.

Table 7.9: Operational Excellence targets

INDICATOR	FY19		FY20		FY21	FY22	FY23
Planned reliability	**Target**	**Actual**	**Target**	**Actual**		**Target**	
Planned SAIDI limit	80.0	84.0	84.9	69.9	92.3	98.2	99.3
Planned SAIFI limit	0.34	0.41	0.37	0.35	0.39	0.41	0.41
Asset management maturity							
AMMAT self-assessment average	3.0	2.53	3.0	2.68		3.0	

Table 7.10: Operational Excellence target commentary

BASIS FOR TARGETS	HISTORICAL PERFORMANCE
Planned reliability	
We decided to split the planned and unplanned reliability (SAIDI/SAIFI) metrics in this AMP. The planned reliability metrics provide an insight into the impact our works programme has on our customers.	Our planned SAIDI performance has increase in line with our larger works programme. Refer to section 7.6.3.1 for more details.
Asset management maturity	
We have proven ourselves as capable asset managers. However, we recognise there is more to do as asset management approaches mature. We consider ISO 55001 certification to be an appropriate good practice target and the year 2020 an appropriate transitional window.	The Asset Management Maturity Assessment Tool (AMMAT) scope proves a proxy for a transition towards ISO 55001 certification. Our approach has matured progressively as evidenced by the gradual increase in our AMMAT from 2013-2021. Details and associated ‘spider’ diagrams are included in Section 7.6.3.2.

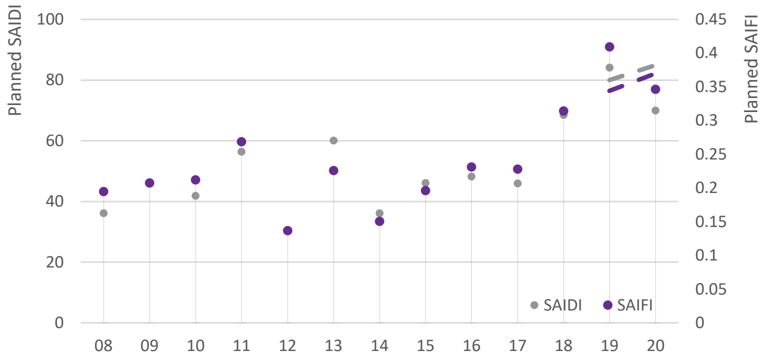
7.6.3 HISTORICAL TRENDS AND BENCHMARKS

7.6.3.1 PLANNED RELIABILITY

Our CPP planned reliability targets were based on our modelling of expected planned SAIDI and SAIFI to provide the increased work volumes of our CPP delivery programme.

Since these CPP planned outage limits were set, we have found it difficult to both fully deliver our works programme while staying within these limits. In FY19 we prioritised our works plan delivery and exceeded our planned outage limits. In FY20 we ensured we stayed within these limits, but this caused operational difficulties in work scheduling and prioritisation.

Figure 7.13: Planned SAIDI/SAIFI



Since FY18, we have had higher planned SAIDI, and especially SAIFI, than what we had modelled for our CPP application. Since developing the CPP forecasts, unforeseen (at the time) changes in live-line work practices[56], in particular, have led to major increases in the outages required for planned works.

We have put significant focus on improving our planned outage processes to minimise customer disruption while ensuring we complete our work. We have increased the use of other forms of SAIDI mitigation, such as generation, and the use of multiple crews. We have also materially improved the efficiency at which we plan and deliver our works.

However, the mitigation of planned SAIFI is more problematic, and some SAIDI mitigation techniques, such as the connection of generation, actually increases SAIFI, as an outage has to be counted both when connecting and again when disconnecting generators. Our ability to deliver our works and maintenance plans is significantly hampered by the restrictions in available planned SAIFI. Finding ways to minimise planned SAIFI remains an ongoing focus.

We are committed to not breaching the regulatory quality threshold, and therefore our forecast of planned SAIDI/SAIFI for the remainder of the CPP period remains at the regulatory limits. Longer term, to continue with our renewal programmes, in particular, we expect to require a similar level of planned SAIDI/SAIFI as to what we have today.

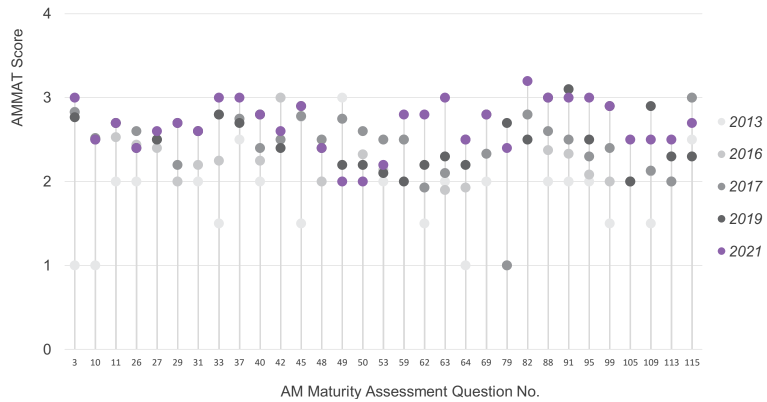
7.6.3.2 ASSET MANAGEMENT MATURITY

We published our first AMMAT assessment in the 2013 AMP and have repeated the assessment in subsequent AMPs.[57] Overall, we have found the repeated use of the AMMAT approach useful, and some of the improvement initiatives we are implementing originated from the AMMAT assessment.

Figure 7.14 shows the AMMAT results from this year's assessment and compares them with prior scores. Scores range from 0 ('innocent' maturity level) to 4 (excellent maturity level).

We are committed to obtaining certification to asset management standard ISO 55001 by 2021. We engaged an Australian asset management consultant, AMCL Ltd, to undertake a review of our asset management systems. This involved a gap assessment as benchmarked against ISO 55001 and the 39 asset management maturity questions posed by the Global Forum on Maintenance & Asset Management (GFMAM). Their results were mapped to the AMMAT scores[58] in 2019. We were assessed as 'competent' or close to competent in most areas. There were several areas where we were classed as 'developing'.

Figure 7.14: Asset maturity self-assessment scores 2013-21



The scores shown in Figure 7.14 reflect an honest reappraisal of our asset management maturity when considered in the light of the assessor's feedback. For example, we have reduced our scores in the areas of corporate strategy and objectives, competency management, asset management system documentation, information management, and achievement of continuous improvement.

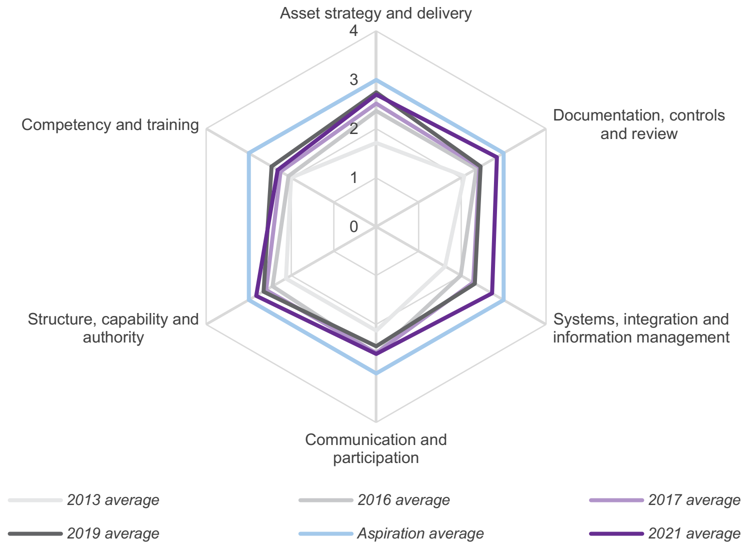
56 In October 2017, we revisited our approach to live-line work practices, introducing an exclusion list of activities and strengthening processes to ensure safety risks are thoroughly assessed before approving live-live permits.

57 As an electricity distributor we are required to undertake and publicly disclose the AMMAT self-assessment results.

58 ISO 55001 used five maturity categories, with the fourth and fifth representing 'effective' and 'excellent' capabilities. AMCL's 4 and 5 scores have been mapped to the AMMAT's 'excellent' maturity level of 4.

In Figure 7.15 we show the scores grouped by assessment areas. We re-assessed ourselves as improving markedly in asset strategy and delivery, marginally declining in the area of communication and participation, and modestly improving in the remaining four areas.

Figure 7.15: Summary of asset maturity self-assessment scores by assessment area



The ISO 55001 assessment results are documented in Table 7.11.

Table 7.11: AMMAT benchmark scores mapped to ISO 55001 clauses

PRACTICE AREA	ISO 55001 CLAUSE	SUBJECT	FY13	FY16	FY17	FY19	FY20
Context of the organisation	4.1	Understanding the organisation and its context	1.0	2.8	2.8	2.8	3.0
	4.2	Understanding the needs and expectations of stakeholders	1.0	2.5	2.5	2.5	2.5
	4.3	Determining the scope of the Asset Management System	2.0	2.5	2.7	2.7	2.7
	4.4	Asset Management System	2.0	2.4	2.6	2.4	2.4
Leadership	5.1	Leadership and commitment	2.5	2.4	2.5	2.5	2.6
	5.2	Policy	2.0	2.0	2.2	2.7	2.7
	5.3	Organisational roles, responsibilities, and authorities	2.0	2.2	2.6	2.6	2.6
Planning	6.1	Actions to address risks and opportunities for the Asset Management System	1.5	2.3	2.8	2.8	3.0
	6.2	Asset Management Objectives and planning to achieve them	2.5	2.8	2.8	2.7	3.0
Support	7.1	Resources	2.0	2.3	2.4	2.8	2.8
	7.2	Competence	3.0	3.0	2.5	2.4	2.6
	7.3	Awareness	1.5	2.8	2.8	2.9	2.9
	7.4	Communication	2.0	2.0	2.5	2.4	2.4
	7.5	Information requirements	3.0	2.8	2.8	2.2	2.0
	7.6	Documented information	2.0	2.3	2.6	2.2	2.0
Operation	8.1	Operational planning and control	2.0	2.1	2.5	2.1	2.2
	8.2	Management of change	2.5	2.5	2.5	2.0	2.8
	8.3	Outsourcing	1.5	1.9	1.9	2.2	2.8
Performance evaluation	9.1	Monitoring, measurement, analysis and evaluation	2.0	1.9	2.1	2.3	3.0
	9.2.1	Internal audit	1.0	1.9	2.5	2.2	2.5
	9.3	Management review	2.0	2.3	2.3	2.8	2.8
Continuous improvement	10.1	Non-conformity and corrective action	1.0	1.0	1.0	2.7	2.4
	10.2	Preventive action	2.5	2.8	2.8	2.5	3.2
	10.3	Continual improvement	2.0	2.4	2.6	3.0	3.0
Average Score			**1.94**	**2.31**	**2.44**	**2.53**	**2.68**

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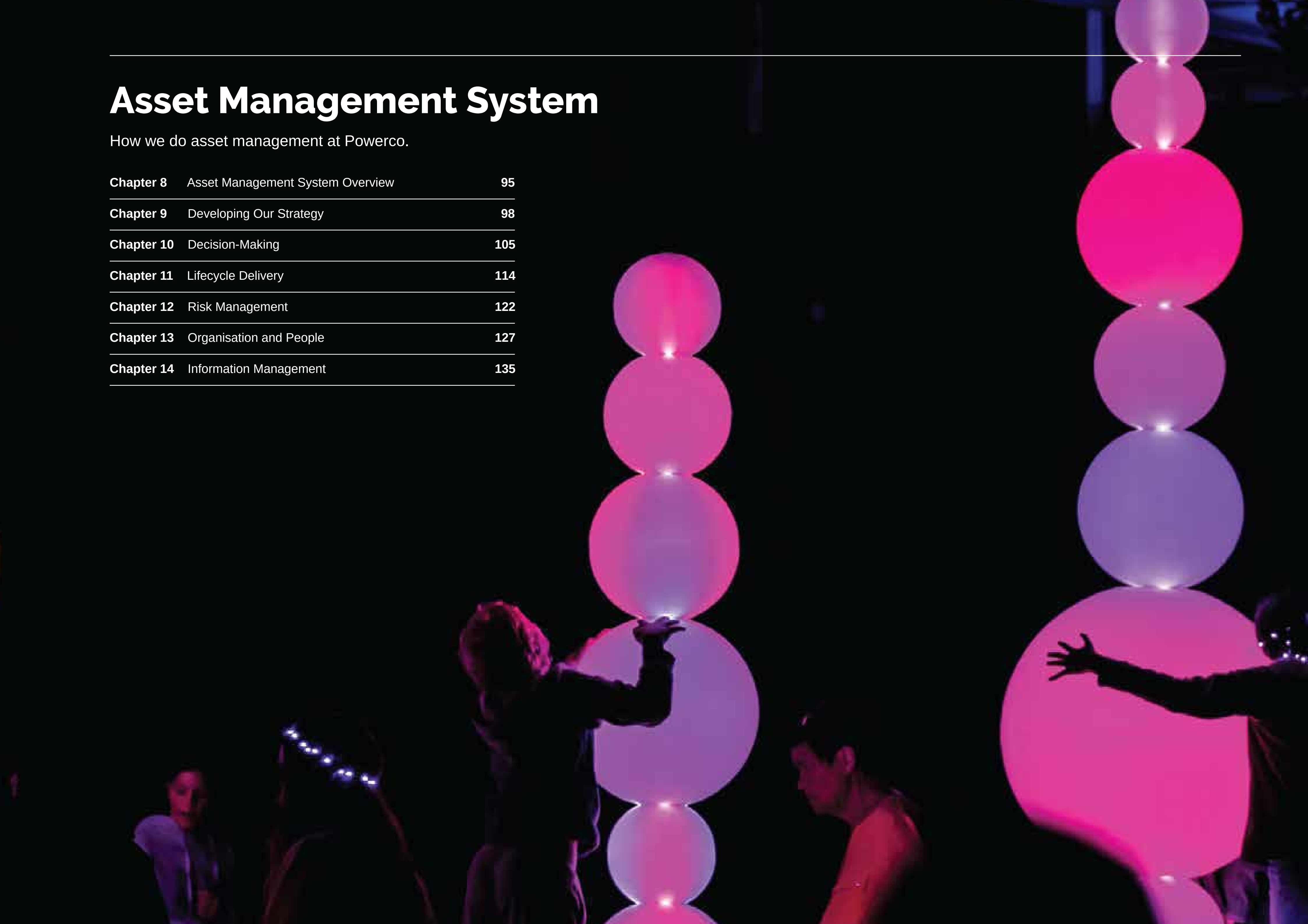
Asset Management System

How we do asset management at Powerco.



8 ASSET MANAGEMENT SYSTEM OVERVIEW

8.1 OVERVIEW

Our business is to distribute gas and electricity. These essential commodities are conveyed through a network of pipes, cables and transmission lines, marshalled, and dispensed from gas pressure regulating stations and electricity substations. Given our heavy reliance on physical assets, asset management lies at the heart of our business.

The processes, practices, organisational and governance structures used to manage our assets and workforce are described in our Asset Management System (AMS).

This introductory section outlines:

- The scope of the electricity business AMS, including processes and assets.
- The AMS framework.
- AMS components.

8.2 SCOPE OF THE AMS

The scope of an AMS is defined in terms of both business functions as well as the assets it covers.

8.2.1 ASSETS COVERED

Electricity network assets

The asset fleets within the scope of our AMS and the regions in which they are located are set out in chapters 18 to 24.

Information assets

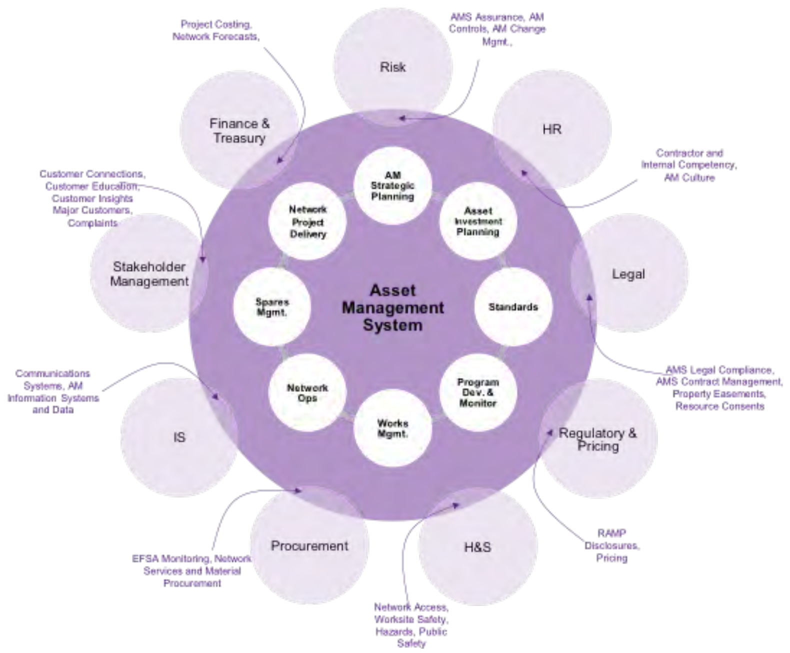
Because good data underpins most asset management decisions, we also regard data as an asset. Our employees use several key software systems to manage data and obtain insights. These systems include:

- Geographical Information System (GIS)
- Maintenance and Works Management System (SAP)
- Field Mobility Solution (MyPM)
- SCADA Master Stations, SCADA Corporate Viewer
- Real-time data processing platform (PI)
- Forecast and planning platform (PSS*Sincal)
- Outage Management System (OMS)
- Customer Works Management System (CWMS) Electricity
- Engineering Drawing Management System (Meridian)
- Protection Settings Management System
- Vegetation Management System (Clearion)
- Network Modelling (PSS Sincal)
- Investment Planning and Optimisation (Copperleaf C55)
- Computer Aided Design and Drafting (AutoCAD)
- Customer Relationship Management (CRM) System including Customer Complaints Management System
- Installation Control Point (ICP) Management

8.2.2 ASSET MANAGEMENT FUNCTIONS

Figure 8.1 demonstrates the functional boundaries and interface of several functions in our AMS.

Figure 8.1: Scope of functions and interfaces within the AMS



(diagram is indicative only and not exhaustive)

These functions are broad ranging, and agnostic to business units and individual roles within the organisation.

8.3 INTEGRATED MANAGEMENT SYSTEMS

We have implemented, or are implementing, several formal management systems, such as for environment (ISO 14001) and asset management (ISO 55001). Although used independently, these management systems are based on the principles of the ISO High Level Structure.

An Integrated Management System (IMS) consolidates business processes from various management systems into one single system of management, resulting in a management system that is leaner, more effective, more efficient and easier to follow.

This manual has integrated overlapping functions from other management systems into the AMS. However, these functions can be considered outside the scope of the AMS if they already exist as part of another certified management system.

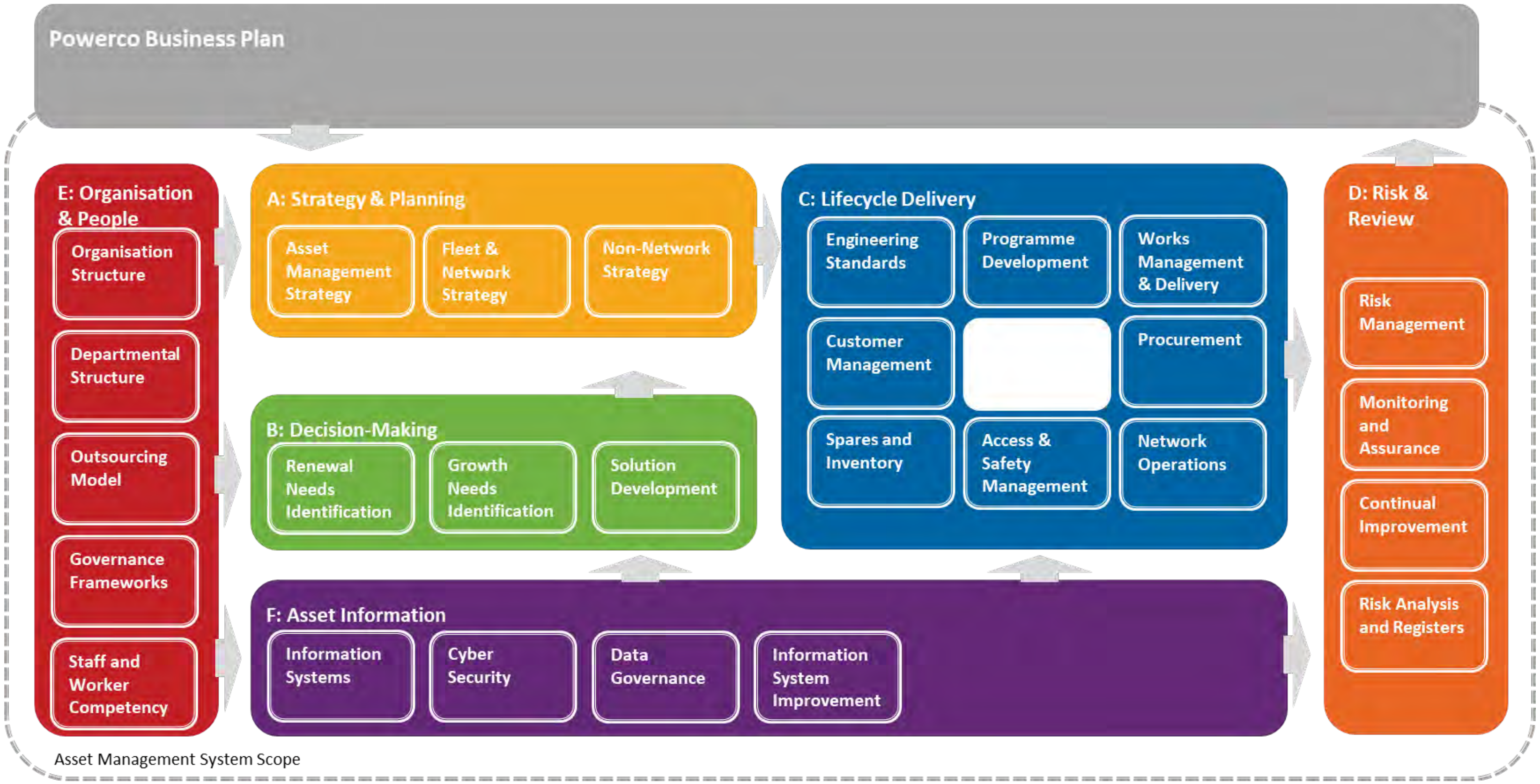
8.4 ASSET MANAGEMENT SYSTEM COMPONENTS

Our AMS is aligned to the IAM Asset Management model.

Figure 8.2 shows the scope of the AMS, its various capabilities and their high-level relationships.

These capabilities are outlined in the chapters that follow.

Figure 8.2: Asset Management System



9 DEVELOPING OUR STRATEGY

9.1 CHAPTER OVERVIEW

This chapter describes the key elements of and contributors to Powerco's Strategic Asset Management Plan (or SAMP).[59]

The roots of our Asset Management Strategy can be found at the corporate level. The Powerco Board and Executive Management Team formulate policies and business objectives that guide the company, in alignment with our company vision, mission and values. These business objectives and policies align our Asset Management Strategies with the Corporate Objectives, and the company's vision, mission and values.

This line of sight between Corporate Objectives and our asset management practice is illustrated in Figure 9.1. This diagram represents our Asset Management System (AMS), showing the contextual drivers behind our corporate direction and our Asset Management Strategy.

Figure 9.1 also shows the interaction of the key processes, documents, reports and systems in our AMS.

Each of the tactical planning areas identified – Fleet Management, Network Development, Network Transformation and Asset Management Improvements – is discussed in detail in following sections.

9.2 DEVELOPING OUR FLEET MANAGEMENT STRATEGIES

Fleet management is an integral part of our AMS. It outlines the renewal investment and maintenance programmes for each of the asset fleets to help achieve our Asset Management Objectives and targets.

Our goal is to manage asset performance within acceptable bounds, ensure assets are safe and in a suitable condition to remain in service, and minimise the total life-cycle cost of ownership.

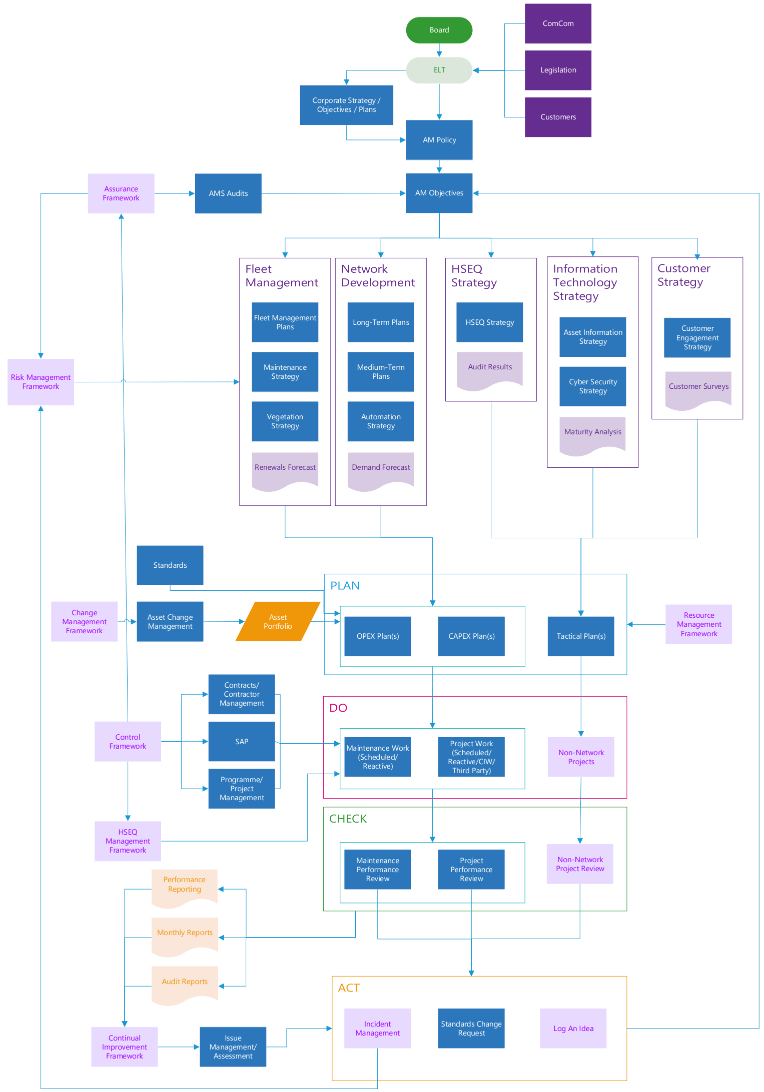
9.2.1 FLEET MANAGEMENT PLANS

Our fleet management plans provide a general overview of the trends, issues and considerations that shape our interventions on our existing asset base. This translates into our forecast renewal and maintenance investments for the planning period. The key points covered in our plans are:

- High-level objectives
- Fleet statistics, including asset quantities and age profiles
- Fleet health, condition and risks

[59] We use the term 'strategy' to refer to a long-term plan of action designed to achieve a particular goal or a set of objectives.

Figure 9.1: Powerco's Asset Management System



- Renewal strategies
- Preventive maintenance and inspection tasks
- Renewal forecasting approaches

9.2.2 RENEWALS FORECAST

As custodians of the distribution network, one of our major responsibilities is to ensure that our networks can continue to deliver to their designed capacity and assets continue to perform to specification over their reasonably expected lifespan. A significant portion of our asset management resources is, therefore, consumed by asset renewal and maintenance activities. These are major components in forecasting the financial and resource requirements on our network. We use various methods to develop these forecasts. These methods vary from fleet to fleet, with our fleet breakdown summarised in Table 9.1 and the renewal drivers shown in Table 9.2.

9.2.2.1 CONDITION-BASED RISK MANAGEMENT

Condition-Based Risk Management (CBRM) is a modelling methodology that facilitates the development of asset renewal forecasts based on the combination of asset condition and risk. CBRM is a mature and widely used methodology that now forms the basis of the United Kingdom regulator Ofgem's (Office of Gas and Electricity Markets) mandatory condition and risk reporting scheme[60].

CBRM differs from other forecasting methods that we use in that it develops a 'bottom-up' estimate of current and future asset health, probability of failure, and risk for each individual asset in the fleet. Information used to produce these estimates includes the asset's characteristics (what the asset is), the asset's condition (how the asset is) and the asset's operational context (how failure could affect safety, operational and financial objectives).

Because CBRM is a bottom-up methodology, the models may also be used for tactical decision-making regarding how and when to intervene for individual assets within each fleet.

CBRM is a relatively data intensive and complex modelling methodology, so at this time we have only applied the methodology for higher value complex equipment. We have developed CBRM models for power transformer, circuit breaker, ring main unit and ground-mounted distribution transformer fleets. We are considering expanding our modelling to include underground distribution cables.

For the purposes of maintaining consistency across disclosure forums we present the output of our CBRM models using asset health indices (AHI) categories.

60 DNO Common Network Asset Indices Methodology (Jan 2017) https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf

Table 9.1: Portfolio and asset fleet mapping

PORTFOLIO	ASSET FLEET
Overhead structures	Poles; Crossarms
Overhead conductors	Subtransmission overhead conductors; Distribution overhead conductors; Low voltage overhead conductors.
Cables	Subtransmission cables; Distribution cables; Low voltage cables.
Zone substations	Power transformers; Indoor switchgear; Outdoor switchgear; Buildings; Load control injection; Other zone substation assets.
Distribution transformers	Pole-mounted distribution transformers; Ground-mounted distribution transformers; Other distribution transformers.
Distribution switchgear	Ground-mounted switchgear; Pole-mounted fuses; Pole-mounted switches; Circuit breakers, reclosers and sectionalisers.
Secondary systems	Supervisory Control and Data Acquisition (SCADA) and communications; Protection; DC supplies; Metering.
Non-network assets	Information and communications technology (ICT); Buildings; Office fittings; Vehicles.

Table 9.2: Asset fleet renewal drivers and forecasting methods

PORTFOLIO	FLEET	RENEWAL DRIVER	PRIMARY FORECASTING METHODS
Overhead Structures	Poles	Reliability; Resilience (storm); Condition.	Survivor curves
	Crossarms	Safety; Reliability.	Survivor curves
Overhead Conductors	Subtransmission Conductors	Resilience (storm); Safety.	Type and age
	Distribution Conductors	Resilience (storm); Safety.	Type and age
	Low Voltage Conductors	Safety	Age
Cables	Subtransmission Cables	Condition; Environment; Reliability.	Type and age
	Distribution Cables	Condition; Reliability.	Type and age
	Low Voltage Cables	Reliability (cable) and Safety (pillar boxes).	Historic trend (cable) and defect rates (pillar boxes).

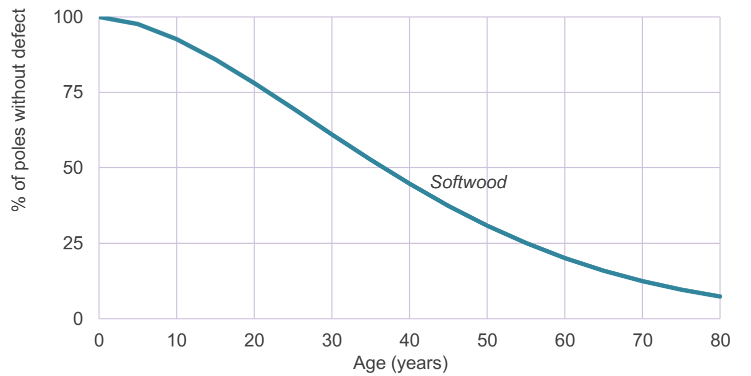
PORTFOLIO	FLEET	RENEWAL DRIVER	PRIMARY FORECASTING METHODS
Zone Substations	Power Transformers	Condition; Reliability; Environment.	Condition-Based Risk Management
	Indoor Switchgear	Condition; Safety.	Condition-Based Risk Management
	Outdoor Switchgear	Condition; Safety.	Condition-Based Risk Management
	Buildings	Resilience (Seismic)	Condition and age
	Load Control Injection	Obsolescence	Type
	Other Zone Substation Assets	Safety and Reliability.	Programmes
Distribution Transformers	Pole-Mounted Transformers	Safety; Environment.	Survivor curves
	Ground Mounted Transformers	Reliability; Safety; Environment.	Condition Based Risk Management
	Other Transformers	Reliability	Age
Distribution Switchgear	Pole- Mounted Fuses	Safety	Survivor curves
	Pole Mounted Switches	Reliability	Age
	Circuit Breakers, Reclosers and Sectionalisers	Condition; Safety.	Type and age
	Ground-Mounted Switchgear	Condition; Safety.	Condition-Based Risk Management
Secondary Systems	SCADA and Communications	Obsolescence	Identified assets and type
	Protection	Safety; Obsolescence	Type and age
	DC Supplies	Resilience (Back-up)	Type and age
	Metering	Obsolescence	Asset identification and historical rates

9.2.2.2 SURVIVOR ANALYSIS

For large fleets with reliable historical end-of-life data, future replacement volumes may be forecast using survivor curves. A survivor curve model uses information on previous end-of-life asset replacements to build a probabilistic replacement rate curve, which produces a likelihood of failure for an asset of a given age. Figure 9.2 presents an example, for softwood poles. The replacement rate curve can then be applied to the current population of assets to predict the future number of replacements. This approach assumes that historical asset failure rates provide an appropriate proxy for expected asset deterioration.

A survivor curve-based forecast results in a more accurate forecast of replacement than an age-based model, as it recognises the probability curve that exists around asset condition – some having longer than average lives, with others shorter. It considers the likelihood of replacement at all asset ages, which provides a smooth replacement rate that still reflects the age profile of the fleet.[61] Individual replacement decisions can then be based on condition factors, rather than age.

Figure 9.2: Survivor curve for softwood poles



9.2.2.3 SPECIFIED PROJECTS/PROGRAMMES

This approach identifies specific projects or programmes that meet specified renewal criteria. We often use this approach where assets have 'type' issues or are obsolete, and to mitigate safety risks or meet seismic standards. These programmes are often directly driven by our renewal strategies, for example, ensuring all our pole-mounted transformers have Low Voltage (LV) fusing by 2023.

[61] Comparatively a simple age-based model assumes all replacement happens at one predetermined age, and can produce a lumpy forecast depending on the age profile of the fleet.

9.2.2.4 HISTORICAL RATE AND TREND ANALYSIS

Where it is difficult to individually assess sites or assets to determine renewal needs, we may approximate annual renewal volumes based on the historical performance rate or trends.

This approach is used for some of our underground assets – where condition cannot be easily assessed, or assets are exposed to random external influences. For example, we use the historical replacement rates to estimate the number of pillar box renewals required because of motor vehicle incidents. Alternatively, we may extrapolate the historical trend of renewals, such as where we have an ageing fleet with an increasing trend in failures.

9.2.2.5 FAILURE RATE REDUCTION

This approach is used only for forecasting distribution reconductoring requirements. It determines the amount of conductor renewal that will be required to achieve good practice reliability for the asset type, assuming we replace conductors in order of failure risk. Actual replacements are then targeted based on the key risk factors, which, in this case, are age, type, and coastal proximity.

The key inputs to the model are historical network faults, excluding faults caused by external influences, and Geographical Information System (GIS) data – age, material, size, and location for each conductor span.

From this data a model of expected conductor failures was developed, which is used to determine renewal requirements for each year of the forecast period. Target performance was derived by considering what average failure rate our distribution conductors would have if the known poor-performing types were not present on our network.

9.2.2.6 AGE-BASED REPLACEMENT

Where we do not have sufficient data to develop survivor models or use condition-based forecasting, we may use a more simplistic age-based forecast approach.

This assumes that assets are replaced at the end of their expected life, based on our experience operating the network. Compared with survivor modelling, this can produce a relatively ‘lumpy’ forecast, depending on the age profile of the fleet. This approach is only used for lower value asset fleets.

Note, that while we forecast renewal volumes using this approach, the actual assets to be replaced are still determined in the short to medium term by condition and other factors.

[62] Our Preventive Maintenance and Inspection portfolio was previously named Routine Corrective Maintenance and Inspections (RCI). The corrective maintenance component of this work is now part of our Corrective Maintenance portfolio. This has been done to better reflect the drivers for these activities and the way we plan and deliver these works. Our Information Disclosure schedules reflect the RCI definition consistent with our historical disclosures.

9.2.3 DEVELOPING OUR MAINTENANCE STRATEGY

Our maintenance activities are categorised as follows:

- **Preventive Maintenance and Inspection**[62] – This portfolio deals with routine maintenance activities, such as testing, inspecting and asset servicing.
- **Corrective Maintenance** – This portfolio is mainly concerned with fixing defects, after they are identified and scheduled appropriately, through activities such as replacement of defected asset components or minor assets.
- **Reactive Maintenance** – This portfolio is about responding to faults and other network incidents, including immediate work to make a situation safe, or to repair broken assets.

Figure 9.3 summarises how we categorise our maintenance activities.

Figure 9.3: Our maintenance portfolios

Preventive Maintenance and Inspection

- inspections
- servicing
- condition assessments

Corrective Maintenance

- defect rectification
- repairs
- replace minor components

Reactive Maintenance

- fault response
- emergency switching
- first response

Our maintenance standards define required inspections and preventive maintenance activities, and the frequency at which these are to be carried out. We use information obtained from inspections to plan our corrective maintenance programme and inform renewal decisions.

Asset condition is assessed on a scheduled time interval basis, with defects, unserviceable assets, or assets with deterioration prioritised for rectification using our criticality framework. Using a criticality based approach to prioritisation allows us to allocate our corrective maintenance funds and resources to more efficiently reduce risk and improve network performance.

9.2.4 VEGETATION MANAGEMENT STRATEGY

Vegetation in contact with our assets can lead to safety and reliability issues, such as asset failures, outages and fires. This must be managed to ensure the security of supply and safety of the public. It is also a legislative requirement to maintain mandated clearance distances between vegetation and our lines.

Managing this hazard involves frequent tree inspections to determine the amount of work required, liaising with tree owners regarding the vegetation trimming work needed on their property, and the actual trimming and removal of identified trees.

Vegetation management was historically planned on a portfolio basis – individual tree sites were not identified in the plans. The identification happened at the execution stage and was carried out by the vegetation service providers.

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

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

9.3 DEVELOPING OUR NETWORK DEVELOPMENT STRATEGIES

9.3.1 DEMAND FORECASTS

Our demand forecasting methodology involves a combination of historical 90th percentile peak demand trends, population growth and new connection forecasts.

We develop load forecasts at the feeder level and aggregate them to develop demand forecasts at zone substation, grid exit point (GXP) and subtransmission level. Feeders serving large industrial customers are assumed to have zero growth unless customers indicate, with a high degree of certainty, a demand increase. In which case it is shown as a step change on that feeder.

Substation growth rates are a weighted average of underlying feeder growth rates, weighted by existing feeder demand. Figure 9.4 shows the key elements of our demand forecasting approach.

Figure 9.4: Demand forecasting approach

9.3.1.1 IMPACT OF EMBEDDED GENERATION

The impact of renewable embedded generation – photovoltaic (PV) or wind – is currently discounted in our forecasts because of its intermittent nature and lack of associated energy storage. In addition, solar PV generation has minimal impact on our predominantly winter evening peak demand. Future PV uptake scenarios may impact future peak demand if combined with energy storage. Wind generation development on our network has been infrequent, although may be substantial in capacity when it does occur.

As we adopt a more probabilistic planning approach, the impact of wind generation will be accounted for, even given its intermittent nature.

Small hydro generation is also very limited in terms of physical opportunities. There is some activity around gas turbine peaking units in Taranaki, and this is subject to the relative economics of the fuel sources. Larger scale generation for any of these sources tends to be connected directly to the transmission grid and therefore does not impact our growth and security planning directly.

Historical demand data includes the net impact of existing embedded generation and ripple control. During the planning period, embedded generation is expected to be below the threshold of significance to peak demand, with a few exceptions that are adjusted manually.

9.3.2 NETWORK DEVELOPMENT PLANS

Justification for network upgrades is generally based on the need to meet increases in demand or to achieve specified network security standards. Such upgrades increase the capacity, functionality, and size of our network; and include the following six main types of investments:

- **Major projects** – More than $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** – Below $1m, including distribution capacity and voltage upgrades, distribution backfeed reinforcements (supports automation), smaller zone substation upgrades, distribution transformer upgrades, and LV reinforcement.
- **Open-access network investments** – Investments in network monitoring, communications and power quality management to support our transition to an open-access network.
- **Communications projects** – To support improved control and automation of the network and provide voice communications to our field staff.
- **Reliability** – Includes network automation projects to help manage the reliability performance of our network.

For individual network projects, we conduct a detailed options analysis before deciding on the final details. This includes consideration of realistic network alternatives, as well as non-network alternatives, such as generation, energy storage or demand management.

Network projects are generally prioritised based on the expected reduction in unserved energy they would achieve. Other than in exceptional cases driven by factors such as specific customer requests or ensuring base capacity is available, we would expect projects to show a positive net present value when comparing the reduction in unserved energy with the lifecycle cost of the project.

The highest priority projects that fit into available budgets make up our Area Development Plans. This is subject to approval by the General Manager Asset Strategy and Investment and ultimately by the Powerco Board.

Our Area Development Plans for this reporting period are described in detail in Chapter 15 and Appendix 8.

9.3.3 NETWORK AUTOMATION STRATEGY

We use network automation to help manage the reliability performance of our network. In this context, network automation refers to the systems and devices that are used to undertake remote switching and reconfiguration of our networks.

Automation is an important investment solution, as it can often provide reliability improvements reasonably quickly and cost effectively. This helps us stabilise reliability outcomes on our networks, allowing major upgrades or renewals to be deferred.

Network automation tactical plans are summarised in Chapter 16.

9.3.4 NETWORK TRANSFORMATION

Our Network Evolution strategy reflects our plans to adapt to a changing energy environment and the emergence of new customer and/or network technology. It broadly covers the research and trialling of emerging solutions and the testing of the impact of new consumer devices used on the distribution edge. Based on these learnings, promising new solutions to network issues (or opportunities) are identified and further developed, before being introduced into our business-as-usual practices.

9.4 INFORMATION & TECHNOLOGY STRATEGY DEVELOPMENT

The Information & Technology Strategy (I&T) is designed to reduce technology risk and increase business resilience and efficiency through the delivery of foundational business practices and technology.

9.4.1 I&T PLATFORM STRATEGY

We have adopted a platform approach where all the information and technology capabilities that will be required to support Powerco's business throughout this planning period are assembled into seven logical groups or platforms. These are described in Chapter 14.

The purpose of adopting a platform approach is to maximise the business value of our technology investments by focusing on a smaller number of technologies and continuously investing to modernise or extend each platform to meet new business requirements. This results in lower overall total cost of ownership and reduced implementation duration and risk than taking a best-of-breed approach.

Our Architecture Review Board governs the selection and development of the I&T platforms as described in Chapter 13.

9.4.2 I&T INVESTMENT PRIORITISATION

We use the terms Run, Grow and Transform to describe the main categories of non-network investments to maintain and improve the functionality of I&T services within Powerco. Different investment governance is applied to each of the three portfolios, as described in Chapter 13.

- **Run** – Investments used to "run the business" include technology foundation, eg IT asset lifecycle refresh, disaster recovery, and investments to address regulatory and compliance issues, including cyber security. The primary goal of run investments is to "keep the lights on" and mitigate operational risks.
- **Grow** – The majority of business unit requests are "grow the business" investments. These improve or extend business processes and capabilities with the goal of return on investment.
- **Transform** – Investments to add or reinvent our business capabilities with the goal of creating new business models, revenue or channels that transform the business.

The highest priority projects that fit into the available non-network budget make up our Information Services tactical plan. The proportion of Run, Grow and Transform projects varies from year to year depending upon the business need and I&T asset lifecycle.

All I&T 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:

- What is the risk of not doing this initiative?
- Which initiatives enable our business plan?
- Which initiatives are the most beneficial?
- How much change can the organisation absorb?
- What can the organisation resource?
- What can we afford?
- What are the implementation risks and impacts?

Additionally, network cyber security and communications projects are prioritised via the electricity asset investment process as either renewal or growth projects.

10 DECISION-MAKING

10.1 CHAPTER OVERVIEW

This chapter discusses the processes and analytical tools that we use to identify network needs and prioritise expenditure.

10.2 OVERVIEW

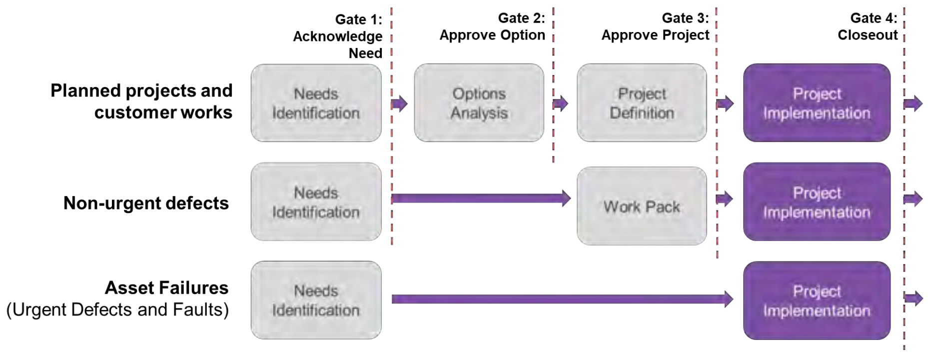
There are various approval processes, depending on the type of asset decisions being made. The level of scrutiny varies based on the size, urgency and complexity of the works. Planned works pass through multiple gates, including approval to move draft proposals to pre-approved status, upload to the rolling works plan, and approval for consultation on the preferred solution.

Works to address defects and faults, which are generally more urgent, have fewer gates to pass through.

This section discusses:

- How urgent needs on the network are addressed.
- How needs are identified for renewal and network growth projects.
- How a project is developed once a need has been identified.
- How we prioritise projects across the portfolio.

Figure 10.1: Asset intervention stages



10.2.1 PROJECT PRIORITISATION

In August 2020 we commissioned Copperleaf C55, a class-leading asset management application to support the prioritisation of our investments. In essence, it applies a value framework to our proposed projects (other than reactive, defect or customer-initiated works), quantifying the expected benefit from each and producing an overall ranking.

Developing the value framework was a critical part of the implementation, and involved our Board, the executive and many teams across the business. The value measures that we adopted are shown in Figure 10.2.

Figure 10.2 : Optimisation value framework

Value Measures

Network Performance	Maintaining or improving reliability of service to customers
Financial	Direct financial impacts (e.g. Opex impact, efficiencies, additional revenue)
Future enabling	Investing to better position the network for the future
Health and safety	Health and safety of employees, contractors, customers and the public
Customer and reputation	Any impact on our reputation, including with our customers, stakeholders and media
Legal and compliance	Compliance with legal or regulatory obligations
Environment	Risk of environmental incidents or reducing our environmental footprint

Another important aspect was the quantification of the value measures by using value models. The models can draw on information from a diverse range of sources, including defined system parameters, asset attributes and information provided by project planners. The sum of these quantified benefits can then be compared with the lifecycle cost to implement a project, and so derive the net value of a proposed investment.

The optimisation tool is used to inform when projects progress into our works plan – picking the most valuable portfolio that fits within our financial and delivery constraints. Its use will expand in future to also inform our five-year investment plan.

10.3 DEFECTS AND ASSET FAILURES

10.3.1 OVERVIEW

The main purpose of the defect remediation process is to restore assets that are damaged or do not perform their intended functions. The intent is to make these safe to operate or to obviate imminent failure and ultimately to avoid network outages. Defects are mostly detected by field staff during fault response or routine inspections, but could also be flagged by our Supervisory Control And Data Acquisition (SCADA) system or by reports from the public.

On some asset fleets, defect remediation constitutes a significant portion of our expenditure. For annual budgets, the current Capex defects[63] backlog is compared against target levels to determine the scope of renewals activity for the year.

10.3.2 DEFECT IDENTIFICATION AND CATEGORISATION

Defects are mostly identified through inspections, which are either scheduled or undertaken on an ad hoc basis following a triggering event (eg a SCADA system alarm) or the identification of an asset type issue. Inspections can be visual, but also include acoustic or thermographic diagnostic techniques.

After a defect is identified, our defect assessment process is used to categorise it as either a red, amber, or green priority. The definitions we use for these categories are shown below.

Red defects are high priority and are dealt with immediately. Amber defects are medium priority – unlikely to cause an immediate fault – and our target is to fix these problems within 12 months of becoming aware of them. Green defects are less urgent and are managed through planned work programmes, with actual projects prioritised alongside the rest of our planned Capex portfolio.

10.3.3 WORK PACK PRIORITISATION AND DELIVERY

Work is scheduled for completion based on assessed priority. Minor defects (less than $800) are directly managed by the field-staff under the find-and-fix process. This gives them the autonomy to fix minor issues as they come across the flaws.

For red and amber defects, we apply our asset criticality framework, which covers aspects such as public safety, customer, financial, and environmental impact. This allows each asset to be ranked in terms of the impact of its failure and prioritises investment for repair or replacement of high-risk defects.

Fault staff are deployed immediately to rectify red defects. These defects are managed and executed by the Network Operations Centre (NOC). These are the most urgent threats on the network and NOC can make quick decisions on our behalf to address these issues.

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.

DEFECT CATEGORY	DEFECT DEFINITION	RESOLVED BY
Find-and-fix	Any job identified by a service provider onsite, which can be fixed on the spot for under $800 and will not require an outage.	Field service provider
Red defect	Imminent risk of asset failure that presents an immediate significant hazard to people, property or the environment, or: Will result in an inability to operate network equipment.	Network Operations Centre
Amber defect	Condition not otherwise classified as a red defect that requires permanent repair or renewal of an asset that will likely fail within 12 months.	Service delivery
Green defect	Condition that requires permanent repair or renewal of an asset that will likely fail in a period greater than 12 months but less than 36 months.	Asset strategy and investment

While resolution of defects within the targeted times reflects good industry practice, our internal processes allow discretion for assets to remain in service, provided appropriate risk assessment has been completed.

Amber defects are included in work packages to help efficient delivery of collocated, high-risk repairs. This process is managed by our defect coordinators.

Green defects are generally a long-term indication of degraded asset condition, leading to renewal projects. The projects are prioritised using our Copperleaf tool, alongside the rest of the project portfolio.

[63] Defects can also be remedied through corrective maintenance activities

10.4 RENEWAL NEEDS IDENTIFICATION

10.4.1 KEY DRIVERS

The decision to renew assets considers condition and operational factors. The drivers can vary between different fleets because respective functionality and purpose can be quite different. Often an investment programme will be driven by more than one of these factors. This section discusses the key drivers for network renewals.

10.4.1.1 SAFETY

Much of our renewal work, such as our overhead structures and overhead conductor renewal, focuses on mitigating safety risks to the public, staff and service providers. We isolate or minimise hazards as much as reasonably practicable.

Safety risks can arise from degrading asset condition, or from environmental factors such as vegetation encroachment. Insufficient protection against intrinsic electrical risks, such as arc flash, may also lead to assets being replaced.

10.4.1.2 ENVIRONMENTAL RISK

Some of our assets can pose environmental risks, particularly those that contain oil or sulphur hexafluoride (SF_6). This can lead to mitigation, for example through upgrades to oil bunding and containment systems, or to replacing assets where no reasonable alternatives exist.

10.4.1.3 RELIABILITY

Improving poor asset performance is a common driver for renewal projects. This includes renewal of poor-condition assets and assets with known failure modes. We regularly review the performance of our network feeders to target asset renewal in areas of worst performance.

10.4.1.4 RESILIENCE

Our understanding of how assets perform in extreme events, such as storms and earthquakes, is always improving. This increased understanding is reflected in our design standards and applied to new assets installed on the network. In some instances, where emerging risks to network resilience make it necessary, we will renew existing assets to newer standards. This includes programmes such as upgrading the seismic ratings of our substation buildings.

10.4.1.5 OBSOLESCENCE

Renewal may be warranted when existing assets are assessed to be obsolete. This can occur when:

- An existing asset is incompatible with our modern systems and standards and lacks required functionality when compared with modern equivalent assets.
- Spares may no longer be available to support the asset, or the asset may no longer be supported by the manufacturer.
- The knowledge within the workforce to maintain the asset is no longer available.

Obsolescence can be the primary driver of renewal of many assets in the secondary systems (control and protection) assets portfolio. In this case, modern assets provide improved functionality and performance that allows us to more efficiently control and operate the network, providing better value to our customers.

10.4.2 RENEWAL ANALYSIS

10.4.2.1 ASSET HEALTH

We routinely inspect and test our assets in the field to get an understanding of their condition. Given this includes a mixture of non-intrusive observational and tested results, as well as more intrusive electrical and mechanical tests requiring outages, gathering this information represents a significant portion of our operational expenditure.

Asset health reflects the expected remaining life of an asset and acts as a proxy for probability of failure. Factors such as age, environmental location, operating duty, observed condition, measured or tested condition, and known reliability are combined to produce the health index (H1-H5), described in Table 10.1.

Table 10.1: Asset Health Indices (AHI) scale

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 one and three years
H3	Increasing failure risk, medium-term replacement	Between three and 10 years
H4	Normal deterioration, regular monitoring	Between 10 and 20 years
H5	As-new condition, insignificant failure risk	More than 20 years

10.4.2.2 COMMON NETWORK ASSET INDICES METHODOLOGY

In 2016 we developed Condition-Based Risk Management (CBRM) models for our substation primary assets - power transformers, circuit breakers, ring main units and ground-mounted distribution transformer fleets. This modelling uses a combination of asset condition and risk to predict failure cost, helping to prioritise renewal expenditure. These were based on the DNO Common Network Asset Indices Methodology (CNAIM).

With the development of our new Copperleaf C55 system, these models, along with a majority of our asset types are now integrated in to it for a total of 9 Asset models, covering 50 different asset types – now including linear assets (cables and conductor) as well as our high volume fleets such as poles and crossarms. This greatly refines our modelling approach for these asset categories.

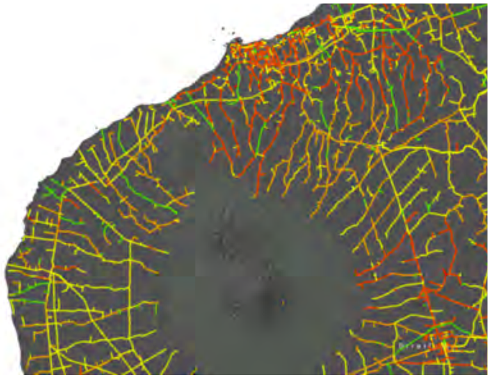
This methodology differs from other forecasting methods that we use in that it develops a bottom up estimate of current and future asset health, probability of failure and risk for each individual asset in the fleet. Information used to produce these estimates includes the asset's characteristics (what the asset is), the asset's condition (how the asset is) and the asset's operational context (how failure could affect safety, network performance, operational and environmental objectives).

The assets and project integration in C55 allows us to directly view the risk reduction benefits of renewals on a project directly via the assets impacted, as well as incorporating other non-CNAIM benefits an investment may provide.

This modelling also allows us to consistently view the impact of different renewal profiles and the impact this has on our current and forecast health and risk profiles.

We have chosen to temporarily omit any asset health forecasts in this AMP to allow us time to calibrate these models and become comfortable with the outputs and use in to our planning and decision-making.

10.4.2.3 OVERHEAD RENEWAL PLANNING TOOL



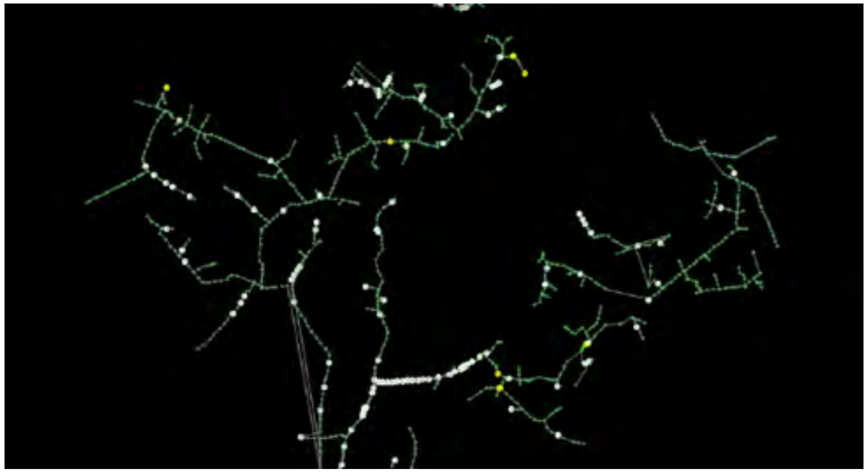
To understand our asset health across all overhead fleets we have built a model using the Common Network Asset Indices Methodology (CNAIM) as a base. The model uses standard CNAIM inputs such as expected life, location, duty, type and age of the asset. We also use additional health score modifiers where we have further information, such as known defects, visual assessments, manufacturing faults and test results. The combination of these inputs calculates an asset health score for each asset.

The output from this modelling is displayed geospatially, and allows for effective project identification to feed out works plans. The results of the spatial analysis is verified through field inspections before the renewal investment is committed.

The Overhead Renewal Planning Tool (OHRPT) is under constant development and improvement. As discussed previously, it is intended that this type of modelling will be developed to cover underground cables assets, as well.

10.4.2.4 OVERHEAD STRUCTURE LOAD ANALYSIS

The resilience of our overhead network, in terms of strength and loads on poles, is not always known. This could be because the network has been erected through rule of thumb techniques, using the knowledge and best practices at the time of construction.



Some of the key elements in the design of the overhead network are wind, snow and ice loads. For many areas, appropriate values would not have been known because weather records had been available for only a limited time.

We undertake load analysis on our network when designing new lines, but also when renewing large segments of a feeder.

10.4.2.5 FEEDER PERFORMANCE

In addition to predicting how much power a feeder will need in the future, and what level of reliability and power quality is required, we regularly check which of our feeders are performing at substandard levels of reliability, and why.

The analysis uses the Feeder Interruption Duration Index (FIDI), which is the average number of minutes without supply a customer on a feeder experiences. The analysis is broken down by feeder class, reflecting the class of connected load.

Remedial options might include a renewal blitz on overhead line hardware, installation of automation technology, improvements in protection systems or capacity enhancements.

10.5 NETWORK DEVELOPMENT NEEDS IDENTIFICATION

10.5.1 KEY DRIVERS

Network development investments are generally prompted when our security of supply criteria can no longer be met for the load being served. This prompts a review of options (network and non-network) to restore appropriate levels of capacity or reliability. Our current security standards are largely deterministic in nature, but as discussed in Chapter 6, we are now moving to a more probabilistic planning approach. Currently, Growth and Security investment (by voltage level) is triggered by:

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

The key drivers for Growth and Security planning are as follows.

10.5.1.1 SECURITY OF SUPPLY

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 Table 10.2, which is a function of both 11kV feeder type and amount of load involved. These classes are shown in demand forecast tables throughout this AMP.

Table 10.2: 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

The restoration targets assigned to each of the security classes are set out in Table 10.3.

Table 10.3: Substation 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, where it must be possible to supply the peak load on the substation even with the loss of the single largest normal supply circuit or transformer. The different security classes simply mandate different restoration times.

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

10.5.1.2 DISTRIBUTION PLANNING

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

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

Table 10.4: 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)

There are cases where feeders serve a mix of load types and, 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 backfeed 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.

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

10.5.1.3 THERMAL CONSTRAINTS

Electric current passing through our assets causes heating which, if excessive, can result in damage. The current-carrying capacity, or ampacity, of our assets is therefore important to determine how much electricity we can distribute on our network.

Alleviating thermal bottlenecks in our networks can act as a trigger for projects such as conductor or transformer upgrades.

10.5.1.4 POWER QUALITY

We must maintain the power quality within statutory limits. The key elements that we monitor to ensure supply quality are:

Voltage: The maintenance of the voltage at the customers' point of connection.

ASSET TYPE	TARGETED VOLTAGE VARIANCE FROM NORMAL	
	MAX	MIN
33kV transmission circuit	+5%	-5%
11kV distribution circuit	+3%	-3%
Distribution transformer	-	-2%
Low voltage distribution circuit	+6%	-6%

Harmonics: The distortion of the voltage waveform. Harmonic voltages and currents passed on to consumers should conform with the Electrical Code of Practice for Harmonic Levels 36.

Maintenance of frequency is not in our quality metrics as it is not presently under the control of Powerco, except for the installation of under frequency load shedding relays at zone substations.

10.5.2 NETWORK DEVELOPMENT ANALYSIS

10.5.2.1 DEMAND FORECASTS

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

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

We use the load forecasts we develop at the feeder level to create the aggregate demand forecast at zone substation, GXP and subtransmission level. We estimate existing peak demand based on 90th percentile of filtered and trended historical peaks. The starting point for our demand forecasts is the distribution (11kV) feeder level forecasts. Our modelling combines NZ Statistics census area population forecasts mapped to each feeder and historical trends in new customer connection trends. This approach works especially well with feeders serving numerous residential and small commercial customers.

Feeders serving one or a few large industrial customers are assumed to have zero growth. If customers indicate a demand increase, with a high degree of certainty, we reflect these as step changes in our base forecasts.

10.5.2.2 LOAD FLOW STUDIES

The network planning team conducts load flow studies for each region. These studies allow us to understand the performance of our network under different demand and network configuration scenarios.

Load flow studies are among the most important tools for investigating problems in our network operating and planning. They allow us to conduct studies on load flow, short circuit analysis, dynamic analysis, optimal capacitor placement, Volt/VAR optimisation, harmonics, ripple control, protection coordination, and power quality.

Asset thermal ratings

While all assets are assigned a specific standard or nominal rating, actual capacities vary in real time, depending on environmental conditions. The approach to asset ratings is tailored to the asset characteristics and thermal environment:

– **Zone substation transformers** – our standard assigns a maximum continuous rating and a four-hour rating, which applies to post contingent load transfer in an N-1 context. Our standard ratings for transformers often vary considerably from nameplate manufacturer ratings. This is done to ensure all our transformers are rated according to consistent and appropriate conditions for the New Zealand environment.

– **Overhead lines** – our standard assigns a nominal continuous rating that is used to systematically identify potential future overloads. Short-term ratings, ie a four-hour rating, are not appropriate for overhead lines because of their limited thermal capacity. Because of the influence of environmental parameters, our standard provides a framework for implementing dynamic rating schemes if a risk assessment confirms this is appropriate.

– **Underground cables** – ratings are being reviewed and we will soon issue a new standard. This will assign consistent, systematic standard ratings for planning analysis, and will also set a framework for dynamic or monitored rating schemes using distributed fibre temperature sensing.

10.6 SOLUTION DEVELOPMENT

10.6.1 OPTIONS ANALYSIS

The complexity of any options analysis is commensurate with the associated level of risk and cost. As an example, overhead line upgrade needs to consider thermal re-tensioning, re-conductoring, or the installation of new lines or circuits, ie dual circuit. We do not use duplexing.

Options analysis assesses costs over a 20-year period. A lifecycle approach involves consideration of all appropriate cost elements, including Capex, maintenance and losses. The analysis models the economic cost of reliability, where this reflects the cost of possible unserved energy to customers. Based on these factors, we identify the most cost effective, long-term solution.

We have developed formal tools and guidelines for undertaking options analysis. This helps ensure that the assumptions and approach remain consistent between options, traceable and documented. It also provides built-in unit rates and helps estimate the cost of different options.

10.6.2 NON-NETWORK ALTERNATIVES

Increasingly we are considering non-network solutions as alternatives to, or in conjunction with, network investments for the deferment of, or instead of, traditional 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

- Photovoltaics (PV), especially at a residential level.
- Wind, generally large installations in rural areas.
- Hydro and micro hydro, although there are limited viable locations.
- Biomass, some specialist possibilities.

Embedded non-renewable generation

- Diesel peaking or backup generators (very low utilisation).
- Gas-fired, typically in an industrial cogeneration context.

Energy storage

At present, the most practical energy storage options for distribution networks are large or small-scale batteries, although other options such as heat, water or flywheel energy storage systems are also being considered. Storage offers several potential benefits, especially related to the ability to shave daily peaks, therefore reducing the network's effective peak demand and/or increasing utilisation.

Demand-side management

Emerging possibilities range from simple variable thermostats through to smart appliances and home energy management systems. Small scale distributed energy storage, eg home batteries, can effectively be treated as a demand-side resource.

Power flow

Management/automation involves techniques to improve utilisation and use of Special Protection Schemes (SPS), dynamic ratings and voltage/phase management devices.

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

Third-party provision of network alternatives

It is our intent to increasingly seek out potential third-party solutions to address major network requirements. These will be adopted where they are more cost-effective than our own network or non-network solutions.

As an example, in October 2018 we went to the market with a combined Request for Information and Registration of Interest (RFI/ROI) for a transmission alternative service. The purpose of the RFI/ROI was two-fold:

- To seek registrations of interest for supply of transmission alternative services for the Hinuera area.
- Use the RFI process to gather additional information and feedback on the process, information potential proponents require, types of services available, and how the services could be integrated into the electricity market.

The RFI process included good feedback that has improved our understanding of potential transmission alternatives and will be incorporated into the process that will be used for future transmission alternatives.

For the Hinuera Area Supply Reinforcement Project the transmission alternative is a permanent substitution of the transmission solution, not just a transmission deferment. It must be located in a specific area, and it has to cover 100% of the demand that would be interrupted (36MVA).

10.6.3 INVESTIGATIVE STUDIES

Investigative studies may be conducted to assist with finalising the scope of a project. These studies are usually conducted for complex projects. Uncomplicated, routine projects can be delivered without the need for an investigative study.

10.6.3.1 FEASIBILITY STUDIES

Feasibility studies are used to check whether the project is technically possible and economically viable. This is to make a ‘go/no go’ decision on a proposed project. It is not used to validate the condition assessment data gained from a desktop study, or for checks on individual assets.

Depending on the context, feasibility studies could be used to help narrow down options, understand the viability of a concept, or try and understand the size of the problem being considered.

10.6.3.2 CONCEPT DESIGNS

If the project is complex and/or very large, then an early design can be requested. They are generally used to help effective decision-making or to clarify the scope for the detailed design. The designer gets involved early in the project delivery process to investigate how the project is best implemented.

10.6.4 PROJECT STAGES

A project goes through various stages as it evolves from an idea to a full detailed design. These stages are captured in our Project Portfolio Planning system.

10.6.4.1 PROJECT SUMMARIES

Project summary is the very initial stage of a project. This stage captures very basic, high-level details about what a project may look like.

Project summaries are used to help the resourcing teams gain insight into the type and quantity of work in the system, so that they can start organising resources for timely delivery when required.

10.6.4.2 PROJECT BRIEFS

Project briefs are used to help finalise the detailed requirements for a project. The briefs also ensure that the needs of multiple stakeholders within the organisation are captured in the project.

During the development stage of Capex projects, asset engineers and planning engineers gather the information required to be able to describe what is needed to deliver the project. The key elements of a robust scope are a high-level design and accurate time and cost estimates. That information is built up and added to until it culminates in a completed ‘project brief’.

10.6.4.3 PROJECT APPROVAL

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

- **Growth and Security** – solutions are generally reviewed by the Network Development Manager. This review assesses whether the proposed solution and its timing supports our overall Asset Management Objectives. Solutions are challenged based on whether the supporting technical and costing analysis is sound, the solution will meet future demand growth projections, and it represents the least-cost, technically feasible solution. The degree to which non-network solutions were considered is also tested.
- **Renewal and Refurbishment** – solutions are generally tested by the Asset Fleet Manager. This review assesses whether renewing the asset(s) and its timing will support our overall Asset Management Objectives. Cost effectiveness and deliverability are important considerations. This may include testing against non-network and/or Opex solutions.
- **Consumer Connections and Asset Relocations** – solutions are generally reviewed by the Commercial Manager. However, less rigour is applied to the assessment of options as the customer often dictates what is required.
- **Network Evolution** – proposals are generally reviewed by the Network Transformation Manager. Research-based investments are tested to assess the expected learning, potential network benefits, cost and practicality of the activity proposed.

Depending on the size of projects, further approval is required to ensure we meet our delegated financial authority rules.

11 LIFECYCLE MANAGEMENT

11.1 CHAPTER OVERVIEW

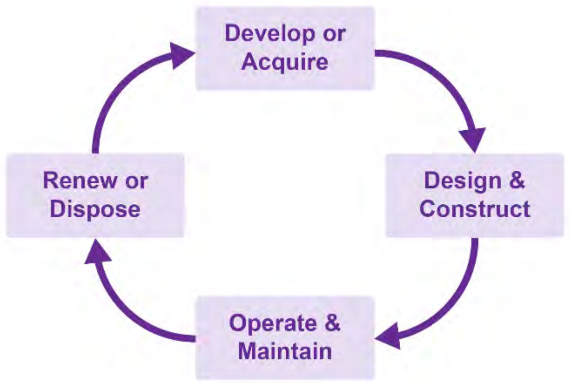
Holistic asset management considers every stage of an asset's lifecycle, including inception and definition, design and construction, operation and disposal. This chapter discusses our approach to lifecycle asset management. We consider:

- The means to achieve cost-effective, reliable and practical operation.
- How to maximise the value of an asset over its lifecycle, tangibly and intangibly.
- The ongoing operational, maintenance and refurbishment costs over the expected life of the asset.
- The complexity and cost of decommissioning and removal.
- Any possible environmental impacts at all stages of the asset lifecycle.

11.1.1 OUR ASSET LIFECYCLE

Our interpretation of the lifecycle is shown in Figure 11.1.

Figure 11.1: Asset management lifecycle



These stages of our assets' lifecycle are supported and delivered by several interconnected activities and processes. For effective management, they are broken into the following categories:

- Engineering Standards, or systems engineering
- Works Programme Development
- Works Management and Delivery
- Procurement
- Network Operations
- Access and Safety Management
- Spares Management
- Customer Management

This section outlines how these processes help us manage the lifecycle of our assets.

11.2 ENGINEERING STANDARDS

11.2.1 EQUIPMENT AND MATERIALS

Equipment used on our network must meet our engineering requirements. Before introducing any new equipment, the Network Approval Test (NAT) process is applied to assess the suitability of equipment for use on our network. It includes a stringent vetting process by a cross-functional group of users.

The list of NAT-approved equipment suppliers is limited, and all new manufacturers and proposed equipment must undergo the process before their products can be installed on our network. Powerco does this to ensure high levels of engineering integrity and safety, as well as to support standardising equipment as much as possible across the network. This in turn simplifies maintenance, repair and the number of critical spares that we need to hold.

11.2.2 DESIGN, INSTALL AND COMMISSIONING STANDARDS

Network designs, whether prepared in-house or by external consultants, must closely follow Powerco standards. These standards describe our design and material requirements, including, for example, how facilities are to be laid out, seismic requirements and operational requirements.

11.2.3 OPERATION STANDARDS

Any operational work carried out on Powerco Electricity networks, or work that will become part of a Powerco network, must comply with the Powerco Network Operations Manual (NOM).

The NOM is a comprehensive group of standards and forms that provide internal operational rules and guidance. It is used in conjunction with industry wide standards, such as those developed by the Electricity Engineers' Association (EEA), including the Safety Manual Electricity Industry (SMEI) and other EEA guides.

Our Network Switching Standard details and prescribes specific procedures, principles and responsibilities for the safe switching of Powerco's Electricity network equipment.

All personnel undertaking work on Powerco's Electricity networks must comply with Powerco's competency requirements as prescribed in 210S002 Electricity Employee Competency Certification and Powerco's Network Operating Philosophy.

11.2.4 INSPECTION AND MAINTENANCE STANDARDS

Our maintenance standards define and scope the frequency of inspections and preventive maintenance activities. We use information obtained from such inspections to plan our corrective maintenance programme and inform renewal decisions.

Increasingly, we are applying a criticality based approach to prioritising corrective maintenance funds, to ensure resources are most efficiently applied to reduce risk and improve network performance. During the AMP planning period we intend to utilise maintenance scheduling capabilities of our new Systems, Applications and Products in Data Processing (SAP) plant maintenance system to further exploit the benefits of criticality based maintenance scheduling.

We independently monitor the completion of service provider, vegetation contractor, and specialist works, and undertake sample audits to ensure compliance with our technical and quality standards.

11.3 WORKS PROGRAMME DEVELOPMENT

11.3.1 CAPITAL WORKS PROGRAMME

Our capital works plan is approved by the Board on an annual basis. It is generally a compilation of the highest priority projects that have been identified at the time, but also includes the rolled-over portions of larger, multi-year projects.

Planning on a purely annual basis is counterproductive to effective service provider works planning, as it would involve having to wait for annual project approval before works can commence. Accordingly, we also prepare a rolling two-year works plan, which is regularly updated with the next highest priority projects. We have approval to commit up to 30% of a following year's work programme in advance, to smooth the service providers' workload.

In addition, we often commission the detailed design well in advance of final project approval. This, in turn, allows us to procure long lead-time equipment and, especially, to acquire the necessary land and get consents for lines and substations.

From our network needs analysis we generally develop, at a high level, a long-term 10-plus year view of required works. The work for the earliest five years is developed in more detail, and the work of the immediate two years is developed to a full concept design stage. The rolling electricity works plan (EWP) draws on this collection of identified projects. It follows a prioritisation process by the Planning team, and also accounts for the availability of design and contracting resources across our network, by the Programme Management team. The Project Manager team determines other possible delivery constraints, such as the available planned SAIDI and SAIFI to undertake works.

Within reasonable limits, there is usually flexibility to move the timing of projects to reflect resource or outage availability, or factors such as preferred construction seasons.

The actual planned construction programme is continually updated and progress is regularly reported.

11.3.2 OPEX PROGRAMME

11.3.2.1 MAINTENANCE

The maintenance work programme is sourced from:

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

Our 10-year portfolio maintenance and vegetation forecasts are updated as part of our AMP process. This reflects updated information on asset condition, criticality, our current maintenance standards, changes in maintenance strategies, and known type or other identified one-off issues that need to be addressed.

Annual maintenance budgets are set as follows:

- Preventive maintenance budgets are set to allow the effective execution of our scheduled maintenance work and inspections for the year. These schedules are determined in accordance with our maintenance standards, using our SAP scheduling tool.
- Corrective maintenance budgets are generally informed by the volume of defects to address, which in turn is informed by asset condition and criticality factors.
- Reactive maintenance budgets are set to historical expenditure run-rates.

The budgets are compiled by the maintenance management teams, reviewed by the General Manager Asset Strategy and Investment, and presented to the Board for approval.

The bulk of our network maintenance activities are completed by our service provider Downer – as part of an Electricity Field Services Agreement (EFSA) – and our approved vegetation contractors. Some specialist contractors are used for non-standard tasks.

11.3.2.2 VEGETATION

The main activities undertaken in the vegetation management portfolio are:

- **Inspections** – cyclic inspections of all subtransmission and distribution feeders to assess tree sites and determine whether trimming or removal is required and if there have been previous tree management activities.
- **Cyclic feeder plan** – prepare plans for contractors to methodically trim or remove vegetation across the network to meet regulatory compliance.
- **Scoping** – work planning, including access to sites, traffic management, outage management, equipment required and resource requirements to perform tree management works.
- **Liaison** – interaction with landowners to agree tree management on their property where trees encroach on electricity network assets.
- **Works management** – the physical works involved in trimming or removal.
- **Audit** – post tree management activity audit checks are made of actual works versus planned works.

All these activities are undertaken by our approved vegetation management contractors apart from the cyclic feeder planning and audit functions, which are performed by our staff. Liaison personnel discuss the scope of work with the tree owner and issue formal notification of the required work.

Vegetation management budgets are set to ensure that we can cycle through the whole network on a three-yearly basis, as well as make an allowance for some risk-based interventions.

11.4 WORKS MANAGEMENT

11.4.1 CAPITAL WORKS TYPES

The acquisition of assets arises out of two principal necessities:

- Network requirements for growth, security, renewals, reliability or proof-of-concept needs.
- Customer-initiated works (CIW).

The need for Growth and Security projects is identified by Powerco's Network Development team, the need for asset renewals by Powerco's Fleet Management team, and for proof-of-concept projects (generally) by Powerco's Network Transformation team. Investments are prioritised using the principles, processes and tools described in Chapter 10.

CIW generally comprise new connections, connection upgrades or asset relocation requests. These are handled by our Customer Works team.

For customer subdivisions or other customer-managed works, we have a list of approved contractors. These contractors work directly with the customer to arrange for the required works. The contractor will obtain approval from us for their proposed design concept and notify the customer of any special requirements, such as easements.

Larger customer projects are often managed by ourselves, or under our supervision.

Our customer connection process is set out on our website. 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.

11.4.2 DESIGN MANAGEMENT

Concept designs and work scopes for network enhancement or renewal projects are generally managed by the Planning teams. For customer requests we have a dedicated Customer Connection team. Following project approval, the project is then passed to Powerco's Design team to either:

- Prepare in-house the design drawings, material and equipment specifications, and the installation specifications required for construction.
- Prepare briefs for external consultants to undertake this work, and to subsequently manage the delivery of drawings and specifications.

The choice is governed by the availability of internal resources and the complexity of the work. Powerco is not equipped to undertake geotechnical surveys or civil design in-house for example.

11.4.3 CONSTRUCTION MANAGEMENT

The delivery of construction services is managed by our Works Delivery teams using a combination of internal and external resources.

Project managers manage contractor performance, focusing on safe construction, delivery on time, within scope and on or under budget. Contractor supervision extends to commissioning of new assets, handover to operations and project closeout.

11.4.4 HANDOVER TO OPERATIONS

When projects have reached the practical completion stage (ie the equipment and all necessary Supervisory Control and Data Acquisition – SCADA – interfaces have been proved safe and ready for operation), Powerco's operations group is requested to take over the works. The process may involve training and will require an assurance that all as-built and commissioning documentation is uploaded within the timeframe agreed to in the Installation Contract.

11.5 PROCUREMENT PROCESS

11.5.1 TESTING THE MARKET

The procurement process can consist of informally or formally testing the market. Informal processes can range from web searches, to cold calls and verbal references. Informal testing of the market is appropriate when making minor purchases.

For more substantial items, more formal testing is undertaken. Formal testing of the market includes Request for Information (RFI), Request for Proposals (RFP) and Request for Tenders (RFT) as discussed in the section below.

11.5.2 REQUEST FOR INFORMATION

An RFI is used in the instances when the cost, risk and performance requirements are uncertain. It is a useful method for us to test the markets and better understand the various options available and their implications.

An RFI does not create a binding commitment on Powerco; responses from the RFI can be used to either enter negotiations with a preferred party, re-evaluate the options, or not proceed at all.

11.5.3 REQUEST FOR PROPOSALS

As our understanding of what we need increases, we may choose to issue a RFP.

RFPs are more prescriptive than RFIs because they contain a clearer scope of what is required. RFPs are often used for procuring design services, special one-off equipment, software, technology solutions and plant.

An RFP suggests a higher level of commitment than an RFI, and although Powerco is not bound to proceed with any of the proposals it receives, the general expectation is that we will engage a provider at the end of the process.

11.5.4 REQUEST FOR TENDERS

RFTs are used when we have a clear understanding of our needs and the key risks. They are accompanied with a detailed scope or specification.

This method for testing the market is generally used for construction contracts, or procurement of equipment that has been Network Approval Test (NAT) approved.

Tenders are the highest level of commitment of all three methods and constitute an offer to contract, subject to price (and any other outstanding details) being accepted by Powerco.

11.5.5 OFFER ASSESSMENT

Responses from RFI/RFP/RFT should be formally assessed, ideally using a multi-criteria analysis framework. This ensures that we consider factors beyond just price in our assessment of the best offer.

The ratio of price to non-price factors used to award a contract will depend on the level of uncertainty within the works. Broadly speaking, RFI assessment will have the most focus on the qualitative aspects of the assessment, followed by RFP, and finally the RFT, which is usually the most price-focused assessment.

11.5.6 CONTRACT PROCESS

Upon selecting a successful supplier, contract process steps are completed using terms that are most appropriate for the transaction's nature, value and risk.

The appointed design coordinator for each project will manage the design contract negotiation, award and execution. The Service Delivery Project Manager for the project will manage the contract negotiation, award and execution of installation contracts.

11.5.7 VENDOR MANAGEMENT

This involves ensuring our contractors have adequate systems in place before we award a new contract. Powerco utilises ISNetworld to authorise prospective contractors via a desktop audit and verification of their health, safety, environmental and quality management systems.

The process and requirements for project completion are detailed within both the Powerco standard and contracts. For all projects, the works will not be taken as complete until the necessary requirements have been met and a certificate of practical completion issued.

The audit programme under our assurance framework ensures that service providers are working safely on our network and assets are built to an acceptable standard. The programme is used to identify systemic issues with the services provided by the contractor. Opportunities for improvements identified under the audit programme are addressed by the relationship manager or the contract owner.

11.6 OPERATIONS

11.6.1 OUTAGE MANAGEMENT SYSTEM

Our Outage Management System (OMS), powered by our SCADA system, is a core tool used in managing the NOC workload. 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 predictive fault locations based on customer calls, and provides NOC staff with geospatial views of the affected area. This tool is used to improve fault responsiveness.

11.6.2 SWITCHING

A written switching instruction is required for:

- The operation of all high voltage (HV) switches and switchgear.
- Operations that are important to safety or network security.
- The application and removal of safety measures required for the issue of permits and assurances.
- Proving HV equipment is de-energised prior to earthing.
- The application of issuer-applied earthing.
- Obtaining approval to and issuing permits.

Switching instructions and permits are prepared by a network coordinator or switching coordinator, and then checked by a second network/switching coordinator.

11.6.3 DISPATCH AND LOAD MANAGEMENT

NOC dispatch operators communicate with retailers and customers to meet load demands. They also communicate with our service providers' SMC to dispatch field staff where work is necessary to maintain or restore power supply. Dispatch operators also manage all low voltage (LV) outages.

Powerco sets load control targets that allow the SCADA to automatically control interruptible load (such as water heating) when demand rises to a pre-determined level. This level can be determined by various factors: network constraints, commercial arrangements, and demand side participation agreements.

11.6.4 ASSET PERFORMANCE MONITORING

SCADA gathers and analyses real-time data on the electricity network, including information on interruptions. When an interruption occurs on an asset linked to SCADA, an outage record is automatically created in OMS.

High Voltage Fault reports are reviewed during daily Quality Assurance (QA) checks to identify large impact or repeat outages, and to direct location and repair efforts.

Retailers can also log customer interruptions into OMS via a business-to-business interface.

11.6.5 PLANNED OUTAGE MANAGEMENT

Each financial year a planned SAIDI and SAIFI allocation is assigned to individual work streams in Service Delivery (eg capital projects, defects etc).

NOC receives applications for work from service providers and calculates the SAIDI and SAIFI required to complete the work requested. Each month this is reported to the Planned SAIDI Group, and Powerco Project Managers then decide which jobs will go ahead while staying within the SAIDI and SAIFI targets set for the month.

In addition, NOC is responsible for managing urgent safety or repair jobs. It works our project managers to schedule these in as priority tasks, alongside the planned construction plans.

11.6.6 UNPLANNED OUTAGE MANAGEMENT

Where an outage is reported, a request with an automated priority is made to the service provider. The priority of the response will be initially set by the feeder rating. The urgency of the response can be raised if a hazard exists, such as a power line down that could affect public safety, or if the network has been reported to be under distress.

Following a fault (outage) in an urban area, the affected network will require a cursory patrol to check that no hazards exist, such as power lines down, before an attempt is made to re-energise supply.

If the fault cause is not obvious or found through the cursory patrol, an 'operational' patrol will be carried out, consisting of a detailed visual inspection of all segments of a faulted area of the HV network to determine the location and nature of the fault.

11.6.7 NETWORK RESTORATION

Where work has been carried out under a permit, NOC confirms that all personal are clear, and applied safety measures have been removed before any livening takes place.

To enable fast restoration of supply while troubleshooting and repair is undertaken, NOC may choose to enact a pre-prepared contingency plan, which includes backfeed options at distribution voltage level.

Where outages have been initiated by an Automated Under Frequency Event (AUFLS) or a grid event, this will be under the control of the System Operator (SO). NOC will in this case follow SO instructions.

11.6.8 CIVIL EMERGENCIES

A Civil Defence (CD) State of Emergency can be declared at a local, regional or national level. In some circumstances, a local Emergency Management Operations (EMO) Centre can be declared operational before the State of Emergency.

When the EMO declares a CD emergency, Powerco will arrange a Civil Defence Liaison Officer (CDLO) representative in the area where the Electricity networks are affected by the emergency. The CDLO will be responsible for the exchange of relevant information between Civil Defence and Emergency Management (CDEM) and the Powerco NOC.

The Powerco footprint has six regional councils that coordinate CD lifeline planning issues. Powerco has appointed a CDLO for each area.

Powerco must comply with the requirements of the CDEM Act and follow all lawful instructions issued by the EMO Group Controller.

11.6.9 EMERGENCY PREPAREDNESS

Powerco has an Emergency Response Plan (Standard 393S131).

Emergencies may be categorised from L1 to L5 based on fault rates, number of Installation Control Points (ICPs) without supply, outage duration and significant loss of load. This dictates the level of response to the event.

11.6.10 OPERATIONS REPORTING

NOC provides the following routine reports to stakeholders:

- Daily HV Outage Report
- Outage Investigation Team Report
- Pre QA Daily Outage Report
- Comms Adjusted SAIDI SAIFI Powerco
- End of Year SAIDI SAIFI Powerco
- Rolling Release
- Check Planned Works
- Advertising Report
- Planned Network Access Planning Application (NAPA) Predicted vs Actual for KPI 3E
- Monthly SAIDI Allocation Report for Project Manager

Various other reports are produced upon request using OMS and NAPA data.

11.7 ACCESS AND SAFETY MANAGEMENT

11.7.1 WORK REQUESTS

NAPA is required to be submitted in order to undertake planned work on the Powerco HV electricity network.

The Release Planning Standard contains the minimum number of clear work days that are required as notice of proposed work for differing work types. The exception is work deemed urgent.

For major projects, the contractor will provide a commissioning plan, with a suitable lead time, to the NOC before commissioning begins.

11.7.2 SAFE ACCESS

All employees requiring access to the HV network are required to follow all parts of the Safety Manual for the Electricity Industry (SMEI). The SMEI specifies minimum safety requirements, minimum approach distances (MADs), general safety guides and rules for work on equipment.

Powerco provides a range of operational standards that sit over the rules and guides to provide further guidance. These are incorporated into the NOM.

11.7.3 WORK PERMITS

All maintenance, test or construction works are undertaken under the conditions of an Access Permit or Test Permit, which will allow the recipient of the permit and their respective work party, or test party, temporary access to specified equipment.

The permit requires that safety measures are to stay in place until the permit is returned and cancelled. Only Powerco-approved contractors with required competencies can hold a permit.

Where work is to be carried out on live equipment, this is managed under a Live Line Permit. The network will be switched to allow a Reclose Block (RB) or Hot Line Tag (HLT) to be installed to the specific area of the network to be accessed for the duration of the permit. The safety measures (RB, HLT) are listed on the permit.

A Close Approach Consent is required when a contractor, who does not hold the applicable Powerco competency class, needs to undertake work adjacent to Powerco's electricity network within the normal minimum safe approach distance of 4.0m. In this case, a competent supervisor must be present.

11.8 SPARES MANAGEMENT

Downer has been contracted to manage our spares inventory in accordance with Powerco standards. Our inventory consists of three types of spares:

- **Critical** – the spares required to repair critical equipment, this being defined as equipment which, upon failure, would have a significant impact on network reliability or safety.
- **Emergency** – the spares needed to return an item of plant to service after an unplanned outage or it has been physically damaged.
- **Operational (rotable)** – the spares required to maintain an item of plant in a serviceable state.

The numbers and types of spares that need to be held are specified in Powerco's standards. Improvements are under way to introduce a risk-based approach to determining which spares we need to hold and the revised inventory lists.

In 2020, we also reviewed our critical spares requirements and conducted a survey of the extent and condition of assets held. This resulted in substantial changes to the spare-holding policy and ordering of new equipment.

11.8.1 TOOLS AND MOBILE PLANT

Most critical specialist tools and mobile plant are held/managed by the contractors under respective EFSA contracts, including lifting equipment mobile plant that requires periodic certification.

Where there are specialist tools associated with a particular asset, the specialist tool is supplied as part of the procurement contract and held at the zone substation where the asset is located.

For tools and mobile plant that are not associated with a particular asset, or in situations where the asset in question is installed in multiple locations, standards are prepared to specify how the associated tools are managed, stored and tested. Examples include mobile power transformers and remote operating devices for certain classes of ring main units.

11.8.2 WARRANTY MANAGEMENT

Warranty management is outsourced to our service providers. We expect the service providers to make clear to their suppliers that the end client is Powerco.

11.9 CUSTOMER MANAGEMENT

11.9.1 COMMUNITY CONSULTATION

Customer consultation and engagement is a consideration for all network changes – particularly major and minor projects in the Works Delivery Programme. Powerco has a Community Engagement Advisor and their role is to assess the requirements for customer consultation and engagement and prepare an engagement plan.

Even if an engagement plan is not required, it may still be necessary to inform the local community of the works that are going to take place. If the community needs informing of the work because of disruption from outages or works in the road corridor, the Marketing and Communications team will take the lead and prepare a communications plan for the project. The process that Powerco follows for making an assessment for customer consultation and engagement is shown in Figure 11.2

Powerco's customer and community engagement aligns with IAP2's (International Association for Public Participation) spectrum of engagement.

Figure 11.2: Community consultation process

INCREASING IMPACT ON THE DECISION

	Inform	Consult	Involve	Collaborate	Empower
Public participation goal	To provide the public with balanced and objective information to assist them in understanding the problem, alternatives, opportunities and/or solutions.	To obtain public feedback on analysis, alternatives and/or decisions.	To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	To partner with the public in each aspect of the decision including the development of alternatives and the identification of the preferred solution.	To place final decision-making in the hands of the public.
Promise to the public	We will keep you informed.	We will keep you informed, listen to and acknowledge concerns and aspirations, and provide feedback on how public input influenced the decision.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how public input influenced the decision.	We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.	We will implement what you decide.

11.9.2 CUSTOMER ENGAGEMENT

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

These include:

- Having stands at agricultural field days, expos and trade shows.
- Direct interaction with larger commercial and industrial customers.
- Customer surveys.
- Stakeholder meetings and focus groups.
- Website, digital services and phone feedback – www.powerco.co.nz and 0800 POWERCO.
- Consultation videos published on YouTube.
- Consultation documents, such as this AMP.
- Community-wide consultation on specific projects.

The scale and range of consultation we complete provides us with appropriate insight into the areas of service that our customers value and their evolving expectations.

11.9.3 COMPLAINTS MANAGEMENT

To meet the definition of a complaint, a communication must contain both an expression of dissatisfaction and an expectation (either implicit or explicit) of a response or resolution. In most cases, a claim will meet the definition of a complaint.

The Energy Complaints Scheme requires Powerco to have and comply with a documented complaints process appropriate to the nature of its services and scale of its operations, including providing and keeping up-to-date information about the staff member(s) responsible for complaint handling.

Powerco's Customer Services team (Dispatch), specifically the Outage and Customer Service Manager, fulfils the role of Complaints Coordinator. Communications are received via a range of channels and it is the Complaints Coordinator's role to assess whether the communication meets the agreed definition of a complaint. If so, the Complaints Coordinator will log the complaint in Powerco's Customer Complaints Management System (CCMS) and assign to a Complaint Owner. The Complaint Owner is responsible for all subsequent communications with the complainant and resolution of the complaint.

Powerco has two Customer Resolutions Officers (one for each electricity region – East and West) who fulfil the role of Complaint Owner for Electricity. The Customer Experience Manager provides an escalation point for complaints and is responsible for maintaining Powerco's relationship with Utilities Disputes and driving improvement by using customer intelligence obtained from complaints.

11.9.4 NOTIFICATIONS

11.9.4.1 PLANNED OUTAGES

Powerco operates an interposed customer relations model with energy retailers. This means retailers are the primary customer contact point for matters relating to distribution services.

If the planned outage is on Powerco's HV networks, Powerco notifies retailers in advance of the need for the outage and which ICPs will be affected. The notification is via email and is sent by the Customer Services (Dispatch) team. Retailers in turn notify their customers according to their notification preferences. Use of system agreements with retailers stipulate how many days in advance notification must be provided.

If the planned outage is on Powerco's LV network, the contractor performing the work will notify customers directly via a physical form or via door knocking, if only a few customers will be affected.

Powerco's website will automatically display planned power cuts that affect 10 or more customers. Powerco recently developed its website to allow anyone to search for any planned outages that will affect a specified property within the next 30 days. Customers can contact Powerco directly via a dedicated email address customerexperience@powerco.co.nz if they have any questions or concerns about a planned outage. Customers can request changes to planned outages via their retailer or directly via Powerco's website.

11.9.4.2 UNPLANNED OUTAGES

With the interposed customer relations model, energy retailers are the primary customer contact point for most communication regarding unplanned outages. Retailer fault teams can log faults directly into Powerco's OMS. They can obtain status updates from OMS or from Powerco's Customer Services team via a dedicated business-to-business phone line.

Powerco's website provides information on unplanned power cuts known to affect 10 or more customers. This is available to retailers and end customers. The website connects directly to OMS and a known fault logged in OMS will automatically be shown on the website. Status updates are manually made on the website by Powerco's Customer Services (Dispatch) team.

11.9.5 CUSTOMER CONNECTION

Residential customers requiring a new connection will generally first contact an electrician. Some electricians will manage the entire connection process, while others will direct customers to our Customer Services team.

When a customer contacts us, we supply them with our list of approved contractors. These contractors work with the customer to determine what is required for electricity 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 of our connections process.

Some larger businesses or large subdivision developers will contact us directly to discuss their connection requirements, or work with large industrial power specialists who are familiar with our requirements and standards for connection. We work with these larger providers to facilitate connection of these larger loads.

Our customer connection process is set out on our website.

12.1 CHAPTER OVERVIEW

Effective risk management is a core component of good asset management. In this chapter, we describe how we approach risk management in relation to asset management at Powerco.

12.2 RISK SCOPE AND CONTEXT

Asset health, criticality and risk-based decision-making is a rapidly developing practice area within asset management. AS/NZS ISO 31000:2018 states that all decision-making within an organisation, whatever the importance and significance, should involve the explicit consideration of risk and the application of risk management to some appropriate degree.

The overall purpose of risk management is to understand the cause, likelihood and consequences of adverse events, manage such risks to an acceptable level, and provide auditable decisions, actions and effects in order to measure effectiveness and to support continual improvement.

The three areas that our risk management practice covers are illustrated in Figure 12.1.

Figure 12.1: Risk categories

Asset Failure Risk refers to functional failure of an asset or group of assets and the impact this might have on customer service levels, safety or environment and, by extension, on meeting our corporate objectives.

Corporate Risk encompasses company reputation, financial health and legal compliance. Reputational risk is primarily linked to customer satisfaction with our response to faults, achieving a satisfactory balance between power quality and price, and meeting environmental expectations.

Management System Risk refers to functional organisational failures leading to the organisation not being able to meet its business objectives.

The effectiveness of our risk management processes is measured and improved upon through our monitoring processes, described in this chapter.

12.3 RISK REPORTING

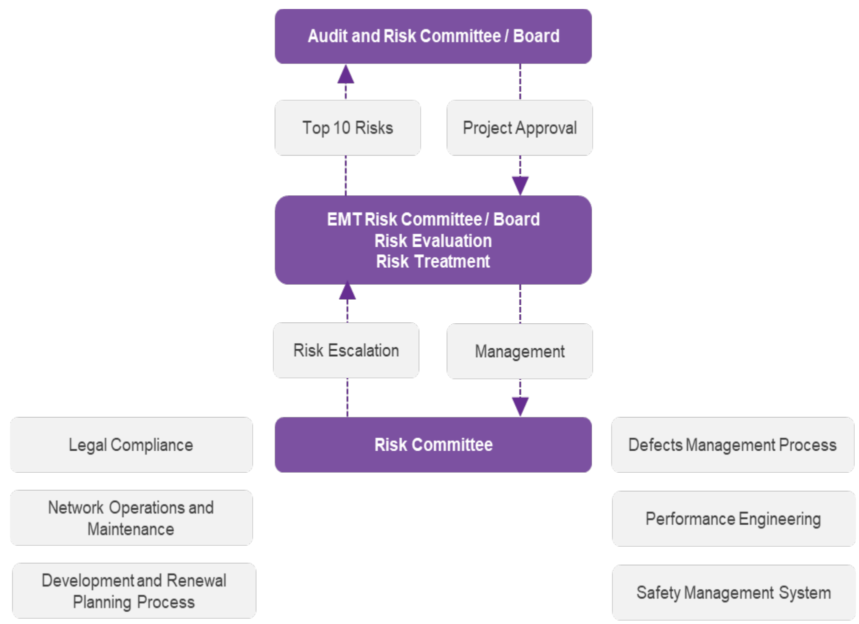
12.3.1 RISK MANAGEMENT FRAMEWORK

Powerco's risk management framework is illustrated in Figure 12.2.

The Powerco Board establishes risk policy (including degree of risk appetite) and enforces compliance. It is kept informed by the Executive Management Team (EMT) with respect to our top-10 risks. It uses an Audit and Risk Committee to monitor and report on how well risk management practices are being applied.

The EMT has oversight of risk management practice, using the Risk Committee to promote its use across the business. It reviews risk and audit issues regularly to implement any changes in response to the strategic and operational environment.

Figure 12.2: Powerco risk management framework



12.3.2 RISK REVIEW AND SIGN-OFF

Risk review, undertaken at both EMT and line manager level, considers the following questions:

- **Risk identification** – are risks being identified from a range of sources that reflect the organisation's core activities?
- **Risk management plans and actions** – are plans being implemented, actions tracked, and are these having the desired effect?
- **Close-out of risks** – are risks being removed from risk registers as they are managed to a minimal level?
- **Residual risk** – if risks have been managed to acceptable levels, are the residual risks well understood?
- **Performance management, risk control, risk profile** – are risk reports being produced that are dynamic, reflecting a changing risk profile?
- **Compliance** – are the asset risk management processes understood and applied in accordance with our Risk Management Policy and procedures?

The executive level risk matrix capture high-level risks – which generally are the culmination of a number of lower-level asset-related, tactical or operational risks, assessed at team levels in the organisation. All risks are ultimately measured as a function of the impact they have on achieving our business objectives and are evaluated on common criteria.

12.3.3 ASSET RISK REGISTERS

Until recently, asset risks resided in various registers spread across the business. As of March 2020, we started recording asset risks in the Risk Module of Safety Manager.

Asset risks are recorded against asset types. The register also allows us to update the status of the risk, list the key controls and treatments for the risk, and assess their effectiveness.

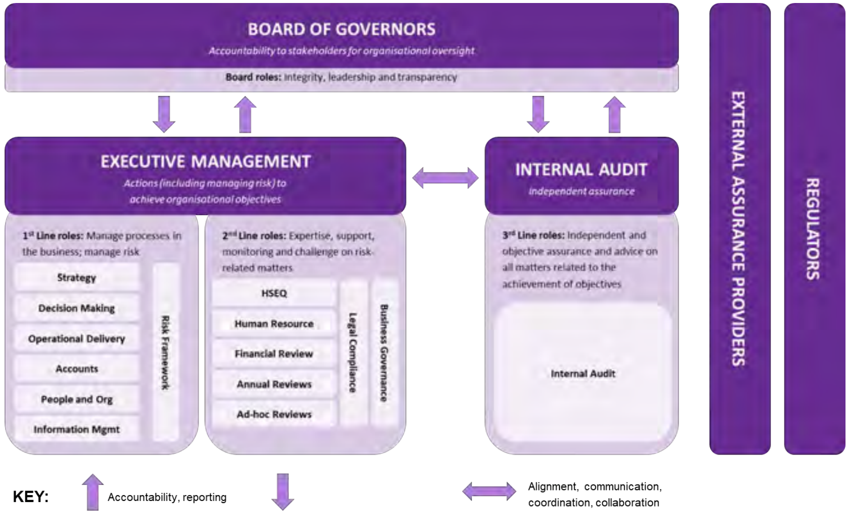
The Fleet Management and Network teams are primarily responsible for updating and maintaining these registers, although they are reviewed by the HSEQ team and Risk Committee on a periodic basis.

12.4 RISK MONITORING AND ASSURANCE

12.4.1 THREE LINES OF DEFENCE

'Assurance' refers to the activities that we undertake to ensure that the systems we have in place are being used consistently and that they are working. The Assurance Framework is built around the three 'lines of defence' illustrated in Figure 12.3 and described below and detailed in Table 12.1: Lines of Defence.

Figure 12.3: Assurance Framework



1st Line of Defence

This is the principal area where we focus our risk management efforts. A significant portion of business-as-usual practices, eg standard operating procedures, permit control, and confined space entry, reside in this layer. This layer includes line supervisors and frontline staff who conduct work on the network. A significant portion of the effort spent by the EMT and senior management also forms part of this layer of defence.

2nd Line of Defence

This includes various compliance oversight functions. The objective of this line is to monitor key risk indicators and tell management where it should focus its efforts. We intend to strengthen the second layer of defence as part of improving our risk management maturity. Functions of this layer include:

- Multiple compliance oversight teams with responsibility for specific types of compliance monitoring, such as health and safety, environmental, regulatory, commercial, legal or human resources.
- Risk management team that provides risk consulting and other business support services consistent to the relevant ISO standards.
- Financial control functions that monitor financial risks and financial reporting issues.

3rd Line of Defence

Internal Audit is the 3rd Line of Defence. This function is managed by the Risk and Assurance team consisting of qualified internal auditing staff. Being a small team, most of the assignments are outsourced to independent external assurance providers.

Table 12.1: Lines of Defence

FOCUS	REPORTING	INDEPENDENCE
1ST LINE OF DEFENCE:		
Management controls: Policies, procedures, standards and other controlled documents are developed by Powerco to direct and control activities undertaken.		None
Internal controls: Conducted within a business unit to confirm that activities are being undertaken as planned and are primarily focused on testing whether the controls identified in standards and control documents are being applied consistently as defined.	Primarily to the business unit senior managers. Outputs are reviewed and are used to inform reporting and assurance planning at higher levels.	Minimal
2ND LINE OF DEFENCE:		
Used to confirm to the control owner that controls are properly deployed and operating as expected. Tests if business units have implemented the 1st Line of Defence controls identified in standards and control documents.	Primary to business unit senior management and Risk and Audit Committee.	Medium
3RD LINE OF DEFENCE:		
Provide assurance to Powerco management and the Board that adequate and effective controls are in place to manage Powerco's strategic risks. Test and report on the effectiveness of the 2nd Line of Defence assurance activities.	Primarily to the Board via Audit and Compliance Committee and the Risk and Audit Committee.	Separate Powerco business groups or external suppliers
MANAGEMENT SYSTEM AUDITS:		
Certifications held by Powerco to management system standards.	Primary to business unit senior management and Risk and Audit Committee.	Independent
REGULATOR AUDITS:		
Provides independent assurance that the assurance practices of a business are working effectively.	The Board via Audit and Compliance Committee and the Risk and Audit Committee	Independent

12.5 RISK COMMUNICATION AND CONSULTATION

Our communication and consultation process is covered by the many continual improvement pathways within our organisation. Some of these are described below.

12.5.1 ALIGNMENT WITH ISO 55001

Powerco is seeking formal ISO 55001 certification by mid-2021. Certification allows us to gauge our asset management maturity and benchmark ourselves against our peers. Regular re-certification by external auditors can offer improvement opportunities.

12.5.2 LOG AN IDEA

The "Log an Idea" portal is used to collect improvement ideas that are suggested by our staff. The process is managed by the Non-network Governance Committee. It provides any employee in the business the opportunity to raise an improvement suggestion.

12.5.3 INCIDENT INVESTIGATIONS

An incident is an event or occurrence that may put people (employees, contractors or members of the public), the environment, or Powerco's business objectives at risk.

Incident investigations identify the organisational or technical root causes that contributed to the incident using an established investigation methodology. Powerco prefers to use the Incident Cause Analysis Method (ICAM).

Improvement opportunities identified as part of incident investigations are stored in our actions register in Safety Manager. Improvement actions are managed by the person who enters them, and are reviewed quarterly by the Safety, Risk and Assurance Manager.

12.5.4 STANDARDS CHANGE REQUESTS

The standards change request form accompanies any new or updated standard that is to be uploaded into Powerco's Online Contracts Works & Network Operation Manual Application. The purpose of the form is to ensure that users of any standard can provide feedback on it.

12.5.5 IMPROVEMENT CULTURE

A culture of continual improvement is encouraged across all levels of the organisation. We encourage this by:

- Promoting it in our core behaviours.
- Actively participating in industry groups.
- Encouraging research, and developing activities.

12.5.5.1 CORE BEHAVIOURS

Two of the six staff behaviours that Powerco fosters are specifically designed to result in continuous improvement:

- **Intelligent** – we make informed decisions for the best outcome. We continually seek improvement and innovative solutions from our suppliers and ourselves.
- **Collaborative** – we work together with our partners, contribute our capabilities and provide timely support and consideration to achieve our collective goals.

These behaviours are reinforced and encouraged by positive recognition of those who exhibit them.

12.5.5.2 INDUSTRY PARTICIPATION

Powerco encourages its employees to look beyond the confines of the company and to collaborate with the wider industry. This leads to our people actively participating in and leading various forums such as:

- Electricity Engineers Association
- Electricity Networks Association
- Business Energy Council

12.5.5.3 RESEARCH AND DEVELOPMENT ACTIVITIES

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

12.5.6 IMPROVEMENT OF ASSET PORTFOLIO

The IS Governance Group is responsible for planning and prioritising the non-network investment required to maintain and support existing Information Communications and Technology (ICT) capabilities and services. Its recommendations are passed to the Non-network Investment Committee, which reviews, approves and monitors progress of programmes and projects.

'Find and Fix' is used for any maintenance job identified by a service provider. It can be used to authorise any <$800 cost on the spot.

The defect process is used to record and schedule any asset portfolio improvements identified in the field.

12.6 RISK ASSESSMENT

Our strategies outline how we plan to deploy resources to manage uncertainties in the future. The analysis techniques used in these strategies are crucial in assessing and informing the risk posed. Some of the primary assessment techniques are summarised in the section below.

12.6.1 NETWORK DEVELOPMENT – VoLL

Network development planning processes address the risk of customers not being served because of network capacity or security constraints – a functional failure of assets or groups of assets. The impact of customers not being served is often quantified in terms of Value of Lost Load (VoLL).

The risk is managed through demand forecasting, maintaining knowledge of major customer investment plans, and responding to identified risks by increasing capacity, providing system redundancy, or instituting load management measures.

Powerco's Network Development approach is discussed in more detail in Chapter 10.

12.6.2 NETWORK DEVELOPMENT – RELIABILITY

Reliability engineering refers specifically to network automation projects designed to minimise the duration of supply outages, thus reducing System Average Interruption Duration Index (SAIDI) risk.

Powerco's automation plans are based on analysis of historical network SAIDI profiles to identify where the most significant SAIDI risks exist, and therefore where the best gains can be made. We then devise automation strategies to minimise the outages or their impact.

12.6.3 RENEWAL AND MAINTENANCE PLANNING – CBRM, RCM

Fleet planning involves consideration of historical failure trends, asset health, asset criticality (ie the relative service level consequences of asset failure), and asset survivor curves. We then derive a measure of service level risk.

Condition-Based Reliability Modelling (CBRM) is a tool that is increasingly being used to quantify fleet risk and to prioritise renewal expenditure. Copperleaf C55 is another tool that has recently been introduced to help rank the importance of proposed projects.

Reliability-Centred Maintenance (RCM) is used to determine the most appropriate maintenance approach for each asset fleet. The RCM approach uses a combination of preventive maintenance, predictive maintenance, real-time monitoring, and run-to-failure (also called reactive maintenance) techniques to reduce the probability of failure.

12.6.4 DEFECTS MANAGEMENT – DEFECT RISK ASSESSMENT TOOL (DRAT)

Powerco uses a colour-coded grading system for identified defects that reflects the priority for repair. The grading is derived from criticality analysis that considers public and personnel safety and customer service level risks.

12.6.5 CONTINGENCY PLANNING AND RESILIENCE ANALYSIS

High Impact Low Probability (HILP) events are rare, but when they do occur they have a more significant impact than that usually catered for in our system planning criteria. They include extended outages (eg snow loading causing multiple pole failures), major common mode failure events (eg a control centre fire), and domino effect failures (ie failures causing related systems to fail).

Such events are hard to predict because there are multiple failure modes. Well-known examples include:

- The Penrose cable trench fire in Auckland.
- The 220kV earth shackle failure at Otahuhu.
- The Christchurch earthquake.
- Powerco cascading pole failures near Taihape as a result of unexpected snow loading.

HILP events generally have a return period 10 times greater than the life of the asset for common mode and domino effect failures, and/or return period of more than 500 years for extended outage events.

Generally, our mitigation of HILP events focuses on making the network as resilient as possible to reduce the probability of asset failure during contingent events, to reduce the impact of failure, and to facilitate easier restoration.

Resilience measures employed by Powerco include:

- Building diversity into our network, not only from an electric circuit perspective (focus of our planning criteria), but also from a geographic and natural disaster perspective.
- Maintaining our assets to updated codes, eg NBS standards and AS7000, results in assets being progressively upgraded to ensure resilience to earthquakes and improved response to storm events.
- Improving our operational response by having appropriate contingency plans in place for extended outage scenarios.
- Taking an active role in Civil Defence and Emergency Management (CDEM) activities associated with any failure to reduce vulnerability, eg establishing contingency plans to deal with the consequences of unknown modes of failure.
- Considering diversity in our designs to improve resilience to type issues as well single event failures ie having a mix of cables and overhead lines as they have different failure modes.
- Geographically diverse and multiple supply points on the network mean that natural disasters will impact only part of our network. This includes considerations such as creating independent physical routes for redundant circuits feeding important load, or multiple grid exit points limiting the impact of upstream failure to localised areas.
- Standardised equipment utilised on our network means equipment can be reallocated/rebuilt easily in the event of failure. Standardised designs and components also make them easy to repair and reconfigure if necessary.
- Holding appropriate critical spares to support easier repair and restoration.
- Multiple control options mean that we have alternative control and emergency management capability available if the New Plymouth facility is disabled.

Improving our HILP analysis

The above Business as Usual (BaU) asset management practices provide multiple layers of protection for HILP risks. However, our improving maturity will include new ways to analyse the risk. This includes understanding the impact of natural disasters on vulnerable portions of our network.

We are considering undertaking a lifelines analysis to better understand these factors. This will allow us to identify the most vulnerable portions of our network, allowing us to target resilience investments.

13 ORGANISATION AND PEOPLE

13.1 CHAPTER OVERVIEW

In this chapter we discuss our organisational structure and responsibilities, in particular in relation to electricity asset management. We also cover our asset management governance arrangements and competency management.

13.2 CORPORATE RESPONSIBILITIES

13.2.1 THE BOARD

Our Board provides strategic guidance, monitors management effectiveness, and is accountable to shareholders for the company's performance. From an asset management perspective, it does this by endorsing key documentation, establishing our business objectives, approving the strategies needed to achieve those objectives and monitoring our delivery to this.

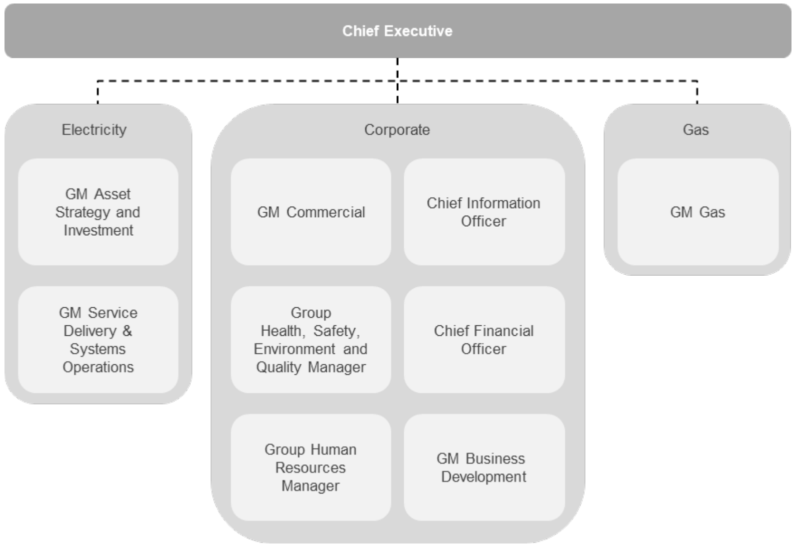
The principal asset management responsibilities of the Board are listed below:

- 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 Asset Management Plan (AMP), which includes our medium-term (10-year) investment forecasts and our shorter-term expenditure plans.
- The Board's Regulatory Committee is responsible for ensuring that our AMP meets regulatory requirements.
- Based on the AMP forecasts, the Board approves our annual electricity Capex and Opex budgets. This includes our prioritised Capital Works Plan, the allowance for reactive works, maintenance and vegetation management programmes, System Operations and Network Support (SONS), and Business Support.
- The Board sanctions individual operational or capital projects involving expenditure greater than $2 million, and the divestment of any assets with a value greater than $250,000. Again, one of the main factors the Board takes into account when considering a project is its alignment with the AMP.
- The Board receives monthly reports that include performance reports regarding the status of key work programmes, key network performance metrics, updates on high-value and high-criticality projects, and the status of our top-10 risks. It also receives audit reports against a prescribed audit schedule. It uses this information to provide guidance to management on improvements required, or changes in strategic direction.
- The Board's Audit and Risk Committee is responsible for overseeing risk management practices and to review audit findings.

13.2.2 THE EXECUTIVE MANAGEMENT TEAM

Our organisational structure is based on two asset management-focused units – the Electricity and Gas divisions – with the support of six functional units. The makeup of our Executive Management Team (EMT), which reflects this organisational structure, is illustrated in Figure 13.1. This structure allows the Electricity division to focus on core activities and decisions and access specialist skills and advice as required.

Figure 13.1: Executive Management Team structure



The Electricity and Gas divisions hold overall responsibility for asset investment, operational management and commercial management of each business line. Support is provided from each of the specialist functional units.

13.2.3 CORPORATE SUPPORT

The **Information Services business unit** manages information and communications technology (ICT) non-network assets, shared between the Electricity and Gas divisions, as well as Electricity network assets such as SCADA, critical communications to field workers, devices and substations, and the corresponding cyber security protections. It provides user support, operations and management of ICT systems for both network operations and corporate functions.

Other functions include cyber security risk management, business process analysis, change management and project services and asset information lifecycle management.

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

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

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

The **Commercial group** manages interactions with our regulators, customers and large industrial and commercial customers. The Regulatory team is involved in developing regulatory strategy, leading our regulatory submissions and disclosures – of which the AMP forms a part, engaging in the rule-setting processes and ensuring that we understand and comply with regulatory requirements. The Customer team is the conduit for communicating with our customers, communities and stakeholder groups. The Commercial team manages our interactions with retailers, and larger industrial and commercial customers. Finally, the Legal and Property team provides internal legal support services, managing the contractual arrangements, such as commercial agreements, use-of-system agreements, and providing easements and access to property for the development of our network.

Business Development is responsible for exploring and investing in new products, solutions and services that complement our core gas and electricity network businesses and creates new shareholder value. The scope of this activity extends from traditional energy infrastructure investments through to relevant adjacencies in the energy market and generation arena. Most notable of these is Base Power Ltd, which is our unregulated subsidiary focusing on remote area power supply (RAPS) solutions.

13.3 CORE ELECTRICITY ORGANISATION STRUCTURE

The Electricity division has specialised teams reporting to two general managers, as depicted in Figure 13.2.

Figure 13.2: Electricity division structure

13.3.1 ASSET STRATEGY AND INVESTMENT

This team is responsible for translating the Asset Management Policy into a practical Asset Management Strategy (AMS) and AMP. It has overall responsibility for our electricity investment programmes and longer term network strategy, including our evolution to a new energy future

The functions of the Asset Strategy and Investment team are:

Network Development

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

Fleet Management

The Fleet Management team is responsible for the asset management of existing electricity network assets, which are divided into several fleets. This involves the preparation of renewal and maintenance plans based on performance and condition assessment, conducting specialised engineering studies, preparing asset management strategies and documentation, capital expenditure plans, concept designs, project briefs (high-level project descriptions and justifications) and rolling work plans. It also manages our maintenance and vegetation management strategies.

Investment Optimisation

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

Network Information

The Network Information team supports our asset management by focusing on the quality of the network and asset information we collect and hold. This includes managing our data standards, governance and quality control, running data quality improvement programmes (including on the low voltage network) and delivering regulatory reporting and disclosures.

New Frontiers

This is a new team created in 2020 to consolidate and spearhead our network evolution and future strategy development. It includes our previous network transformation function, as well as a number of network specialists focusing on leading the ongoing adaption of our network. Its primary focus areas are:

- Network transformation, with a bias towards emerging network and customer technology.
- Developing new and updated network strategies for our core network, including evolving our network architecture, automation and security standards.
- Enhancing our visibility and operation of the low voltage networks.
- In-depth data analytics to enhance network operations and efficiency, applying emerging mass data processing and visualising techniques.

Chief Engineer

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

13.3.2 SERVICE DELIVERY AND SYSTEMS OPERATIONS

This team is responsible for the efficient operation and maintenance of our network as well as the delivery of capital and maintenance works plans. In addition, the team manages new customer connections on the network.

Network Operations

Day-to-day operation and access to the network is managed by the Network Operations Centre (NOC). This includes controlling fault restoration, network shutdowns and switching, coordinating the response to network outages, managing the load control process, maintaining the Supervisory Control and Data Acquisition (SCADA) system, and ensuring adherence to contractor competency requirements. This team also oversees urgent repair works.

Delivery Performance

Amber category defects and the day-to-day oversight of the maintenance and vegetation management delivery is provided by the Delivery Performance team. It investigates unplanned network outages in the first instance to establish root cause and recommends remedial actions. The maintenance delivery team oversees the effective and efficient delivery of the scheduled maintenance plan. The vegetation management team oversees delivery by our vegetation contractors.

Works Delivery

The Works Delivery team manages the execution of work plans through our three tier-1 service providers, as well as numerous tier-2 suppliers that are accessed through contestable tender processes.

Commercial and Contracts Management

This team manages the contractual relationships with service providers and suppliers, sets and monitors competency requirements, and monitors contractor performance. It is also responsible for our procurement policy and overseeing spares management.

Customer Solutions

The Customer Solutions team manages the connection of new mass market customers to our network. This includes the engineering and planning of optimal technical solutions, agreement on commercial arrangements, and managing of contractors appointed to do the physical connection work. This team coordinates with the Electricity division to understand the impact on the network of new connections.

Design

The design team supports delivery functions by providing protection, substation and overhead design services, and managing external design consultants.

Electricity Programme Management

This team monitors the overall electricity programme delivery, providing visibility to the rest of the electricity business on current and expected delivery status and resource requirements. This is essential to support early intervention to avoid potential delivery shortfalls or constraints.

13.4 OUTSOURCING MODEL

The bulk of our field services are provided by external contractors. We have developed a close working relationship with these contractors to provide essential services on our network. These services are managed under a series of foundational agreements. Table 13.1 summarises our contract arrangements with our major service providers.

Table 13.1 Summary of our major contracts

CHARACTERISTICS	NAME	KEY CONTRACTS
Guaranteed programme of works **Minimum agreed commitments**	CPP Field Services Foundation Agreements	2 x contractors
One-off projects **Pre-agreed terms of engagement**	Master Field Services Agreements	7 x contractors (variable)
Division based on work type and value	Annual Contestable Vegetation Management Services Agreements	3 x contractors (variable)

13.5 ASSET MANAGEMENT GOVERNANCE

We have established several internal asset management governance groups to ensure a prudent delivery of our objectives.

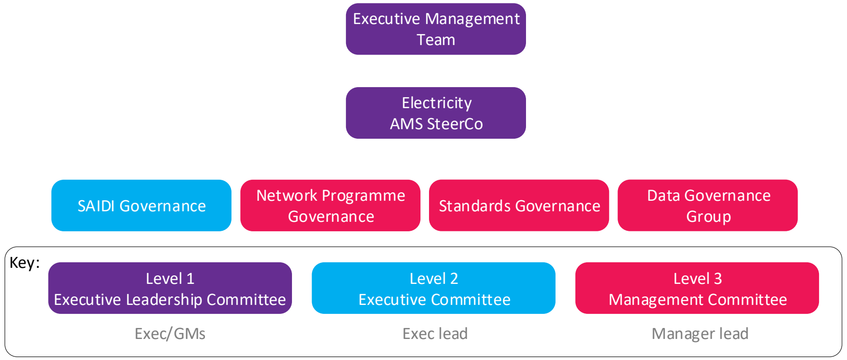
Internal governance bodies are at the management (not Board) level. They are cross-functional and often cross-disciplinary teams with a targeted mandate to lead, review and report in particular areas.

Our Asset Management Governance Framework defines the committees, steering groups and boards used within the AMS. These structures provide a single point of control and governance for specific activities. It also outlines a set of procedures to formalise the key interactions and responsibilities across our business.

13.5.1 NETWORK GOVERNANCE GROUPS

In Figure 13.3 our network governance groups are illustrated.

Figure 13.3: Overview of network governance groups



Asset Management System Steering Committee

The Asset Management System Steering Committee is an executive level committee responsible for our electricity operations. It is accountable for, and provides strategic guidance and oversight on, the development and implementation of our AMS.

SAIDI/SAIFI Governance Group

The SAIDI/SAIFI Governance Group provides the structure, develops strategies, and coordinates the activities of our business to ensure that our planned and unplanned reliability quality targets are met.

Network Programme Governance Group

This committee ensures that our programmes for vegetation, maintenance, renewal and growth projects meet our Asset Management Objectives, are planned sufficiently far ahead, are sufficiently resourced and are being achieved.

Standards Governance Group

This committee includes appropriate managers or engineers across Asset Strategy and Service Delivery with in-depth technical appreciation of the standards applicable on the network. Its primary role is to review and approve new or changes to Network Standards.

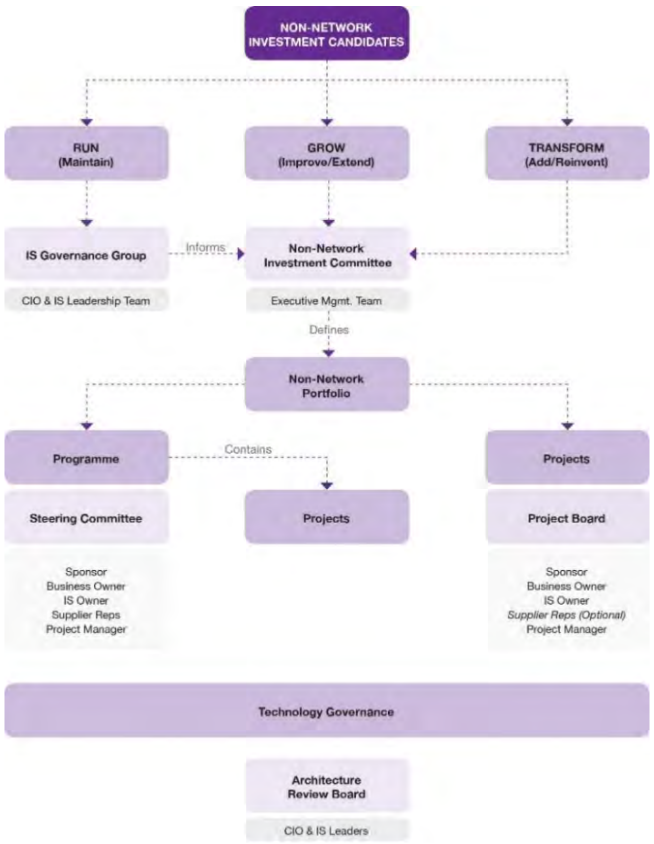
Data Governance Group

This committee is accountable for the governance of all Powerco business data. It oversees and coordinates several data communities from different parts of the business. The intent is to maintain a culture of ongoing data improvement through policies, procedures, standards, ownership, accountability, communication and teamwork.

13.5.2 NON-NETWORK GOVERNANCE GROUPS

The interactions between these groups and our operational and project teams are summarised in Figure 13.4.

Figure 13.4: Overview of non-network governance groups



IS Governance Group

This group is responsible for planning and prioritising the non-network investment required to maintain and support existing ICT services. The outputs from this group inform the wider Non-Network Portfolio of Information System (IS) expenditure required to meet existing performance and quality criteria.

Non-Network Investment Committee

This committee is responsible for defining the composition of the Non-Network Portfolio to ensure it delivers maximum value to the organisation. Its key functions are to review and approve expenditure in the form of programmes and projects, and review progress of initiatives within the portfolio to maintain alignment with organisational priorities. This requires a balancing of investment in existing ICT-based capabilities against pursuing development of new capabilities.

Steering Committee/Project Board

The role of these groups is to provide governance to a programme (comprised of multiple projects) or individual project within the Non-Network Portfolio. They maintain oversight of the relevant initiative(s) and act as a guidance function with the appropriate authority to endorse key decisions, govern programme/project-related risks, and ensure continual alignment of the initiative against organisational needs.

Architecture Review Board

This board ensures consistent alignment with business strategies and provides strategic and tactical direction on ICT investments. It fulfils a key technology governance role, supporting the Chief Information Officer (CIO) in setting and implementing our strategic technical architecture.

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

- Degree of alignment with our I&T Strategy, platform strategies and 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.

13.5.3 ASSET MANAGEMENT PLANNING RESPONSIBILITIES

We have broadly eight levels of asset management planning activity, ranging from strategic decisions by the Board and CEO, to approval of operations and maintenance decisions by operations staff and field crew. Each layer of governance is designed to provide clear ‘line-of-sight’ between our Corporate Objectives and asset management activities.

Table 13.2 provides an overview of these expenditure planning governance levels.

Table 13.2: Asset management planning responsibilities

LEVEL	PURPOSE	RESPONSIBLE	DOCUMENTATION
Corporate strategy	Setting high-level objectives and targets for the company.	CEO, Executive	Vision, Mission and Values, Corporate Objectives, Asset Management Policy, Business Plan
Asset Management Strategy	Supports Corporate Objectives, sets Asset Management Objectives, goals and targets.	GM Asset Management and Network Transformation	Asset Management Strategy, Asset Management Framework
Asset Management Plan	The plan to implement the Asset Management Strategy.It sets out the 10-year investment plan, drawing on the short, medium, and long-term planning documents.	GM Asset Management and Network Transformation	Asset Management Plan
Long-term planning	The plan for development of the network and its bulk supply points to meet the needs of customers in the long term – up to 20 years.	Network Development Manager, GM Asset Management and Network Transformation	Long-term Network Development Plan
Medium-term planning	Fleet, network development and operating activity plans, covering the next 10 years, including expenditure forecasts.	GM Asset Management and Network Transformation, Network Development Manager. Asset Fleet Manager, Investment Optimisation Manager, Asset Analytics Manager, Network Transformation Manager	Network Development Plan, Fleet Management Plans, Maintenance Strategy, Network Evolution Plan, Deliverability Plan
Electricity Works Plan	Planning of Capex and maintenance delivery programmes.	GM Asset Management and Network Transformation, Network Development Manager, Asset Fleet Manager, Operations Manager	Two-year Rolling Works Plan, Annual Maintenance Plan
Detailed project plans	Detailed planning of project and activity delivery.	Network Development Manager, Asset Fleet Manager	Project briefs, business cases and Board papers
Works Delivery and field operations	Oversight of capital project and maintenance delivery.	Works Delivery Manager, Project Managers, Network Operations Manager	Detailed construction schedules, detailed maintenance schedules, outage schedules, tendering material

13.5.4 DELEGATED FINANCIAL AUTHORITY

The Delegated Financial Authority (DFA) policy aligns with our corporate governance charter and group delegations of authority. It sets out expenditure limits that each manager is authorised to approve, the process for approving payments, and the cross-checks built into this. Application of the DFA policy is externally audited on an annual basis.

Expenditure limits apply to capital and operational expenditure, network or non-network, and budgeted or reactive. The DFAs for our Electricity division are listed in Table 13.3.

Table 13.3: Delegated Financial Authority limits

LEVEL	CAPEX LIMIT	OPEX LIMIT
Board	>$2m	>$2m
CEO	$2m	$2m
GM Asset Strategy and Investment	$1m	$1m
Senior managers[64] (up to, depending on role)	$700k	$700k
Other managers (up to, depending on role)	$400k	$400k

13.6 MANAGING OUR COMPETENCIES

The people who work in our organisation are of vital importance in managing our business. Competency management includes the processes used to systematically develop and maintain an adequate supply of competent and motivated people to fulfil our Asset Management Objectives, including arrangements for managing competence in the boardroom and workplace.

13.6.1 GRADUATE DEVELOPMENT

Recruitment of experienced engineers remains problematic, given their short supply. This is particularly acute in areas such as network protection and network development planning.

The Powerco Graduate Programme has been designed to help give newly graduated engineers or technologists an early career boost and to help meet our future skills requirements.

Powerco's Graduate Programme provides a framework within which aspiring technical engineers can develop both professional and personal skills to assist them in their future career. The framework provides for the following:

- A structured introduction for graduates to the electricity industry and the professional working environment.
- Graduates working in roles that provide an appropriate level of challenge and that deliver a solid foundation and understanding of our business from both a technical and operational perspective.
- A structured rotation programme through different departments over a three-year period. This contributes to the development of a broad base of both technical skills and cross-company relationships through working in diverse teams, and with colleagues at various levels of the business.
- Graduates work on projects and job assignments that are aligned with their development needs, Powerco's business needs and, wherever possible, the individual's interests so that they gain an understanding of their desired longer-term career path.
- Graduates are supported through coaching and mentoring by experienced, competent staff.

Following completion of the programme, graduates are generally offered Powerco roles which, as far as possible, meet their personal preferences. (It is also possible for graduates to apply for permanent roles before completing the programme if they have identified the area in which they wish to continue their career).

13.6.2 TRAINING

The EMT, with HR support, is responsible for organisational development strategies. Implementation generally happens within business areas.

Core training strategies reflect required development areas that have been identified through business planning, employee survey feedback and individuals' review and development processes. Examples of this type of training include executive and senior management development, behavioural training (eg coaching skills) and work skills training.

Line managers are responsible for identifying the need for technical training in their areas and will generally address this directly. Where more complex, or widespread, needs exist, the HR team will assist.

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

13.6.3 CONTRACTORS' COMPETENCIES

We outsource most of our field staff requirements to our contractors. However, we remain responsible for ensuring that only competent staff work on our network. Therefore, we have a competency framework for our contractors to:

- Ensure all persons accessing or working on our networks are competent for the tasks they undertake.
- Assist the safety of contractors, staff and the public through providing direction on appropriate training, development and certification.
- Ensure safe working practices and procedures are consistently applied and to a high standard.
- Assist personnel to effectively identify, manage and minimise risk related to accessing and working on our networks.

The competency certifications are closely aligned with the New Zealand Qualifications Authority (NZQA) unit standards framework.

14.1 CHAPTER OVERVIEW

This chapter gives a brief overview of the information systems (IS) that are at the core of asset management at Powerco. This relates primarily to information that we use to plan, design, operate, monitor and maintain the electricity network and its performance, but also extends to our activities for Information Disclosure, regulatory and statutory reporting, customer management and billing management.

Having easy access to accurate and useful information is essential for an effective electricity utility. Therefore, information is considered a valuable company asset that sits alongside our physical assets and demands the same care in protecting and managing the asset throughout its lifecycle.

Asset management information systems are predominantly software-based applications, which can range from extensive, integrated, enterprise-wide systems to stand-alone processes or spreadsheets. They also include paper-based and photographic records, maps and drawings.

The ultimate objective of these systems is to enable an organisation to provide comprehensive, easy-to-access asset information, and to ensure that this is accurate and consistent.

14.2 INFORMATION TECHNOLOGY ARCHITECTURE

We have adopted a platform approach where all the information and technology capabilities that will be required to support Powerco's business throughout this planning period are assembled into seven logical groups or platforms. This forms our future state architecture, as shown in Figure 14.1, and will see the addition of three new platforms: Customer Experience, Business Ecosystem and Internet of Things.

It is important to note that we have not specified a separate cyber security platform as this is a component of each of the platforms.

Figure 14.1: Technology infrastructure platform architecture (future state)

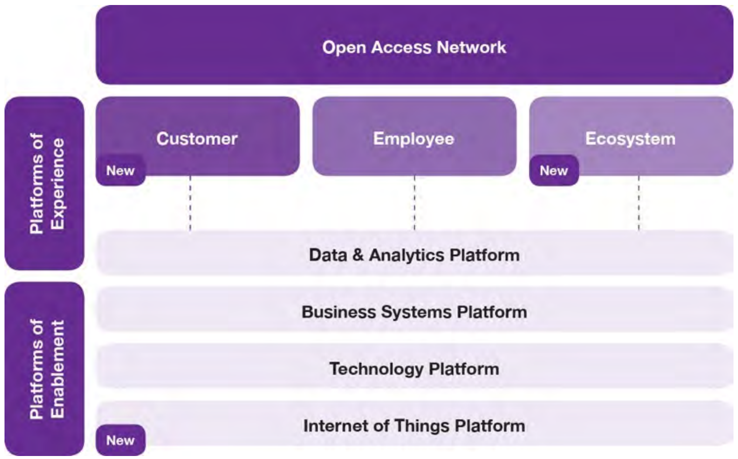


Table 14.1: IS architecture

TERM	DESCRIPTION	KEY SYSTEMS
Customer Experience platform	Contains the main customer-facing elements, such as customer portals, multichannel commerce and customer apps.	Salesforce CRM, SiteCore Experience Platform
Employee Experience platform	Consumerised tools and services to aid employee engagement, collaboration and productivity. This includes the management of unstructured information, such as designs, standards and procedures.	Microsoft Office 365 email, Teams, Sharepoint, Meridian, Cisco Unified Communications
Business Ecosystem platform	Supports the creation of, and connection to, external ecosystems, marketplaces and communities. API management, control and security are its main elements.	Dell Boomi, SAP PO/PI, Microsoft Azure API Gateway
Data & Analytics platform	Contains data management, business analytics and advanced analytics capabilities. Data management programs and analytical applications fuel data-driven decision-making, and algorithms automate discovery and action.	SAP Business Objects, Data Services and Information Steward, Tableau Online, SQL Server Datawarehouse, Google Cloud Platform, Alation Data Catalog

TERM	DESCRIPTION	KEY SYSTEMS
Business Systems platform	Supports the back office and operations, such as ERP, ADMS and information management. For Powerco these include:	SAP S/4 HANA, ESRI GIS, Clearion vegetation management, Junifer Billing, Customer Works management system, OSII SCADA & OMS, Safety Manager, Autocad, OSI PI
Technology Infrastructure platform	Traditional infrastructure and communications services (telephony, collaboration, corporate network).	Hytera DMR, Zetron Radio Console, Juniper WAN, Cisco LAN, Microsoft Hyper-V, Microsoft SCOM, CyberX, CrowdStrike
Internet of Things	Connects physical assets for monitoring, optimisation, control and monetisation. Capabilities include connectivity, real-time data processing/ analytics and integration to core and operational (OT) systems.	HiveMQ MQTT broker, OSI PI

14.3 BUSINESS SYSTEMS USED TO MANAGE ASSET DATA

The main applications comprising the Business systems platforms used to manage asset data are described in more detail below.

14.3.1 ENTERPRISE RESOURCE PLANNING (ERP) SYSTEM

We have recently implemented a new ERP using Systems, Applications & Products in Data Processing (SAP).

It provides a single, integrated software system that connects our financial and works management (projects, maintenance etc) systems, and is the master of non-spatial asset and financial data.

SAP also provides financial tracking, works and maintenance programming, works and maintenance management, procurement, asset information database, asset condition database, and defect and rotable asset management.

14.3.2 MOBILE WORKFORCE MANAGEMENT

We have also integrated a mobile workforce management solution (MyPM) to provide field staff with real-time access to SAP. All these capabilities are interconnected, which will lead to operational efficiency gains, the primary benefit of an ERP. This application enables field capture of asset condition, maintenance activity results and defects. Data entered in MyPM, and synchronised with SAP, allows us to generate key reports.

MyPM 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.

14.3.3 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. Importantly, it is also where we maintain information about the interconnectivity of our assets – essentially the master model of our network.

It also distributes and informs other systems about our current assets.

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.

14.3.4 ASSET INVESTMENT PLANNING AND MANAGEMENT (AIPM)

Our AIPM tool, is a software package that allows us to optimise investment for our portfolios. We use Copperleaf's C55 product (known internally as Copperleaf), to help with our portfolio optimisation process. Copperleaf is used globally by utility companies to identify annual programmes of works, based on asset condition information.

The aim of utilising Copperleaf is to use our understanding of our asset risk position, to efficiently identify and validate investment solutions. The program allows us to quickly explore multiple varied scenarios to make optimal use of our limited resources.

The implementation of Copperleaf represents a significant step change in our portfolio optimisation capabilities.

14.3.5 SCADA MASTER STATIONS, SCADA CORPORATE VIEWER, AND PI SYSTEM

We operate OSI Monarch Supervisory Control And Data Acquisition (SCADA) in both our regions. The master stations to control and monitor our network are highly available and are located in each of our data centres. In the event of a failure, the SCADA support team is able to safely de-energise parts of the network from another location.

Monarch Lite provides real-time access to users outside of our Network Operations Centre (NOC). This application provides users with access to real-time network information for use in planning and network management.

The OSIsoft PI system specialises in the collection, processing, storage and display of time-series data.

14.3.6 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 faults reported by customers and retailers. Our 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 installation control points (ICPs). This information is then given to service providers so they can dispatch a resource to resolve the fault.

OMS is also used as the fault database to produce external reports for the Commerce Commission and Ministry of Business, Innovation and Employment, 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 System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) totals are reported monthly. An annual network reliability report is prepared for Information Disclosure purposes.

14.3.7 CUSTOMER 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 customers with a choice of prequalified contractors 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.

14.3.8 ENGINEERING DRAWING MANAGEMENT SYSTEM

The engineering drawing management system is based on BlueCielo Meridian and works in conjunction with AutoCAD drawing software. It is a database of all engineering drawings, including substation schematics, structure drawings, wiring diagrams, regulator stations, and metering stations. In addition, there is a separate vault that contains legal documents relating primarily to line routes over private property.

14.3.9 PROTECTION SETTINGS MANAGEMENT SYSTEM

This application provides us with a protection database to manage settings in our protection relays.

14.3.10 CUSTOMER COMPLAINTS MANAGEMENT SYSTEM (CCMS)

This is a workflow management system that maintains an auditable record of the lifecycle of a customer complaint. The application is designed to work within the Utilities Disputes' 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.

14.3.11 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 (HSEQ) team in supporting the management of personal protective equipment (PPE) and Health and Safety competencies for all our employees.

14.3.12 BILLING SYSTEM

Powerco receives consumption data from retailers and customers. Bills are calculated using the Junifer billing engine and invoiced from SAP.

14.3.13 VEGETATION MANAGEMENT SYSTEM

We use Clearion's Vegetation Management solution to identify, track and manage vegetation encroachment within our electricity networks.

14.3.14 OTHER SYSTEMS OF RECORD

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
- High Voltage (HV) drawings

14.4 INFORMATION SECURITY

Information security involves protecting information and information systems from unauthorised access, use, disclosure, disruption, modification, or destruction in order to provide integrity, confidentiality and availability. Information security at Powerco is managed by the Cyber Security team together with the Privacy Officer.

While our cyber security programme aims to manage the risk of attack on our electricity network assets, it also includes protection of our corporate environment. We “build in” security to everything we do.

We are also addressing increased risks relating to data privacy.

- Increased data sharing with partners and third parties leads to increased risks of data compromise, breach of privacy laws, and reputational damage.
- Legal and regulatory changes place more emphasis on privacy and security of personal data.

To address this we will undertake ISO 27001 certification for the management of sensitive customer information.

14.5 IT SYSTEMS IMPLEMENTATION AND CONTINUOUS IMPROVEMENT

Powerco’s strategy for information and communications technology (ICT) is to improve reliability, simplify operations, reduce costs and enable business agility. We are doing this by reducing the number of configurations, customisations, products and suppliers that we support.

We have adopted a platform approach where all the information and technology capabilities that will be required to support Powerco’s business throughout the planning period are assembled into seven logical groups or platforms, listed in Table 14.1.

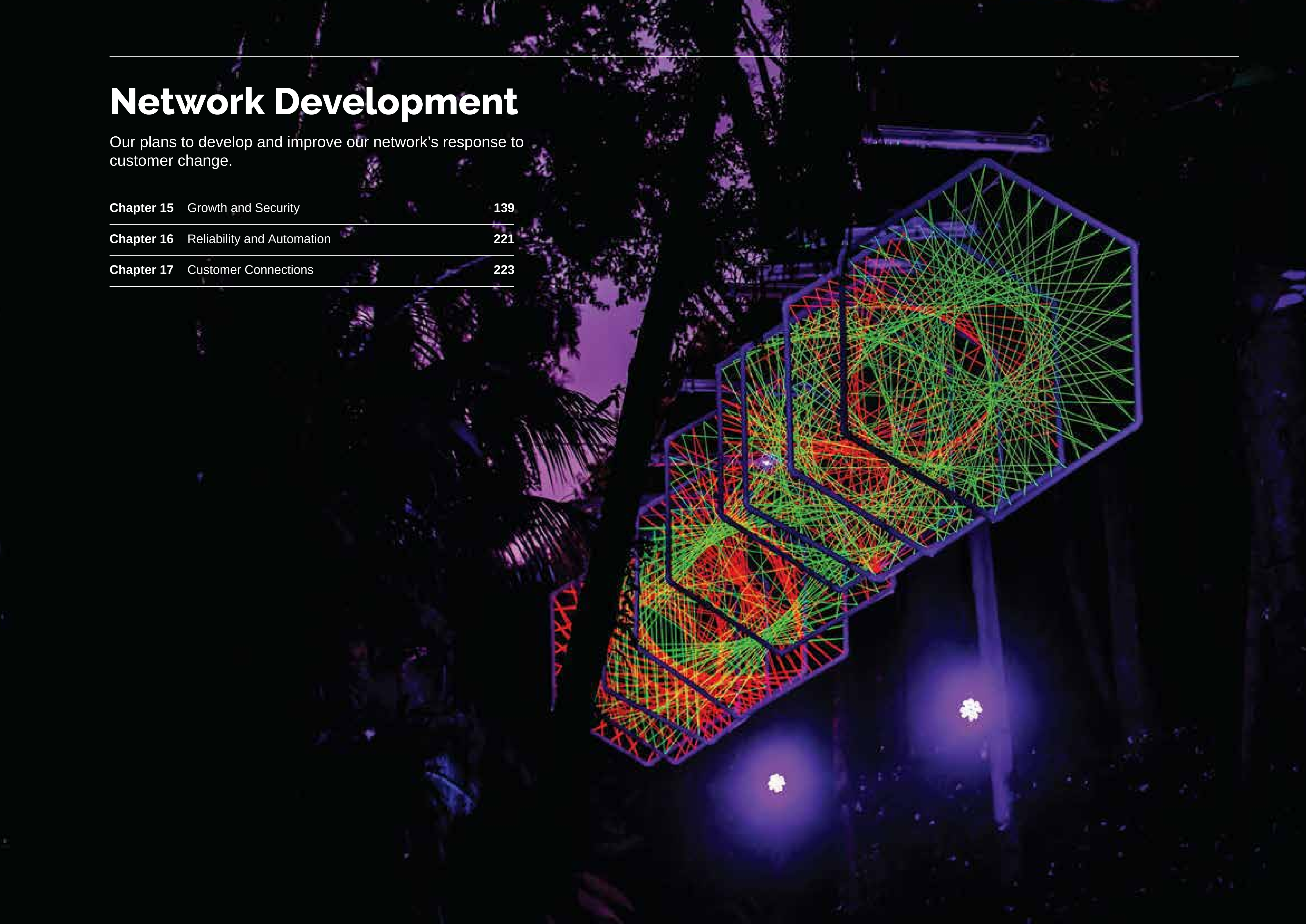
We have also adopted a “cloud first” strategy for non-mission critical IS services. This means that all new applications will be either software as a service (SaaS) or cloud hosted, and we will integrate solutions using integration platform as a service (iPaaS) and cloud-based application programming interface (API) management. Use of cloud services will help to drive standardisation, reduce implementation time, and bring operational benefits important for a midsize organisation such as Powerco.

Existing systems will transition to the cloud over time. We also plan ongoing investment to modernise and/or extend each platform to meet new business requirements.

Our approach for real-time systems, which includes operational technologies such as SCADA and NOC communications, is to continue to host on-premises.

Network Development

Our plans to develop and improve our network's response to customer change.



15.1 CHAPTER OVERVIEW

Most of our network continues to experience sustained demand growth, in contrast to the reported national trend. This is mainly driven by residential growth in areas such as Tauranga, and dairy and industrial growth in Waikato and Taranaki. We also anticipate some uplift in demand as a result of increased use of electric vehicles and conversion of (smaller-scale) industrial processes to electricity. These trends will continue to drive sustained Growth and Security investments.

For the Customised Price-quality Path (CPP) period, we demonstrated a need to significantly lift our investment in Growth and Security. 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. Our network planning is based on 13 discrete areas, which are described in this chapter, along with our main planned investments in each area. These larger investments are coming to a close, and we are now focusing our planning on the period beyond this.

Although less certain, following the CPP period (from FY24 on) we still foresee continuing growth in our regions, with associated demand growth. The rate of demand growth will be highly influenced by factors such as the uptake of electric vehicles, local generation, energy storage, electrification from process heat conversion, and the potential for customer energy trading over our network.

Long term, we see these factors likely to drive increased investment in our Growth and Security portfolios, and this is discussed further in this chapter. This will be balanced, however, by our introduction of probabilistic planning standards, which will allow us to better understand our reliability risks and plan more efficient investments to manage these risks. We have included more projects in our area plans in this chapter than we intend to execute overall. As we introduce probabilistic planning and better understand future demand trends we will update these area plans to be within our overall forecasts. Projects will only be committed for execution when the need is confirmed (as we do now).

These demand trend factors are uncertain and could lead to various future scenarios. But for any future scenario there is a clear underlying need to have better visibility of utilisation, power flows and power quality on all parts of the network, including the Low Voltage (LV) network. This is especially true for a network with multi-directional energy flows. The proposed investment associated with implementing this capability and supporting a transition to an open-access network is also discussed below.

15.2 GROWTH AND SECURITY PRINCIPLES

15.2.1 OVERVIEW

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

- **Major projects** – more than $5m, generally involving subtransmission or grid exit points (GXP) works.
- **Minor projects** – between $1m and $5m that typically involve zone substation works and small subtransmission projects.
- **Routine projects** – below $1m, including distribution capacity and voltage upgrades, distribution backfeed reinforcements (supports automation), smaller zone substation upgrades, distribution transformer upgrades, and LV reinforcement.
- **Open-access network investments** – investments in network monitoring, communications and power quality management to support our transition to an open-access network.
- **Communications projects** – to support improved control and automation of the network and provide voice communications to our field staff.
- **Reliability** – includes network automation projects to help manage the reliability performance of our network. These are discussed in Chapter 16.
- **Network evolution** – includes investments in network trials to understand our long-term network response to the 3Ds – decarbonisation, decentralisation and digitalisation.

15.2.2 STRATEGY AND OBJECTIVES

To guide our strategy for network development, we have defined a set of objectives, as listed below. They are linked with our overall Asset Management Objectives in Chapter 4.

Table 15.1: Growth and Security objectives

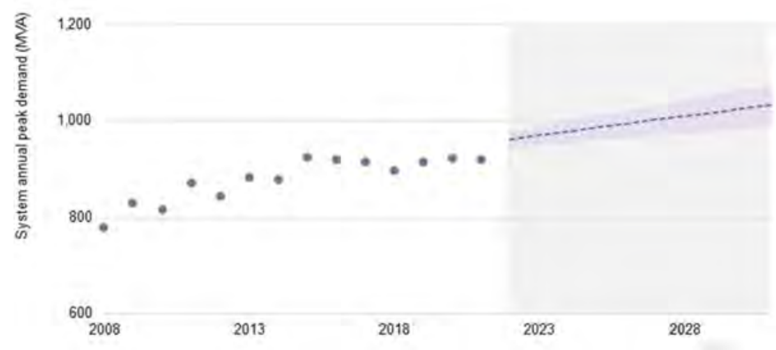
ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Use safety-in-design to ensure appropriate design of the network to provide for alternative supply during maintenance, reducing the need for high-risk live line work. These principles also help ensure the intrinsic safety, ease of 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.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Customers and Community	Minimise planned interruptions to customers by coordinating network development with other works.
	Consult with our customers regarding 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 to more effectively provide 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 Installation Control Points (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 of risk-based analysis and lifecycle 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.

15.3 DEMAND TRENDS

Our network has continued to experience steady and sustained growth. Figure 15.1 shows both the historical trend and our forecast of total system demand for the whole network.

Figure 15.1: System demand trend and forecast



The consistent growth exhibited is mainly a result of:

- Steady residential subdivision activity, especially in key areas such as Tauranga and Mt Maunganui.
- Significant changes in the demand of some larger industrial customers, especially from the dairy industry, and the oil and gas industry in Taranaki.
- Smaller contributions from irrigation developments, cool stores, and other agricultural loads.

Growth in each area of our network varies according to demographic changes and economic activity. The maps in Figure 15.2 and Figure 15.3 indicate annual forecast growth rates by planning area for the Western and Eastern regions.

Figure 15.2: Forecast demand growth in Western planning areas

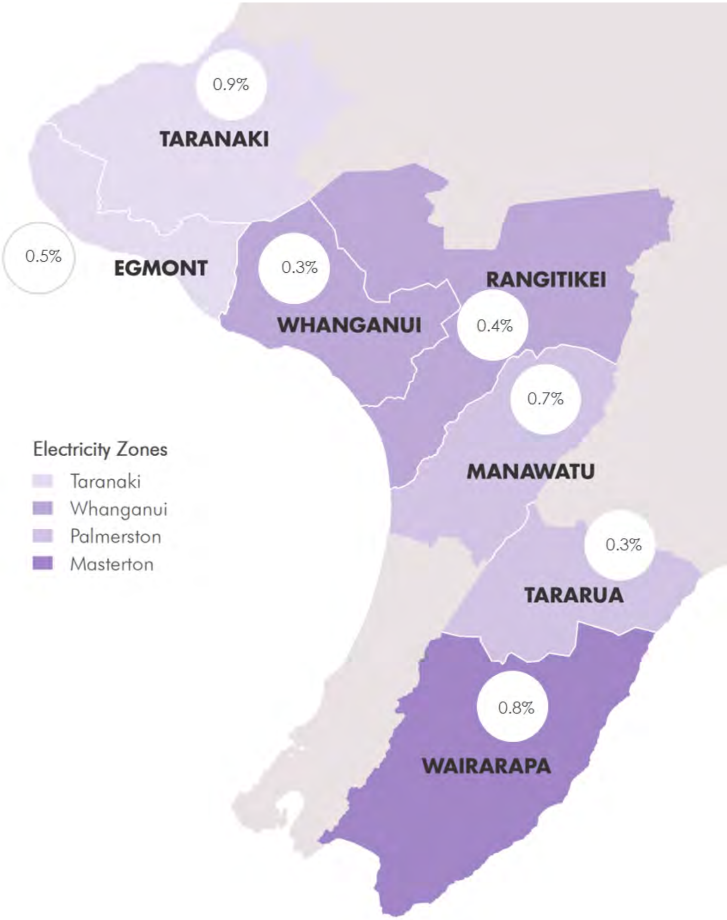
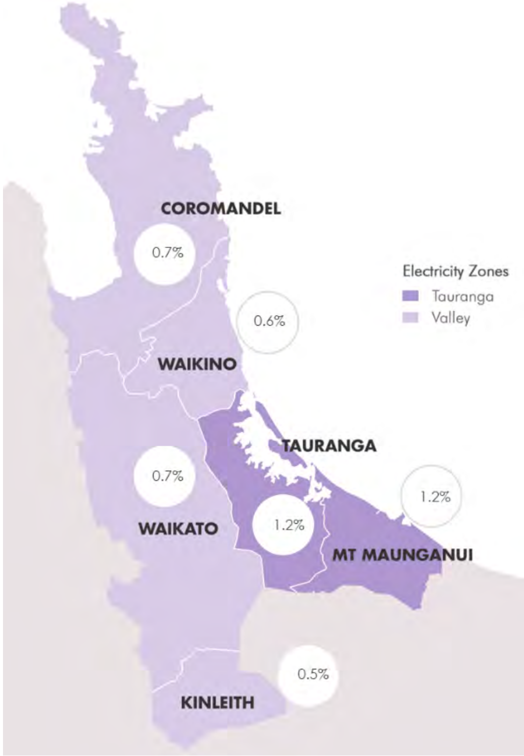


Figure 15.3: Forecast demand growth in Eastern planning areas



Higher growth is evident in areas such as:

- Tauranga and Mt Maunganui – population increase driving residential subdivisions and commercial/industrial developments.
- Coromandel – increased holiday and tourism activity in Coromandel and popular coastal areas.
- Taranaki – industrial, often associated with oil and gas.

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. In demand forecast tables, grey shading indicates that peak demand exceeds current firm capacity.

For more detailed descriptions of the options considered for our large Growth and Security projects, refer to Appendix 8.

15.4 COROMANDEL

Strong growth in the Coromandel area has created legacy security issues, which is coupled with increasing expectations from customers regarding the reliability of supply, particularly from holiday homeowners on the Coromandel Peninsula. 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 during the next 10 years is $57m.

15.4.1 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 based on tourism, 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 been operating in a closed loop after protection upgrades were made.

Figure 15.4: Coromandel area overview

Voltage constraints and, in places, thermal capacity constraints, 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 and rugged terrain. 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.

15.4.2 DEMAND FORECASTS

Demand forecasts for the Coromandel zone substations are shown in Table 15.2, with further detail provided in Appendix 7.

Table 15.2: Coromandel zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Coromandel	AA	0.5	4.3	4.5	4.6	4.8
Kerepehi	AA+	0.0	10.0	10.5	10.9	11.4
Matatoki	AA+	0.0	4.6	4.7	4.9	5.0
Tairua	AA	7.5	8.9	9.2	9.4	9.6
Thames T1 & T2	AAA	0.0	11.7	11.9	12.1	12.3
Thames T3	AA	6.9	1.8	1.8	1.8	1.8
Whitianga	AAA	0.0	16.5	17.3	18.1	19.0

Growth is forecast to be steady, especially on those substations that supply popular holiday towns. This is, to a degree, linked to national economic prosperity, since demand here grows in response to additional holiday accommodation.

Shaded years indicate that the demand exceeds the capacity we can provide with appropriate security. All of the Coromandel substations already exceed our security criteria in 2020. 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 (A & G Price) with customer-specific security requirements. This customer has recently closed a substantial part of its operation and the load has reduced accordingly.

15.4.3 EXISTING AND FORECAST CONSTRAINTS

None of the substations in the Coromandel area 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 – ie mostly during peak holiday periods/weekends.

Major constraints affecting the Coromandel area are shown below:

Table 15.3: Coromandel constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND 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.	The solution project is to construct the 10km **new Kopu-Kauaeranga 110kV-capable line**. The line will initially operate at 66kV until the need arises for 110kV conversion to meet demand growth.
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.	The solution project is to construct the 10km **new Kopu-Kauaeranga 110kV-capable line**. The line will create two dedicated circuits for Thames as a result, and separate the subtransmission supply for Thames from Coromandel, Whitianga and Tairua.
Coromandel, Whitianga and Tairua substations	Coromandel is supplied on a spur off a hard tee connection at Kaimarama and does not have its own dedicated 66kV supply circuit. It shares the same circuit as the long Tairua-Whitianga 66kV line. Hence, a fault anywhere on the Tairua-Whitianga line takes out supply to Coromandel at the same time. The three-terminal line configuration complicates protection coordination and affects the reliability of “distance to fault” elements.	The preferred solution project is a **new Kaimarama 66kV switching station.** This will give Coromandel a dedicated circuit from Kaimarama, thus improving the reliability of supply to Coromandel. This will also change the three-terminal arrangement to a simple radial network, simplifying the protection system. In the future, when the need to convert to 110kV operation arises, a new 110/66kV transformer can be installed at the switching station to enable this requirement.
Coromandel, Whitianga and Tairua substations	The Kopu-Tairua 66kV line has insufficient capacity to supply all three substations for a Kopu-Whitianga 66kV circuit outage.	The current preferred option is to carry out a **Kopu-Tairua 66kV line upgrade** project. This project will increase the thermal line capacity of the line. Separate 66kV voltage support will also be needed to address post-contingent voltage constraints (a separate project). In addition to this project, Powerco is evaluating an alternative non-network solution to install distributed generation to address the thermal and voltage constraints. Refer to Note 1.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Whitianga substation, Matarangi feeders	Two existing 11kV feeders supplying Matarangi are overloaded at times, have excessive ICP counts and insufficient backfeed capability.	Currently, the option is to build a **new Matarangi 66/11kV substation**. In conjunction with this option, we are also evaluating alternative non-network solutions. Refer to Note 1.
Whitianga substation, Whenuakite feeders	Two existing 11kV feeders supplying Coroglen, Cooks Beach, Hahei and Hot Water Beach from Tairua North feeder are overloaded at times, have excessive ICP counts and insufficient backfeed capability.	The preferred solution is to build a **new Whenuakite 66/11kV substation**. This will significantly improve network reliability in the area and cater for demand growth.
Kerepehi substation	Kerepehi substation is supplied via a single ~14km subtransmission circuit. An outage on this circuit results in loss of supply to the substation and there is limited 11kV backfeed to meet its security supply class criteria.	The solution is to provide **backup supply to Kerepehi substation** by installing distributed generators at Kerepehi substation that will offer emergency backup, peak lopping and grid scale microgrid capabilities.
Coromandel substation	Coromandel substation is supplied via a single ~24km subtransmission circuit. An outage on this circuit results in loss of supply to the substation and there is limited 11kV backfeed to meet its security supply class criteria.	The current preferred option is a **Coromandel substation alternative supply** to offer subtransmission peak reduction and islanding-capable backup generation at Coromandel township. Refer to Note 1.
Matatoki substation	Single transformer. The 11kV backfeed capacity does not provide the required security.	Preferred solution is to install a **Matatoki second transformer**, improving security of the substation and accommodating future load growth.
Tairua substation	Demand exceeds secure capacity of the two transformers.	Refer to Note 2.
Whitianga substation	The demand exceeds the existing (N-1) substation capacity. Several 11kV feeders at Whitianga substation have an ICP count well in excess of the targeted maximum for their respective security levels, with minimal 11kV backfeed.	The preferred solution is to build a **new Whenuakite 66/11kV substation.** Several 11kV feeders from Whitianga substation will reduce the ICPs count following commissioning of Whenuakite substation. **Matarangi 66/11kV substation** will also reduce Whitianga feeders that supply the Matarangi area.
Thames feeders	The 11kV feeders supplying the northern area of Thames are highly loaded with high ICP counts, and backfeed capability is constrained.	The preferred option is to install a **Thames new 11kV feeder** that will split existing Thames feeders and improve backfeed capabilities.
Kerepehi feeder	Ngatea feeder (KPE6) has an ICP count well in excess of the targeted maximum, is highly loaded within sufficient capacity for growth, and has end-of-line voltage issues. Because of the growth in these areas, performance will deteriorate over time.	The current option is to install a **Kerepehi new 11kV feeder** that will split existing Kerepehi feeders and improve feeder reliabilities. The new feeder caters for future development in the Ngatea area.
Matatoki feeder	Matatoki Kopu feeder is highly loaded, has insufficient spare capacity to cater for growth, and struggles to provide backup to adjacent 11kV feeders.	Currently, the preferred option is to install a **Matatoki new 11kV feeder** that will split the existing Kopu feeder into two, catering for future growth and improving backfeed capabilities.
Colville and Kapanga Rd feeders	The Colville (COR1) and Kapanga Rd (COR7) feeders in the Coromandel do not have backfeed capability, with a long loss of supply during a planned or unplanned outage.	The preferred option is to establish the **Colville-Tuateawa 11kV link** between the feeders to allow them to backfeed each other.
Kopu GXP	Peak load at Kopu is forecast to exceed the N-1 capacity of the supply transformers beyond 2030.	Refer to Note 3.

Notes:

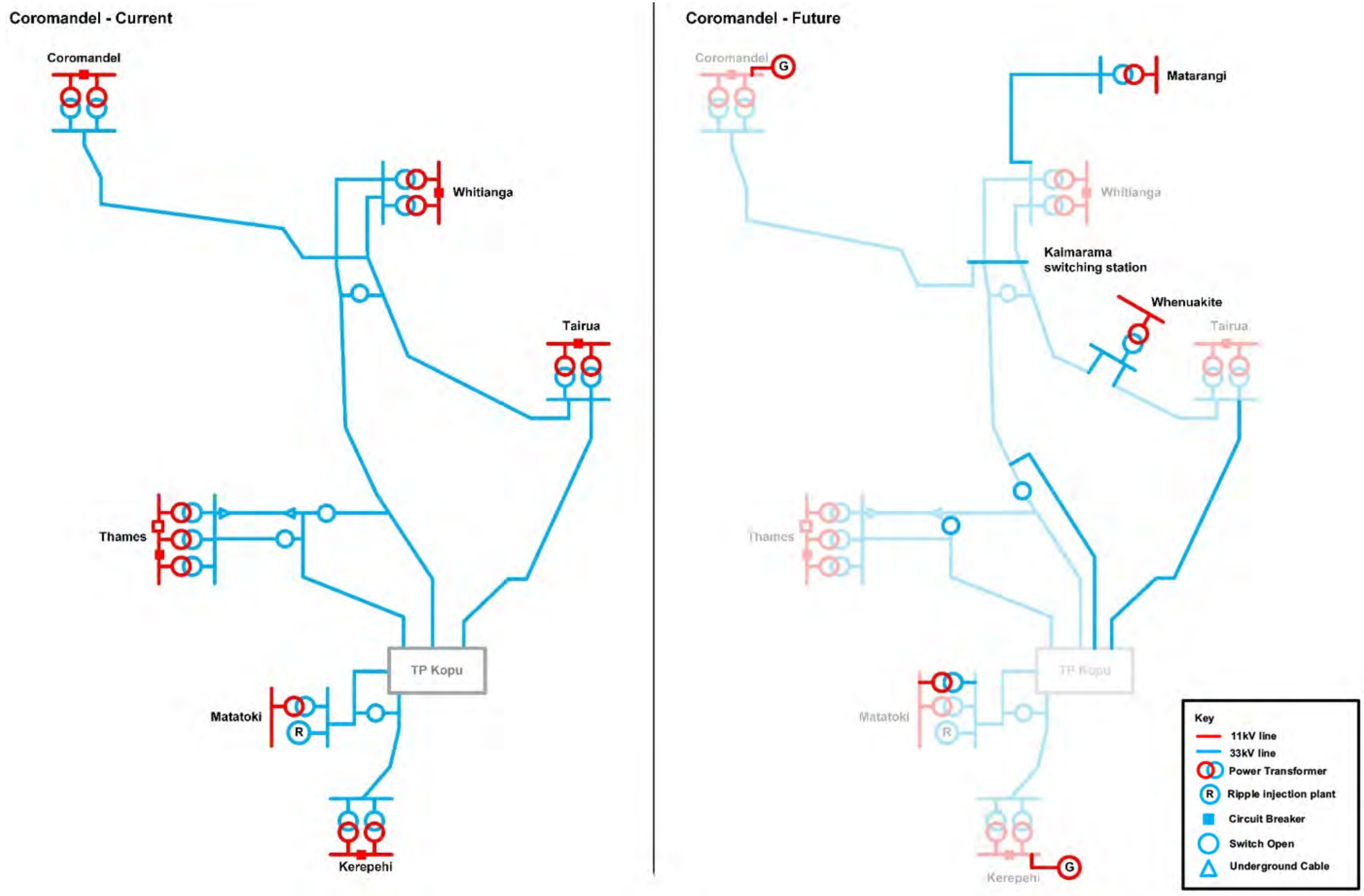
1. Coromandel area generation: This solution option is to introduce strategically scattered distribution generation (DG) units spread across the Coromandel Peninsula on the 11kV network to resolve a collection of the identified network issues in a cost-effective manner. Issues addressed are:

- **Kopu-Tairua line thermal constraints** – DG will offer demand side reduction of peak load and provide regional voltage support during Kopu-Whitianga outage.
- **Matarangi substation** – One of the preferred locations for DG is at Matarangi to offer peak reduction on the 11kV network.
- **Coromandel substation alternative supply** – DG to offer subtransmission peak reduction and islanding-capable backup generation at Coromandel township.
- **Tairua-Coroglen line thermal constraints** – DG will offer demand side reduction of peak load and provide regional voltage support during Kopu-Whitianga outage.

   Before selecting a preferred option(s) to address these network issues we will engage with local stakeholders on their price/quality preferences, including other potential options.

2. The risk of lost supply with these transformers is minimal and can be managed operationally until future transformer upgrades can be scheduled.
3. Transpower Transmission Planning Report 2020 – The enhancement approach is to resolve the protection limit on the supply transformers that will provide sufficient N-1 capacity until the end of the forecast period.

Figure 15.5: Coromandel area overview



15.4.4 PROPOSED PROJECTS

Table 15.4: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)
Whenuakite 66/11kV substation	13,820	2021-2023
New Kaimarama 66kV switching station	9,720	2021-2023
Kopu-Tairua 66kV line upgrade	14,176	2021-2023
Matarangi 66/11kV substation	10,000	2021-2023
Matatoki new 11kV feeder	1,360	2021-2023
Backup supply to Kerepehi substation	5,000	2022-2024
Kerepehi new 11kV feeder	1,800	2022-2024
Coromandel substation alternative supply	3,000	2025-2027
Colville-Tuateawa 11kV Link	1,770	2025-2027
Thames new 11kV feeder	3,430	2025-2027
New Kopu-Kauaeranga 66kV line	9,900	2028-2030
Matatoki second transformer	2,130	2029-2031
Whenuakite second transformer	2,000	2030-2031
Coromandel area voltage support	9,360	2030-2032
Tairua-Coroglen 66kV line upgrade	8,000	2031-2033
Mangatarata or Rawerawe 66/11kV substation	17,740	2031-2034

15.4.5 POSSIBLE FUTURE DEVELOPMENTS

Protection systems have been upgraded on the subtransmission circuits to allow the 66kV ring to be operated permanently closed. Future upgrades will involve high-speed communication systems to enable fast inter-trip schemes to operate on the subtransmission network.

The future long-term strategy for development in the Coromandel area is to provide for 110kV supply from Kopu GXP to Kaimarama. Operation at 110kV is unlikely to occur until beyond the next decade. However, projects to date and those identified above (new Kopu-Kauaeranga 66kV line, new Kaimarama 66kV switching station) provide 110kV capable circuits in anticipation of this significant potential voltage change.

Some remote parts of the network north of Coromandel are supplied via single wire earth return (SWER) reticulation. Low voltages are seen on the SWER network during high loads and lead to increased unbalance on the 11kV network. Further load growth will worsen these issues. We propose to progressively upgrade the SWER network to a three-wire three-phase supply but will consult with customers on their price-quality preferences.

Transpower’s dual circuit 110kV lines from Hamilton to Kopu, known as the Valley Spur, are forecast to exceed N-1 capacity in about 2023. This has some impact on Kopu security, but the scope of any future upgrades is likely to be outside the Coromandel area.

Decarbonisation in the region, for example, electrification of transport, smart charging for EVs, electrifying industries etc, could impact the network. As demand increases, subtransmission and substation supply capacities could be exceeded, which would directly impact on security of supply to our customers. In addition, customers could potentially be impacted by quality of supply issues such as low voltages. More on decarbonisation is described in Section 15.19.

There have been recreational customer-related queries in Kopu area, but nothing ascertained. We will continue to monitor this situation and evaluate the need to consider any additional or alternative solution in due course if required to accommodate the future load.

The following projects have been identified as possibly occurring in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Upgrade of SWER systems	The capacity of the SWER circuits north of Coromandel town is at its limits. As load increases, the situation will worsen. Conversion of the SWER lines to three-phase is the most likely solution, but non network alternatives are being considered.
Conversion to 110kV operation	The 66kV Kopu-Whitianga circuit will be 110kV-capable once the Kopu-Kauaeranga line is completed. When 66kV line capacity is exceeded, a possible solution is to convert the 66kV circuit to 110kV operation, which will resolve the issue beyond the planning horizon.
Coromandel area voltage support	Coromandel area generation (refer to Note 1) will address the immediate voltage issues that exist on the network following a post contingent event. Later in the planning period, increased demand may require further voltage support using a Static Synchronous Compensator (STATCOM) at Whitianga paired with a capacitor bank at Whenuakite to provide post-contingent reactive support.
Tairua-Coroglen 66kV line upgrade	Coromandel area generation will offset the need for upgrading the subtransmission line. The distributed generation will be used to provide peak lopping during a contingent event on the subtransmission network, reducing thermal constraints on the 66kV circuits and, therefore, the need to upgrade the subtransmission line can be deferred.
Rawerawe/ Mangatarata substation	Future demand growth in Kerepehi and Ngatea region may exceed the Kerepehi substation supply transformer firm capacity. The preferred solution is to build a new substation near Ngatea region, supplied from Matatoki. The existing 50kV-capable circuit will be upgraded to 66kV so that Matatoki, Kerepehi and the new substation can be interconnected in a ‘ring’ formation. The existing 11kV feeders supplied from Kerepehi will be divided and supplied from the new substation.
Whenuakite second transformer	Single transformer and 11kV backfeed capacity will be eroded as the load grows in the region. The preferred solution is to install second transformer, matching the existing unit.

15.5 WAIKINO

The Waikino area includes the popular holiday town of Whangamata, which is supplied by a single 33kV circuit from Waihi. We have installed an energy storage system comprising batteries and diesel generator to provide backup supply to the critical loads in the central business district of Whangamata.

Major and minor project spend related to security during the next 10 years is forecast to be $10m.

15.5.1 AREA OVERVIEW

The Waikino area covers the southern end of the Coromandel Peninsula and a small section of the eastern Hauraki Plains.

As with the Coromandel area, much of the Waikino area is rugged, hilly and covered with native bush. It is not heavily populated and road access is quite limited in some parts.

The region has a temperate climate with mild winters and warm summers. Rainfall can be high, and storms often come in from the Pacific Ocean, which can affect network operation.

The main towns in the Waikino area are Paeroa, Waihi and Whangamata. The region’s economy is based on tourism, particularly seasonal holidaymakers, with some primary agriculture. The Waihi mine also has a significant bearing on the electrical demand in the area.

This area takes grid supply from the Waikino GXP at 33kV. Zone substations are located at Paeroa, Waihi, Waihi Beach and Whangamata. The subtransmission system has a ring configuration between Waikino GXP and Waihi. A single circuit supplies Whangamata from Waihi. A single circuit also supplies Waihi Beach, with a tee connection to the Waikino GXP-Waihi ring. There are two dedicated circuits supplying Paeroa from Waikino.

The subtransmission and distribution networks are mainly overhead. Occasional extreme weather and rugged, bush-covered terrain make line access and fault repair challenging. Of concern are those substations supplied by single circuits.

Figure 15.6: Waikino area overview

15.5.2 DEMAND FORECASTS

Demand forecasts for the Waikino zone substations are shown in Table 15.5, with further detail provided in Appendix 7.

Table 15.5: Waikino zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Paeroa	AA+	6.0	7.8	8.1	8.4	8.8
Waihi	AAA	16.0	16.7	17.1	17.4	17.8
Waihi Beach	AA	3.3	5.7	6.0	6.3	6.5
Whangamata	AA+	0.0	10.5	10.7	10.9	11.2

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. 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 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.

15.5.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikino area are shown in Table 15.6

Table 15.6: Waikino constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Waikino GXP	TP Waikino supply transformers are close to end-of-life. Low voltages during 110kV Hamilton-Waihou circuit contingency.	Refer to Note 1.
Whangamata substation	Loss of subtransmission supply to Whangamata substationfor an outage on the single Waihi-Whangamata 33kV circuit. Main 11kV backup line shares same poles as 33kV. Battery Energy Storage System (BESS) backup for commercial area only.	Refer to Note 2.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Waihi Beach substation	Single circuit to Waihi Beach. There is insufficient 11kV backfeed when the 33kV circuit is out of service.	**Waihi Beach distributed generation** is proposed to offer subtransmission peak reduction and islanding-capable backup generation at Waihi Beach township during a subtransmission outage.
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.	The preferred option is to remove the Waihi Beach 33kV tee supply by installing a **33kV indoor switchboard at Waihi** to give Waihi Beach a dedicated supply.
Whangamata substation	Demand exceeds secure capacity of one transformer. T2 transformer firm capacity exceeded.	Refer to Note 3.
Waihi Beach substation	Has a single transformer, which does not provide sufficient security. The load at Waihi Beach is forecast to be 6.3MVA by 2030. The existing transformer is insufficient firm capacity for growing demand at Waihi Beach.	The preferred solution is to install a **Waihi Beach second transformer**, currently at Lake Rd substation (a matching pair), resolving the supply transformer firm capacity issue.
Paeroa substation	Demand exceeds secure capacity of the two transformers.	Refer to Note 4.
Whangamata, Waihi and Waihi Beach substations	Low voltages during an outage on either Waikino-Waihi 33kV circuits.	The preferred solution is to provide voltage support by installing a **33kV capacitor at Waihi substation,** switched multi-staged capacitor bank. Refer to Note 5.
Opoutere and Hikuai feeders	No backup to Opoutere (WGM3) and Hikuai (TAI3) feeders during a planned and unplanned outage	Preferred option is to establish a **Whangamata 3-Tairua 3 11kV link** between the feeders to backfeed each other.

Notes:

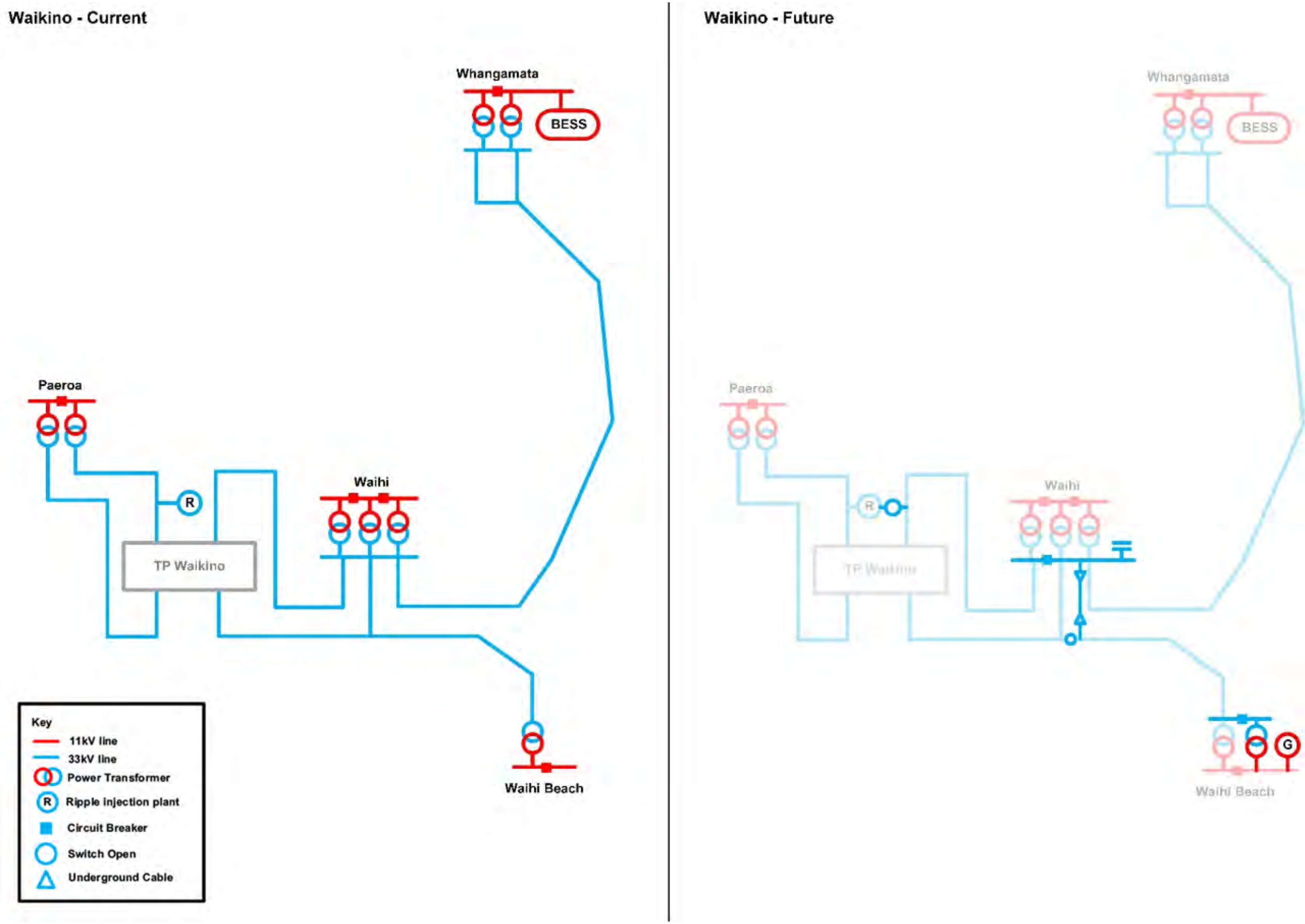
1. Transpower Transmission Planning Report 2020 – Transpower plans to replace the T2 transformer and carry out an outdoor-to-indoor conversion of the 33kV assets in 2020 followed by replacement of the T1 transformer in the period 2026-2028. The new transformer units will have on-load tap changers, which will address the steady state voltage issues.
2. BESS partially feeds the commercial area in Whangamata following a loss of supply to Whangamata substation during peak times, reducing the outage impact. If the outage occurs during off-peak times, the BESS can extend its supply beyond the commercial area, further reducing the outage impact. Once the proposed **Whangamata 3-Tairua 3 11kV link** project is completed, outage impacts will be reduced even further. These solutions reduce the outage impact risks to acceptable levels.
3. T2 transformer capacity upgrade is a solution, but a possible alternative is to refurbish an existing transformer from Tirau substation. This will be considered based on its remaining asset life. The risk is considered minimal for a transformer outage. Also, the Whangamata BESS and backup diesel generator mitigate the risk of transformer overload should an outage occur to the other unit.
4. Work is under way to replace the two 5MVA transformers with 7.5MVA units previously used at Maraetai substation via a renewals project, to be completed by mid-2021.
5. Transpower Transmission Planning Report 2020 – Post-contingent static voltages on the Waikino 33kV bus can drop below 0.95pu with a voltage step exceeding planning guidelines of five per cent. The lack of on-load tap changers on the supply transformers makes it impractical to regulate static voltages on the supply bus to within the operational band of 0.95-1.05pu. A potential investment option is installing capacitors on the Waikino 33kV bus, which would also relieve the Hamilton-Piako transmission issue.

15.5.4 PROPOSED PROJECTS

Table 15.7: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)
Waihi 33kV indoor switchboard	$4,314	2021-2023
Waihi Beach second transformer	$2,400	2021-2023
WGM3-TAI3 11kV link	$1,860	2021-2024
Waihi Beach distributed generation	$1,800	2023-2025
Waihi 33kV capacitor	$1,170	2026-2027
Paeroa 33kV bus security	$2,510	2030-2031

Figure 15.7: Waikino area network diagram



15.5.5 POSSIBLE FUTURE DEVELOPMENTS

Transpower's dual circuit 110kV lines from Hamilton to Kopu, known as the Valley Spur, are forecast to exceed N-1 capacity in about 2023. This has some impact on Waikino security, but the scope of any future upgrades is likely to be outside the Waikino area.

Decarbonisation in the region, for example, electrification of transport, smart charging for EVs, electrifying industries etc, could impact the network. As demand increases, subtransmission and substation supply capacities could be exceeded, which would directly impact on security of supply to our customers. In addition, customers could potentially be impacted by quality of supply issues, such as low voltages because of decarbonisation. More on decarbonisation is described in Chapter 15.19

A resource consent application is under way for a significant new wind generation site near Te Aroha. The intention is for this to connect to the Hamilton-Kopu 110kV circuits.

The gold mine at Waihi in the past has looked at increasing its operations, which could possibly affect the load forecast at Waihi region. We will continue to monitor this situation.

The following projects have been identified as possibly occurring in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Paeroa 33kV bus security	An outage on one of the subtransmission circuits from Waikino to Paeroa will also result in an outage to its associated supply transformer at Paeroa substation. The preferred solution is to install a 33kV indoor switchboard to improve subtransmission reliability.
Paeroa transformers capacity upgrade	The proposed Paeroa 33kV bus security project will resolve the risk of a subtransmission circuit fault taking out a Paeroa supply transformer. The risk of a breach of Paeroa's firm capacity is then reduced to the risk of a supply transformer outage, which is a lower probability event. Overloads can be managed operationally through 11kV backfeeds, or the transformer capacity upgraded through forced cooling until they reach end-of-life. However if, in the future, demand grows substantially more than forecast, there may be a need to upgrade to larger capacity units as 11kV backfeed capability will deteriorate.

15.6 TAURANGA

The Tauranga region has historically had high demand growth driven by population increases, and we expect this to continue. Security in the area is generally good with twin circuits supplying most of our substations. 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 during the next 10 years is $70m.

15.6.1 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. The Tauranga area of supply 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 Kaitimako GXPs. Tauranga GXP is a grid offtake at both 11kV and 33kV.

The Tauranga GXP supplies 11 zone substations: Bethlehem, Tauranga 11kV (TP), Waihi Rd, Hamilton St, Sulphur Point, Otumoetai, Matua, Omokoroa, Aongatete, Katikati and Kauri Point. The Kaitimako GXP supplies Welcome Bay substation and Pyes Pa substation.

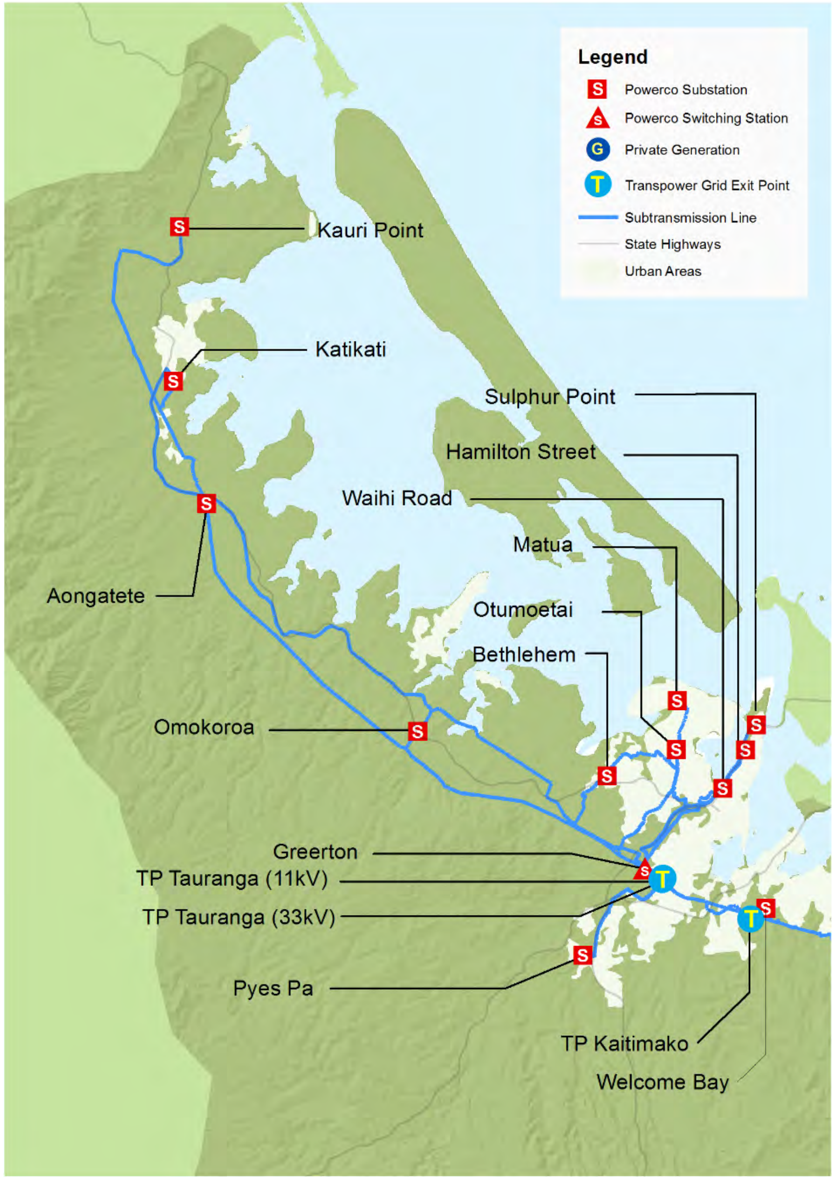
The region uses a 33kV subtransmission voltage. Twin dedicated circuits feed each of the critical inner-city substations of Hamilton St and Waihi Rd.

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, Aongatete and Katikati) via dual circuits, and Kauri Point on a single circuit from Katikati. A 33kV ring from Greerton also supplies Bethlehem via Otumoetai. Otumoetai is now supplied from twin radial subtransmission circuits from Greerton, with a single 33kV radial circuit from Otumoetai supplying Matua. The Bethlehem/Otumoetai ring and the twin Omokoroa circuits share poles for several spans out of Greerton, which raises common types of failure risks and protection issues. A project under way will install a third subtransmission circuit from Greerton to Omokoroa while also reducing the number of poles shared between the Bethlehem/Otumoetai ring.

Trustpower's Kaimai generation scheme feeds into the Greerton switching station.

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.

Figure 15.8: Tauranga area overview



15.6.2 DEMAND FORECASTS

Demand forecasts for the Tauranga zone substations are shown in Table 15.8, with further detail provided in Appendix 7.

Table 15.8: Tauranga zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Aongatete	AA+	7.2	4.3	4.6	5.0	5.3
Bethlehem	AA+	8.0	9.3	10.0	10.8	11.5
Hamilton St	AAA	22.4	16.1	16.4	16.8	17.1
Katikati	AA	4.6	8.5	9.0	9.4	9.8
Kauri Point	A1	1.6	2.7	2.8	2.9	3.0
Matua	AA	7.4	8.8	9.0	9.1	9.3
Omokoroa	AA+	13.2	10.4	11.2	11.9	12.7
Otumoetai	AA	13.6	14.7	15.4	16.0	16.7
Pyes Pa	AA+	11.7	10.4	12.2	14.0	15.7
Sulphur Point			8.0	12.0	16.0	20.0
Tauranga 11kV	AAA	30.0	24.4	25.9	27.4	28.8
Waihi Rd	AAA	24.1	21.5	22.1	22.8	23.5
Welcome Bay	AA	21.4	22.9	24.5	26.2	27.8

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, Omokoroa and Welcome Bay – are those supplying the major subdivisions. A recent substation commissioned at Pyes Pa has offloaded Tauranga GXP supplying the large industrial and residential developments in this area. The suburb of Pyes Pa comprises industrial and residential developments. Several large customer-initiated works projects have been indicated for development during the next few years. The district council is also moving forward with significant residential sections, expected to be complete within the planning period.

Omokoroa has substantial areas of land zoned for urban development on the peninsula, and increased growth in this area has been observed.

Substations supplying the inner city and established urban areas continue to be subject to steady growth from in-fill 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. Urban intensification signalled by the Tauranga City Council in the Cameron Rd area will increase demand on the Waihi Rd and Hamilton St substations. The Port of Tauranga has signalled considerable growth at Sulphur Point zone substation, potentially justifying the need for another dedicated subtransmission circuit.

Aongatete and Katikati demand is dominated more by significant increases from coolstore loads, which are being driven by the horticulture market.

15.6.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tauranga area are shown in Table 15.9.

Table 15.9: Tauranga constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Tauranga GXP	An outage of one of the two Kaitimako-Tauranga 110kV circuits can overload the other circuit. Transformer T3 and T4 are operating at the firm load. As future substations are commissioned from 2025 to 2028, Tauranga GXP will exceed the firm capacity.	A bulk supply solution is required to address this and provide capability to support growth in the long term. Transpower has signalled that upgrading the existing 110kV transmission lines into Tauranga is uneconomical. Our likely solution is the **Tauranga GXP capacity upgrade project,** which would install a new 100MVA-rated third 110kV circuit between Kaitimako and Tauranga and a third 110/33kV transformer at Tauranga GXP. Refer to Note 1.
Omokoroa, Aongatete, Kauri Point and Katikati substations	An outage on one of the two Greerton-Omokoroa 33kV circuits will cause overloading on the remaining circuit supplying these four substations. Significant low voltages are anticipated at Katikati and Kauri Point under post-contingent situations. With significant growth expected at Omokoroa peninsula, it is expected that these issues will worsen.	The solution project, **Omokoroa capacity reinforcement,** will increase the capacity available at Omokoroa and increase the reliability of the northern ring. Later, we plan to install 2x5MVA capacitor banks at Aongatete to support post-contingent voltage in the area (**Aongatete voltage support** project).

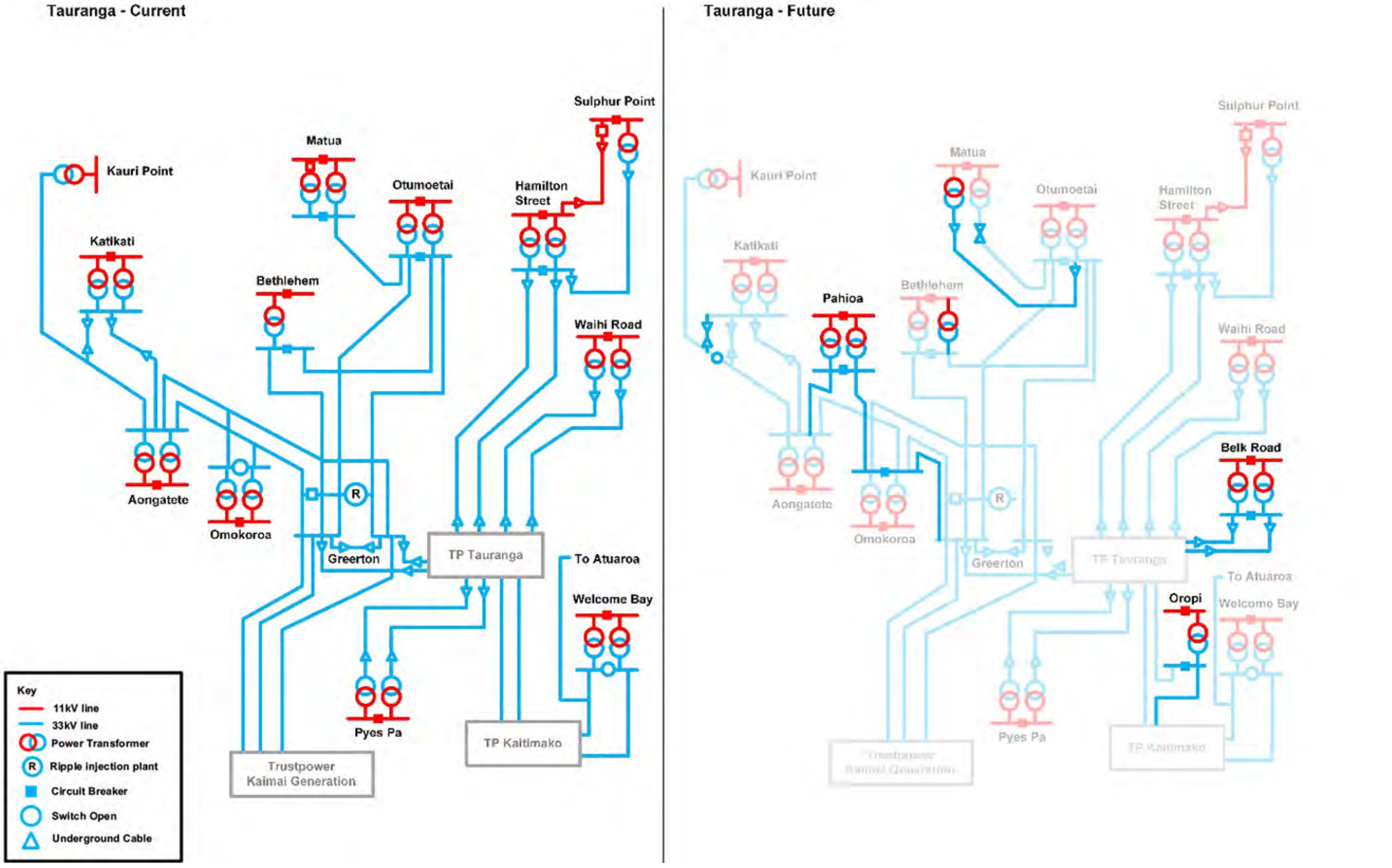
LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Matua substation	Matua substation has a single circuit and a 12.5/17MVA 33/11kV transformer. There is a 5MVA 33/11kV transformer on hot standby, but it will be removed imminently as its condition is poor and poses a risk to the environment as a result.	The solution project, **Matua second transformer,** will install a second 12.5/17MVA 33/11kV transformer at Matua to ensure reliable contingency operation. Before the installation, the risk of a subtransmission outage at the substation can be managed operationally through 11kV backfeed. Refer to Note 2.
Bethlehem substation	Bethlehem substation has a single 16/24MVA 33/11kV transformer. There are two existing 33kV circuits supplying Bethlehem substation. The 11kV transfer capacity is constrained and the extensive switching necessary to restore the full load exceeds the prescribed time required for an AA+ designated substation.	The solution project, **Bethlehem second transformer,** involves installing a second 16/24MVA 33/11kV transformer at Bethlehem to provide firm support and increase reliability. Refer to Note 3.
Welcome Bay/ Tauranga 11kV substations	Welcome Bay substation is approaching its firm load (approx. 23/24MVA) and has higher than prescribed ICPs per feeder. Tauranga City Council is proceeding with 1,600 new sections in the Ohauiti area. The forecast growth will further constrain Welcome Bay substation.	The solution project, **Oropi zone substation,** involves commissioning a substation in the vicinity of the proposed load to reduce the ICPs/ load on Welcome Bay substation. This would also enable reliable backfeed to Welcome Bay and parts of Tauranga 11kV substations.
Omokoroa substation	Omokoroa substation is approaching its firm capacity limit. The suburb of Omokoroa has 2,500 proposed residential sections due to be released during the next five years, and there are also significant commercial developments planned for the area. Omokoroa is primarily supplied via two 11kV feeders from the substation. As the load increases, it will be difficult to reliably backfeed the area.	The solution project, **Pahoia zone substation,** involves commissioning a substation in the vicinity of the proposed load, which would offload Omokoroa substation while also catering for the proposed developments in the area.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Omokoroa/ Aongatete/ Katikati/ Kauri Point substations	The Omokoroa capacity reinforcement project will install a third 33kV circuit between Greerton and Omokoroa. Because of uncertainty regarding the final position of Omokoroa substation after the Tauranga Northern Link highway is completed, the underground circuit will be terminated near the existing tee-off temporarily. This third circuit's benefit can be fully utilised once it is accommodated at Omokoroa substation. The existing 33kV switchgear have reached the end of their useful life and require replacement.	The solution project, **Omokoroa substation,** involves installing a new 33kV switchboard at Omokoroa. This would provide accommodation to remove both existing tee-offs, the third circuit, and further development. This would increase reliability and switching flexibility, enabling maximum use of the additional capacity from the third GRE-OMO circuit.
Pyes Pa substation	Pyes Pa substation is recently commissioned with a maximum demand of 10.4MVA. There are several large industrial developments under way in the area, including a 10MVA Gib factory. A proposed residential development, Tauriko West, is projected to add 3,000-6,000 new residential sections by 2030. These developments will constrain Pyes Pa substation and its subtransmission supply circuits.	The solution project, **Belk Road zone substation,** involves installing two new 33kV circuits from Tauranga GXP to Belk Road and commissioning a new substation at Belk Road. In the interim, the industrial load will be supplied via 33kV-capable cables operating at 11kV supplied from Pyes Pa substation.
Kaitimako GXP	Single transformer at Kaitimako GXP provides no firm capacity.	Refer to Note 4.

Notes:

1. We are in preliminary discussions with Transpower about possible long-term solutions. Risk in the near term is mitigated by a Special Protection Scheme (SPS), plus the availability of generation from Kaimai hydro scheme. Transpower is also suggesting the possible implementation of Variable Line Ratings (VLR) as a mitigation measure to lift capacity.
2. The 5MVA 33/11kV transformer at Matua zone substation will be refurbished and kept as a spare. The existing 33kV cable operated at 11kV in conjunction with the surrounding 11kV network can provide adequate backfeed until the second transformer project begins. It is proposed that this second transformer project will be co-ordinated with the Matua 11kV switchboard replacement in future.
3. Because of low probability of failure, there is only a small risk with single transformer substations or dual transformer substations where firm capacity is marginally exceeded. Options are considered to increase capacity or install new units as appropriate, as is economically cost effective. At Bethlehem, it is more cost effective to install a second transformer to meet the security of supply requirements rather than improving 11kV backfeed capability and response times.
4. The existing Kaitimako GXP to Tauranga GXP 33kV circuits provide sufficient backfeed for Welcome Bay so that the Kaitimako GXP load is secure even with one supply transformer. When load exceeds this backfeed capacity, we will need to investigate a second 110/33kV transformer with Transpower. The growth of the Welcome Bay and Pyes Pa loads will help justify the need for a second transformer at Kaitimako.

Figure 15.9: Tauranga area network diagram



15.6.4 PROPOSED PROJECTS

Table 15.10: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)
Omokoroa capacity reinforcement	$10,036	2021-2023
Belk Road substation	$14,605	2022-2027
Bethlehem second transformer	$1,589	2023-2025
Tauranga GXP capacity upgrade	$25,955	2022-2032
Pahoia Zone substation	$6,406	2023-2028
Oropi Zone substation	$9,471	2024-2027
Omokoroa substation	$2,684	2026-2028
Matua second transformer	$2,490	2026-2028

15.6.5 POSSIBLE FUTURE DEVELOPMENTS

Because of the rapid development taking place in Tauranga and planned by Tauranga City Council for the future, there are very significant impending constraints on the 110kV circuits from Kaitimako to Tauranga. The Poike tee also causes operational difficulties and reduced security. Tauranga GXP's 110/33kV transformers are operating at their firm capacity and are largely dependent on the Kaimai generation to manage overload risk. With several large-scale developments requiring zone substation solutions within the planning period, this will add pressure to the transmission system's capability to support the growth beyond the next 10 years.

Developing a transmission solution is a lengthy process. Therefore, we are looking at alternatives to resolve the transmission bulk supply risk at our level, in collaboration with Transpower and the local authorities. The Tauranga GXP capacity upgrade project seeks to develop a long-term solution that will meet the growing needs of the city and the surrounding region. Upon completion of the Tauranga GXP project, sufficient capacity would be available for longer term developments indicated by the Tauranga City Council.

Several additional zone substations, which were previously identified in our longer term planning, will likely be commissioned during this planning period. These include, Tauriko (Belk Road), Oropi and Omokoroa urban (Pahoia). Investment is not expected for these until after 2022, but this will depend on the rate of growth and subdivision development. The larger planned developments detailed above cover most of the significant risks exposed by the subtransmission constraints. Timing of these investments will be flexible, based on the rate of development and the interdependence with other drivers.

The Port of Tauranga has indicated a growth plan specifying its future requirements, with potential growth from 8MVA currently to 20MVA in 2030. The forecast increase will place significant strain on the Tauranga-Hamilton Street 33kV circuits eventually, necessitating other network projects, such as the Waihi Road bus security project, to lift subtransmission capacity into the inner-city area. Sulphur Point substation was recently commissioned to supply the port's growing load. While one 12.5/17MVA transformer has been installed at Sulphur Point, a second transformer and 33kV circuit will be installed as the port's load requires it. Eventually, the port will require its own dedicated 33kV circuits as its load grows further, and these new circuits will be taken out of Waihi Road substation following the completion of the Waihi Road bus security project.

Besides inner-city growth, which is spearheaded by the port and CBD redevelopment, Tauranga City Council is signalling an urban intensification plan for the Te Papa Peninsula. This plan will see the rezoning of the suburban area to allow for high-density population growth. The trend is to move towards more mixed-use development comprising high-rise residential and commercial complexes to energise growth within the city.

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 to maintain security in the upstream network. In-fill growth also drives new or upgraded feeders in existing parts of the network.

The following projects have been identified as possibly occurring in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Waihi Road bus security project	Tauranga GXP supplies Waihi Road and Hamilton Street substations via double 33kV circuits to each. Because of rapid growth forecast within the planning period as a result of urban intensification, the parallel circuits will not be able to support each other during contingency. The solution project is the construction of a solid bus at Waihi Road substation, where the four cables can be terminated to increase reliability to the Te Papa Peninsula area. This will result in an N-1 event no longer breaching the subtransmission capacity of the circuits.
Welcome Bay 33kV reinforcement	Welcome Bay substation is supplied via two circuits from Kaitimako GXP. By the latter half of the planning period, forecast growth would result in a loss of one circuit causing the remaining circuit to operate above the rated capacity. The solution project would construct a third circuit from Kaitimako and install a 33kV solid bus to reinforce Welcome Bay substation.
Welcome Bay East zone substation	Welcome Bay substation is nearing firm capacity and the 11kV feeders each have high ICP counts. The district council has earmarked locations in Welcome Bay for residential development. Although currently deferred by the council, as demand for housing grows, these locations will be targeted for development, possibly towards the end of the planning period. The solution project for this eventuality would be Welcome Bay East substation, offloading Welcome Bay substation and lowering feeder ICP counts.
Gate Pa/Hospital zone substation	Tauranga Hospital's primary supply is via an 11kV feeder from Waihi Road substation. In the event of a fault, backfeed is provided via the Tauranga 11kV substation. The hospital has plans to expand, and growth is expected to exceed the 11kV backfeed capability of the network. The vicinity surrounding the hospital has also been identified by the district council for urban intensification, including mixed-use developments and high-rise buildings. The solution project would be Gate Pa/Hospital zone substation. This would entail cutting into one of the existing TGA-WRD 33kV circuits and commissioning a substation in the vicinity of the hospital. This is a customer-driven project and timing will be dependent on future district plans.

15.7 MT MAUNGANUI

The Mt Maunganui area has historically had a high growth rate, driven by population growth and residential expansion. We recently completed the Wairakei substation, which helps to reduce the load on the Papamoa substation and provides additional capacity to support the growth in the area. The project also offers improved security between the two GXPs at Mt Maunganui and Te Matai. Major and minor project spend related to Growth and Security in this region during the next 10 years is $31m.

15.7.1 AREA 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. In recent years we have constructed a dual 33kV circuit from Wairakei to Te Matai which links the two areas. This has made it 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 many kiwifruit orchards, which use the local coolstores and pack-houses for their product. 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 four zone substations – Matapihi, Omanu, Te Maunga and Triton. The Te Matai GXP supplies six zone substations – Wairakei, Papamoa, Te Puke, Atuaroa, Paengaroa 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. All new intensive subdivision is 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 to Papamoa substation as the tie point between the two GXPs.

Figure 15.10: Mt Maunganui area overview

The 33kV subtransmission from the Te Matai GXP has a meshed architecture. Dual circuits supply the Te Puke substation. Atuaroa is an urban substation, installed to offload Te Puke, and is normally supplied through a single 33kV circuit out of Te Matai. Its alternative supply comes from the Kaitimako to Te Matai line. Paengaroa is supplied by a single circuit from Te Matai. Paengaroa, in turn, supplies Pongakawa through a single circuit.

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.

15.7.2 DEMAND FORECASTS

Demand forecasts for the Mt Maunganui zone stations are shown in Table 15.11, with further detail provided in Appendix 7.

Table 15.11: Mt Maunganui zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Atuaroa Ave	AA+	0.0	8.2	8.6	8.9	9.3
Matapihi	AAA	24.1	13.0	13.3	13.6	13.8
Omanu	AAA	24.3	11.9	12.6	13.4	14.2
Paengaroa	AA	3.6	4.8	5.0	5.3	5.5
Papamoa	AAA	21.3	15.5	16.8	18.1	19.4
Pongakawa	A1	1.3	4.5	4.7	4.9	5.1
Te Maunga	AA	10.3	9.8	10.7	11.6	12.5
Te Puke	AAA	22.9	18.8	19.5	20.3	21.0
Triton	AAA	21.3	20.0	20.7	21.3	22.0
Wairakei	AA	6.0	6.6	8.4	10.2	12.0

The Mt Maunganui area has one of the highest growth rates in our network. Substantial investment has recently been made 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 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 smaller 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 in-fill 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 development for stage one of the business park will begin early 2021, with stage two following in 2023. This will encompass approximately 60 hectares of industrial land. The first loads are expected about 2024. However, the potential for these loads to develop earlier remains a planning risk.

The Te Puke and surrounding rural load continues to grow steadily, largely in response to kiwifruit and avocado growing operations.

15.7.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Mt Maunganui area are shown in Table 15.12.

Table 15.12: Mt Maunganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Te Matai GXP	The T1 110/33kV supply transformer firm capacity will be exceeded by about 2028. Transpower has recently indicated to Powerco that T1 at Te Matai is scheduled for renewal in 2028. In 2019, Papamoa substation received a new 33kV switchboard which allowed it to be switched over to Te Matai GXP.	Refer to Note 1.
Pongakawa and Paengaroa substations	An industrial park located at Rangiuru is under way and will begin stage one of development in early 2021. The area is supplied via 11kV feeders from Te Puke substation. Without further development the future load growth will cause thermal overloads and voltage constraints across the eastern Te Puke area. A single feeder from Te Matai GXP serves both Paengaroa and Pongakawa – with loss of supply to both substations from an outage to the Te Matai-Paengaroa 33kV circuit.	The **Rangiuru Business Park project** involves the construction of a new zone substation at Rangiuru Business Park. It will create a 33kV ring between Wairakei, Te Matai Paengaroa and the new business park substation, providing a second subtransmission supply to Paengaroa and Pongakawa. To enable the 33kV ring to be implemented, a 33kV connection is required at Paengaroa. Refer to the **Paengaroa second transformer and bus extension** project for details.
Pongakawa substation	A single 33kV circuit supplies Pongakawa substation from Paengaroa substation, which leads back to Te Matai GXP. With recent load growth in the area there is insufficient backfeed to secure all loads in Pongakawa during an outage of the 33kV circuit between Te Matai and Paengaroa, with associated voltage issues.	The **Pongakawa security of supply** project, to install diesel generation at Pongakawa substation, is currently the preferred solution, providing backup supply in a contingent event.
Atuaroa substation	Atuaroa was built to offload Te Puke substation. In recent years, demand has grown steadily at Atuaroa, driven mainly by coolstore expansion. Further industrial development is anticipated in the area from the Western Bay of Plenty District Council's development plans. As demand grows and exceeds 11kV backfeed capability, the increasing risk will need to be addressed to improve Atuaroa's subtransmission security.	The preferred option is **Atuaroa second transformer and Atuaroa bus security upgrade.** These upgrades will support the growth by providing the necessary capacity and bus security. The new bus will allow for an **Atuaroa second circuit,** which eventually will be required to provide Atuaroa with dual 33kV supply to meet its security requirements. With these projects, Atuaroa will have a fast restoration time with spare capacity to support load growth within the area.
Te Puke substation	Te Puke substation has an AAA security class. An outage on one of the two Te Matai-Te Puke 33kV circuits is forecast to cause overloading on the other from 2026.	The **Te Puke bus security upgrade** project involves installing a new 33kV bus at Te Puke substation, enabling an in-and-out arrangement of the Te Matai to Atuaroa circuit. This creates a third circuit for Te Puke, greatly increasing the security of supply. The project is also a prerequisite for enabling the connection of the **Atuaroa second circuit.**
Paengaroa substation	Paengaroa substation has only one 12.5/17 MVA transformer. The load in the area has started to increase as larger industrial business expands into the area.	To keep up with growth, a **Paengaroa second transformer and bus extension** will be needed. This project will improve the substation security and allow load in the area to increase beyond the existing transformer capacity.
Wairakei substation	Wairakei substation has one 16/24 MVA transformer. The load within the area continues to increase with new subdivisions, apartments and shopping centres.	The preferred option is to install a **Wairakei second transformer** at Wairakei to provide security and allow for growth in the area.

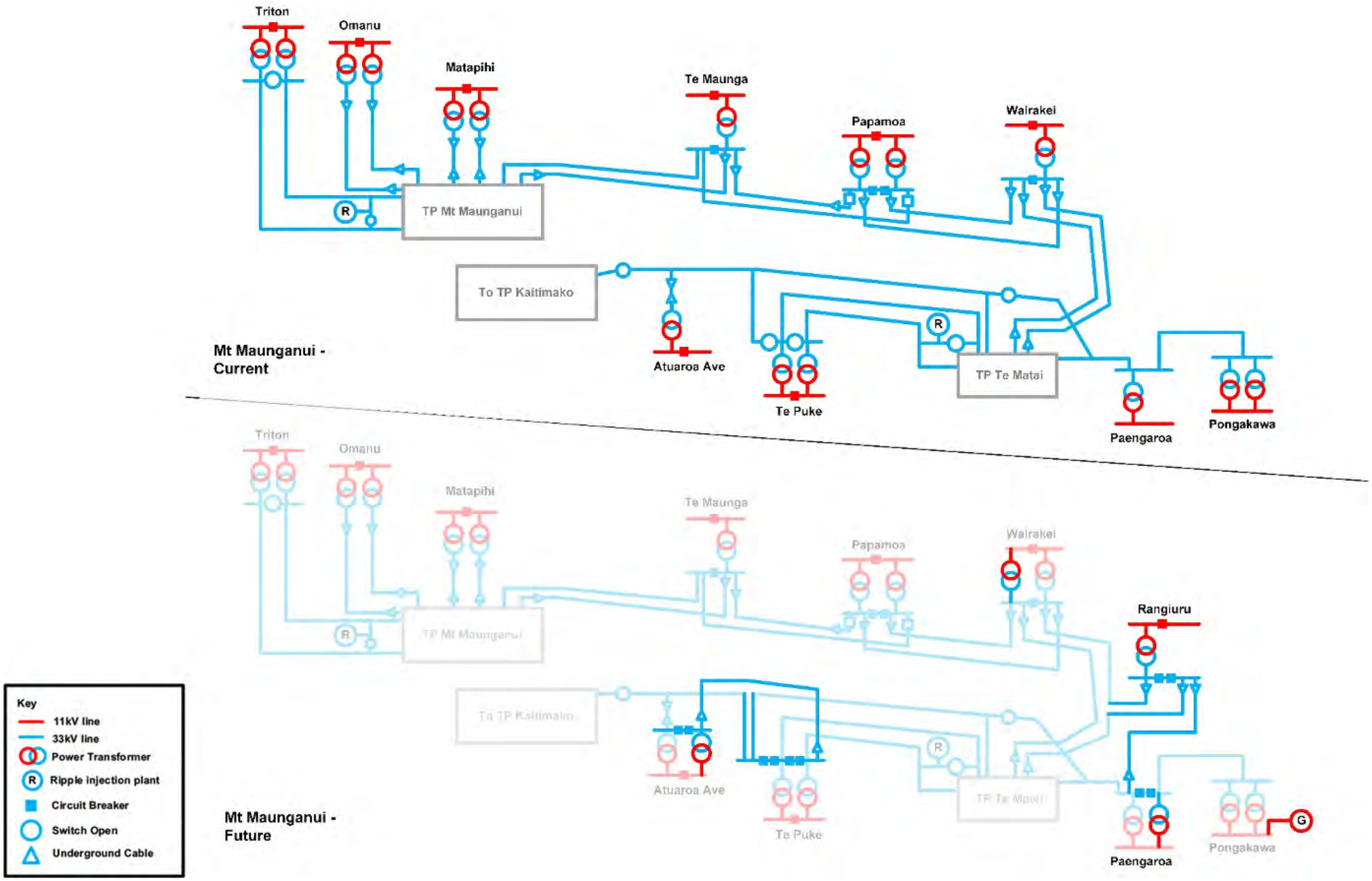
LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Kaituna and Rangiuru feeders	The network capacity in the area has exceeded acceptable load limits on the surrounding feeders. A new Rangiuru Business Park with large industrial customers will be located in the area within the next few years. Other, already existing, local customers are requesting significant load increases for 2021, which will place further pressure on the existing infrastructure.	**Paengaroa feeder Young Road** is a 33kV-capable cable from Paengaroa operating at 11kV initially. This project will provide support into the growing area until the future substation at Rangiuru is constructed. When a substation site is located, the cable will supply the new substation at 33kV. It will form a ring between Wairakei, Paengaroa and Te Matai to improve reliability in the region.
Rotoehu feeder	Rotoehu feeder is prone to faults in the Pongakawa area. Its long feeder length means that reliability is poor.	Install a **new feeder to offload Rotoehu.** The new feeder will improve network reliability and improve transfer capacity during a contingency event.
Royden Downs Rd	An expected step increase in demand has been indicated on the Royden Downs Rd feeder, which is one of two 11kV ties into Pongakawa. This reduces the backfeed capacity to Pongakawa substation during a loss of the 33kV supply.	The preferred option is to install a **new Paengaroa feeder – Royden Downs Rd** to offload the large step change load**.** Project timing is customer dependent**.**

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Bruce Road extension	Papamoa's Reid Road feeder had the highest number of faults in 2019 in the Mt Maunganui area. The relevant council has indicated future residential load growth along the Reid Road feeder.	To address the load increase and fault rate an **extension of Bruce Road feeder** from Te Maunga substation will split Reid Road feeder into two, thereby improving its network performance.
Two new Atuaroa feeders	The relevant council has indicated large industrial growth in the western Te Puke area. The existing feeder capacity in these areas is limited and the anticipated load increase will place further strain on existing infrastructure.	**Two new Atuaroa feeders** involves the installation of two new underground 11kV feeders from Atuaroa Ave substation. One feeder will offload Washer Road's industrial area, transferring a large customer from Te Puke to Atuaroa substation. The second feeder will target the planned industrial area adjacent to Jellicoe Street in western Te Puke.

Notes:

1. Given this information, Powerco will offload Papamoa substation back to Mt Maunganui GXP to lighten the load at Te Matai until 2028 when T1 is renewed by Transpower. Papamoa is equipped with remote changeover for operational flexibility between the two GXPs during contingent events. Powerco will continue to monitor the load on both GXPs.

Figure 15.11: Mt Maunganui area network diagram



15.7.4 PROPOSED PROJECTS

Table 15.13: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)
Atuaroa second circuit	$2,110	2026-2029
Atuaroa second transformer	$1,320	2025
Atuaroa bus security upgrade	$2,970	2023-2025
Te Puke bus security upgrade	$2,920	2023-2025
Pongakawa security of supply	$5,600	2023-2025
Paengaroa second transformer and bus extension	$1,960	2024-2027
New Rangiuru substation	$10,370	2024-2028
Wairakei second transformer	$1,308	2021-2022
Te Tumu substation	$14,630	2027-2032
Te Maunga supply security	$1,170	2026
Paengaroa new feeder – Young Road	$1,909	2021
New feeder offload Rotoehu	$1,487	2024
Paengaroa new feeder – Royden Downs	$1,857	2024
Bruce Road extension	$936	2023
Atuaroa two new feeders	$1,255	2027-2028

15.7.5 POSSIBLE FUTURE DEVELOPMENTS

As with the Tauranga area, the high growth from in-fill and greenfield developments will require continued investment in 11kV feeder backbone capacity and new 11kV feeders. Unless they are deemed as significant distribution projects, these projects are not specifically identified but will be scoped when required in our programme of smaller routine Growth and Security projects.

We will continue to monitor the load on the 110kV into Mt Maunganui GXP. While our strategy to move Papamoa back to Mt Maunganui GXP will remove load off Te Matai GXP, it will put more load back onto the 110kV transmission between Kaitimako and Mt Maunganui, exacerbating the N-1 overload issue at the Poike tee. Our load forecast indicates this configuration will need to be temporary until 2028 to avoid upgrades to these circuits. Should a contingency event occur on the transmission network the risk will be managed operationally. Transpower has indicated the renewal of the T1 transformer at Te Matai GXP in 2028. After this upgrade, Papamoa will be shifted back to Te Matai GXP and the load reduced at Mt Maunganui GXP.

The 110kV Okere-Te Matai circuit's N-1 capacity constraint is another issue we are working with Transpower to address in the long term. As load continues to grow in the Te Matai region, the 110kV circuit will be thermally overloaded during an outage of the Kaitimako-Te Matai 110kV circuit at high load times.

The following projects have been identified as possibly occurring in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Pongakawa substation transformer capacity upgrade	Load at Pongakawa substation exceeds the firm capacity of the transformers. It is proposed to upgrade the transformers to restore adequate security of supply. However, the **Pongakawa security of supply** project can effectively resolve this risk in the interim by providing load reduction during a transformer outage situation. We will continue to monitor the situation as timing is dependent on the rate of growth in the area.
Te Tumu capacity reinforcement	As residential growth continues at pace in eastern Papamoa, a new zone substation will be required to supply the new load for the Te Tumu growth area. Timing is customer load-driven.
Te Maunga supply security	Te Maunga has one 12/17MVA transformer. Te Maunga has a security class of AA. During an outage on this transformer Te Maunga is resupplied via adjacent substations, Papamoa and Matapihi. To meet the security class criteria, these tie points will be automated in FY26 under our reliability plan to provide fast response backfeeds. Alternatively, if growth becomes significant because of urban intensification, then a second transformer will be installed instead. We will continue to monitor developments in this area.
Triton substation	Triton is supplied via two parallel 33kV circuits. An outage on one circuit causes an overload on the parallel circuit at maximum demand. The risk of the outage is low because of the availability of multiple backfeed ties from adjacent substations. Development of the port on the eastern side is signalled in the longer term once the western end is completed. It is anticipated that the load will increase substantially, which will likely exceed the firm capacity of the transformers at Triton. Presently, the Triton rebuild project will replace the existing transformers with larger capacity units. If future load grows, driven by the port expansion, then a third transformer may be required to support the load in the area. The timing of this project is customer-driven.

15.8 WAIKATO

Our Waikato area covers the eastern Waikato region and does not include Hamilton or western Waikato. It is largely an agricultural area, with a strong dairy industry. There are several locations supplied by single circuits that don't meet our security criteria. Our largest project in this area is the construction of a new GXP at Putaruru to improve security. We also have several other projects to increase security and capacity. Major and minor project spend related to Growth and Security during the next 10 years is $67m.

15.8.1 AREA OVERVIEW

The Waikato area extends from the Hauraki Plains north of Morrinsville and Tahuna, through the rural land of 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 GXP is being rebuilt by Transpower and the transformers are also being upgraded.

The new Piako GXP supplies six zone substations – Piako, Morrinsville, Tatua, Farmer Rd, Walton and Waharoa[65]. In the future, Walton will be offloaded to Waihou GXP following the establishment of Kereone-Walton circuit along with the Piako to Kereone line upgrade. This will free up some capacity at Piako GXP, which will enable Waharoa to be supplied from Piako GXP.

Hinuera GXP supplies six zone substations – Waharoa, Browne St, Tower Rd, Lake Rd, Putaruru, and Tirau. Upon the establishment of Putaruru GXP, Putaruru and Tirau will be supplied from this GXP.

All subtransmission in the region is at 33kV, and mainly interconnected 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 backfeeds, often from different GXPs. Therefore, parallel operation of supply lines is often not possible.

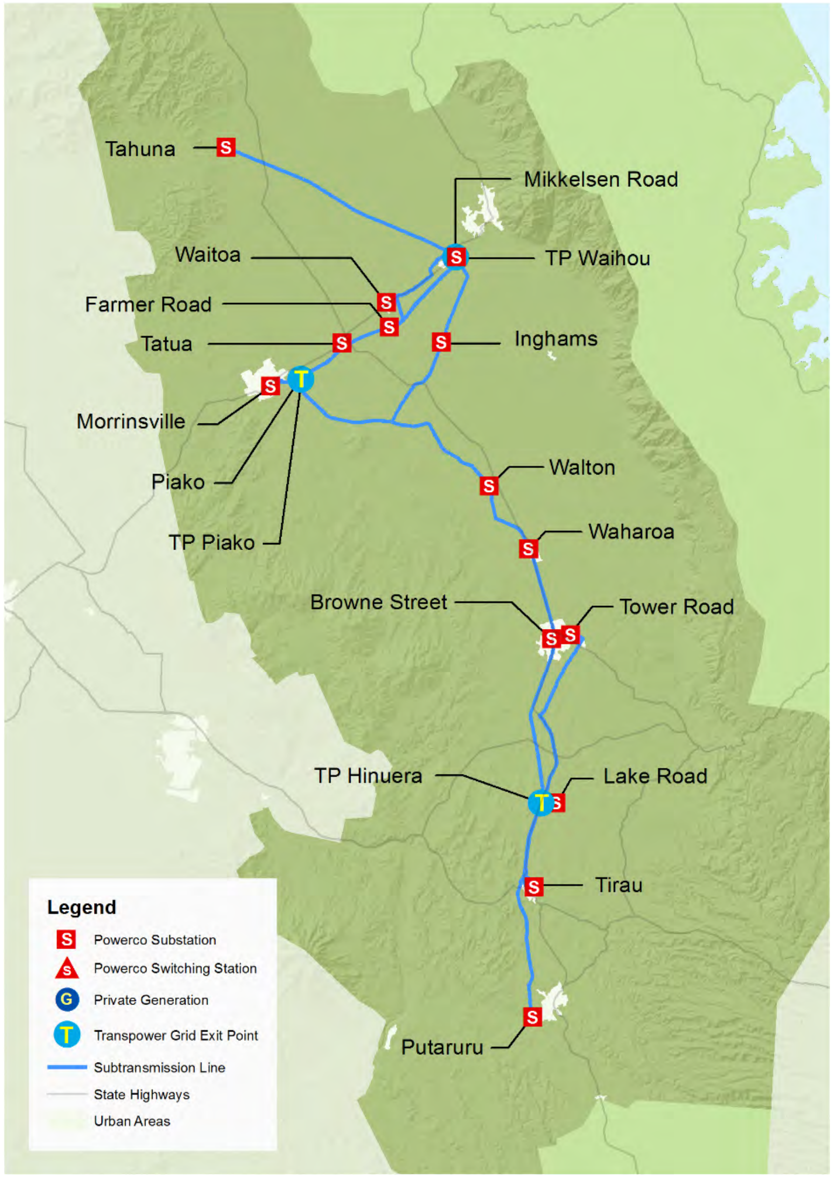
The two dedicated customer zone substations at Tatua and Inghams have security that is specific to the customer, with just single zone transformers. At Waharoa the security is a balance between our nominal security standards and the specific requirements of large customers.

Tahuna and Putaruru are notable in that they are supplied via long, single, 33kV circuits, with no alternative source other than limited 11kV backfeed. 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, which 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.

65 The supply to Waharoa substation is shared between two GXPs, Piako and Hinuera.

Figure 15.12: Waikato area overview



15.8.2 DEMAND FORECASTS

Demand forecasts for the Waikato zone substations are shown in Table 15.14, with further detail provided in Appendix 7.

Table 15.14: Waikato zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Browne St	AA	10.6	9.8	10.4	10.9	11.5
Farmer Rd	AA+	0.0	6.9	7.1	7.2	7.4
Inghams	AA	0.0	3.8	3.8	3.8	3.8
Lake Rd	A1	1.7	6.5	7.0	7.5	8.0
Mikkelsen Rd	AAA	19.2	12.6	13.1	13.7	14.2
Morrinsville	AA+	0.0	8.8	9.1	9.3	9.6
Piako	AAA	15.2	13.1	13.6	14.2	14.7
Putaruru	AA+	0.0	11.6	11.9	12.3	12.7
Tahuna	A1	0.7	5.8	6.1	6.4	6.6
Tatua	AA	0.0	4.8	4.8	4.8	4.8
Tirau	AA+	0.0	9.7	10.0	10.2	10.5
Tower Rd	AA+	0.0	8.2	8.6	9.0	9.4
Waharoa Nth	AA	2.5	3.7	3.9	4.1	4.3
Waharoa Sth	AA	0.0	5.3	5.3	5.3	5.3
Waitoa	AAA	18.8	11.9	11.9	11.9	11.9
Walton	AA+	0.0	5.9	6.2	6.4	6.7

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:

- Zone substations at Inghams and Tatua are dedicated to industrial customers and have recently resulted in significant changes in demand. Tatua Dairy Company has plans to expand the wastewater treatment plant in stages from 2021 to 2026.
- 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. Fonterra

at Tirau will be expanding its production facility and the load uptake further causes the transformer firm capacity at Tirau to be exceeded. A second transformer is proposed at Tirau to cater for the extra load.

- Farmer Rd substation supplies a major industrial load. Following a recent change of ownership, the existing site is being planned for rapid expansion. A dedicated substation for this site, along with subtransmission network enhancement, is proposed to meet the customer's growth strategy.
- Mikkelsen Rd substation supplies Silver Fern Farms' meat processing plant. No load increase has been forecasted by the customer.
- Piako substation supplies the Evonik chemical plant. No load increase has been forecast by the customer.

Demand growth is generally from small gains in population in urban centres and also from increased dairy activity in some rural areas. Historically, much of the area is 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.

15.8.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Waikato area are shown in Table 15.15.

Table 15.15: Waikato constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hinuera GXP	Single 110kV circuit from Karapiro to Hinuera. N-1 capacity of the transformers has been exceeded. In the event of an outage at Hinuera, there is insufficient backfeed to supply all load. Some backfeed is available from Piako GXP but there is limited backfeed from the adjacent substation (Baird Rd) in the south, so most of Putaruru and Tirau cannot be supplied.	The preferred solution is to construct the proposed **Putaruru GXP**. The proposed GXP takes supply at 110kV out of the Arapuni switchyard and will provide improved security to the customers in the region. An extensive upgrade programme is to be carried out at Putaruru substation to accommodate the future GXP. Projects include a new 33kV/11kV switchroom and new 33/11kV supply transformers. Together with the proposed Putaruru-Tirau underground circuit and the completed Hinuera-Tirau underground circuit, the transfer capacity between the future Putaruru GXP and Hinuera GXP will be enhanced.
Putaruru substation	Single 33kV Hinuera-Putaruru circuit. Insufficient 11kV backfeed to supply all load.	The preferred solution is to install a **Putaruru Tirau underground circuit.** This will provide a dual 33kV subtransmission supply to Putaruru. Following the completion of the proposed Putaruru GXP project, this project also provides Tirau with a dual 33kV supply from Putaruru GXP.
Waharoa and Browne St substations	Backfeeding Waharoa and Browne St from Piako GXP is limited by a low-capacity 33kV line between Kereone and Walton substation. This constrains backfeed capacity to Browne St and Waharoa substations.	The preferred solution is **Kereone-Walton 33kV subtransmission enhancement**. The project covers the construction of a new 33kV cable between Kereone tee and Walton substation and utilises the low-capacity line to supply Walton substation from Waihou GXP**.** The offload of Walton to Waihou increases the backfeed capacity from Piako GXP into Hinuera.
Waharoa substation	Two supply transformers are connected to an overhead strung 33kV bus arrangement via 33kV outdoor breakers and separated by a normally open recloser. The equipment is exposed to weather with greater exposure to failure. T1 is approaching firm capacity and it will be replaced with a 12.5/17MVA, 33/11KV transformer through a planned renewal programme.	Because of the space constraints on-site, the preferred solution is to establish a modern 33kV switchboard through the proposed **Waharoa 33kV outdoor to indoor (ODID) project**. This eliminates the risks associated with weather and improves overall safety.
Morrinsville substation	Morrinsville is a single 33kV supply from Piako GXP and does not meet Powerco's security criteria. The existing transformer firm capacity is insufficient for growing demand at Morrinsville.	The preferred solution is to install the **Morrinsville second circuit** to improve subtransmission circuit reliability in the near term. As load grows in the area, it will be necessary to increase the transformer supply capacity. A **Morrinsville substation upgrade** is proposed to expand the existing site, as it is currently space-constrained, build a new 33/11kV switchroom, and upgrade the existing transformers to higher capacity units.
Piako 11kV feeder	Kereone feeder is 114km in length and is a heavily loaded feeder off Piako substation. Historically, network reliability for this feeder is poor. It is both voltage and capacity constrained during normal supply and backfeeding.	The proposed **new Piako substation-Te Miro 11kV feeder** will split the existing feeder and improve security of supply to the area.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Farmer Rd substation	Demand at Farmer Rd is approaching the transformer firm capacity limit. The substation also supplies a major customer, which has recently signalled a rapid expansion plan over the next few years. Existing infrastructure will not have the capacity to meet the anticipated growing demand.	Powerco is working closely with the customer to explore options to accommodate the load increase. The concept solution developed from recent analysis recommends the current proposed solution of **Wood Rd substation and subtransmission network enhancement.** A new substation will be situated near the customer's site. To lift the subtransmission capacity, the existing lines will be bonded as part of the project. This shall be confirmed closer to the time, following consultation and agreement with the customer.
Hinuera GXP	With the new underground link between Browne St and Tower Rd, the existing arrangement at Hinuera 33kV does not have the capability for a closed ring setup to work between Hinuera, Tower Rd and Browne St.	The solution is to construct a full indoor substation at Hinuera – **GXP Hinuera ODID conversion** – with fast bus protection to facilitate the connection of the 33kV circuits into the new switchboard.
Lake Rd substation	Lake Rd has a single transformer and the 11kV backfeed is insufficient to meet security standards.	The solution is to install a **Lake Rd second transformer.** This is preferred over increased 11KV backfeed capacity. This project will be implemented together with **Hinuera ODID conversion.**
Tatua substation	Tatua has a single transformer supplying the industrial site. The site is undergoing an expansion to the wastewater treatment plant. The proposed demand growth at the site will likely exceed the transformer capacity.	Refer to Note 1.
Tirau substation	There is a single transformer supplying the large dairy factory and surrounding Tirau. 11kV backfeed is insufficient to meet security standards. The transformer capacity will be exceeded because of further expansion of the dairy factory.	The preferred solution is to install a **Tirau second transformer.** This has the advantage over upgrading the existing transformer because it increases firm capacity at the substation. Depending on the dairy factory's rate of growth, the existing transformer could be upgraded at a later stage to match the proposed new unit (allowing the existing transformer to be refurbished and relocated to Whangamata to address the firm capacity constraint there).

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Putaruru-Waotu	Two of the long feeders out of Putaruru substation are Horahora and Waotu feeders. The feeder lengths are long and network reliability is historically poor as a result. There can be low voltage at the end of the feeder during peak load.	The preferred solution is to create a **new 11kV feeder to Waotu** to balance the loads on the two feeders and thereby improve the voltage and the feeder performance.
Maungatautari and Horahora	Maungatautari and Karapiro are areas on the edge of Powerco's network. The ability to provide a reliable and secure supply to the area is set back by distance and terrain. A total of 746 ICPs are supplied by Cambridge Rd feeder, and 11kV backfeed capacity from Lake Rd substation is minimal because of the great distance	The preferred solution is to reinforce the network through **Maungatautari area reinforcement**. This comprises a new feeder to address the voltage constraint during backfeed, and underground link on the Cambridge Rd feeder with loop automation. This strategy improves the voltage while backfeeding into Maungatautari region during a fault.
Waihou GXP	TP Waihou supply transformers are close to end-of-life. Low voltages during 110kV Hamilton-Waihou circuit contingency.	Refer to Note 2.

Notes

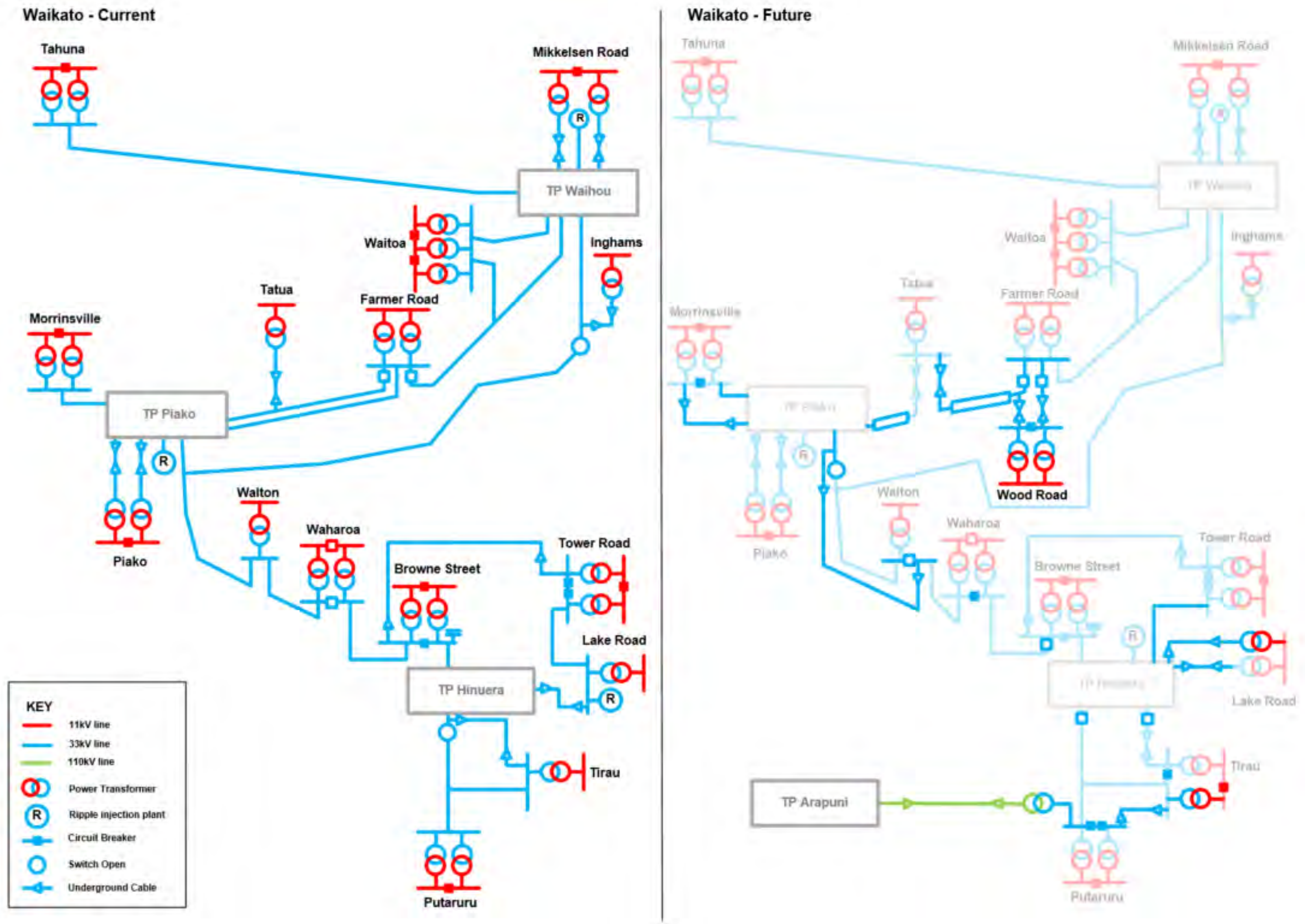
1. We are discussing with the customer the possibility of increasing capacity either with a second transformer or replacement of the existing transformer with a larger unit. Adding a second transformer at the site will increase Tatua's transformer firm capacity substantially but will require a 33kV bus to be constructed. The outcome will likely be a balance between our nominal security standards and the major customer requirements.
2. Transpower Transmission Planning Report 2020 – Transpower plans to replace the transformers and carry out an outdoor-to-indoor conversion of the 33kV assets in 2020. The new transformer units will have on-load tap changers with a total capacity of 160MVA. Powerco will upgrade its existing ripple injection plant at Waihou so that it is suitable for the new assets.

15.8.4 PROPOSED PROJECTS

Table 15.16: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)
Putaruru GXP	$25,400	2019 - 2022
Kereone-Walton 33kV subtransmission enhancement	$7,650	2019 - 2023
Putaruru-Tirau underground circuit	$6,700	2019 - 2022
Morrinsville second circuit	$2,829	2020 - 2023
Wood Rd substation and subtransmission network enhancement	$10,300	2022 - 2023
Hinuera outdoor indoor (ODID) conversion	$2,780	2021 - 2022
Lake Rd second transformer	$540	2021 - 2022
Morrinsville substation upgrade	$10,888	2023 - 2029
Tirau second transformer	$3,275	2021 - 2022
Waharoa – 33kV ODID conversion	$3,815	2030 - 2033
Piako substation – Te Miro 11kV feeder	$1,712	2021 - 2022
Maungatautari area reinforcement	$3,876	2024 - 2026
New 11kV feeder to Waotu	$1,480	2027 - 2028
3 x new 11kV feeder to Morrinsville north and west	$5,400	2031-2034

Figure 15.13: Waikato area network diagram



15.8.5 POSSIBLE FUTURE DEVELOPMENTS

Associated with the larger projects identified previously to secure the load at Hinuera GXP, a new indoor 33kV switchboard will be installed at Putaruru substation when building the Putaruru GXP.

The transmission serving the Waikato area is particularly pertinent to our development plans and strategies. As noted already, Putaruru GXP and a number of associated projects are primarily driven by the lack of security of the single Karapiro to Hinuera 110kV circuit. Piako GXP was built specifically with the intention of offloading Waihou and helping refurbishment projects. With Putaruru GXP coming off the north bus at Arapuni, the GXP is unlikely to be affected by network constraints on the wider transmission system, therefore ensuring its off-take capacity is not compromised. The existing 40MVA 110/33kV transformer at Piako GXP will be relocated to Putaruru GXP and, in its place, a new transformer will be installed at Piako GXP to match the existing 60MVA transformer on site.

In recent years, Matamata-Piako District Council has signalled future residential and industrial development at Matamata and Morrinsville. Some of the developments have already come online. It is expected that the growth will continue at the same pace. It will be necessary to reinforce the existing network infrastructure to cater for the planned development and growth.

The following projects have been identified as possibly occurring in the latter part of the planning period. The following description represents the most probable solution, but the final solution and optimal timing are subject to further analysis and will be confirmed closer to the time.

PROJECT	SOLUTIONS
Tahuna substation subtransmission supply	Tahuna substation is supplied via a long single subtransmission circuit. 11kV backup is limited. A second subtransmission circuit is unlikely to be economic because of the distance involved. Increased 11kV interconnection is the most likely solution.
Morrinsville new 11kV feeders	At the moment, the load at Morrinsville is supported from Piako and Morrinsville substations. Because of the space constraints at Morrinsville substation, the expansion of the existing 11kV switchboard is not possible. It is Powerco’s intention to construct a new modern substation at Morrinsville with higher capacity transformers allowing space for new 11kV feeders to cater for the growing demand north of Morrinsville. The new feeders will offload some of the existing load, which is currently supplied from Piako substation, to these new feeders.

PROJECT	SOLUTIONS
Tatua subtransmission circuit capacity upgrade	The supply to Tatua is teed-off from one of the two subtransmission circuits between Piako and Farmer Rd. The single subtransmission circuit that supplies Tatua will be overloaded through the planned waste water treatment plant expansion at Tatua. Following the proposed Wood Rd substation and subtransmission upgrade project mentioned earlier, further load increases in the region (Tatua and the proposed Wood Rd substations) can potentially overload the bonded subtransmission circuit between Piako and Tatua. The proposed solution is to construct a second 33kV circuit between Piako and Tatua to address this constraint.

15.9 KINLEITH

The Kinleith area includes Tokoroa and a major pulp and paper mill at Kinleith. There will be no major project spend in the Kinleith area during the next 10 years.

15.9.1 AREA 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 14,300.

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.

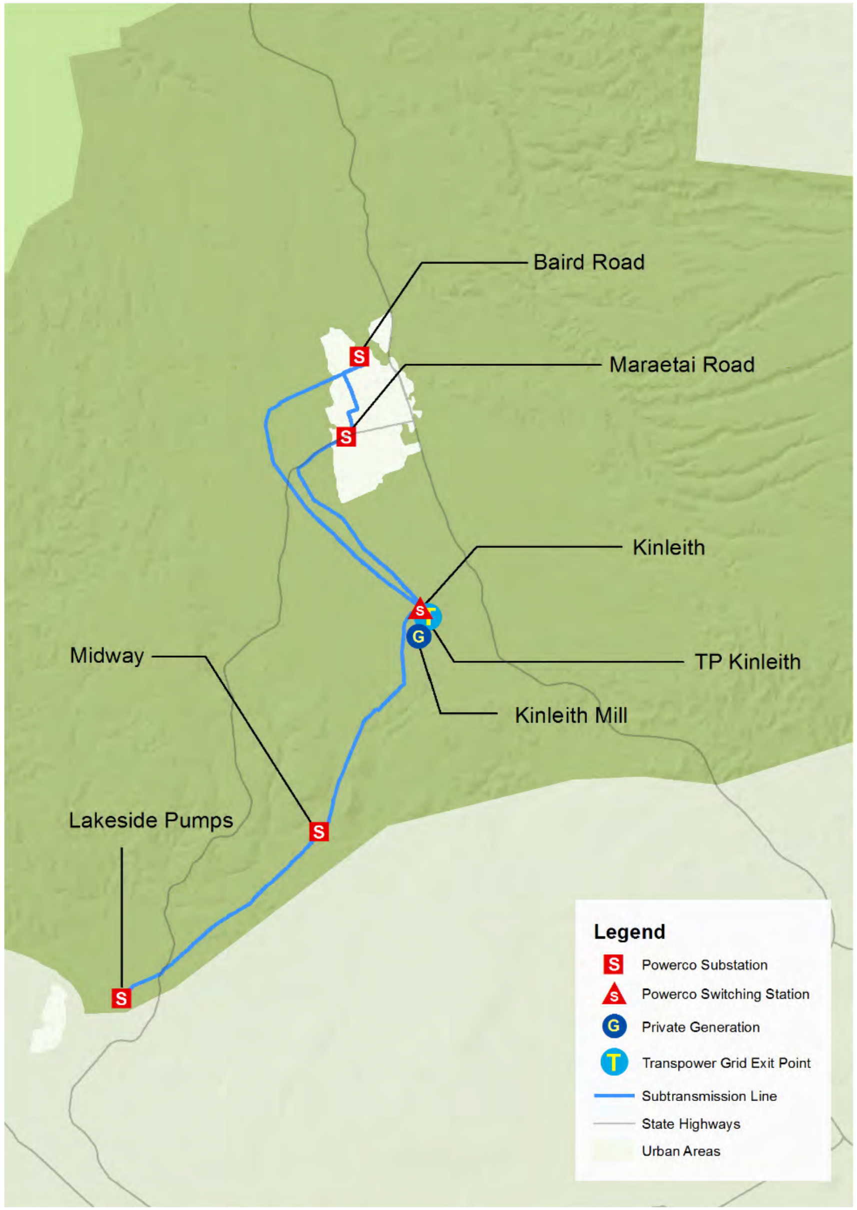
The subtransmission and distribution networks in the Kinleith area are mainly overhead.

Kinleith GXP is the sole grid supply point for the area. There is no 33kV interconnection with other areas and only limited 11kV backfeed.

Kinleith GXP provides offtake at both 33kV and 11kV. The 33kV supply feeds the Tokoroa substations Baird Rd and Maraetai Rd. There is one 33kV line to each substation and both substations are connected to each other via a single circuit to form a 'ring' formation. 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.

Figure 15.14: Kinleith area overview



15.9.2 DEMAND FORECASTS

Demand forecasts for the Kinleith zone substations are shown in Table 15.17, with further detail provided in Appendix 7.

Table 15.17: Kinleith zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Baird Rd	AA+	0.0	10.2	10.6	10.9	11.3
Maraetai Rd	AA+	0.0	8.3	8.4	8.6	8.8
Midway/Lakeside	AA	0.0	4.2	4.2	4.2	4.2

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. Recently there has been an inquiry from the mill about upgrading its wastewater systems. We are working with the mill to find out what load will be connected and find out what types of constraints could occur on our network. These proposals are not reflected in the base forecast. The Kinleith GXP redevelopment project by Transpower and the associated Powerco 11kV cabling work is now completed.

There is existing generation and some potential for future developments. However, these are likely to be directly connected to the grid and do not significantly impact the development of our network.

15.9.3 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.

As highlighted in the Tokoroa Concept Plan by council, the projection for Tokoroa's population is either static or slight growth in coming years. The council is looking at the possibility of zoning specific areas around the edge of Tokoroa for rural residential (lifestyle block) development.

In Tokoroa south, new connections to small industries are on-going, however there is a large amount of industrial land suitable for a major industry. Several inquiries for 6-8MVA load have been received during the past few years, but none have been taken further. New industrial load would constrain the existing network, therefore new subtransmission supply with a new substation may be required to accommodate industrial load.

Major constraints affecting the Kinleith area are shown in Table 15.18.

Table 15.18: Kinleith constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Baird Rd and Maraetai Rd substations	Baird Rd and Maraetai Rd substations are supplied via subtransmission circuits in a 'ring' formation from Kinleith GXP. An outage on the ring circuit can cause thermal constraints to supply the combined substation load.	Refer to Note 1.
Kinleith GXP	Firm capacity for 110/11kV supply transformers is exceeded.	Refer to Note 2.
Kinleith GXP	The 110/33/11kV supply transformers are not able to operate in parallel because of incompatible vector groups. Therefore, 33kV supply capacity does not meet the security standard.	Refer to Note 3.
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.	Refer to Note 4.
Lakeside and Midway substations	Single supply transformer in each respective substation. No security provided.	Refer to Note 4.

Notes:

1. Baird Rd and Maraetai Rd are supplied via a 33kV subtransmission circuit which consists of overhead line and cable combination. The overhead subtransmission line has been thermally upgraded. Baird Rd 33kV incomer cable upgrade was completed in 2020. The remainder of cable (Maraetai Rd incomer cable and cables from Kinleith GXP to overhead for both substations) will be upgraded in the coming financial year.
2. The security for the Kinleith mill is determined by the customer, Oji Fibre Solutions, and not the Powerco security standard. We continue to work with Kinleith mill and Transpower to improve security of supply.
3. No-break N-1 security for the 33kV bus supplying Baird Rd and Maraetai Rd substations is not possible as the vector group for the 33kV windings on the new T9 and T5 transformers are not identical. The configuration requires a short loss of supply to the 33kV load when switching the 33kV bus between the two transformers, which can be managed operationally.
4. 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.

15.9.4 PROPOSED PROJECTS

There are no significant growth projects planned for the Kinleith area.

15.9.5 POSSIBLE FUTURE DEVELOPMENTS

Powerco will implement a staged programme to install differential protection on all 11kV feeder circuit cables at Kinleith mill. Protection upgrades will be carried out at the same time. The design has been constrained by the need to utilise the existing cable tunnels and by the inability to significantly alter the feeder arrangement on the new switchboard. This work will be coordinated with Transpower and the customer.

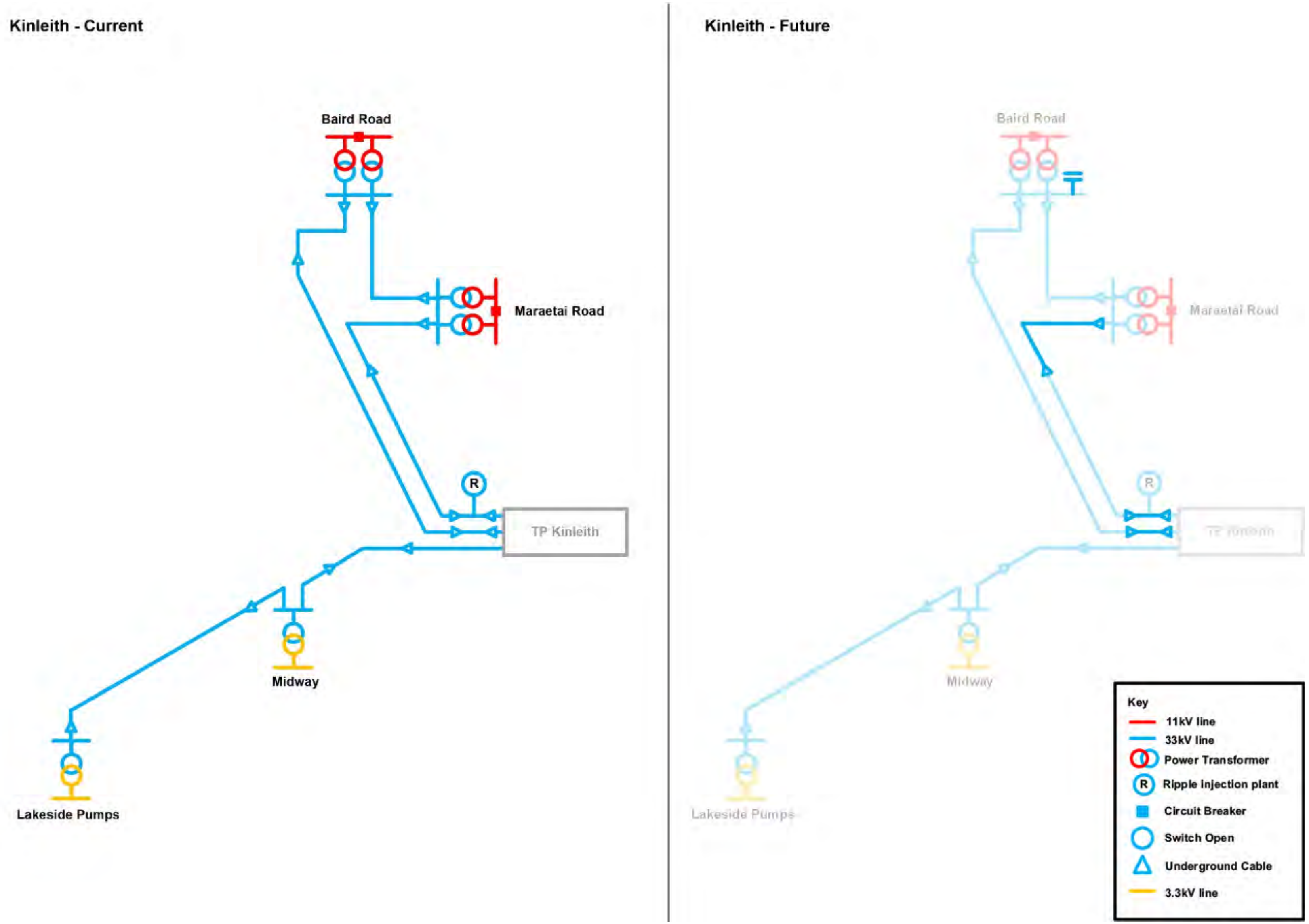
Kinleith GXP is also affected by the grid capacity constraints on the 110kV between Tarukenga and Arapuni.

Forestry to dairy farm conversions, once a major impact on feeder loading, have now tapered off but recently chicken farm connections were approved.

Later in the planning horizon, it is anticipated that post-contingent 33kV low voltage issues at Baird Rd and Maraetai Rd will eventuate with increasing load. Voltage support in the form of reactive support will be needed at either Baird Rd or Maraetai Rd substations to resolve the constraint.

Decarbonisation in the region, for example, electrification of transport, smart charging for EVs, electrifying industries etc could impact the network. As demand increases, subtransmission and substation supply capacities could be exceeded which would directly impact on security of supply to our customers. In addition, customers could potentially be impacted by quality of supply issues, such as low voltages because of decarbonisation. More on decarbonisation is described in Chapter 15.19.

Figure 15.15: Kinleith area network diagram



15.10 TARANAKI

The most recent development work in the Taranaki area has been the alternative supply to our Moturoa substation from the Carrington St GXP, as Transpower exited the New Plymouth substation in the third quarter of 2019. Major and minor project spend related to Growth and Security during the next 10 years is $67m.

15.10.1 AREA 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.

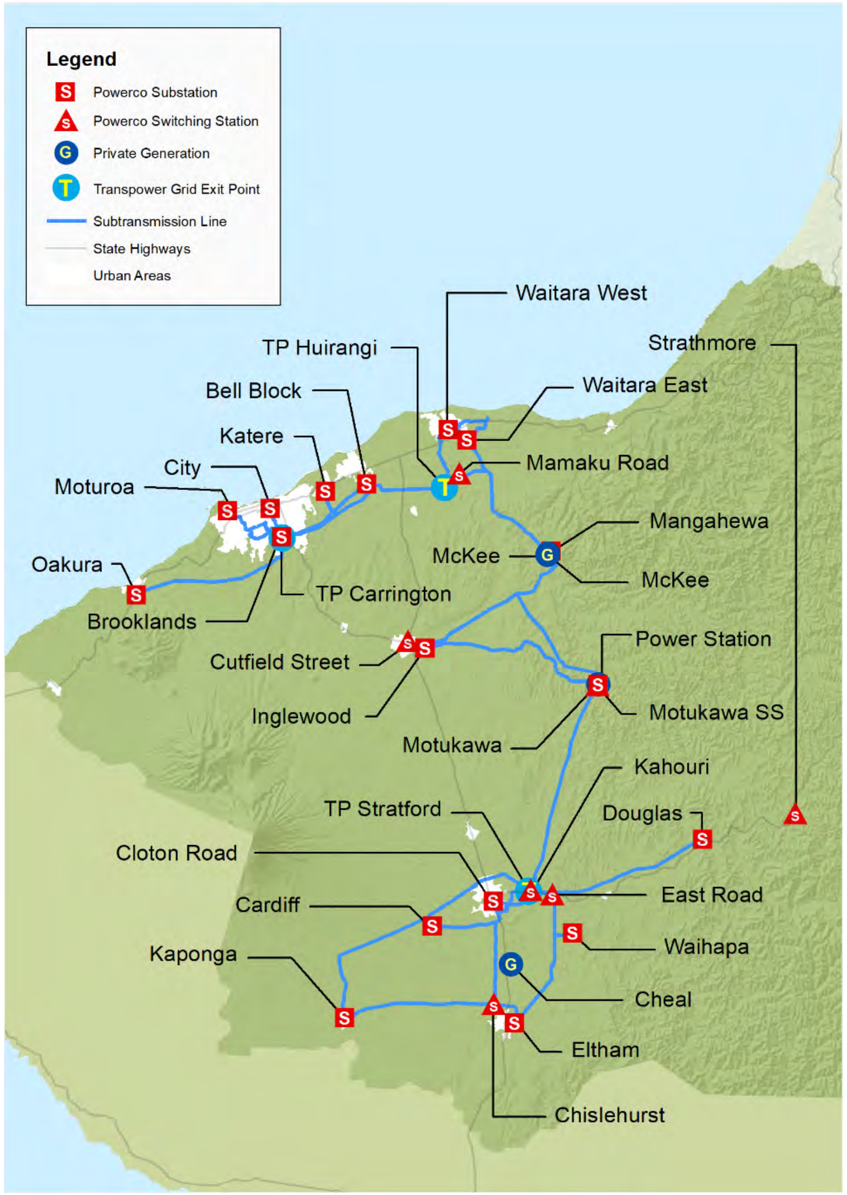
The area is supplied from GXPs at Carrington St, Huirangi and Stratford.

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 are dedicated circuits directly from the GXP.

Figure 15.16: Taranaki area overview



15.10.2 DEMAND FORECASTS

Demand forecasts for the Taranaki zone substations are shown in Table 15.19, with further detail provided in Appendix 7.

Table 15.19: Taranaki zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Bell Block	AAA	24.5	15.6	16.5	17.4	18.3
Brooklands	AAA	24.0	16.6	17.2	17.7	18.3
Cardiff	A1	2.0	1.6	1.7	1.7	1.8
City	AAA	20.1	16.5	17.1	17.7	18.3
Cloton Rd	AA+	13.0	9.9	10.2	10.5	10.8
Douglas	A1	1.7	1.6	1.6	1.6	1.7
Eltham	AA+	11.3	9.9	10.2	10.5	10.7
Inglewood	AA	6.2	5.1	5.3	5.6	5.9
Kaponga	A1	3.0	3.0	3.2	3.3	3.4
Katere	AAA	20.6	13.6	14.5	15.4	16.3
McKee	AA	0.7	1.3	1.3	1.3	1.3
Motukawa	A1	1.3	1.0	1.0	1.1	1.1
Moturoa	AAA	20.7	18.2	18.9	19.7	20.4
Oakura	AA	3.5	3.4	3.7	3.9	4.1
Waihapa	AA	1.0	1.2	1.2	1.2	1.2
Waitara East	AA	10.1	4.7	5.0	5.3	5.6
Waitara West	AA	6.4	6.7	6.8	6.9	7.0

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 and Taranaki Base Hospital, supplied by Moturoa substation.
- McKechnie Aluminium Solutions and Tegel Foods, supplied by Bell Block substation.
- ANZCO Foods processing site and the Fonterra pastoral foods plant, supplied by Eltham substation.
- The Waihapa petroleum production station, supplied by Waihapa substation.
- ANZCO Foods manufacturing processing plant, supplied by Waitara West substation.

Taranaki Base Hospital is increasing its load from 1.3MVA to 3.5MVA in December 2023. A project has been included in this AMP for the distribution network upgrade requirement for this additional load.

We are not aware of any other significant changes in demand for any other 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 recently commissioned 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. The need to reduce carbon emissions and the moratorium on further oil and gas exploration will also have an impact.

There is a focus on the potential of hydrogen production. The move to hydrogen could have a substantial effect on electricity demand in the region, however large-scale production plants are likely to be grid connected.

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. 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.

15.10.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Taranaki area are shown in Table 15.20.

Table 15.20: Taranaki constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Inglewood substation	The Inglewood substation distribution feeders' operating voltage of 6.6kV causes excessive voltage drops as the load grows. Three rural feeders are experiencing poor voltage quality at far ends during peak demand period. 6.6kV is also a non-standard distribution voltage for Powerco.	The solution project, **Inglewood 6.6kV to 11kV conversion**, replaces 6.6/0.415kV transformers with 6.6-11/0.415kV units and then switches all the transformers for 11kV operation. This resolves present voltage quality issues and provides more capacity for future load growth.
Eltham substation	Eltham transformer's firm capacity has been exceeded and the 11kV backup supply availability from neighbouring substations is very limited, with poor voltage quality. Existing shortage of firm capacity also restricts new load connections.	The solution project, **Eltham transformers upgrade**, increases firm capacity from 10MVA to 17MVA and thus provides adequate capacity for future load growth and removes contingency constraints.
Taranaki Base Hospital	The hospital has confirmed that its load will increase from 1.3MVA to 3.5MVA in December 2023 to supply its new facilities and to electrify its heating system. Normal and backup supply feeders, Whiteley St (Moturoa sub) and Brooklands-14, at their present state cannot supply this additional load.	The solution project, **Hospital 4km 11kV cable and 3 RMUs,** installs 2.4km of new cable on Brooklands-9 feeder and 1.6km of new cable along with three RMUs on Whiteley St feeder to provide normal and backup supply to the hospital total load of 3.5MVA.
Waitara East, West McKee and Inglewood	An outage on the Waitara West 33kV line can overload the single circuit from Huirangi GXP to Waitara East-McKee tee supplying four substations – Waitara East, Waitara West, McKee and Inglewood.	The solution project, **Huirangi to McKee tee second 33kV line**, provides a dedicated circuit for each of the McKee and Waitara East circuit and thus resolves the existing constraints for contingencies.
Midhirst 11kV regulating station	Midhirst regulating station supplies Midhirst town and its northern side large rural network. Its 11kV supply is from Cloton Rd substation. Voltage quality, before Midhirst regulator, is marginal. Being close to Stratford town, Midhirst load is expected to grow.	The solution project, **new Midhirst substation**, constructs a 10MVA capacity substation at Midhirst by extending the present 33kV line that supplies Cardiff and Kaponga substations. It provides adequate capacity for future load growth in the Midhirst network and contingency supply to the neighbouring feeders.
Bell Block substation	Paraite Rd feeder from Bell Block supplies two industrial customers – Tegel Foods (1.8MVA) and McKechnie Aluminium Solutions (2.8MVA) – plus another 92 ICPs. Demand (4.9MVA) of this feeder cannot be supported by other feeders.	The solution project, **Paraite Rd feeder backup supply**, installs 2.8km of 11kV cable from a new circuit breaker at Katere substation to McKechnie. This creates the option to provide backup supply to Paraite feeder and, in the future if required, the feeder can be offloaded onto Katere substation.
Inglewood substation	Inglewood is forecast to exceed the secure capacity of the power transformers by 2027. Shortage of firm capacity could restrict new customer connections. Being close to New Plymouth, Inglewood load is expected to grow through new subdivisions.	The solution project, **Inglewood substation transformers upgrade**, replaces two 5MVA transformers with two 7.5/10MVA transformers. This provides adequate capacity for long-term future load growth, and contingency situation supply to Inglewood and Motukawa customers.
Motukawa substation	Motukawa distribution feeders operate at 6.6kV, which draws more current than 11kV-rated feeders and causes excessive voltage drops. Two rural feeders (out of three) experience marginal voltage quality during the peak demand period. 6.6kV is also a non-standard Powerco distribution voltage and Motukawa will shortly be the only remaining substation operating at 6.6kV.	The solution project, **Motukawa 6.6kV to 11kV conversion**, replaces 6.6/0.415kV transformers with 6.6-11/0.415kV units and then switches all the transformers for 11kV operation. This resolves voltage quality issues and increases feeders' capacity for future load growth.
Oakura substation	Oakura substation is supplied by a single 33kV circuit and single transformer. The 11kV backup supply is forecast to be insufficient by 2027. A subdivision of about 300 lots, next to Oakura, is planned for development in 5-10 years.	The solution project, **Oakura second 33kV line and second transformer**, would provide adequate capacity for the contingency constraints that would arise with future load growth.
Mangorei 11kV regulating station	Mangorei regulating station's 11kV supply feeder is forecast to exceed its capacity by 2030. Also, the regulating station is not located at the centre of the load it supplies and the voltage quality on its two feeders is close to threshold (95%)	The solution project, **new Egmont Village substation**, constructs a 10MVA capacity new substation at Egmont Village by extending Mangorei's 11kV supply feeder another 6km. This resolves the voltage quality issue and supports future load growth.
Cloton Rd and Eltham substation	One of Cloton Rd's 33kV supplies is mostly shared (3.9km of 5km) with one 33kV supply of Eltham substation. This shared section reaches its capacity (16.5MVA) when there is an outage on either of Cloton Rd's or Eltham's other 33kV supplies.	The solution project, **Cloton Rd substation second 33kV supply**, separates the shared part by installing 4km of 33kV cable from Stratford GXP and, therefore, removing existing contingency constraints.

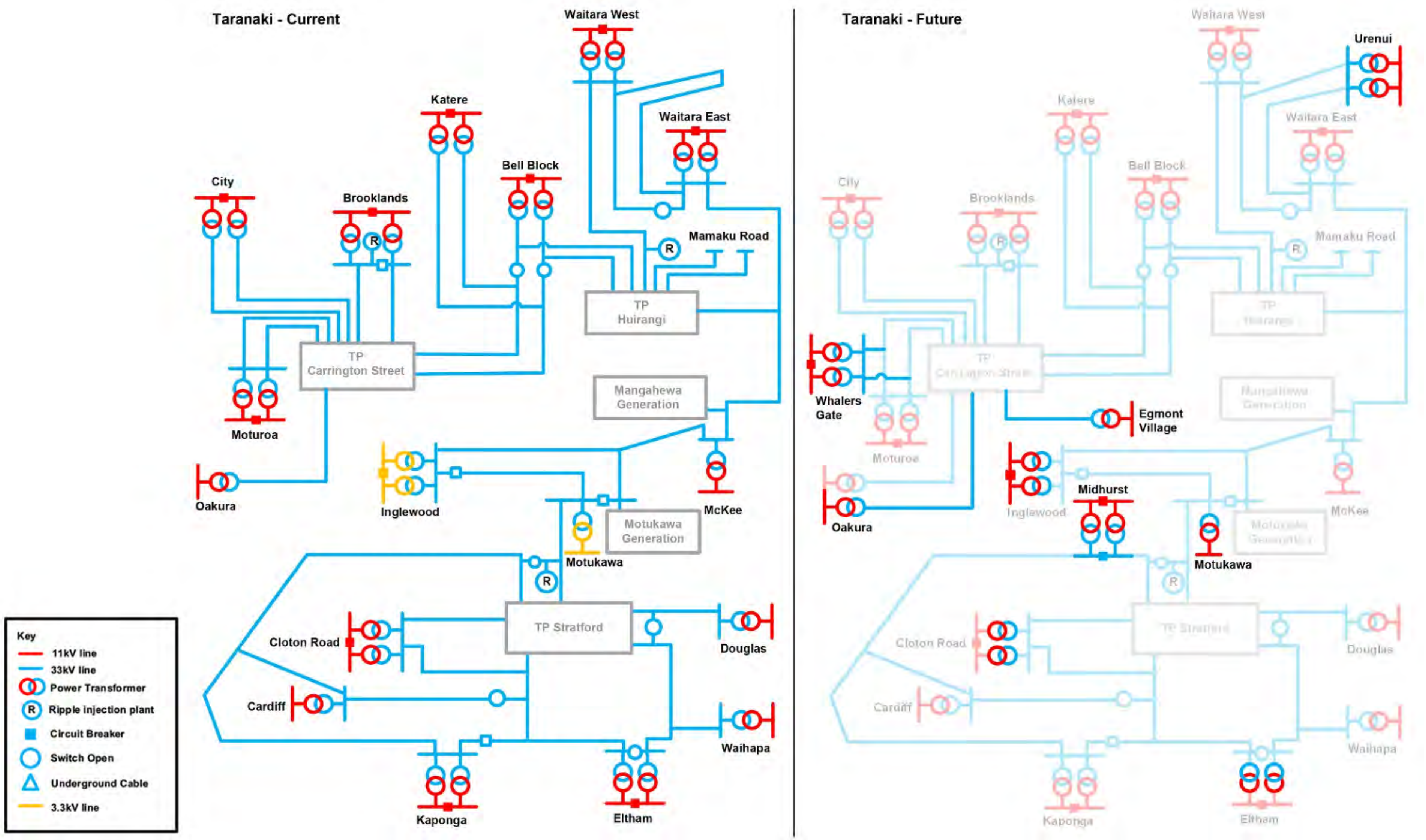
LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Moturoa substation	Moturoa substation's 2030 forecast demand of 22.2MVA is close to its firm capacity of 24MVA. One of its large customers, Taranaki Base Hospital, is increasing its load from 1.3MVA to 3.5MVA in December 2023. Furthermore, new subdivisions and developments in certain areas of New Plymouth, such as Whalers Gate, would add additional load to Moturoa.	The solution project, **new Whalers Gate substation**, constructs a 24MVA capacity substation at Whalers Gate by extending Moturoa's two 33kV cables (each 1km). This would offload Moturoa, Brooklands and City substations' load and would provide adequate capacity to supply future load growth.
Cloton Rd substation	Cloton Rd's 2020 demand of 10.5MVA is close to its firm capacity of 13MVA. As the substation supplies Stratford town, its load is expected to grow. Cloton Rd's security class is AA+, which requires restoration of supply within 15 seconds in N-1 situation. At times Cloton Rd supports Cardiff, a single transformer substation.	The solution project, **Cloton Rd substation transformers upgrade**, replaces the two transformers with 12.5/17MVA capacity transformers. This provides sufficient capacity for longer term future load growth and to provide contingency supply to Cardiff.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Waitara East substation	The Main Rd Motunui feeder from the Waitara East substation supplies Urenui township and its eastern side large rural network. This feeder, on its way to Urenui, operates with two voltage regulators and the voltage quality before the regulators is marginal. There is no alternate supply option for Urenui network and it is one of the worst performing feeders.	The solution project, **new Urenui substation**, constructs a 10MVA capacity substation at the outskirts of Urenui town by extending ex-Pohokura 33kV cables. This brings the substation at the centre of the load and splits Urenui network into three feeders, which improves the voltage quality and reliability of supply.
Cardiff substation	The single supply transformer does not provide sufficient security. Renewal is scheduled for 2022.	Refer to Note 1.
Kaponga substation	Demand exceeds secure capacity of the two transformers. Transformers are scheduled for replacement in 2026.	Refer to Note 1.
Motukawa substation	The single transformer does not provide sufficient security and is scheduled for replacement.	Refer to Note 1.
Douglas substation	The single supply transformer does not provide sufficient security.	Refer to Note 1.

Notes:

1. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.

Figure 15.17: Taranaki area network diagram



15.10.4 PROPOSED PROJECTS

Table 15.21: Growth and Security projects

PROJECT	COST ($000)	TIMING (FY)
Inglewood 6.6kV to 11kV conversion	$5,200	2019-2022
Eltham transformers upgrade	$4,400	2020-2022
Hospital 4km 11kV cables and 3 RMUs	$3,400	2021-2024
Huirangi to McKee tee second 33kV line	$1,340	2021-2023
New Midhirst substation	$10,000	2023-2026
Paraite Rd feeder backup supply	$1,680	2023-2025
Inglewood substation transformers upgrade	$2,100	2024-2026
Motukawa 6.6kV to 11kV conversion	$2,690	2024-2026
Oakura second 33kV line and second transformer	$5,900	2025-2028
New Egmont Village substation	$6,500	2025-2028
Cloton Rd substation second dedicated 33kV line	$1,840	2026-2028
New Whalers Gate substation	$7,910	2025-2028
New Urenui substation	$11,000	2028-2031
Cloton Rd transformers upgrade	$3,100	2026-2028

15.10.5 POSSIBLE FUTURE DEVELOPMENTS

Transpower's grid developments can have a significant impact on network development, as seen with the recent removal of the New Plymouth GXP and the need for a new supply to the Moturoa substation.

Gas-fired generation opportunities can arise. Larger generation of 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 must quickly reconsider some of our network development plans.

Taranaki has many spot-load increases driven by industrial customers, either those associated with agriculture or with the oil and gas industry. These spot-load increases have limited lead times 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 backfeeding schemes. Long rural feeders often need voltage support, which requires regulators or more permanent conductor upgrades.

The following project has been identified as being likely to occur during the planning period. The following description represents the most probable solution, but the final solution and optimal timing are subject to further analysis and will be confirmed closer to the time.

PROJECT	SOLUTIONS
Motukawa substation second transformer	The Motukawa substation consists of a single transformer. In the case of a transformer outage, it relies on its backfeed capability from neighbouring substations' distribution network. In the future, if the demand exceeds the present class capacity, there is a possibility for loss of supply at the substation for a transformer fault. The preferred solution is to add the second transformer to the substation.

15.11 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 at Mokoia has replaced the Whareroa substation. Major and minor project spend related to Growth and Security during the next 10 years is $19m.

15.11.1 AREA 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 are 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, Mokoia, and Livingstone substations.

A 33kV ring supplies Mokoia 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, which is the main substation serving Hawera township, is supplied by two dedicated 33kV oil-filled cables.

Historically, two different power companies owned the Opunake and Hawera networks. The two subtransmission networks are operated at a 50Hz frequency but with different phase angles, so they cannot be interconnected. The subtransmission and distribution networks are mainly overhead.

The major Fonterra plant at Whareroa is connected directly to the 110kV grid.

Figure 15.18: Egmont area overview

15.11.2 DEMAND FORECASTS

Demand forecasts for the Egmont zone substations are shown in Table 15.22.

Table 15.22: Egmont zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Cambria	AAA	17.0	13.1	13.4	13.7	14.0
Kapuni	AA+	7.0	5.5	5.5	5.5	5.5
Livingstone	A1	3.0	2.6	2.7	2.7	2.7
Manaia	AA	4.0	5.9	6.1	6.2	6.3
Mokoia	A1	4.0	3.1	3.2	3.4	3.5
Ngariki	A1	3.9	3.8	4.0	4.1	4.3
Pungarehu	A1	4.5	3.0	3.1	3.3	3.4
Tasman	AA+	6.4	6.5	6.7	6.9	7.0

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.

15.11.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Egmont area are shown in Table 15.23.

Table 15.23: Egmont constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hawera GXP	i) An outage on the 110kV supply circuit to the Hawera GXP can cause low voltages at the substation.ii) Supply transformer firm capacity exceeded because of bus section capacity limitations.	(i) Refer to Note 1. (ii) Refer to Note 2.
Manaia substation	Manaia's short section of single 33kV circuit and the single transformer at the substation do not meet its required security class of AA+. 11kV backup supply is insufficient. Yarrows The Bakers needs to reduce most of its load to mitigate the shortage of backup supply, which it is unhappy about.	The solution project, **Manaia tee removal**, constructs a second 33kV line through the installation of an indoor 33kV board at the tee point and a second transformer at Manaia substation. This would provide Manaia's required security class of AA+.
Hawera GXP	Transpower's outdoor 33kV switchgear that supply Powerco's six 33kV feeders are in poor condition and have reached their expected life. Transpower's approach is to replace them through an indoor conversion, although Powerco has the option to take on the works.	The solution project, **Hawera GXP 33kV ODID**, will be constructed by Powerco on land provided by Transpower, and Powerco will take the ownership. Therefore, the project will be delivered at reduced cost and Powerco will have more control and visibility at GXP level.
Opunake GXP	Transpower's outdoor 33kV switchgear that supply Powerco's three 33kV feeders are in poor condition and have reached their expected life. Transpower's approach is to replace them through an indoor conversion, although Powerco has the option to take on the works.	The solution project, **Opunake GXP 33kV ODID**, will be constructed by Powerco on land provided by Transpower, and Powerco will take the ownership. Therefore, the project will be completed at reduced cost and Powerco will have more control and visibility at GXP level.
Kapuni and Manaia substations	Kapuni and Manaia substations take 33kV supply from a ring network that runs Hawera GXP to Kapuni (16.4km long), Kapuni to Manaia tee (6.9km) and Manaia tee to Hawera (13km). It has a capacity of 15MVA in an N-1 situation. This capacity is forecast to reach its limit at 2030.	The solution project, **Kapuni and Manaia third 33kV line**, constructs a new 33kV line from Hawera GXP to the Manaia tee point new 33kV board. This provides adequate capacity for contingency situation supply.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Tasman substation	Tasman substation 2020 demand exceeds its firm capacity. The 11kV backup supply availability is from Ngariki, which is forecast to run out of capacity to support Tasman by 2027. Furthermore, Tasman transformers would be 54 years old in 2030 and would be more unreliable.	The solution project, **Tasman transformers upgrade**, replaces two transformers with two 7.5/10MVA units. This provides sufficient capacity for future load growth and contingency situation supply.
New Normanby substation	Normanby township and its northern side large rural network is supplied through an 11kV feeder – Tawhiti Rd – off Cambria substation. The voltage quality at Normanby township and its downstream line is close to threshold during peak demand periods. Furthermore, the reliability of supply is poor, because of the large network it supplies. Tawhiti is one of the worst performing feeders.	The solution project, **new Normanby substation**, constructs a new 10MVA capacity at Normanby by constructing two 33kV lines (each 4km) from Hawera GXP. This splits the network into three feeders and, therefore, improves the capacity and reliability of supply.
Pungarehu substation	Demand exceeds secure capacity of the two transformers.	Refer to Note 3.
Livingstone substation	Transformer firm capacity has been exceeded. Transformers are scheduled for replacement in 2024.	Refer to Note 3.
Ngariki substation	Single transformer. The 11kV backfeed does not meet security criteria.	Refer to Note 4.

Notes:

1. Transpower is investigating possibilities for additional reactive support for use during 110kV outages. Only constrains with no generation.
2. Capacity is limited by a bus section and can be managed operationally using the adjoining Kupe transformer in emergencies.
3. Managed operationally. Very low risk as backfeed capacity is sufficient for the required security class.
4. Managed operationally.

15.11.4 PROPOSED PROJECTS

Table 15.24: Growth and Security projects

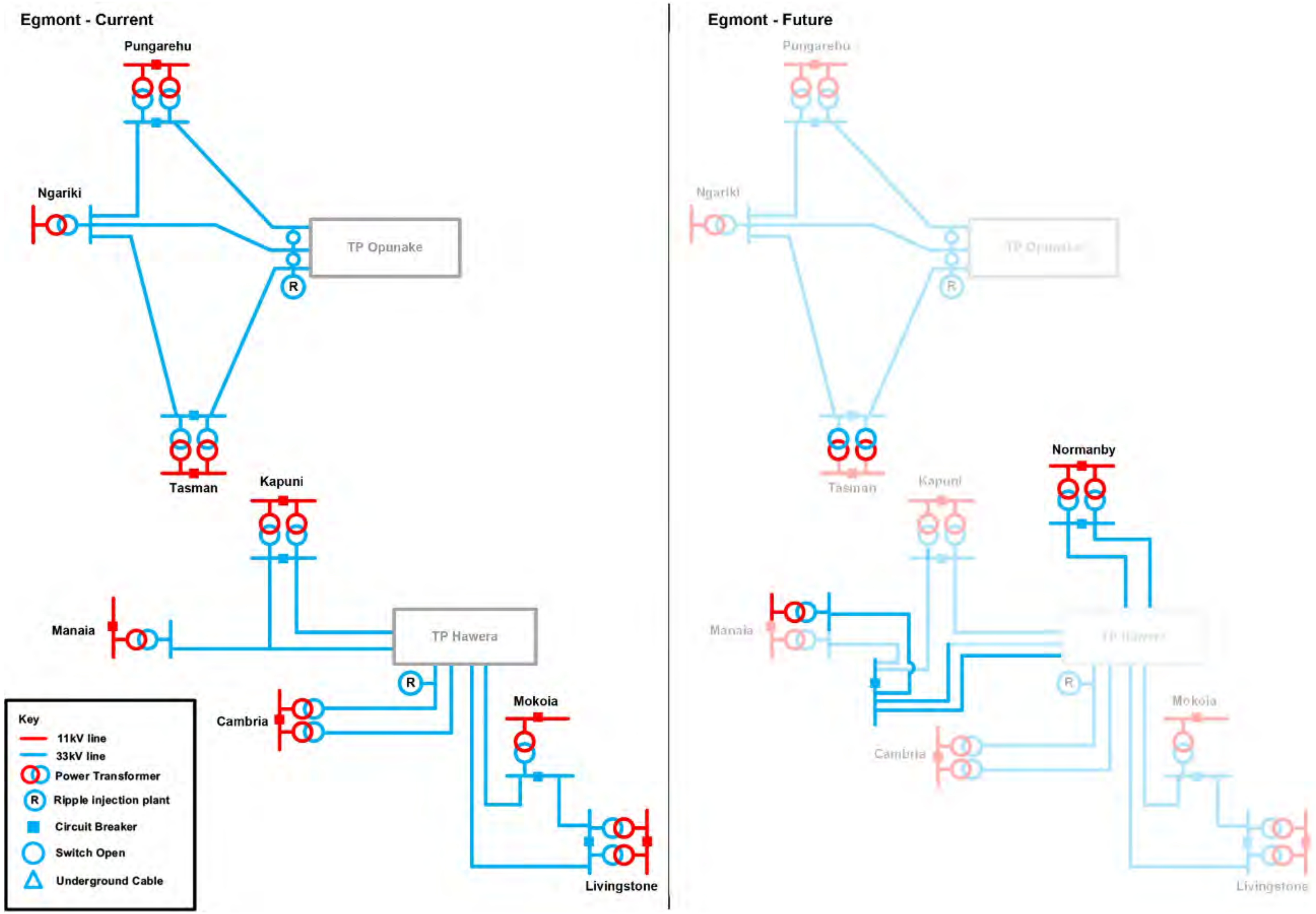
PROJECT	COST ($000)	TIMING (FY)
Manaia tee removal	$7,800	2021-2023
Hawera GXP 33kV ODID	$5,400	2021-2024
Opunake GXP 33kV ODID	$4,400	2021-2024
Kapuni and Manaia third 33kV line	$3,200	2024-2028
Tasman substation transformers upgrade	$2,200	2025-2027
New Normanby substation	$7,700	2028-2031

15.11.5 POSSIBLE FUTURE DEVELOPMENTS

The following project has been identified as being likely to occur during the planning period. The description represents the most probable solution, but the final solution and optimal timing are subject to further analysis and will be confirmed closer to the time.

PROJECT	SOLUTIONS
Livingstone substation supply transformers	There is limited backfeed capability from the 11kV distribution network. The preferred solution is to upgrade the transformers during the planned renewals replacement project.

Figure 15.19: Egmont area network diagram



15.12 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 under way in the area include a second 33kV circuit to the Taupo Quay and Peat St substations. Major and minor project spend related to Growth and Security during the next 10 years is $37m.

15.12.1 AREA 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 sunshine hours slightly higher than the national average sunshine at 2,100 hours per annum, and about 900mm of annual rainfall. The Whanganui River is prone to flooding in heavy rain.

The Whanganui area also gets hit by occasional storms off the Tasman Sea. High winds cause the main disruption as they can fell trees and throw debris into lines, which leads to widespread and prolonged outages.

The district's economy is driven by agriculture, forestry and fishing. Whanganui city is both the main service centre for the rural district and a self-sustaining commercial entity.

There are several industrial and commercial customers of significance within Whanganui city. However, none are of sufficient size to warrant a dedicated substation.

The area connects to the grid through three Transpower GXPs. Whanganui and Brunswick GXPs supply Whanganui city and surrounding areas. Waverley GXP supplies the town of Waverley.

There are nine zone substations in the Whanganui area, five of which – Blink Bonnie, Taupo Quay, Beach Rd, Hatricks Wharf and Whanganui East – are supplied from the Whanganui GXP. Peat St, Roberts Ave, Kai Iwi, and Castlecliff are supplied from the Brunswick GXP. Waverley GXP directly supplies the Waverley township and surrounding areas via 11kV distribution feeders.

Whanganui has a unique, somewhat 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 subtransmission and distribution networks are mainly overhead, even in most urban areas.

There are renewal project intentions to refurbish conductors, river crossing towers between Whanganui GXP and Taupo Quay substations in the near term.

Figure 15.20: Whanganui area overview

15.12.2 DEMAND FORECASTS

Demand forecasts for the Whanganui zone substations are shown in Table 15.25, with further detail provided in Appendix 7.

Table 15.25: Whanganui zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Beach Rd	AA+	16.2	9.8	10.0	10.1	10.3
Blink Bonnie	A1	3.0	3.8	3.9	4.0	4.1
Castlecliff	AA+	8.7	9.1	9.2	9.4	9.5
Hatricks Wharf	AA+	0.0	13.4	13.7	14.0	14.2
Kai Iwi	A1	1.0	2.2	2.3	2.4	2.5
Peat St	AAA	0.0	14.1	14.4	14.6	14.9
Roberts Ave	AA	5.8	4.5	4.6	4.7	4.8
Taupo Quay	AA+	0.0	10.8	10.9	10.9	11.0
Whanganui East	AA	3.4	5.2	5.3	5.3	5.4

Recent underlying growth in demand has been modest throughout the Whanganui area. Major industrial customers 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 Mill Road industrial subdivision will add 0.5MVA to Castlecliff substation. Larger customers have been looking into expansion options around Castlecliff. There has been feasibility interest in substantial electrification near Pukepapa and Blink Bonnie substations. Hatricks Wharf will supply expanded art infrastructure in the city.

Growth and Security plans are moving towards security class capacity, improving security and reliability for the existing load base, and catering for future new load. Growth and Security plans will balance a probabilistic theory, improve transfer capacity between critical substations, raise security at Brunswick GXP and further mesh the subtransmission ring.

15.12.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Whanganui area are shown in Table 15.26.

Table 15.26: Whanganui constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Beach Rd	Brunswick is a single transformer GXP, so occasional maintenance outages are requested by Transpower. Contingent modelling of a Brunswick GXP outage shows the Taupo Quay to Beach Road line loading at 71% (14.3MVA) rated for the cable (20.4MVA) and exceeds conductor rating (20.2MVA). There is no alternative path for supply from Whanganui, aside from past Hatricks Wharf where Peat St draws on that route.	The solution project, **Taupo Quay to Beach Rd**, would upgrade both cable and conductor to 35MVA, enabling cable and conductor loadings to remain within 65% capacity rated during contingent scenario. A commitment to dual transformers at Brunswick GXP will reduce the risk of this forecast constraint.
Hatricks Wharf	Powerco has a project under way to install a second high-capacity (30MVA+) line from WGN GXP Bus K to Taupo Quay. Upon completion of this project, the subtransmission export capacity of WGN GXP Bus K and L will be mismatched in totality. This presents a constraint under a half Bus K outage scenario. In winter, there is a capacity constraint between WGN GXP and Hatricks Wharf sub (12MVA) when parallel supply is compromised.	The solution project, **Whanganui GXP Bus L to Hatricks Wharf**, would upgrade conductor capacity to above 23MVA, lessening the Brunswick GXP outage scenario constraint. The various conductor types would be upgraded to a uniform size by design.
Hatricks Wharf and Peat St	In later years, likely in the next decade, the ability to transfer greater capacity from WGN GXP into the city zone substations will become important. During a Brunswick GXP outage at year 2029 demand forecast, supply between Whanganui GXP and Hatricks Wharf sees insufficient capacity on the overhead conductor. This line parallels with the WGN GXP Bus K supply to Hatricks Wharf.	The solution project, **Whanganui GXP Bus K to Hatricks Wharf**, would upgrade capacity to above 23MVA, removing the existing Brunswick GXP outage scenario constraint.
Peat St	Hatricks Wharf is centrally located on the subtransmission ring between Brunswick and Whanganui GXP stations. This centrality requires Hatricks Wharf to provide bi-directional high-capacity supply to Peat St. When supply to Roberts Ave, Castlecliff or Peat St is compromised, at later year demand forecast levels, supply between Hatricks Wharf and Peat St becomes over-loaded on both the 630mm² cable and conductor portion.	The solution project, **Hatricks Wharf to Peat St**, would upgrade cable and conductor capacity to minimum 32MVA, providing sufficient contingent capacity to the steadily growing Peat St sub demand.
Castlecliff	Taupo Quay subtransmission forms part of the Peat St, Beach Rd, Castlecliff and Hatricks Wharf ring. At year 2029, forecast demand outage modelling of a malfunction of the Taupo to Beach conductor, shows the alternative Peat St to Castlecliff ring loading 99% of the cable and conductor.	The solution project, **Peat St to Castlecliff**, would upgrade existing cable and conductor to minimum 24MVA, allowing supply of Castlecliff and Beach Road subs at forecast demand levels.
Roberts Avenue and Peat St	Supply to Peat St from Brunswick GXP is constrained during an outage of the 5.49km 30MVA direct path conductor. There is a current project delivering a new large capacity cable between Roberts Ave and Peat St subs. Once the Roberts Ave to Peat St new cable project is completed, there will be an alternative path for supply to Peat St. However, the capacity of the conductor upstream of Roberts Ave is only 22MVA. The lower-capacity portion of this alternative path lessens future security of Peat St and dependent substations.	The solution project, **Brunswick GXP to Roberts Ave conductor**, is a conductor capacity upgrade for the 3.6km conductor between Brunswick GXP and Roberts Ave sub, ensuring adequate contingent supply through Roberts Ave. This would ensure a high-capacity alternative supply path between Brunswick GXP and Peat St, and dependent subs beyond.
Beach Rd and Castlecliff	There are two options for supplying Castlecliff and Beach Rd, one of which heavily loads the main supply lines out of WGN GXP. Supply from Brunswick GXP to Beach Road, under select scenarios, must pass through Roberts Ave, Peat St, then Castlecliff or Hatricks Wharf and Taupo Quay, which is unachievable with available capacities of conductors.	A solution project, **Hatricks Wharf to Beach Rd new line**, is for a new line between Beach Rd and Hatricks Wharf, or similar in path, providing a more direct route supply option via advancement towards a meshed configuration.

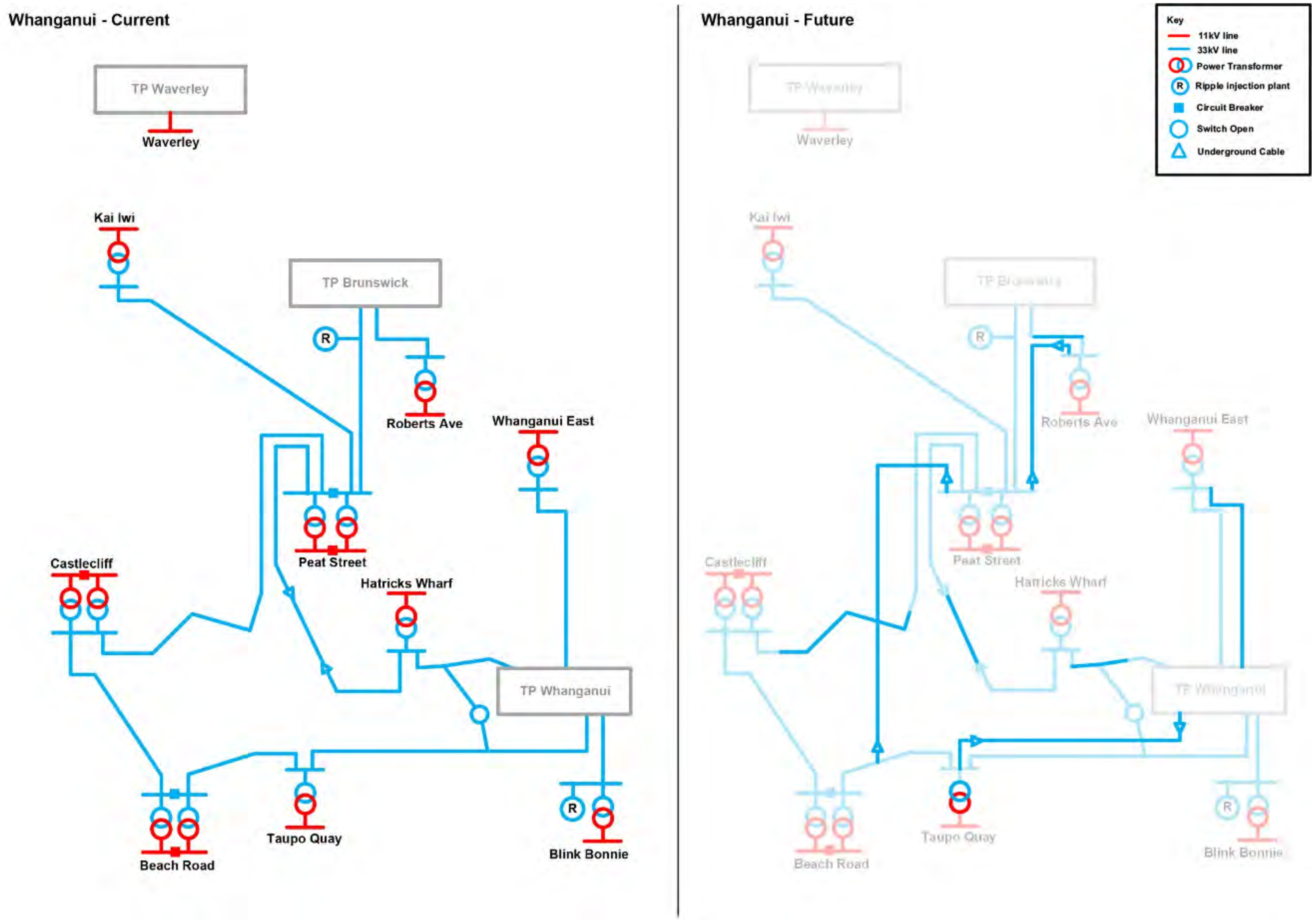
LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Peat St and dependent substations	Peat St is the most critical substation in Whanganui but is supplied by a single circuit, meaning security is dependent on backfeed from Whanganui GXP substations. Such cross GXP backfeed arrangements also require break-before-make changeover, which is inappropriate for a substation serving the city's CBD. When existing circuits from Whanganui GXP are unavailable there is insufficient capacity through Peat St to secure all dependent substations.	The preferred project, **Roberts Ave to Peat St**, involves the construction of a new 33kV circuit between Roberts Ave and Peat St substations. The project will provide a partial alternative supply to Peat St.
Beach Rd and Taupo Quay	There is insufficient supply capacity to Beach Road under contingent configuration. The network capacity is inadequate.	The solution, **Peat St to Taupo Quay New 33kV Line**, is under way to install an additional 33kV circuit from Brunswick GXP into Taupo Quay.
Peat St and broader ring	The capacity limitation is due to having only a single subtransmission feeder from Brunswick GXP into Peat St. This project seeks to double the available 36MVA capacity, reducing reliance primarily on the Castlecliff through Hatricks Wharf subtransmission circuits and secondarily on the Whanganui/Marton 110kV circuit.	This second subtransmission line project, **Brunswick GXP second 33kV line**, aligns with present day thinking that capacity upgrades to Transpower's 110kV circuits are uncertain, and Whanganui ring reliance upon Brunswick GXP for future enabling capacity and security is advised. The outcome might be achieved by different route options, should the Roberts Ave to Peat St project be delivered.
Whanganui East and Roberts Ave	The Whanganui East substation supplies urban and rural loads to 5.2MVA. The substation is supplied by one single 33kV circuit from WGN GXP and contains one supply transformer. There is potential for loss of supply at the substation for a transformer or subtransmission fault. There is also limited backfeed capability from the distribution network, approximately 3.4MVA not served during an outage.	The solution is the **Whanganui East second line** project.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Hatricks Wharf via Taupo Quay	The existing transformer at Taupo Quay is 10/12.5MVA rated. The transformer does not have the capacity to supply both Taupo Quay and fully backfeed Hatricks Wharf load during an outage via the 11kV bus tie if Hatricks Wharf was to lose supply from WGN GXP.	The solution project, **Taupo Quay transformer upgrade**, would upgrade the existing transformer to provide adequate contingent capacity to supply the Taupo Quay demand, future growth, plus Hatricks Wharf demand. Refer to Note 1.
Castlecliff	Castlecliff sub modelling at present year forecast demand, shows an outage of one transformer will load the single transformer to firm capacity. There exists a local community preference to maintain a rating near to AA+ security class.	The solution project, **Castlecliff transformers**, would upgrade one or both transformers to provide firm capacity well above 10MVA, factoring for future growth. Currently we expect to install one 17MVA transformer, although the exact rating will be decided during the feasibility design phase.
Blink Bonnie	The substation contains a single 6MVA supply transformer and has N-1 subtransmission switching capability. The 3.9MVA demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from distribution network.	The solution project is **Blink Bonnie second supply and transformer**. It is reasonable to expect probabilistic planning standards and land access may defer investment on this project.
Kai Iwi	The Kai Iwi substation is situated northwest of Whanganui and supplies the Whanganui city water pumping station, the residential area east of the Whanganui River, and rural area to the east of Whanganui. Its 11kV backup supply is not adequate for the supply of the substation load.	Under the **Kai Iwi 11kV upgrade** project, as a sensible interim solution funded by the routine project budget, a temporary generator pad will further improve the backfeed ability by 6.6kV conversion.

Note:

1. Taupo Quay and Hatricks Wharf are linked by a high-capacity 11kV bus tie. Hatricks Wharf can backfeed Taupo Quay in the case of a single transformer outage. Taupo Quay sub does not have adequate capacity to backfeed Hatricks Wharf, so the changeover scheme is on manual.

Figure 15.21: Whanganui area network diagram



15.12.4 PROPOSED PROJECTS

Table 15.27: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)
Taupo Quay to Beach Rd	$740	2028-2030
Whanganui GXP Bus L to Hatricks Wharf	$1,610	2023-2025
Hatricks Wharf to Peat St	$1,200	2024-2026
Peat St to Castlecliff	$2,400	2024-2026
Brunswick GXP to Roberts Ave conductor	$1,154	2024-2025
Roberts Ave to Peat St 33kV circuit	$3,800	2022-2023
Peat St to Taupo Quay New 33kV Line	$5,500	2022-2023
Whanganui East second line	$2,020	2025-2027
Taupo Quay transformer upgrade	$1,460	2023-2025
Castlecliff transformers	$2,280	2023-2025
Kai Iwi 11kV upgrade	$1,500	2030

15.12.5 POSSIBLE FUTURE DEVELOPMENTS

TP Whanganui has one 30MVA and one 20MVA transformer. Maximum demand is about 41MVA. T1 is 51 years old and T2 is 58 years old. T2 is planned for replacement by Transpower in 2023. This upgrade may be altered in scope, considering the 110kV network's utilised capacity and the new switchable level of supply from TP Marton into the Sanson Bulls interconnect.

We are investing in larger capacity out of TP Whanganui in the near term. The project improves the ability of TP Whanganui to supply Taupo Quay, Hatricks Wharf and Beach Rd during peak maximum demand periods, but under particular scenarios, there are still several capacity constraints present in the subtransmission ring between TP Brunswick and TP Whanganui. This makes bus outages at both GXPs increasingly difficult to achieve throughout the year.

The cross GXP subtransmission backfeeds 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.

We have pursued discussions with Transpower in regards to dual transformers to TP Brunswick GXP. A second transformer at Brunswick was an original alternative option for the Peat St improvement projects, providing security into the critical substation. TP Brunswick sees demand between 30 and 40MVA. Near-term Powerco investment in subtransmission ring capacity upgrades could enable further utilisation of TP Brunswick and less of TP Whanganui. TP Brunswick has a single 50MVA transformer consisting of three single phase tanks, plus a spare tank on site. Powerco has recently investigated feasibility and route options for new 33kV feeders out of TP Brunswick to Peat St and perhaps on to Beach Rd zone substation.

Other proposed projects are listed in the following table.

PROJECT	SOLUTIONS
Second transformer to TP Brunswick GXP	Agreement between Transpower and Powerco for the installation of a second-hand or new three-phase tank transformer into Brunswick. The transformer would be of similar capacity to the existing single phase(s) transformer bank. The project would necessitate an expansion, likely an ODID of the 33kV switchyard at the site.
TP Brunswick ODID	The existing 33kV switchyard at Brunswick can not accommodate a second transformer, so an ODID with Powerco ownership makes sense to pursue, alongside a second transformer. The region would also benefit from the option to install a third line out of Brunswick towards Peat St, which an ODID could provide.
Hatricks Wharf to Beach Rd new circuit	The longest existing ring from WGN to BRK encompasses Taupo Quay, Beach Rd, Castlecliff and Peat St subs. There are two options for supplying Castlecliff and Beach Rd, one of which heavily loads the main supply lines out of WGN GXP. Supply from Brunswick GXP to Beach Rd, under select scenarios, must pass through Roberts Ave, Peat St, then Castlecliff or Hatricks Wharf and Taupo Quay, which is unachievable with available capacities of conductors. A solution project for a new line between Beach Rd and Hatricks Wharf, or similar in path, providing a more direct route supply option via advancement towards a meshed configuration. If an alternative 33kV line from BRK is achieved, this project becomes an extension of such.

PROJECT	SOLUTIONS
Taupo Quay to Hatricks Wharf 11kV upgrade	As growth occurs through the city of Whanganui, we may see a need to upgrade the 33kV-rated but 11kV in-service cable between Hatricks Wharf and Taupo Quay. It is a useful interconnect for transfer capacity and should be maintained to the necessary capacity for risk management purposes.
Roberts Ave second transformer	The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. There is also limited backfeed capability from the distribution network. Our fleet management plans intend to replace the existing transformer in 2024, which is an opportunity to uprate the unit and enable future customer demand growth.
Blink Bonnie second supply and second transformer	The substation contains a single 6MVA supply transformer and has N-1 subtransmission switching capability. The 3.9MVA demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from the distribution network.
Waverley	The Waverley substation is Transpower-owned and operated. The 11kV bus and switchgear is aged and has limited ability to provide real time monitoring of feeders by the Powerco Network Operations Centre (NOC). Faults can occur that are not cleared solely by the 11kV circuit breakers, instead tripping the upstream circuit breaker and single transformer. The TP Waverley 11kV ODID project would replace the aged switches and bus with a new indoor switchboard with full remote monitoring and operability for Powerco NOC. Alternatively, there is the option of installing new reclosers on the three circuits on the first pole out. This would provide both metering for NOC remote balancing of interconnected feeders and protection if needed.

15.13 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. Major and minor project spend related to Growth and Security during the next 10 years is $4m.

15.13.1 AREA 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 places more than 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 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.

Between Pukepapa and Rata there is a 22kV distribution tie that serves as a backup for Rata. Isolating and restoring the network after a fault can be challenging and often time-consuming.

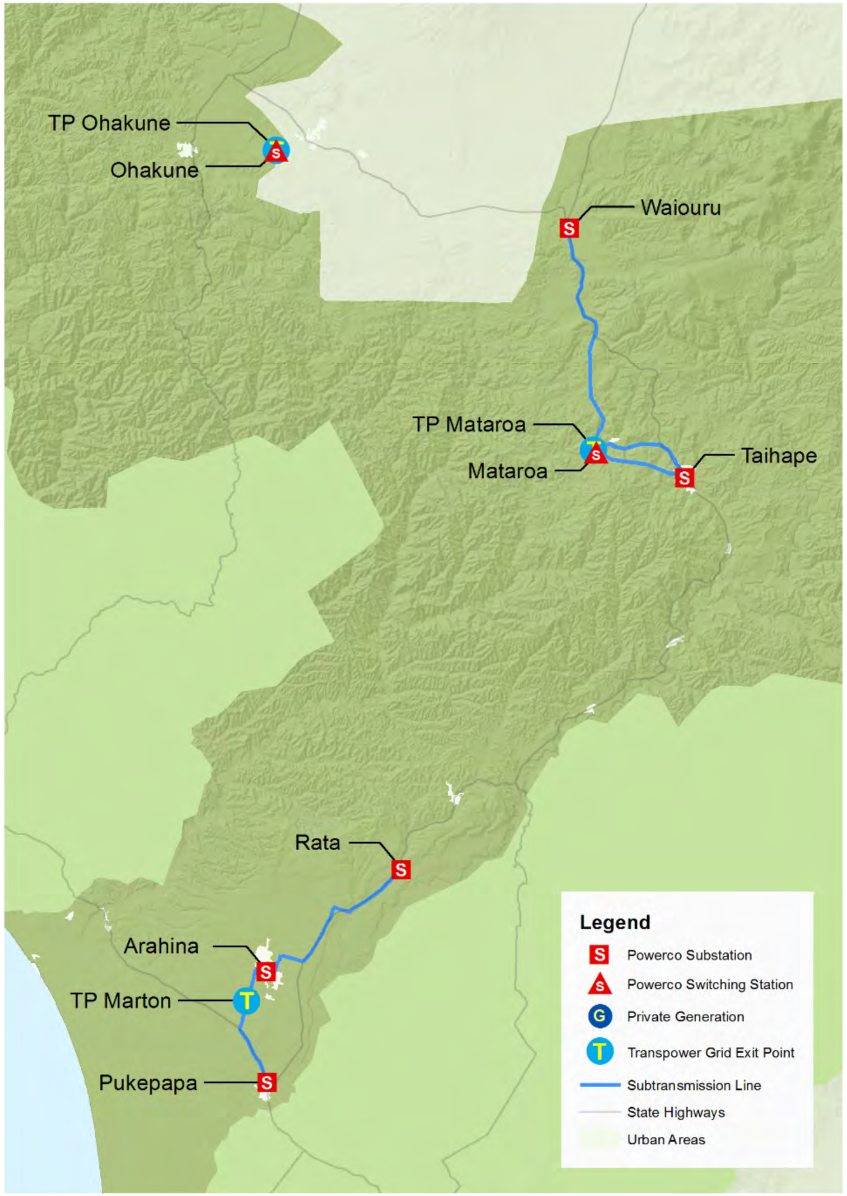
Switching points and lines can be hard to access, and there are very limited backfeed opportunities, especially on long spur lines.

Development projects have re-instated overhead switches out of Pukepapa substation, allowing more effective use of alternative subtransmission lines through to Arahina and Rata again.

In the past year, a subdivision was developed in Bulls, and electric vehicle chargers were installed in the hills out of Taihape and downtown Bulls.

There has been subdivision and commercial expansion feasibility work completed for larger customers supplied from Bulls, Rata and Arahina.

Figure 15.22: Rangitikei area overview



15.13.2 DEMAND FORECASTS

Demand forecasts for the Rangitikei zone substations are shown in Table 15.28, with further detail provided in Appendix 7.

Table 15.28: Rangitikei zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Arahina	AA	3.1	8.1	8.3	8.4	8.5
Bulls	AA	2.0	5.7	5.9	6.1	6.3
Pukepapa	A1	1.9	5.5	5.7	6.0	6.3
Rata	A1	0.7	3.0	3.0	3.1	3.2
Taihape	A1	0.8	4.4	4.5	4.6	4.7
Waiouru	A1	0.5	2.4	2.3	2.2	2.1

Growth in the Rangitikei area has historically been low. These are mature rural communities with a relatively static electricity requirement. A step change in demand is anticipated to occur through conversion of generator supplied irrigation loads to mains network supply in the Parewanui region.

As with other rural parts of our network, a lot of substations do not meet our security criteria, even with existing load.

15.13.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Rangitikei area are shown in Table 15.29.

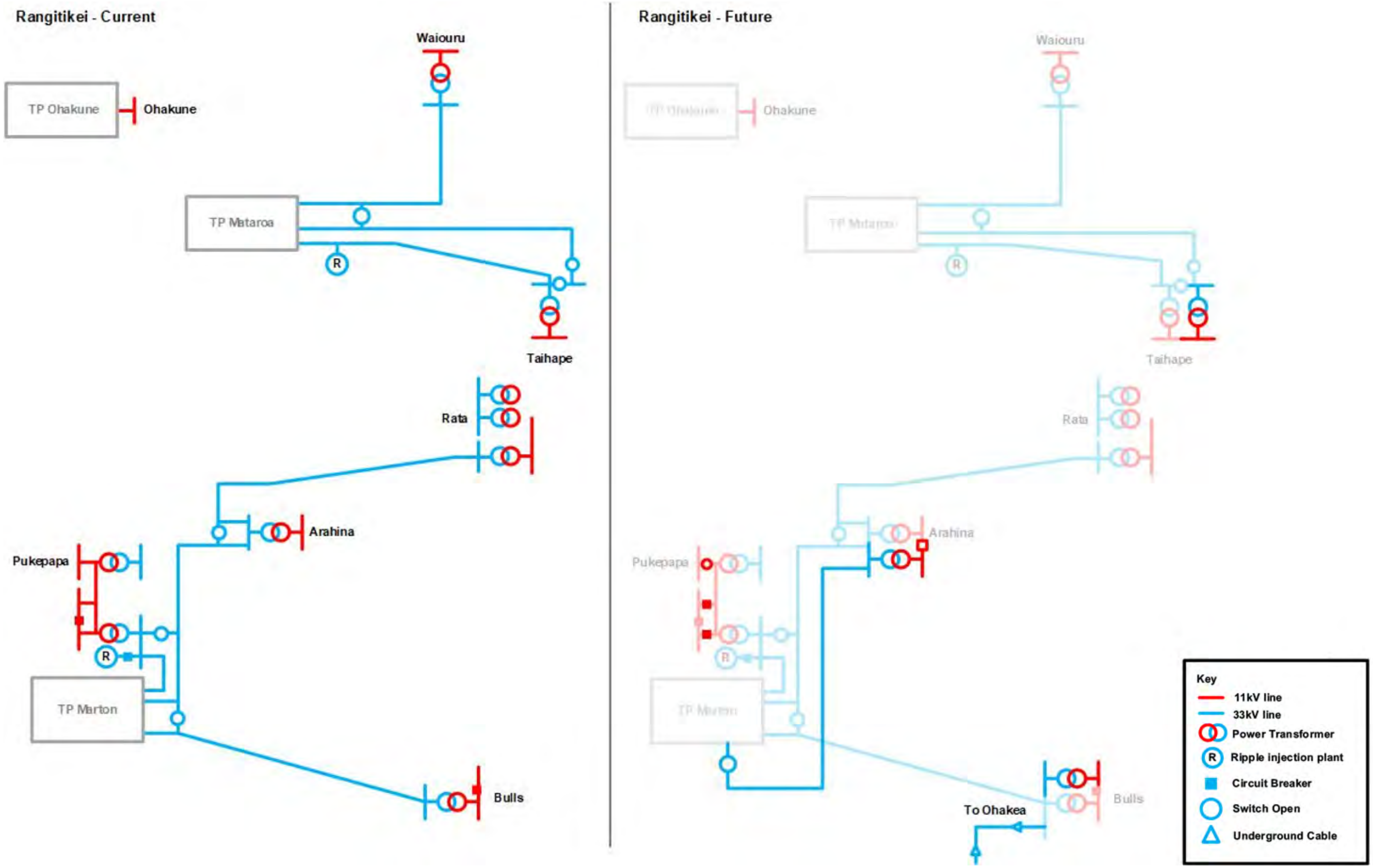
Table 15.29: Rangitikei constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Taihape	The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. Taihape substation has two 33kV incomers, which give the sub good security to expand the number of feeders and support any neighbouring sub offload plans.	The preferred solution, a **new Taihape switchboard**, involves expansion works on the 33kV switchyard and a new expanded 11kV board. A solution project, **Taihape second transformer**, will install a second transformer at the substation. This will support the switch room upgrade project also planned.
Rata	Rata substation is supplied by one single 33kV circuit from the Arahina substation (N security) and contains one 7.5MVA supply transformer. The demand has exceeded class capacity, sustained at 3MVA, and there is potential for loss of supply at the substation for a transformer or subtransmission fault.	The solution, **Rata 22kV upgrade**, is to increase backfeed through 22kV distribution and install a pad and connection point for a temporary generator.
Waiouru	Waiouru substation is supplied by one single 33kV circuit from Mataroa GXP (N security) and contains one supply transformer. The demand has exceeded the class capacity, sustaining around 2.9MVA, and there is potential for loss of supply at the substation for a transformer or subtransmission fault.	This solution project, **Waiouru 11kV upgrade**, increases distribution backfeed capability. Because of the long lengths and high impedances of the conductors, upgrades to 22kV will be considered.
Bulls substation	The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault, affecting two large commercial customers. The Sanson Bulls major project will prepare the site for a second transformer, installing a bund and bus infrastructure.	The preferred solution is to install a second transformer under the **Bulls second transformer** project. Refer to Note 1.

Note:

1. The same result may be able to be achieved more efficiently if a second-hand transformer can be sourced from the network and condition/age/size are suitable.

Figure 15.23: Rangitikei area network diagram



15.13.4 PROPOSED PROJECTS

Table 15.30: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)
Taihape install new switchboard	$1,375	2025
Taihape second transformer	$1,370	2026-2028
Rata 22kV upgrade	$1,500	2029
Waiouru 11kV upgrade	$1,500	2028
Bulls second transformer	$130	2023

15.13.5 POSSIBLE FUTURE 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 backfeeding and automation. This can require increased capacity of tie circuits, offload reconfigurations and new tie circuits or feeders.

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 Lake Alice substation if required. In the interim, preparatory subtransmission rated lines are being installed out of Pukepapa towards the region.

The following descriptions represent the most probable solutions but the final solution and optimal timing are subject to further analysis.

PROJECT	SOLUTIONS
Lake Alice zone substation	The Parewanui and Lake Alice areas are supplied by the Bulls and Pukepapa substations via 11kV feeders. The strong growth in this area signals that these feeders will reach their capacity in the near future. The preferred solution is to construct a new Lake Alice zone substation, upon receipt of an MOU with irrigation farmers.
Arahina substation second transformer and subtransmission supply	The substation is supplied by 33kV circuits from Marton GXP, reducing to a single circuit into the one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a transformer or subtransmission fault. Customer growth largely depends on a single nearby commercial site and its future plans. The solution is to install a second subtransmission supply and transformer at the substation.
Pukepapa substation second transformer	The Pukepapa substation is adjacent to Transpower's Marton GXP and supplies Marton's surrounding 5.5MVA rural residential and irrigational loads. The substation contains a single supply transformer and has N-1 subtransmission switching capability. The demand has exceeded the class capacity and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from distribution network. The solution project would install a second transformer to the substation. Probabilistic planning standards may defer the timeline or suggest an alternative option in the interim.
Mobile sub for single Tx GXP	Building a mobile substation, custom designed, as backup for GXP supply in the Rangitikei and Whanganui planning areas, will support an investment profile of a probabilistic standard. Both areas have single transformer GXPs.

15.14 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 under way involves building two new 33kV circuits and a new inner-city substation at Ferguson St, with a total estimated cost of $27m. Total major and minor project spend related to Growth and Security during the next 10 years is $63m.

15.14.1 AREA 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 area 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 – the Royal New Zealand Air Force Ohakea base (near Sanson), and the New Zealand Army Linton Military Camp (south of Palmerston North).

The Massey University complex and associated research centres are also significant contributors to the city's vitality.

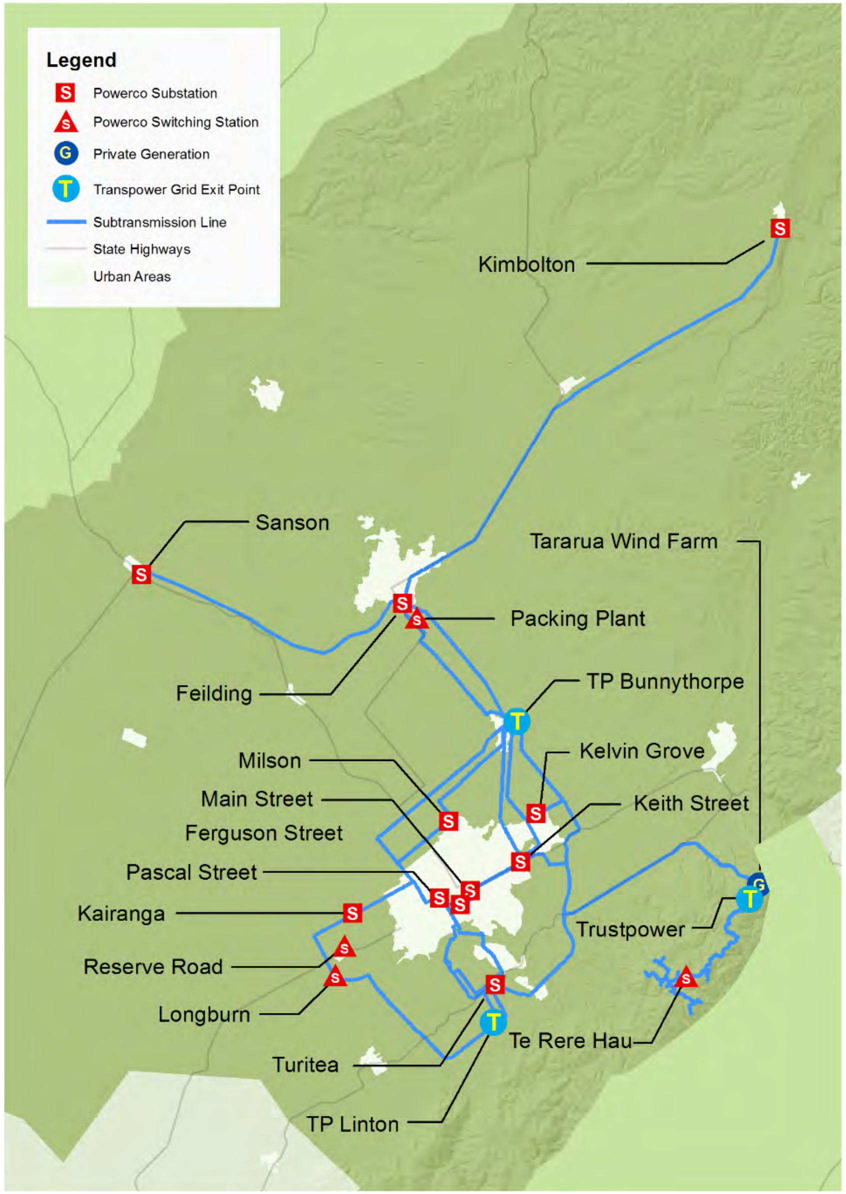
The Manawatu area is connected to the grid through the Bunnythorpe and Linton GXP substations. Bunnythorpe GXP supplies seven zone substations – Keith St, Kelvin Gr, Main St, Milson, Feilding, Kimbolton and Sanson. The Linton GXP supplies four zone substations – Kairanga, Pascal St, Turitea and the new Ferguson sub. Both subtransmission networks supplied by these GXPs have 34MW generation feed from the Tararua Wind Farm.

The subtransmission and distribution networks in the rural areas are mainly overhead. Within Palmerston North city there are some overhead lines, but predominantly circuits are underground.

The 33kV subtransmission network is mostly meshed. The two subtransmission networks from each GXP are operated independently but can be interconnected at several points across the city. City substations generally have full N-1 circuits in either twin circuit or ring circuit configurations. Some ring connections are open because of protection issues or they cross GXP boundaries. The two rural substations, Kimbolton and Sanson, are on single radial spurs.

The 11kV distribution in the city is mainly underground cable, which is a legacy of earlier local council objectives. The network operates independent feeders with multiple manually switched open points to other feeders, ie interconnected radial. One unique feature in Palmerston North is the legacy of tapered capacity, where feeders reduce in capacity from the substation out to the extremities. This can severely limit backfeed and protection settings. We have been addressing this through a consolidated upgrade programme.

Figure 15.24: Manawatu area overview



15.14.2 DEMAND FORECASTS

Demand forecasts for the Manawatu zone substations are shown in Table 15.31, with further detail provided in Appendix 7.

Table 15.31: Manawatu zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Feilding	AAA	23.7	21.6	22.5	23.5	24.4
Ferguson St	AAA	15.0	11.0	11.2	11.4	11.7
Kairanga	AAA	19.1	17.9	18.5	19.1	19.7
Keith St	AAA	21.9	18.5	19.0	19.5	20.1
Kelvin Gr	AAA	17.2	17.0	17.9	18.8	19.8
Kimbolton	A1	1.4	2.7	2.8	2.9	3.0
Main St	AAA	17.0	21.8	22.3	22.7	23.2
Milson	AAA	18.1	16.8	17.3	17.8	18.3
Pascal St	AAA	17.0	22.5	22.9	23.3	23.7
Sanson	AA+	0.0	8.5	9.0	9.5	10.0
Turitea	AAA	0.0	14.0	14.7	15.5	16.2

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 North East 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 has been 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.

15.14.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Manawatu area are set out in Table 15.32.

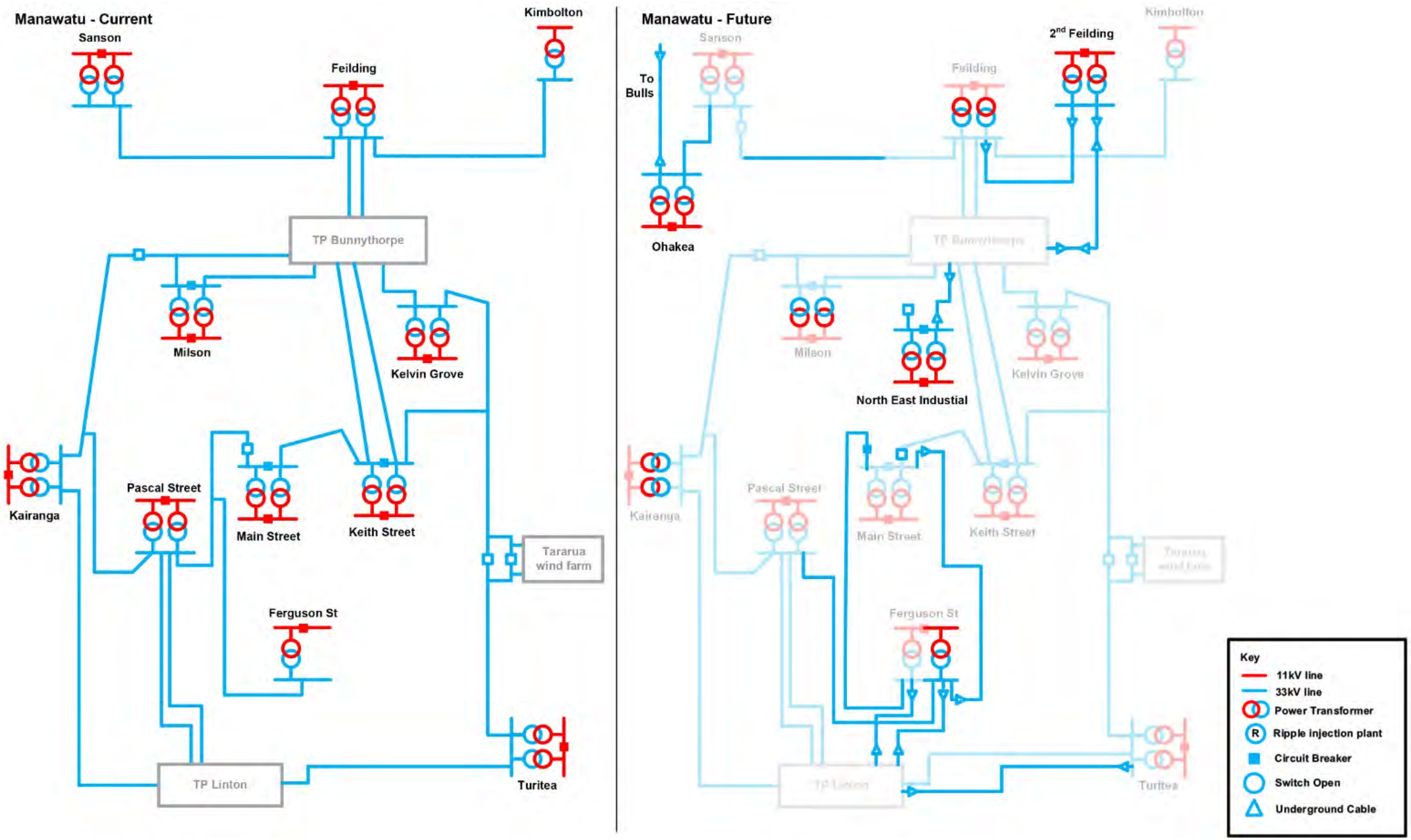
Table 15.32: Manawatu constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Bunnythorpe GXP, Keith St, Pascal, Keith St and Main St substations	Firm capacity of the GXP transformers has been exceeded. Because of its size and complexity, any upgrades at Bunnythorpe will be challenging and costly. The N-1 capacity of the 33kV Keith St and Kelvin Gr subtransmission circuits is exceeded. Both Main St and Pascal St substations have already reached their capacity limit. Further expansions at these substations is not practical because of space limitations. Under-rated cable from Manawatu River to Pascal St can not meet N-1 security criteria.	The solution project, **Palmerston North CBD**, involves constructing a new substation at Ferguson St, installing two new 33kV circuits between the Linton GXP and the Ferguson St substation, installing two new 33kV circuits between Main St and Ferguson St, and installing a new 33kV circuit between the Pascal St and Ferguson St substations.
Feilding, Sanson and Kimbolton substations	The N-1 capacity of the two 33kV Bunnythorpe-Feilding circuits has been exceeded. There is a single circuit from Feilding to Sanson. There is insufficient 11kV backfeed to meet the security criteria. The New Zealand Defence Force (NZDF) has embarked on significant upgrades to the airbase at Ohakea and has requested increased capacity beyond what can be supplied from our existing network.	The solution project, **Sanson-Bulls 33kV line**, involves thermally upgrading the Bunnythorpe to Feilding 33kV lines, constructing a new 33/11kV substation at Ohakea, constructing a new 33kV line from Bulls substation to the new Ohakea substation, and installing an automatic load transfer facility at Sanson substation.
Turitea substation	Turitea substation single 33kV supply limits its security level to AA, but AAA is intended. The substation has switched N-1 subtransmission switching capability from Bunnythorpe and Linton GXPs. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a subtransmission fault.	The solution project, **Turitea sub new 33kV line**, involves constructing a new 33kV line from Linton GXP to Turitea substation to improve the security level of this substation.
Sanson substation	The Feilding-Sanson 33kV line supplies the Sanson zone substation through a single 33kV circuit (14.7km long). This 33kV line will also serve as an alternative supply to Bulls substation when the Sanson-Bulls 33kV interlink project, coupled with a new substation to supply Ohakea air force base, is completed. The addition of Bulls substation load will overload the Sanson 33kV supply, therefore a new line upgrade will be needed.	The solution project, **Feilding-Sanson line upgrade**, involves upgrading the Feilding-Sanson 33kV line to increase its thermal capacity and support the additional loads.
Milson substation	Milson substation takes its 33kV supply from Bunnythorpe GXP by two dedicated 33kV lines, Milson-1 (7.1km long) and Milson-2 (13.7km long). For an outage on Milson-1 line, Milson-2 line cannot supply the substation because of thermal capacity constraints.	The solution project, **Milson-2 33kV line upgrade**, involves upgrading the Milson-2 33kV line to increase its thermal capacity and being able to support a Milson subtransmission N-1 situation.
Feilding substation	Feilding substation takes its 33kV supply from Bunnythorpe GXP by two lines, one is 8.6km long (FEI East) and the other is 9.1km long (FEI West). Each 33kV line has a rating of 23.7/30.8MVA. Feilding's 33kV bus future configuration will supply Kimbolton substation and a future second Feilding substation. Feilding will serve as an alternative supply to Sanson, Bulls and Ohakea substations for the upcoming Sanson-Bulls 33kV interlink. The total demand of Feilding, Sanson, Bulls, Ohakea, Kimbolton and Feilding 2 substations on the Bunnythorpe-Feilding circuits will exceed their N-1 capacity.	The solution project, **Feilding East and Feilding West thermal upgrades**, involves increasing its capacity and being able to support the additional loads.
Sanson and Bulls substations	We are transferring the 33kV supply to Sanson from Bunnythorpe GXP to Marton GXP. Transferring Sanson zone substation across will result in loss of control of any load control receivers on the Sanson network. The converse also applies when the supply to Bulls substation is transferred across to the Bunnythorpe GXP.	The solution project, **Sanson-Bulls ripple injection plant**, involves installing two 11kV injection plants to provide control for two frequency operations (317Hz and 383Hz) that will allow the transfer of Sanson and Bulls substations to different GXPs without loss of control to any load control receivers.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Kelvin Gr substation	The demand has exceeded the transformers' capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from the 11kV distribution network.	The solution project, **Kelvin Gr transformer upgrade**, involves replacing the existing transformers with two larger units. This will provide adequate capacity for future demand. To fully meet our required security level, however, enhancement to the subtransmission network will be needed.
Feilding substation	The substation contains two transformers nominally rated at 21MVA each. The load growth is high in areas covered by Feilding substation. The demand has exceeded the firm capacity of the transformers. Because of limitations in backfeed capability, the security of supply will not be adequate as load grows.	The solution project could be **Feilding transformers upgrade** or a **new Feilding substation**. We are investigating which is the more appropriate long-term strategy. Our approach to the 33kV supply for a second Feilding zone substation is to build two new 33kV capable lines, one coming from TP Bunnythorpe and the other one from Feilding substation.
Kelvin Gr substation	Kelvin Grove substation supplies several important loads, which include the North East Industrial area. The North East Industrial area has been planned as a transport and warehouse hub because of its strategic location in the national transport infrastructure. Major industrial load is emerging within the industrial park and surrounding area. These future developments will not be able to be supplied from Kelvin Gr with the current transformer capacity.	The solution project, **North East industrial zone substation**, involves constructing a new zone substation and a new 33kV supply from TP Bunnythorpe to accommodate the load growth on the north east side of Palmerston North area.
Kairanga substation	Kairanga substation contains two 15MVA rated transformers. The demand has exceeded the transformer firm capacity. High growth is expected in this substation because of both residential and agricultural developments.	The solution project, **Kairanga transformers upgrade,** involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Turitea substation	Turitea supplies Massey University, Linton Army Camp, and NZ Pharmaceuticals, and includes residential and rural load to the south east of Palmerston North. It has two 12.5/17MVA transformers, and the forecast demands will exceed single transformer capacity. Massey has reviewed the feasibility of electrifying its existing gas-fired heating systems, with 10-15MW of additional electrical capacity potentially required.	The solution project, **Turitea transformers upgrade**, involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand.
Milson substation	Milson supplies the industrial, commercial and residential load in western Palmerston North, including the airport and industrial park. It has two 12.5/17MVA transformers, and the forecast demand is close to exceeding its single transformer capacity. Also, there is an ongoing development along Airport Drive for between 3.1MVA and 4.6MVA. This development will affect the demand on the Milson substation.	The solution project, **Milson transformers upgrade,** involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand.
Sanson sub-Oroua Downs feeder	In its current configuration, the Oroua Downs feeder from Sanson sub is very long and serving about 1331 ICPs. Because of the length and demand of the feeder, growth is constrained in this area and additional customer load can not be added without voltage levels decreasing below regulated limits. Customers have expressed frustration at the inability to connect new large loads in this area.	The solution project, **Oroua Downs express feeder,** involves constructing a new 17km express underground 33kV-capable HV feeder, splitting Oroua Downs feeder. This is the first phase for the proposed long-term solution of building a new zone substation.

Figure 15.25: Manawatu area network diagram



15.14.4 PROPOSED PROJECTS

Table 15.33: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)
Palmerston North CBD	$25,000	2016-2023
Sanson-Bulls 33kV line	$11,500	2019-2023
Turitea sub new 33kV line	$2,000	2023-2025
Linton Camp sub new 33kV line	$4,800	2025-2027
Feilding-Sanson line upgrade	$1,400	2023-2025
Milson-2 33kV line upgrade	$1,300	2026-2027
Feilding new (third) 33kV line	$2,900	2025-2026
New 33kV line BPE-NEI	$8,500	2024-2026
Sanson-Bulls ripple injection plant	$956	2021-2022
Kelvin Gr transformer upgrade	$3,045	2021-2022
Feilding transformers	$2,400	2026
New Feilding zone sub	$5,800	2025-2027
North East industrial zone substation	$5,300	2023-2026
Kairanga transformers	$2,140	2025
Turitea transformers	$2,140	2024-2025
Milson transformers	$2,140	2026-2027
Oroua Downs express feeder	$5,500	2023-2025
Feilding East and Feilding West thermal upgrades	$5,900	2023-2025

15.14.5 POSSIBLE FUTURE 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 backfeed 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 ensuring adequate reliability, ie backfeed capability. Most of these involve conductor replacements or voltage regulators.

Significant changes in demand, such as for a rapid and concentrated uptake of irrigation, will likely result in a new substation, ie the Rongotea project described below.

New urban subdivisions generally require continued investment in upgraded upstream or backbone sections of feeders. There is regular communication with Massey University to ensure appropriate supply and capacity. We are also planning an 11kV link between Turitea substation and the inner CBD substations, although this is subject to physical obstacles, such as the river crossing.

The Manawatu area is known for its wind generation. Most of the prime sites appear to have been used and we are not aware of any immediate new developments. The larger scale of wind generation often means these projects connect directly with the grid. Smaller embedded generation is not yet of a nature or scale to have an impact on demand peaks.

We will investigate non-network opportunities, particularly where this might defer major investment, ie cogeneration in central Palmerston North.

The following projects have been identified as being likely to occur in the latter part of the planning period. The following descriptions represent the most probable solutions, but the final solution and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTIONS
Linton Army Camp zone substation	Linton Army Camp future planned upgrades require additional electrical supply provision. An additional 5MVA load is forecast, in addition to the existing 1.7MVA supply to the military base. The preferred solution is to establish a new 33/11kV substation within or adjacent to the military base. The initial primary supply for this new substation will come from the existing 33kV line.
Rongotea zone substation	The Rongotea area is supplied from the Sanson and Kairanga substations through several interconnected radial 11kV feeders. Because of strong growth in irrigation and other rural activities, these feeders are heavily loaded. Interim solutions, such as voltage regulators, have already been used. 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, shorten all the 11kV feeder lengths, therefore improving network voltages and reliability, and offload Sanson and Kairanga substations.
Ashhurst zone substation	Ashhurst is a town 10km to the east of Palmerston North. It is served by two distribution feeders, CB8 Pohangina and CB10 Ashhurst, from Kelvin Gr substation. Nearby, Bunnythorpe village is supplied by one feeder from Milson substation. The town of Ashhurst can no longer maintain adequate voltage regulation of the high voltage (HV) network. The preferred long-term solution is to establish a new zone substation, named Ashhurst, to cater for the load growth in this area.
Kimbolton substation security upgrade	Kimbolton is a single transformer substation. Its security level is A2. Its 11kV backup supply is not adequate for the supply of the substation load. Kimbolton's small load and the large distance to the substation makes a second 33kV circuit or a second transformer unlikely to be economic. The preferred solution is to increase backfeed capacity via the 11kV network.

15.15 TARARUA

Other than some industrial activity, the Tararua region has low growth and reasonable security. Major and minor project spend related to Growth and Security during the next 10 years is $2m.

15.15.1 AREA 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.

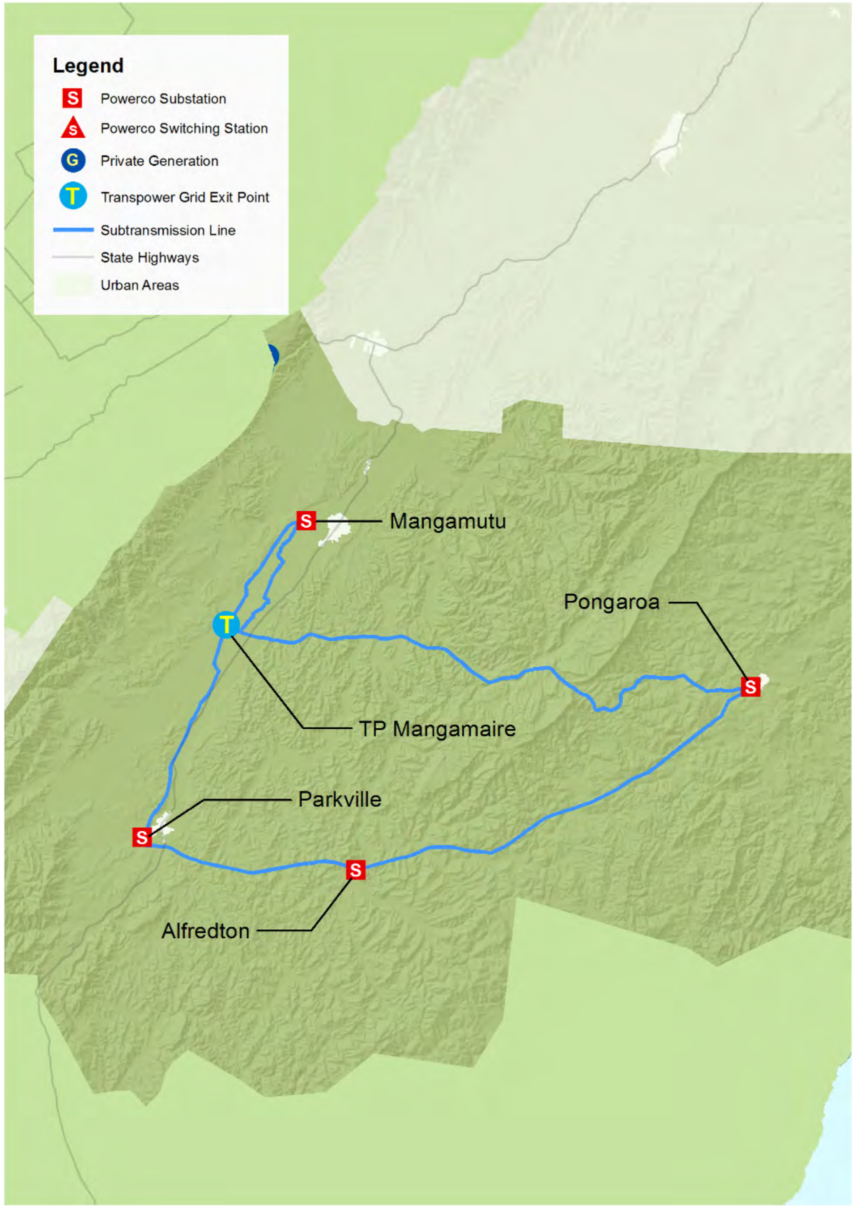
Mangamaire GXP supplies four zone substations – Mangamutu, Parkville, Alfredton and Pongaroa.

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.

Figure 15.26: Tararua area overview



15.15.2 DEMAND FORECASTS

Demand forecasts for the Tararua zone substations are shown in Table 15.34.

Table 15.34: Tararua zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Alfredton	A2	1.4	0.5	0.5	0.5	0.5
Mangamutu	AAA	12.8	12.3	12.4	12.6	12.7
Parkville	A1	0.0	2.2	2.3	2.3	2.3
Pongaroa	A2	2.9	0.9	0.9	0.9	0.9

The demand at Mangamutu substation incorporates the now confirmed significant increase in capacity for Fonterra Pahiatua. Underlying growth at Mangamutu and the other substations is much lower and generally not expected to exceed 0.1%.

Other than Mangamutu, the substations service very small loads, with quite low criticality in most cases. These loads are unlikely to justify security upgrades, unless a significant change occurs, such as irrigation. Future demand growth in the Tararua area is expected to be 0.1% per year.

15.15.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Tararua area are shown in Table 15.35.

Table 15.35: Tararua constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Pongaroa	When supply from Eketahuna 33kV (Mangamaire GXP to Parkville sub) feeder is lost, Pongaroa 33kV feeder carries the entire load of the Mangamaire-Parkville-Alfredton-Pongaroa 33kV ring. During this contingency scenario, the bulk of the load is also at the end of the open 33kV ring. Even at present demand levels, this causes 33kV bus voltage of 84.5% at Pongaroa substation, 79.7% at Alfredton substation and 77.6% at Parkville substation.	Install 33kV voltage regulator and upgrade parts of Pongaroa 33kV feeder. Solution projects are **voltage regulator on Pongaroa 33kV feeder** and **Pongaroa 33kV upgrade Lamprey to Coyote**.
Parkville substation	Has a single transformer. The 11kV backfeed does not meet security criteria. The transformeris due for renewal.	Refer to Note 1.
Alfredton substation	Has a single transformer.	Refer to Note 2.
Pongaroa substation	Has a single transformer.	Refer to Note 2.

Notes:

1. Two transformers to meet security criteria cannot be economically justified. Transformer capacity will be addressed during planned renewal. Parkville substation enclosure has other operational and physical security issues and we may consider an upgrade to the whole site.
2. Two transformers to meet security criteria cannot be economically justified. Transformer capacity will be addressed during planned renewal.

15.15.4 PROPOSED PROJECTS

Table 15.36: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)
Voltage regulator on Pongaroa 33kV feeder	542	2023-32
Pongaroa 33kV upgrade Lamprey to Coyote	4,347	2023-32

15.15.5 POSSIBLE FUTURE DEVELOPMENTS

Parkville substation supplies Ekatahuna township. Although load growth is flat at present, Ekatahuna is somewhat of a rural transportation hub because of its location.

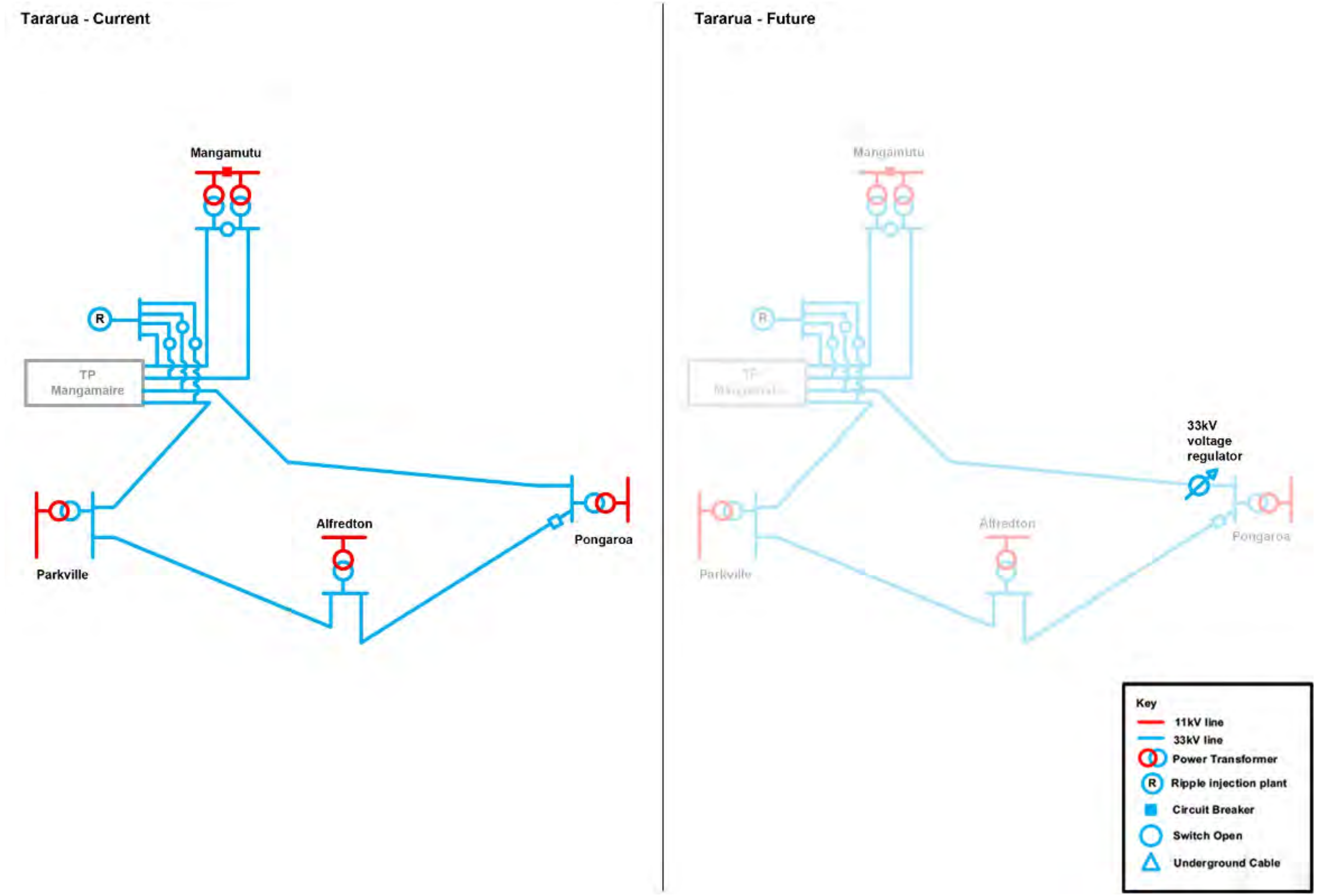
We have fielded inquiries relating to large scale electric vehicle charging stations in the area. If electric vehicle uptake accelerates, there could be significant load increases that would require increased capacity at Parkville substation and improved security of supply for both the substation and the subtransmission network.

Decarbonisation has the potential to cause a step increase in load at Mangamutu substation because of the Fonterra Pahiatua factory.

The following description represents the most probable solutions, but the final solutions and optimal timing are subject to further analysis and would be confirmed closer to the time.

PROJECT	SOLUTION
Parkville second transformer	Increase the capacity of Parkville substation and install a second transformer.
Mangamutu transformer	Replace both zone transformers with high-capacity transformers.
Mangamutu subtransmission	Rebuild Mangamutu-1 and Mangamutu-2 33kV feeders or build a third 33kV feeder to Mangamutu substation.

Figure 15.27: Tararua area network diagram



15.16 WAIRARAPA

The Wairarapa region, overall, has low growth with shifting load centres. While Masterton town comprises much of the region's load, the towns of Carterton and Greytown are growing and are expected to grow further. Load in south Wairarapa also appears to be shifting further southwest.

Major and minor project spend related to Growth and Security during the next 10 years is $31m. In addition to the planned Growth and Security projects, routine expenditure will be needed on distribution circuits.

15.16.1 AREA 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.

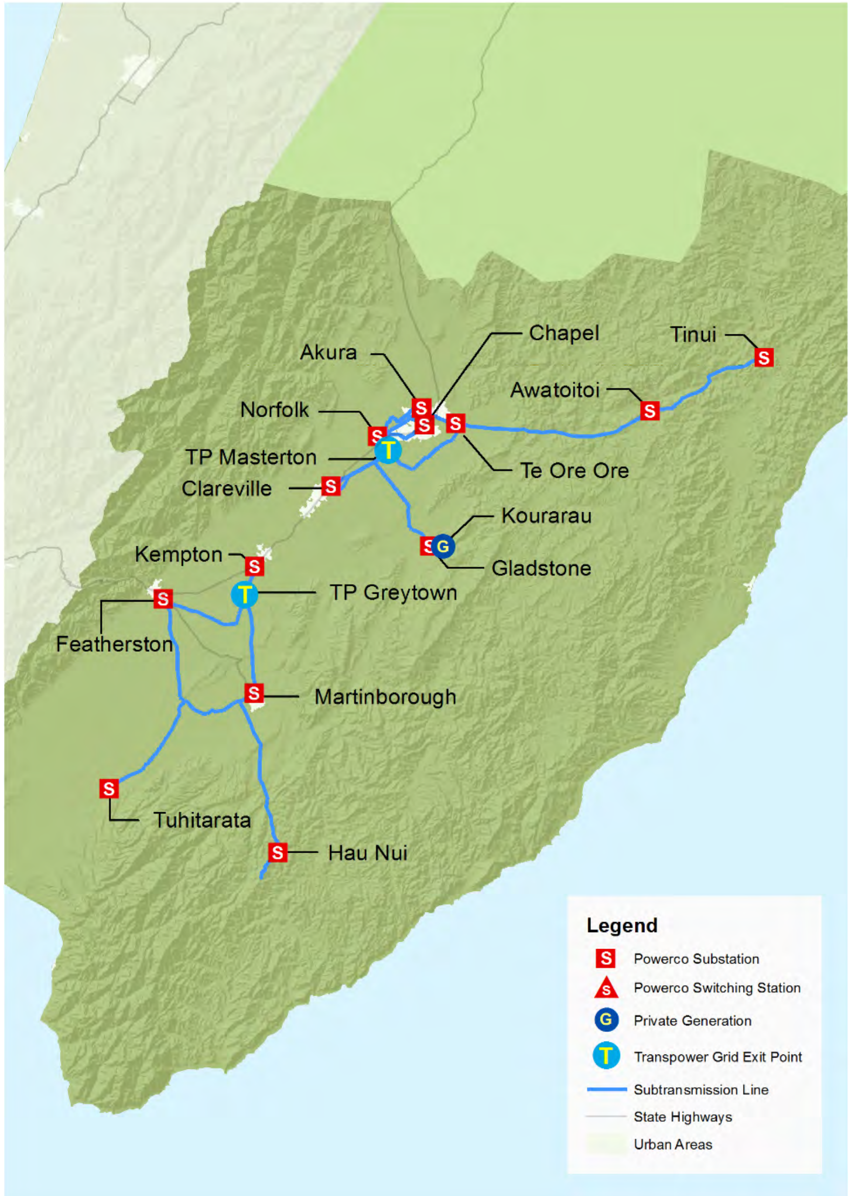
Forestry, cropping, sheep, beef and dairy farming are the backbone of the economy. The area around Martinborough, in the south, is notable for its vineyards and wine, as are the outskirts of Masterton and Carterton. Deer farming is growing in importance.

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, especiallyin 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.

Figure 15.28: Wairarapa area overview



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.

15.16.2 DEMAND FORECASTS

Demand forecasts for the Wairarapa zone substations are shown in Table 15.37, with further detail provided in Appendix 7.

Table 15.37: Wairarapa zone substation demand forecast

SUBSTATION	SECURITY CLASS	CLASS CAPACITY	2020	2025	2030	2035
Akura	AAA	9.0	13.0	13.5	14.0	14.5
Awatoitoi	A2	3.0	1.3	1.4	1.4	1.5
Chapel	AAA	13.8	12.4	12.7	13.1	13.4
Clareville	AA	9.4	9.2	9.7	10.3	10.8
Featherston	A1	0.1	4.4	4.6	4.8	5.0
Gladstone	A2	1.4	1.1	1.1	1.1	1.2
Hau Nui	A1	0.0	1.4	1.4	1.5	1.5
Kempton	A1	0.4	4.2	4.4	4.6	4.9
Martinborough	A1	0.1	5.0	5.2	5.5	5.8
Norfolk	AA+	10.6	6.3	6.5	6.7	6.8
Te Ore Ore	AA	6.8	7.0	7.2	7.4	7.6
Tinui	A2	1.3	1.1	1.1	1.1	1.2
Tuhitarata	A1	0.0	3.9	4.1	4.3	4.6

Growth in the Wairarapa area is modest. No significant residential demand increases, such as large subdivisions, are anticipated. Modest demand increase is anticipated from existing industrial customers, but significant step changes are not likely. Major wind generation plants have been investigated but are likely to be at a scale where they would connect directly to the grid.

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.

15.16.3 EXISTING AND FORECAST CONSTRAINTS

Major constraints affecting the Wairarapa area are shown in Table 15.38.

Table 15.38: Wairarapa constraints and needs

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Featherston, Martinborough, Hau Nui and Tuhitarata substations	An outage on the Greytown-Martinborough 33kV feeder causes the Greytown-Featherston 33kV feeder to overload and causes 33kV bus voltage issues at Tuhitarata, Martinborough and Hau Nui zone substations. Conversely, an outage on the Greytown-Featherston 33kV feeder causes the Greytown-Martinborough 33kV feeder to overload and causes 33kV bus voltage issues at Featherston zone substation.	Solution projects are Bidwells 33kV feeder extension to Greytown GXP and a new zone substation in Bidwells-Cutting.
Clareville substation	Contingency analysis shows >95% loading on Clareville-1 and Clareville-2 33kV feeders. Commercial and residential growth is occurring and expected to continue through the next decade.	Solution projects are re-tension Clareville 33kV -1 feeder and re-tension Clareville 33kV -2 feeder.

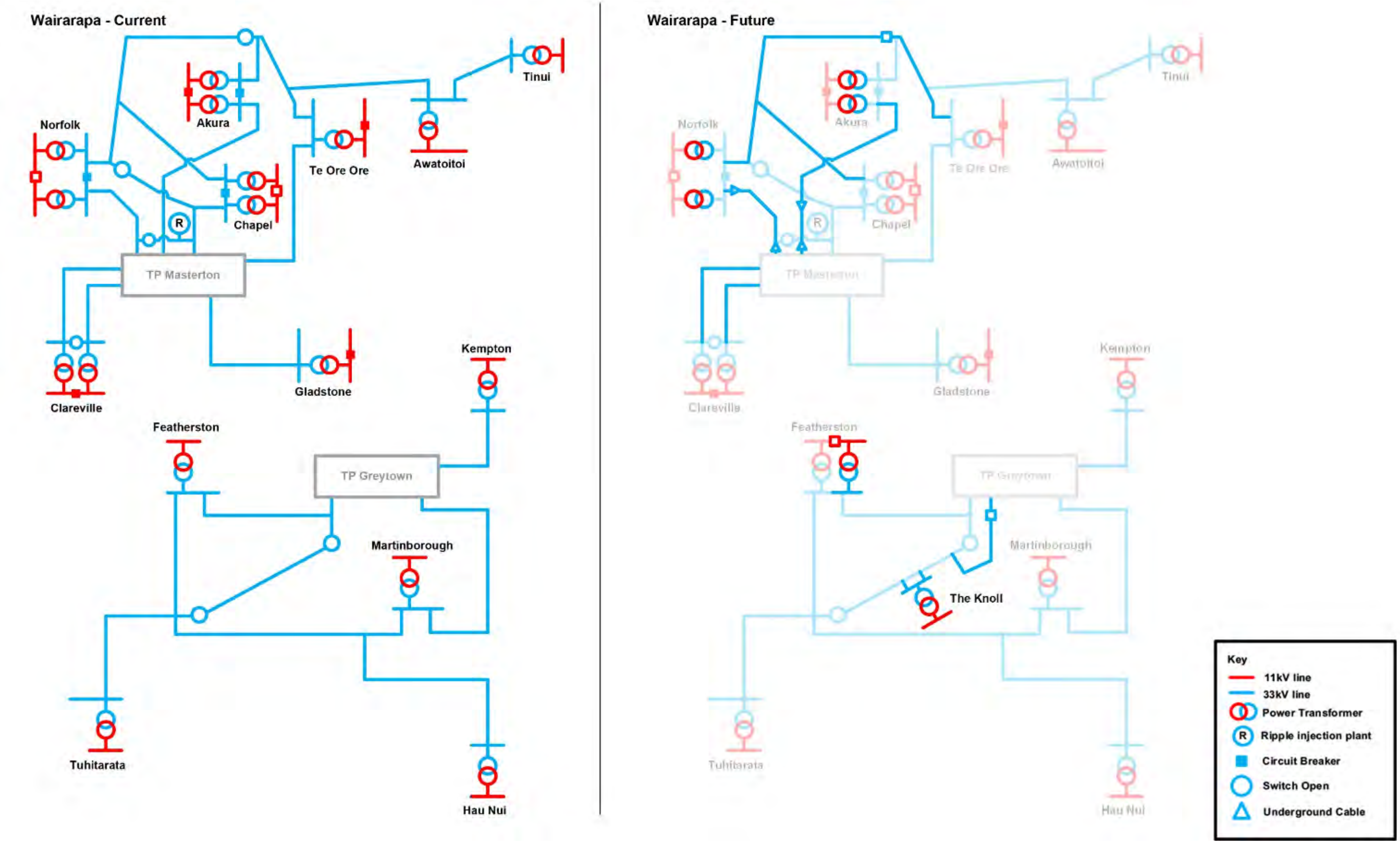
LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Norfolk and Chapel substations	Contingency modelling shows Masterton-Norfolk 33kV feeder at 163% thermal loading. Masterton-Norfolk 33kV feeder is a 1.91km long OH line. It is built together side-by-side with the first 1.91km of the Masterton-Akura 33kV feeder. On Norfolk Rd, there are 11kV and LV circuits built under the 33kV dual line in a non-standard configuration that makes servicing the 11kV line nearly impossible without causing major outages.	Solution projects are convert 800m OH 33kV dual supply to UG and re-tension 1.1km of dual 33kV OH line.
Norfolk and Chapel substations	The Chapel-Norfolk tie feeder overhead line is just over 7km long. Circuit is overloaded post-contingency.	The planned project is **r**ebuild 2.2km of CHA-NOR 33kV OH line.
Akura, Te Ore Ore, Awatoitoi and Tinui substations	Contingency modelling shows 125% loading on Masterton-Akura feeder. 1.9km of this feeder on its GXP end is planned to be upgraded under the Masterton-Norfolk 33kV upgrade.	The solution project is Akura re-tension 5km 33kV OH line.
Akura, Te Ore Ore, Awatoitoi and Tinui substations	Notable industrial customers supplied are Breadcraft Ltd, Hansells Ltd and Webstar Ltd. Contingency modelling shows 175% loading on Masterton-Akura feeder and voltage below acceptable levels at Akura (89.9%), Awatoitoi (88.1%) and Tinui (87%) zone substations.	The solution project, **rebuild 10.6km OH line,** will utilise excess subtransmission capacity on Masterton-Chapel-Norfolk 33kV ring, to supply part of Akura sub during loss of supply from Masterton-Akura 33kV feeder.
Kempton substation	Kempton substation supplies approximately 4MVA of load and 2100 ICPs in Greytown township and surrounding areas. South Wairarapa District Council plans to rezone part of Greytown, indicating potential for high growth in the near to medium term. This substation is a single transformer substation that is supplied by a single 33kV feeder from Greytown GXP and, as such, the substation has 'N' subtransmission and transformer security.	The solution project is a **new zone substation in Bidwells-Cutting** to increase transfer capacity to Kempton substation.

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Tuhitarata	With load growth in the southern areas supplied by Tuhitarata substation, eg Kahutara, a number of issues arise; 1. Unavailability of 11kV backup supply to an increase share of loads supplied by Tuhitarata substation. 2. Loss of protection sensitivity because of the combination of growing demand (albeit moderate) and low fault level. 3. Likely harmonic issues because of irrigation load growth and low fault level.	The suite of solution projects: **New zone substation in Bidwells-Cutting** to increase transfer capacity to Kempton substation. Tuhitarata 33kV feeder extension to Pirinoa. New zone substation in Pirinoa. Second 33kV supply from Hau Nui (or Featherston).
Greytown GXP	Powerco neither owns nor operates any of the 33kV switchgear at Greytown substation. Isolation or repair of bus fault at Greytown GXP generally takes four hours or more, causing, on average, more than $900,000 in lost load per outage, as Powerco relies on Transpower work parties at Haywards GXP travelling to and working onsite for isolating and clearing the fault. A new 33kV feeder is planned for a new zone substation at Bidwells-Cutting.	The solution project is a **Greytown 33kV switchgear outdoor to indoor conversion**, with Powerco taking ownership and control from Transpower.
Akura substation	Akura substation supplies about 13MVA of load (4,500 ICPs). It supplies the northern part of Masterton City up to the Mount Bruce area. The northern Masterton area is a mix of urban residential, commercial and industrial loads. Already, Akura substation is 3MVA over 'N-1' transformer capacity.	The solution project is an Akura transformer capacity upgrade (12.5/17MVA).
Clareville substation	Clareville substation is expected to undergo significant growth, with load increases at industrial customers in the near future, and council plans for subdivisions, including industrial, commercial and residential lots in the southern areas of Carterton during the next 30 years. The zone transformers at Clareville substation are at almost full 'N-1' capacity, under normal configuration of its 11kV feeders.	The solution project is a Clareville transformer capacity upgrade (12.5/17MVA).

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Te Ore Ore substation	Te Ore Ore zone substation supplies about 7MVA of load and 3,200 ICPs, including Masterton Base Hospital. Te Ore Ore zone substation is also the only substation that provides 11kV backup supply to Awatoitoi and Tinui substations, which are supplied by a 33kV spur of poor reliability. Te Ore Ore substation has 'N' transformer security.	The solution project is Te Ore Ore install second transformer (7.5/10MVA).
Martinborough substation	Martinborough zone substation supplies about 4MVA of load and about 2,100 ICPs in the Martinborough township and surrounding areas, including along White Rock Rd, leading to Hau Nui substation. Martinborough zone substation is one of the two main 11kV backup supplies to Tuhitarata substation, which has 'N' subtransmission security and 'N' transformer security.	The suite of solution projects are: **New zone substation in Bidwells-Cutting** to increase transfer capacity to Kempton substation. Martinborough install second transformer (7.5/10MVA).

LOAD AFFECTED	MAJOR ISSUES	GROWTH AND SECURITY PROJECTS
Tuhitarata substation	Tuhitarata zone substation supplies about 4MVA of load and just over 9,100 ICPs in the area stretching from the eastern and southern shores of Lake Wairarapa to Cape Palliser on the Wairarapa south coast. Tuhitarata substation is a single transformer substation supplied by a single 33kV feeder and, as such, is on 'N' security.	The suite of solution projects are: **New zone substation in Bidwells-Cutting** to increase transfer capacity to Kempton substation. Tuhitarata install second transformer (7.5/10MVA).
Burnside to Tuturumuri	Burnside feeder off Tuhitarata is 99.5km long with 605 ICPs. Reaching the end of the feeder from Masterton depot takes 1.5 hours or more. Tuturumuri feeder off Hau Nui substation is 77.5km long with 171 ICPs. Reaching the end of this feeder from Masterton depot takes 1hr 10min or more. A fault around the middle of the feeders leaves a large part of the feeder downstream without supply, and fault finding can take up to four hours.	The solution project is Burnside-Tuturumuri 11kV tie line.

Figure 15.29: Wairarapa area network diagram



15.16.4 PROPOSED PROJECTS

Table 15.39: Growth and Security projects

PROJECTS	COST ($000)	TIMING (FY)
Bidwells 33kV feeder extension to Greytown GXP	1,840	2025-28
New "The Knoll" zone substation in Bidwells-Cutting	3,233	2025-28
Re-tension Clareville 33kV -1 and -2 feeders	665	2026-28
Akura 33kV and Norfolk 33kV – Convert 800m OH 33kV dual supply to UG and re-tension 1.1km of dual 33kV OH line	681	2024-26
Akura 33kV re-tension 5km 33kV OH line	210	2024-26
Te Ore Ore 33kV rebuild 10.6km OH line	1,116	2030-32
Kempton second 33kV feeder from Greytown GXP	5,520	2029-32
Kempton install second power transformer	2,611	2029-32
Kempton 33kV tie feeder to Clareville substation	460	2029-32
Tuhitarata 33kV feeder extension to Pirinoa	805	2029-32
New zone substation in Pirinoa	3,233	2029-32
Second 33kV supply from Hau Nui (or Featherston)	2,300	2029-32
Greytown 33kV switchgear outdoor to indoor conversion	4,208	2022-2024
Akura transformer capacity upgrade (2 x 12.5/17MVA)	2,031	2023
Clareville transformer capacity upgrade (2 x 12.5/17MVA)	2,460	2023-26
Te Ore Ore install second transformer (7.5/10MVA)	1,480	2023-26
Featherston upgrade old transformer (7.5/10MVA)	1,309	2029-32
Martinborough install second transformer (7.5/10MVA)	2,499	2029-32
Tuhitarata install second transformer (7.5/10MVA)	1,285	2029-32
Burnside-Tuturumuri 11kV tie line	920	2029-32

15.16.5 POSSIBLE FUTURE DEVELOPMENTS

Inquiries relating to large scale electric vehicle charging stations in the area have been received. The likely location for the first ultrafast charging station is Chapel St or Renall St in Masterton. Present upgrades to the Masterton-Norfolk-Chapel 33kV subtransmission ring and to Chapel St substation will make available the necessary capacity and security for such a facility.

However, if electric vehicle uptake accelerates, there could emerge a need for more charging stations along State Highway 2 and possibly even State Highway 53. In such a scenario, there would be significant load increases affecting one or more of Clareville, Kempton, Featherston and Martinborough substations. This may necessitate the use of larger transformer units for the upgrades planned for Kempton, Featherston and Martinborough substations.

The forestry and timber industry is a mainstay in Masterton. The largest two customers are Juken NZ Ltd and Kiwi Lumber. Both these customers are supplied by Norfolk substation and are planning load increases that, in aggregate, exceed 3MVA.

De-carbonisation is also likely to have a significant impact on the industrial customers of the area and this may necessitate bringing forward or expanding planned major and minor projects.

Furthermore, population overflow from Wellington city is starting to have a growth impact in areas connected to Wellington by rail. Retirement villages and lifestyle blocks add to this mix.

These drivers introduce the possibility of additional work being required on existing subtransmission lines.

15.17 GRID EXIT POINTS (GXPS)

Our network connects to the transmission grid mainly at 33kV, but also at 110kV, 66kV and 11kV. We have 30 points of supply or grid exit points (GXPs). Most assets at GXPs are owned by Transpower, although we do own some transformers, circuit breakers, protection and control equipment. The GXPs supplying our electricity network are detailed in Table 15.40, along with their respective peak load, capacity and security characteristics.

Table 15.40: GXP summary statistics for financial year 2020

GXP NAME	TRANSFORMER NAMEPLATE RATING (MVA)	N-1 CAPACITY SUMMER/WINTER (MVA)	2020 MAX OFFTAKE (MVA)	N-1 SECURE	2021 MAX EXPORT (MW)
Brunswick (BRK)	50	-	32.7	No	
Bunnythorpe (BPE)	83, 83	83/102	91.6	No	1
Carrington St (CST)	75, 75	65/65	63.9	Yes	
Greytown (GYT)	20, 20	20/20	12.9	Yes	2
Hawera (HWA)	30, 30	30/35	25.4	Yes	22
Hinuera (HIN)	30, 50	30/40	45.4	No	
Huirangi (HUI)	60, 60	74/74	28.7	Yes	0
Kaitimako (KMO)	75	-	27.5	No	
Kinleith 11kV Mill (KIN)	30, 30	60	41.4	No	
Kinleith 11kV Mill (KIN)	30	-	68.0	No	
Kinleith 11kV Cogen (KIN Gen)	50	-	18.1	No	39
Kinleith 33kV (KIN)	20, 30	20	18.9	Yes	
Kopu (KPU)	60, 60	59/59	47.6	Yes	
Linton (LTN)	120, 100	81/81	59.7	Yes	14
Mangamaire (MGM)	30, 30	27/27	16.0	Yes	
Marton (MTN)	20, 30	20/24	15.8	Yes	
Masterton (MST)	60, 60	60/78	46.5	Yes	
Mataroa (MTR)	30	-	6.8	No	
Mt Maunganui (MTM)	75, 75	63/77	54.1	Yes	
Ohakune (OKN)	20	-	2.0	No	
Opunake (OPK)	30, 30	14/14	13.2	Yes	
Piako (PAO)	60, 40	40	41.4	Yes	
Stratford (SFD)	40, 40	40/55	27.2	No	
Tauranga 11kV (TGA)	30, 30	30/30	25.6	Yes	
Tauranga 33kV (TGA)	90, 120	90/90	80.3	Yes	3
Te Matai (TMI)	30, 40	36/38	55.1	Yes	
Waihou (WHU)	20, 20, 20	48	29.9	Yes	
Waikino (WKO)	30, 30	37	35.9	Yes	
Whanganui (WGN)	30, 20	24/24	36.8	No	
Waverley (WVY)	10	-	4.2	No	

The supply transformers at Piako are owned by Powerco.

Three of our smaller GXPs (Mataroa, Ohakune and Waverley) have only a single transformer. The three substations have relatively low demand – 7MVA, 2MVA, and 6MVA respectively – and N-1 security cannot necessarily be justified for these, but contingency plans are in place and spares are coordinated to minimise the impact should the single transformer fail.

Brunswick and Kaitimako are larger GXPs but also have just one transformer and therefore only N security. Brunswick has partial backup from Whanganui GXP, the capacity of which is a focus of our future development plans. Kaitimako is a newer GXP and there is 33kV backfeed capability from Tauranga. When the load at Kaitimako exceeds the backfeed capacity a second transformer at Kaitimako will be considered.

Hinuera is a single circuit GXP. Improving the security has been a significant focus of our Growth and Security plans for the past decade and is the main driver behind our proposed new 110/33kV supply point at Putaruru.

Bunnythorpe GXP is just in breach of the N-1 transformer capacity. Our major Palmerston North Growth and Security project will transfer some load on to the Linton GXP and reduce the loading on the Bunnythorpe GXP, within N-1 capacity.

Security at Kinleith GXP is a function of the customer’s specific needs. Transpower is undertaking major replacement work at Kinleith.

Tauranga 11kV and Waihou are both on the limit of firm capacity. Pyes Pa effectively transfers load off Tauranga onto Kaitimako, while Waikino load is managed operationally until projects to replace the transformers are completed.

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.
- 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 has eased the constraints by transferring some load to Te Matai GXP, but a constraint on the 110kV to Te Matai will then emerge.
- The Te Matai transformers also need to be upgraded to maintain firm capacity. Longer term, constraints may reoccur at Mt Maunganui also.

Spur acquisitions

Transpower's programme of asset divestment to distributors has lost momentum in the Powerco network area. The previously discussed divestment opportunities for complete spur assets are not being actively pursued because of the need for both Powerco and Transpower to focus resources on other topics. While we have no agreements for any acquisitions of complete spurs in the near future, both parties remain committed to investigating transfers in the future should these prove efficient for our customers.

Transfer of 11kV and 33kV assets to Powerco

Transpower has an ongoing programme for the replacement of existing outdoor 11kV and 33kV outdoor structures and switchgear with indoor switchboards. During the next five years there are a number of conversions proposed at GXPs that supply Powerco. There are significant operational benefits for Powerco to own and operate these switchboards. Powerco will be pursuing the transfer of the assets and construction of the new indoor switchboards, where these prove efficient for our customers

15.18 EMBEDDED (DISTRIBUTED) GENERATORS

Table 15.41 lists the generators greater than 1MW in size that are connected to the Powerco networks.

Table 15.41: Distributed generation greater than 1MW by GXP

GXP	CAPACITY [KW]	VOLTAGE	GENERATION NAME	MOTIVE POWER
Tauranga 33	40,000	33kV	Kaimai Hydro Scheme	Hydro
Kinleith	35,000	11kV	Kinleith Cogen	Cogen
Bunnythorpe	34,000	33kV	Tararua Wind – North	Wind
Linton	34,000	33kV	Tararua Wind – South	Wind
Hawera	30,000	110kV	Patea Hydro	Hydro
Hawera	2,500	11kV	Ballance Kapuni	Cogen
Hawera	1,200	11kV	Origin Hawera	Gas
Huirangi	9,000	33kV	McKee (Mangahewa)	Gas
Huirangi	2,000	11kV	McKee (Mangahewa)	Gas
Huirangi	4,800	33kV	Motukawa Hydro	Hydro
Greytown	5,000	33kV	Hau Nui Wind Farm (33kV)	Wind
Greytown	3,850	11kV	Hau Nui Wind Farm (11kV)	Wind
Carrington St	4,500	11kV	Mangorei Hydro	Hydro
Mt Maunganui	4,000	11kV	Ballance Tauranga	Cogen
New Plymouth	1,875	11kV	Taranaki Base Hospital	Diesel backup
Stratford	2,000	11kV	Cheal – 2x1MW units – Stratford injection	Gas
Stratford	1,063	11kV	Cheal – 1x1MW – Eltham injection	Gas
Waihou	4,200	11kV	Waitoa Dairy Factory Cogeneration	Cogen

15.19 PROCESS HEAT CONVERSION (DECARBONISATION)

We have allowed for a significant uplift in our Growth and Security portfolio to account for the impacts of the decarbonisation of process heat during the next 20 years, beginning in FY24. We expect this trend will be driven by our customers, with our support, in response to incentives related to New Zealand's commitment to the Paris agreement and the Government's goal to be carbon neutral by 2050.

Many of the very large customers (eg Fonterra) have indicated they would prefer to change to biomass, as opposed to electricity, for their high temperature processes. Effective electrical solutions for very high temperature processes are not yet available. In addition, the cost of converting to electricity, including building new supplies, may be prohibitive and take too long to implement. Even if major plants, such as those operated by Fonterra, convert to electricity, their size means they cannot be realistically fed off distribution networks, and would therefore be directly Transpower grid-connected.

However, there are a significant number of smaller customers with lower temperature heat processes, or sub-processes within larger customers, that could realistically be converted to electricity and will be at a distribution network load level. Our current, conservative, estimate is that this could add up to 100MVA of peak demand to our network.

There is still a significant degree of uncertainty around the likely impact of decarbonisation. Factors that may affect our forecast include:

- Adoption of a combination of renewable energy sources such as biomass/electricity heat pumps.
- Willingness of customers to forgo some degree of reliability by way of special protection schemes that allow the network demand to exceed N-1 thresholds.
- Changes to carbon prices and electricity costs making conversion to electricity more attractive or accelerate the rate of conversion.

It is impractical for us to make wholesale changes to our network to accommodate the potential increase in load without clear direction from our customers. Our focus is therefore on improving our agility to respond to these changes as and when they occur. We intend to work closely with our customers to understand their decarbonisation journey and how we can help them with their decision-making.

15.19.1.1 FORECAST DEVELOPMENT

It is difficult to predict what options or timing industry may choose for their individual decarbonisation goals. In coming up with our forecast, we therefore had to make broad assumptions on what loads are likely to change by assessing the various types of carbon-fuelled, low temperature heat processes loads on our network.

From the available information on medium and low temperature heat processes, we have assumed that some of our larger industrial customers (eg Oji Fibre Solutions) will either become energy self-sufficient, or where practical, shift to be a Transpower direct connection. This is particularly true for any greenfield developments, where location near an energy source will be a key project feasibility factor.

For loads where electricity conversion is practical, we have factored in some degree of boiler inefficiencies, and assumed that the primary technology adopted by these customers would be industrial heat pumps, which offer significant efficiencies over other technologies.

We have also allowed for a certain amount of diversity to be applied, recognising that peak load times differ from industry to industry, and factored in some existing surplus capacity.

Our customers have also indicated that a gradual conversion is more likely, where they target conversion projects for sub-processes that are capital efficient, rather than wholesale rebuilds.

The net result shows a potential increase in demand of about 100MW that we would need to cater for. We have assumed a linear uptake over the planning period, beginning in FY24, and that the types of upgrade projects necessary will be similar to our overall mix of Growth and Security projects.

We consider this to be a prudent estimate, based on current carbon prices and current electricity costs. We have also assumed that the extra network capacity will be built at the same average cost for additional capacity as we see on normal growth projects.

15.20 PREPARING FOR AN OPEN-ACCESS NETWORK

15.20.1 OVERVIEW

There is much discussion in the industry about customers' changing energy needs and expectations. This is being driven by trends, such as the growing choice and availability of new technology for on-premise storage and generation, uptake of electric vehicles, and society's increasing awareness of the impact on the environment.

The combined impact of these trends on overall electricity consumption on our network is still relatively minor, as is discussed further in Chapter 6.2. But looking later into the AMP planning period, we anticipate their impact on the network will become noticeable and continue to accelerate.

As stated in our strategy, we want to support these changes – helping our customers in their drive for energy efficiency, and providing them an easily accessible, stable and economic platform over which to conduct energy transactions. This is the essence of the open-access network.

While an open-access network promises significant opportunities, it will also pose substantial challenges to ensure our network remains secure, safe, and stable under the anticipated highly variable load and two-way power-flow conditions. It will therefore require substantial changes to the way we plan, construct and operate the network.

We endorse the work of the Electricity Network Association's Smart Technology Working Group, in particular their views as expressed in the Network Transformation Roadmap. The research and development work that we will undertake to prepare ourselves for implementing this roadmap is described in Chapter 6.2. However, that chapter focuses on research and development work. Since we foresee investment in the future on open-access networks will be part of our business-as-usual, the provision for this work to commence is included in this chapter, alongside the rest of the network development forecasts. This investment will be based on the learnings from our research and development programmes outlined in section 15.23.

15.20.2 INVESTMENTS TO DEVELOP AN OPEN-ACCESS NETWORK

New Zealand is still some way behind other developed countries in customer uptake of local generation, electric vehicles and energy storage. The debate about how networks should be operated to facilitate these trends is, therefore, also lagging somewhat. However, we believe that the relatively slow uptake rates of new technology will accelerate, and it is only a matter of time before this will become a material factor for electricity networks, as it already is in parts of Australia, the United Kingdom, the United States and Europe.

One clear network need that we see as common across all future open-access scenarios is to gain good visibility of power flows and power quality right across our network. This is particularly important at LV level, where most customers connect and where the impact of changing energy patterns will be most evident. Closely associated with this, albeit potentially somewhat later, is a need for more automation across our network, to allow us to respond actively to variable demand trends. We anticipate this need regardless of how the energy market (and Distribution System Operator) may eventually be structured.

Therefore, we intend to commence with investments on a no-regret path to transition to an open-access network post the current CPP period, from FY24 onwards. This includes investments in the following areas:

- **LV monitoring** – we intend to commence rolling out advanced metering across all our LV feeders, providing information on (semi) real-time power flows, voltage levels, power quality, demand patterns and other parameters essential to network operation. To limit costs, we will prioritise rollout to our high demand circuits or where we have know system constraints, in a programme that will stretch over ten years.
- **Higher voltage network monitoring** – while we have far better visibility of power flows and signal quality on our distribution and subtransmission networks, there are still large areas where improvement is required. This is particularly important from an operational perspective – for example improved accuracy in identifying where exactly a fault occurred – as well as automation and maximising network utilisation.
- **Communications systems** – network monitoring requires supporting communications systems to transmit the information gathered to centralised databases and to our control centre. This will be expanded alongside the metering roll-out. This is additional to our general communications requirements described in the next section.
- **Analysis support** – managing large volumes of network data, extracting valuable information from this and building systems that will automatically raise alarms when needed, will all require investment in back-office information systems.
- **Power quality management** – as the uptake of customer edge devices accelerates, we anticipate more power quality issues to arise. We therefore include additional (limited) provision for power quality management devices to be installed progressively post FY24, including voltage regulators, capacitor banks, VAR compensators and automatic tap changing schemes.

These investments are included in our Minor Growth and Security works forecast, shown in section 15.24.

If we do not commit to this investment now, in the absence of good visibility across our network, we will eventually have to manage network risks through applying conservatively based static analysis of worst-case scenarios. This will result in limits on the volumes and types of devices that can be connected to our network, or in substantial investments in network reinforcement.

Conversely, with a real-time visible network, we will be far less limited by worst-case assumptions as we will be better able to assess situations as they occur, and respond accordingly. That will allow a much higher level of calculated, controlled and targeted risk-taking, with more tolerance for working closer to our asset's supply limits and associated higher levels of network capacity. This is anticipated to bring improved outcomes and lower costs for our customers.

Preference for cross-industry collaboration

The bulk of the proposed open-access network investment uplift will be on LV metering and monitoring. We fully recognise that the need for this investment would be substantially reduced if we had access to real-time or semi-real-time network information from existing smart meters or other intelligent devices across the network. However, at present not only do we not have free access to useable smart meter data, but the availability of real-time data, particularly around power quality aspects, is severely limited. Without substantial upgrades and/or configuration changes to the metering hardware and associated communications systems, the existing smart meter fleet in New Zealand is in the main not suitable to provide the support needed to effectively run open-access networks.

There would be significant opportunity to collaborate with existing meter providers and electricity retailers to avoid duplication of metering installations. This would require agreement on data structures, access to data, what is measured and the frequency of such measurements. While potentially complex, this is not insurmountable and we believe that as a supply industry we could, and should, collaborate to ensure an optimal customer outcome – one that would avoid our customers bearing the unnecessary cost of duplicated metering and supporting installations.

So, while our current expenditure forecast from FY26 onwards assumes that we will be rolling out the required metering on our own, we intend to pursue better outcomes with other industry participants and, based on this, will revise the forecast expenditure in future.

15.21 COMMUNICATIONS INFRASTRUCTURE

15.21.1 OVERVIEW

The communications network plan aims to ensure there is a robust, flexible and scalable communications network to enable delivery of our strategic outcomes.

Timely access to data for decision-making is becoming both increasingly important and difficult as more devices producing more data become common at remote locations along our electricity networks, where connectivity and speed can be challenging. A big part of this challenge is the widely distributed and rural nature of our electricity network, and the lack of terrestrial public network services at many locations. This drives cost into any solution, because the network transport, voice and data communications that are required are often not available unless built by us.

Communications infrastructure is also a key enabler for the electricity networks of the future. Electricity networks will increasingly require complex multi-layered systems and architecture to support current and future functions. These communications systems play a vitally important role in facilitating and supporting the way our electricity networks function.

We already have the need for increasing visibility and a degree of real-time control of many disparate devices to feed our Supervisory Control and Data Acquisition (SCADA) platforms, and this will accelerate as we implement our Advanced Distribution Management System (ADMS). This requires a reliable, robust, secure, low latency communications network.

The key drivers to achieve these outcomes are

- **Staying safe** – delivering safe and reliable supply and ensuring the underlying condition of our networks is maintained and replaced in a prudent and timely way.
- **New technology** – network evolution, embracing and leveraging new technology and cost-effective asset management requirements.
- **Utilising flexible architecture** – enabling networks to be designed and delivered in a manner that responds dynamically to changing demands and needs.
- **Modernising the grid edge** – using distributed technologies that enable new methods of network operations, management and service provisioning.
- **Visibility** – on our network and assets to prepare for changing consumer needs and enhance asset management and network performance. This is key to enabling our ADMS strategy.

While this is complex, and building this type of capability is important, we also need to be considerate of the costs associated with such a development. Our planning approach will help ensure there is due consideration to effectively make trade-offs between current needs, future opportunities and the costs associated with building out a largely rural communications network.

The communications network asset management plan addresses these challenges. It is designed to enable our current and future business services that we need to have in place to ensure a reliable, safe and sustainable power supply that promotes safety and wellbeing for our communities.

15.21.2 COMMUNICATIONS NETWORK PRINCIPLES

Our communications network has been designed based on three key principles. These are:

Reliable networks – communications engineered for resilience

We will improve health and safety risk outcomes by providing reliable communications platforms, engineered for security and resilience in the face of natural disasters, with appropriate levels of redundancy and self-healing. Communications network faults will be managed efficiently. We will seek to drive consistency across our networks by having in place robust and well-communicated standards and operational procedures.

Flexible and scalable – agile and responsive to changing needs

We will invest in flexible, responsive and cost-effective communications architecture that will serve our changing requirements over time. We will be agile in our response to communications requirements and ensure our solutions are scalable. We will minimise risk by seeking diversity in our selection of vendors and partners.

Leveraging investment – maximise the benefits of existing infrastructure

We will maximise the benefits of our existing infrastructure to improve the coverage and reach of our networks. This will enable us to provide visibility of network status to stakeholders, which will enable management of risks to people and assets. We will report against agreed service levels and employ an asset management approach to ensure efficient investment and asset management.

15.21.3 COMMUNICATIONS NETWORK PLATFORM

Powerco's communications network comprises the base layer Packet Transport Network, which is the backbone to which we transport a series of services.

These transport services include the following:

- Packet Transport Network Platform (PTN)
- Digital Mobile Radio Platform (DMR)
- Narrow Band Radio (UHF/VHF)
- Internet of Things (IoT) – LoRaWAN/4G

15.21.3.1 PACKET TRANSPORT NETWORK PLATFORM (PTN)

The PTN is the main highway for data and voice communications back into Powerco's NOC. The PTN is a Multiprotocol Label Switching (MPLS) based packet switching network that uses fibre, microwave and leased line services to transport information. It is a critical component in the operation of Powerco's electricity grid. This network covers the expanse of our core network locations with a programme to extend into all substations.

15.21.3.2 DIGITAL MOBILE RADIO PLATFORM (DMR)

The DMR allows Powerco's NOC staff to communicate to field contractors in locations where public mobile services are unavailable. As the primary means of communication with field resources, DMR is built with a high level of redundancy to help ensure the health and safety of staff and contractors working in remote locations. We are constantly reviewing performance and testing additional functionality within this platform. There are additional sites to be deployed to enhance current coverage and trials are under way to provide SCADA telemetry via the DMR using this extended coverage.

15.21.3.3 NARROW BAND RADIO

The narrow band platform provides both VHF and UHF data services for control and telemetry of the electricity grid. Although it is considered a legacy technology, it is still widely used by Powerco because of the remote nature and geographic spread of its electricity grid. If the DMR SCADA trials and Internet of Things (IoT) functionality being tested is successful, we will be able to modernise this existing fleet to these newer technologies.

15.21.3.4 INTERNET OF THINGS (IOT)

The IoT platform (LoRaWAN/4G) is an emerging platform with its ability to use low-cost, low-power sensors and base stations that can cover a wide geographic area. The sensors are considered disposable and will be rolled out in large quantities and only replaced when a certain percentage have failed. The IoT platform will likely replace a large percentage of the narrow band platform over time. These items will provide us with additional insight and a considerable volume of new data points to better enable decision-making, fault finding and restoration. Many of these data inputs from Line Fault Indicators (LFIs) and other sensors will become increasingly important in visibility, ensuring time to diagnose and repair faults is reduced.

15.21.4 FUTURE ROLLOUTS

Our principal development programmes are built around the communications network platforms as shown in the Table 15.42.

Table 15.42: Communications network development programme

FUTURE ROLLOUT PLATFORM	DETAIL
Digital mobile radio platform	Digital mobile radio network additional coverage and capacity.
	Implementation of data functionality. SCADA telemetry.
Packet Transport Network (PTN) platform	Transport network expansion to all zone substations.
	Network segmentation capability to allow flexibility for all services to use PTN.
	Transport resilience – east to west microwave link.
	Migration of the distributed IP network to PTN. Leveraging other existing/new fibre assets.
Internet of Things (IoT) platform	IoT pilot.
	IoT network build or integration of services.
	Expansion of IoT platform.
Other supporting initiatives	
Communications governance	Implementation of a new communications network governance structure.
Communications Service Level Agreements (SLA)	Finalisation of communications SLAs and reporting.
Conatal to DNP3 conversion	Complete conatal to Distributed Network Protocol version 3 (DNP3) conversion in the east

15.22 ROUTINE PROJECTS

15.22.1 OVERVIEW OF ROUTINE CAPEX

Routine Capex incorporates the lower cost, usually repetitive projects that address capacity and security.

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 more 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.

Historically, these investments mostly occur at the HV distribution level. However, we are now turning more attention to our LV network. This is to understand and then manage the impact of new technology, such as increased distributed generation, energy storage and electric vehicle charging, particularly from residential customers on our LV networks. Our aim is to ensure that the network is an enabler for our customers to invest in these technologies.

While it is not practical to identify specific projects in the routine class, there are trends and patterns that influence each planning area. Commentary on these is provided near the end of each area section earlier in this chapter.

15.22.2 HV ROUTINE PROJECTS FORECAST CAPEX

Historical expenditure trends on routine Growth and Security projects have been used to inform appropriate expenditure levels.

Types of projects include those that come from distribution planning analysis (refer to Chapter 10). These projects typically add capacity to existing parts of the feeder network or create additional feeders or backfeed ties.

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.

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 backfeed capability. This includes new feeder interconnections (or ties) and larger conductors or cables to allow better voltage or thermal capability under backfeed conditions.

Our automation plan (refer to Chapter 16) has driven 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 backfeed upgrades.

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.

Our move to probabilistic planning standards is also expected to impact our HV distribution planning, although to a lesser extent than our substransmission planning. We are forecasting a small reduction in HV distribution routine projects from the historical average through the application of this improved decision-making.

15.22.3 LV ROUTINE PROJECTS FORECAST CAPEX

Our initial focus will be on operationalising the underground LV network, followed by the LV overhead network. In most cases the investment will be directed to ensuring we can safely and efficiently utilise backfeed and sectionalising opportunities on our LV network. We have also allowed for additional expenditure to upgrade sections of LV network where capacity constraints arise because of electric vehicle (EV) and photovoltaic panels (PV) uptake increase.

The types of initiatives include:

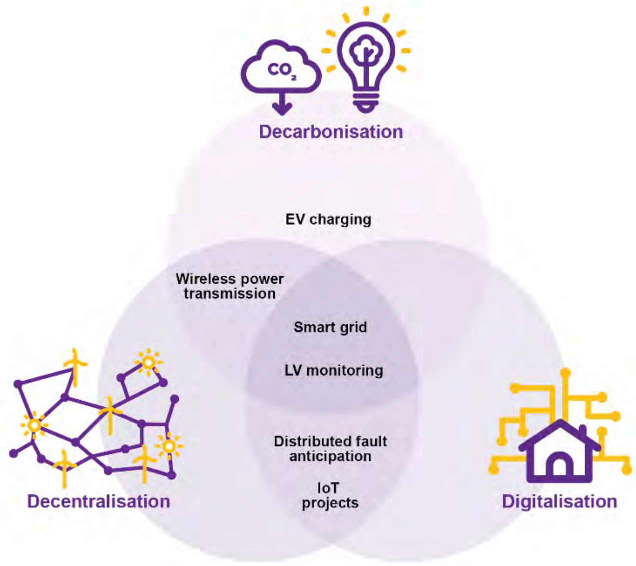
- Replacement of LV feeder interconnection points on the underground LV network with operational linkboxes.
- Installing resettable LV fuses on high-value customer loads.
- Creating operable LV link points on our LV overhead network to facilitate backfeeding.
- Upgrading LV cable and conductors in areas of our network where we are seeing high PV and EV uptake.

These initiatives and the overall strategy to improve the operational effectiveness of our LV network is discussed in more detail in Chapter 6. We expect this investment on our LV network to increase from around FY26.

Complementing this investment is our LV monitoring programme, discussed in section 15.20.2. Together, these investments will move us towards a fully administered LV network, capable of being operated much like our HV network today.

15.23 NETWORK EVOLUTION

Decarbonisation, decentralisation and digitalisation are three of the key factors influencing the future of our network. Understanding how the customer will respond to these factors is crucial in enabling us to evolve our network to meet these changing demands. We have several projects under way to help us develop our understanding.



15.23.1 EV CHARGING PROJECT

Electric vehicles are widely accepted to be one of the key disruptive technologies that may impact electrical networks in the future.

This project aims to understand the impact of electric vehicles on our network. The main objective of the project is to predict the additional peak load that can be expected as EVs become more prominent on our network footprint.

This project strongly aligns with the decarbonisation trend outlined in Chapter 6. To a lesser extent, this project also covers the digitalisation trend.

Each of the four network transformation scenarios outlined in Chapter 6.2 are likely to feature a strong concentration of EVs across the network. Decarbonisation is an undisputed global objective, and electric vehicles are one of the leading means of achieving this.

As illustrated in Chapter 6.2, the peak demand because of EV charging is strongly dependent on whether domestic EV charging is managed or unmanaged. If unmanaged, there are significantly higher demand peaks expected. This would require additional investment in our network to cope with the additional load.

The true future scenario is likely to lie somewhere between Figure 7.4 and Figure 7.5. The intent of this project is to understand where we may end up on the spectrum between these two scenarios.

15.23.2 SMART GRID

PV and behind-the-meter battery storage are two other technologies that are likely to materially influence the future of the electricity distribution network. This project involves developing a small-scale smart grid in an existing subdivision on our network. This will be used to simulate a residential area with a high penetration of PV and battery storage. This project explores each of the three ‘D’ mega-trends – decentralisation, decarbonisation and digitalisation.

A distribution network with a high proportion of PV and battery storage is quite different to a traditional network where power flows are unidirectional. As discussed in Chapter 6.2.4, the distribution network of the future is likely to lie somewhere between the extremes of a traditional network and a full smart grid.

The four scenarios outlined in Chapter 6.2.4 would each contain differing concentrations of distributed energy resources. The traditional network, with a very low concentration of Distributed Energy Resources (DERs), is already well understood. This is our current distribution network.

A network containing a high concentration of DERs would be more closely aligned to the Intelligent Network scenario. By completing this project, the Intelligent Network scenario will be better understood. Understanding both scenarios allows us to better prepare for any eventuality between the extremes of these two scenarios.

15.23.3 LV MONITORING

This project complements the open-access network work described in section 15.20 and focuses on emerging monitoring technology. As discussed before, LV visibility is seen as a potentially major expenditure item on our network in future, so keeping a close watching brief on developments in this area to ensure we adapt the most suitable, cost-efficient solutions is deemed essential.

15.23.4 IOT SENSORS AND LORAWAN

Establishing a low-power wide area network (LPWAN) is a key facilitator for the ‘Digitalisation’ mega-trend previously discussed. Our chosen technology is LoRaWAN. As discussed in Section 15.21.3.4 there are several key advantages of LoRaWAN over older radio technology.

A variety of different sensors are being trialled using LoRaWAN for communication. These sensors have a range of benefits, including fault localisation and reporting outage and power quality information. Some examples of these sensors are:

- Smart line fault indicators. These devices detect faults by sensing sudden increases in current through a conductor. When detected, the devices provide indication in the field by flashing a light. The trial LoRaWAN variant of this product will also immediately report this event to our network operations team.
- LV monitoring equipment. These trial sensors report outages and power quality information. These devices can also detect fallen HV conductors. This is a key safety feature, as traditional HV protection systems are not always able to detect this type of fault.
- Drop-out fuse sensors. A drop-out style fuse changes orientation when the fuse blows. This change in orientation can be detected by these trial sensors. The event is reported over LoRaWAN. This provides immediate indication and localisation of blown drop-out fuses.

15.24 FORECAST GROWTH AND SECURITY CAPEX

Figure 15.30 shows the forecast Capex on major projects. The completion of our CPP Major Projects is responsible for the large investment in FY22 and FY23, for example our Putaruru GXP project and Palmerston North CBD upgrade. These larger projects create a ‘lumpy’ major project expenditure, which we balance as far as practicable by activity in the minor works portfolio. From FY24 we expect investment in this portfolio to reduce as our larger CPP investments, which were typically aimed at correcting large historical security issues, will be complete. Beyond this, investment will still be required to address new security issues where driven by continued demand, but will also be moderated by improved planning through the application of probabilistic planning assumptions.

Figure 15.30: Forecast Capex on major projects

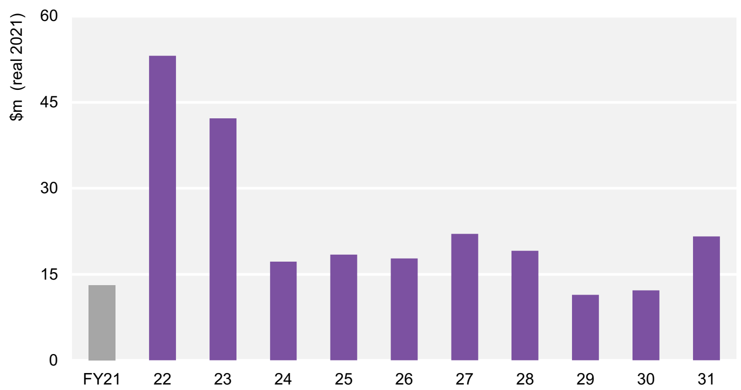


Figure 15.31 shows the forecast Capex expenditure on minor Growth and Security. This is forecast to increase in the latter half of the planning period because of new investment programmes, including the rollout of network visibility, increased LV investment, and a predicted increase in network reinforcement driven by electrification from process-heat conversion.

Figure 15.31: Forecast Capex on minor Growth and Security works

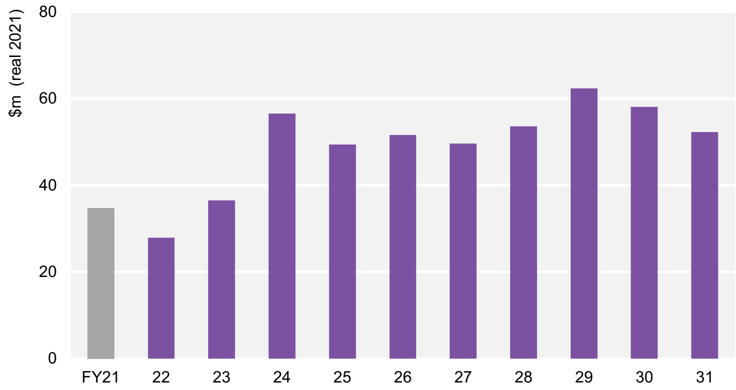
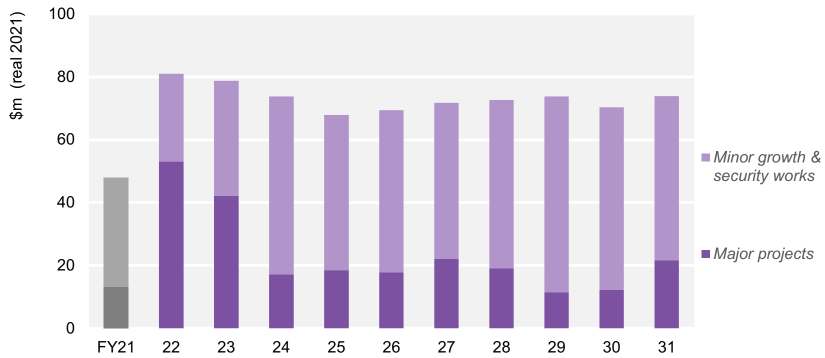


Figure 15.32 shows forecast Capex on both major projects and minor Growth and Security works during the planning period. With both portfolio forecasts added together, expenditure is expected to be relatively stable over the planning period.

Figure 15.32: Forecast Capex on major projects and minor Growth and Security works



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16 RELIABILITY AND AUTOMATION

16.1 OVERVIEW

Many projects contribute to the long-term reliability of our networks. Renewal projects address reliability concerns of our older assets, while Network Development projects help enhance reliability by providing alternative options for supply.

In this chapter, we consider only the expenditure not specifically covered in our other sections – Network Development Plans, Fleet Management Plans, and Operational and Maintenance Plans.

The only expenditure that falls into this category is network automation projects.

We use network automation to help manage the reliability performance of our network. In this context, network automation refers to the systems and devices that are used to undertake remote switching and reconfiguration of our networks.

Automation of distribution switchgear allows us to:

- Remotely isolate and reconfigure networks.
- Automate fault response actions.
- Gain better visibility of network operating conditions.
- More easily pinpoint fault locations.

Automation is an important investment focus as it enables reliability improvements to be achieved reasonably quickly. This helps us stabilise reliability outcomes on our networks while we work to address and stabilise emerging asset health and network security issues.

16.2 AUTOMATION PLAN

Our automation expenditure increases significantly during the planning period. In addition to our 'business as usual' application of reclosers, sectionalisers and fault passage indicators, we intend to apply the types of technology required to facilitate our Advanced Distribution Management System (ADMS) strategy and to transition to an open-access network with our role ultimately aligned to a distribution system operator (DSO). To achieve this, initially there will be increased expenditure on:

- Remote operable switches at existing tie points on both our overhead and underground distribution networks.
- Increased Supervisory Control and Data Acquisition (SCADA) visible fault passage indication.
- PQM metering at each substation.

Later in the planning period we intend to expand the remote control capabilities to enable faster sectionalising and minimisation of faulted areas through:

- Replacing more of our manually operated distribution switches on our rural network with remote control switches.
- Retrofitting strategically located ground-mounted switches with remote control operation in our high value load areas.
- Applying fault anticipation monitoring on selected zone substations.
- Applying end-of-line monitoring to the remote ends of selected rural feeders and urban feeders.
- Replacing fused spur connections with monitored devices to improve visibility.

16.3 ALIGNMENT WITH ASSET MANAGEMENT OBJECTIVES

16.3.1 SAFETY AND ENVIRONMENT

Automation brings substantial benefits in improved reliability, but automatic reclosing of circuits that have been subject to a fault can present risks for the public and workers.

We use a risk-based assessment process to understand and manage the safety implications of automated reclosing schemes, whether on meshed or radial circuits. We do not automatically re-liven circuits where there is a possibility of danger to workers or the public.

16.3.2 NETWORKS FOR TODAY AND TOMORROW

Our focus on networks fit for today and tomorrow helps us ensure our assets provide the services our customers require and provide the benefits that technology can practicably deliver.

Network automation provides several benefits that complement our goal of shaping our networks for the benefit of customers over time. Specifically:

- Automation helps us improve reliability on heavily loaded or older circuits where faults have a material impact on customers.
- Automation lifts the level of central oversight and control we have on our network, giving us operational flexibility and real-time control.
- Automated switches provide a range of real-time measurements that are complementary and can be used for advanced asset management.
- Automation provides the means to monitor and correct power quality issues, in particular, those issues that are likely to arise through increased distributed generation and two-way power flows.

Overall, new switching and control capabilities, especially when combined with communications, data gathering and data processing technologies, can greatly improve the reliability, flexibility and adaptability of our networks.

As our data availability and reliance grows, integration of field automation devices with modern Outage Management Systems (OMS) such as Fault Location, Isolation and Restoration (FLISR) is essential. Our automation strategy focuses on installing devices that help us to step toward that future while providing immediate reliability benefits.

16.3.3 ASSET STEWARDSHIP

This objective requires that we manage our large number of diverse assets efficiently, keeping them in good health.

Network automation systems enable us to remotely reconfigure networks without the need for ground crews. This provides faster restoration times, thereby helping us manage our System Average Interruption Duration Index (SAIDI). They also enable us to pinpoint fault causes and locations accurately, reducing fault crew effort.

All of this reduces costs, improves efficiency, and helps us manage our assets effectively.

16.3.4 OPERATIONAL EXCELLENCE

Automation provides us with a range of important short-term benefits that are of value while we move to address emerging issues associated with ageing assets and security-related exposure.

The benefits include:

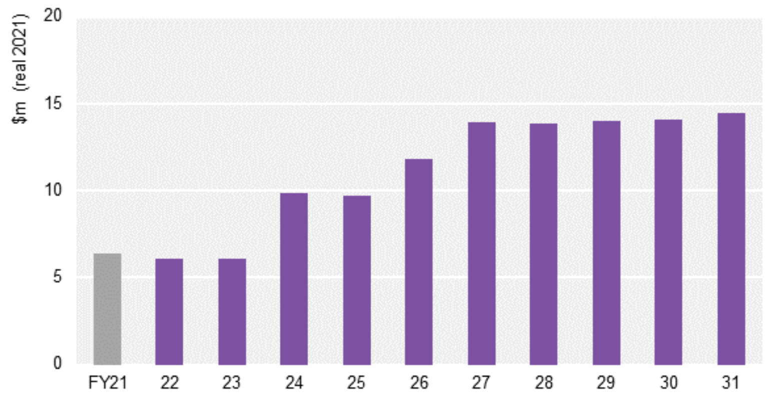
- Shorter outages through faster fault location and reduced time to reconfigure the network.
- Minimising the number of customers affected by faults.
- Reduced costs relating to line patrols, manual switching and manual fault location.
- Reduced likelihood of equipment damage because of overloading, under-voltage or slow protection settings.

Overall, automation is an important investment area to enable us to manage our networks effectively in real time.

16.4 EXPENDITURE FORECASTS

Our forecast expenditure is shown in Figure 16.1. The cost estimates are based on historical unit rates, including costs related to extending the communications network from our backbone network to each remote device. The forecasts do not include the rollout of Low Voltage (LV) monitoring (network visibility), which is included in the Minor Growth and Security forecasts in Chapter 15.

Figure 16.1: Forecast Capex – reliability



The expenditure level reflects the automation density in our rollout works plan. During the planning period we will regularly assess the performance benefits of our automation strategies. We may also have to revise the forecast later in the planning period when considering changes to the technological landscape.

17.1 CHAPTER OVERVIEW

Every year, several thousand homes and businesses connect to our electricity network. These new connections require investment in network infrastructure. The expenditure we directly incur when connecting new customers – net of any contribution they make – is defined and forecast as consumer connections Capex.

Chapter 11 provides an overview of our customer connection process. The process we use to connect new customers is designed to ensure the cost of connection is economical, and that connections can be completed in a timely way. This chapter explains how we forecast expenditure for these connections.

Further detail on our customers and how they impact our investment plans can be found in Appendix 4.

17.2 FORECAST EXPENDITURE

Below we set out and explain our forecast consumer connections Capex for the planning period.

17.2.1 EXPENDITURE DRIVERS

Consumer connection Capex is largely driven by growth in population (residential) and the overall economy (commercial/industrial). Specifically, investment levels tend to be driven by the following:

- New residential properties stimulated by population growth, land supply and Government policy that 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. The connections range from small connections, such as water pumps and telecom cabinets, to large connections, such as factories and supermarkets.

17.2.2 FUNDING

Customer requests for new connections or upgrades of existing connections may impact assets owned by us. We contribute towards the cost of constructing those new assets. This is because we receive some benefit from ongoing network charges and, in some cases, new assets benefit our existing customers.

In most cases, customers requesting new connections fund the majority of the cost. This is to ensure that these customers pay a fair amount for the assets that are used to serve their connection over its lifetime, and ensures our existing customers are not disadvantaged. We generally require contributions for the following works:

- Extensions or reinforcements that solely benefit individual customers.
- Network connections that require new assets to be built.

We have a customer contribution policy that we follow to determine the need for and amount of contribution. We publish a guide online to explain this.

In calculating contributions, it is important to demarcate our assets from those of the customer. 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 Low Voltage (LV) and distribution levels. However, incremental growth from existing customers can lead to upgrades at the distribution level, which are funded by us. Similarly, reinforcement of our network at subtransmission levels is funded through our system growth expenditure.

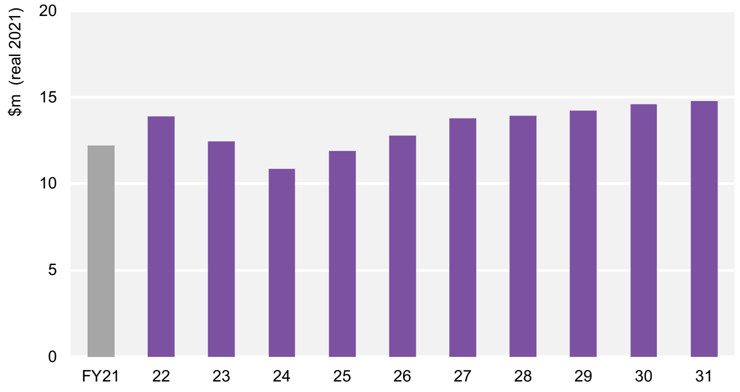
17.2.3 FORECAST CAPEX

Our forecast is based on trending historical activity as customer connections are externally driven with short lead times, limiting our ability to accurately forecast medium-term requirements. We use the current in-year FY21 expenditure forecast as a baseline, as we have recently seen a rise in customer connection activity that is not reflected by historical expenditure levels. We then use forecast Installation Control Point (ICP) growth to modify the base into a final forecast.

Our ICP forecast is based on household growth data, derived from econometric parameters. ICP growth correlates well with historical consumer connection expenditure. Forecast ICP growth is also used to inform our demand forecast for Growth and Security investments.

Our forecast assumes continuing our current capital contributions policy.

Figure 17.1: Forecast consumer connection Capex (net of contributions)



Expenditure in this portfolio has been high in recent years because of strong growth on our network, particularly in the eastern region.

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.

Fleet Management

Our plans to manage our existing assets to deliver a safe and reliable service.

18 OVERHEAD STRUCTURES

18.1 CHAPTER OVERVIEW

This chapter describes our overhead structures portfolio and summarises our associated fleet management plan. The portfolio includes two asset fleets:

- Poles
- Crossarm assemblies

This chapter provides an overview of these asset fleets, including their population, age, type 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 $361m in overhead structures renewals. This portfolio accounts for 38% of renewals Capex during the period.

Continued 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. Overhead structures renewals Capex is driven by the need to:

– Maintain the number of pole defects to steady state levels.
– Continue to replace poles and crossarms with a low Asset Health Indicator (AHI).
– Replace and monitor type issues in our pole and crossarm fleets.
– Ensure overhead structures meet current design standards when the associated conductor is replaced.
– Improve resilience to extreme weather events.
– Pole and line realignment to improve safety and reliability.
– Continue to review material and design to build resilient overhead networks for the appropriate investment levels.

Below we set out the Asset Management Objectives that guide our approach to managing our pole and crossarm fleets.

18.2 OVERHEAD STRUCTURES OBJECTIVES

Poles and crossarms are the primary components of our network. Combined with overhead conductors, they make up our overhead network (76% of total network circuit length), connecting our customers to the transmission system at grid exit points (GXP) and enabling the flow of electricity on circuits of varying voltages.

The performance of these assets is essential for maintaining a safe and reliable network. As most of our overhead network is accessible to the public, managing our overhead structure assets is also critical in ensuring public safety.

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 Table 18.1. The objectives are linked to our Asset Management Objectives set out in Chapter 4.

Table 18.1: 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 all poles responsibly.
	Ensure timber crossarms and poles are sourced from sustainable forests.
	Construct robust networks to perform to the designed lifecycle with consideration to the impacts of climate change.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works.
	Maintain a high standard of reliability.
	Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Investment renewals are designed to current industry standards with consideration for future requirements.
	Consider the use of alternative technologies and materials to improve reliability and network resilience; for example, remote area power systems, alternative construction materials and construction configurations to suit the economic and service performance of each investment.
Asset Stewardship	Continue the adoption of AHI to inform renewal investments.
	Reduce the number of pole and crossarm defects and maintain levels of pole and crossarms with poor AHI scores to sustainable levels.
	Continually monitor the performance and condition of the pole and crossarm fleets to identify trends, such as type issues and end-of-life characteristics.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Operational Excellence	Improve and refine our AHI assessment techniques and processes for poles and crossarms.

18.3 POLES STRUCTURES

18.3.1 FLEET OVERVIEW

Our network comprises concrete poles (87%), wooden poles (12%) and a small number of steel poles. We have 267,000 poles on our network.

There is a wide range of poles in terms of height, strength, material, age, and AHI, and a range of failure modes.

Concrete poles

There are two main types of concrete poles – pre-stressed and reinforced. Pre-stressed poles constitute most of our concrete pole fleet on our network. 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, leading to differing lifecycle performance.

Pre-stressed poles are a mature technology and are expected to perform their function reliably over a long period.[66] Pre-stressed poles have been used for more than 50 years and are manufactured with tensioned steel tendons (wire). Most new poles installed are pre-stressed and are designed and manufactured to meet stringent structural standards. The pre-stressed poles installed today have a design life of 70 years. Pre-stressed poles are difficult to inspect for internal corrosion, therefore we are continually researching techniques for this type of inspection.

Reinforced concrete poles contain reinforcing steel bars covered by concrete. These poles were regularly manufactured and used from the 1960s to the 1990s but less so during the past 30 years.

[66] Note: An issue has been identified with a certain type of pre-stressed concrete pole. This is discussed in the Condition, Performance and Risks section.

Figure 18.1: A modern pre-stressed concrete pole and a rural softwood pole

Timber poles

Timber poles can be categorised into three types based on the wood type and species – hardwood, larch, and softwood.

Timber poles were historically used extensively in parts of the network because of the availability and technology of the time. In the right application, timber poles are more suited to dynamic loading, such as severe weather events, than the concrete pole equivalents.

Many hardwood species are used on our networks, most of which were installed before 1985. The species is unknown in some cases and performance varies within and across species.

The category of larch poles incorporates species such as Ponderosa pine, Douglas fir and Macrocarpa. The use of larch poles was phased out from 1990.

Softwood poles are generally Pinus radiata, which has been treated with copper chrome arsenic (CCA). Softwood poles are lighter and lower cost than others. The inconsistency in lifecycle performance meant we used fewer from the mid-1990s. On investigation, some barn-type poles have been used in place of standard certified power poles, which has reduced the expected lifecycle of the softwood pole fleet.

The use of timber poles in the construction of new networks is being now considered as a lower cost option for remote area applications and lightly loaded spur lines. Modern timber poles (softwood and hardwood) have an expected service life of 50+ years as selectively grown forests, modern treatment techniques and quality controls have improved the performance and life expectancy of these poles. The added advantage of using sustainable softwood poles is that the poles have a low carbon footprint as they are grown and manufactured in New Zealand.

Life extension techniques, such as pole staking, are used for timber poles installed on remote networks, where the costs and complexity of rebuild is out of proportion with the projected economic value of the line.

We continue to evaluate better condition assessment techniques for wooden poles to better manage the safety and reliability of those remaining on our network.

Steel poles

We have a small number of steel poles in service. There are three main types – legacy 'rail iron' poles, modern tubular poles and steel lattice towers.

Rail iron poles are being organically replaced on the network.

Tubular steel poles are useful for specific design loads where concrete and timber poles are not suitable. Steel poles usually require an engineered concrete foundation. The use of steel monopoles is being assessed as an option for remote access sites as they are lightweight and more suited to dynamic loading (wind, snow and ice) than concrete poles.

There is a small population of steel lattice towers on the network. These structures were used for major river crossings and legacy towers purchased from Transpower. We maintain the structures to a serviceable standard.

Fibre reinforced concrete poles

Fibre reinforced concrete poles have been introduced into network reconstruction as an option for pole replacement.

These poles are constructed from high-quality fibreglass combined with an engineered concrete to create a highly durable pole material. This pole is suitable for corrosive environments such as coastal frontage, estuaries and wet areas.

The poles are considerably lighter than the standard concrete pole with better structural characteristics for remote area installations where access is difficult, and snow and ice loading is prevalent.

Fibre reinforced concrete poles have an expected design life of 70+ years.

18.3.2 POPULATION AND AGE STATISTICS

Table 18.2 summarises our population of poles by type.

Table 18.2: Pole population by type

POLE GROUP	POLE TYPE	NUMBER OF POLES	% OF FLEET
Concrete	Pre-stressed	158,058	59
	Reinforced	75,741	28
Wood	Hardwood	6,791	3
	Larch	6,695	3
	Softwood	19,246	7
Steel	Steel	722	0.3
Total		267,253	

Figure 18.2: Wooden pole age profile

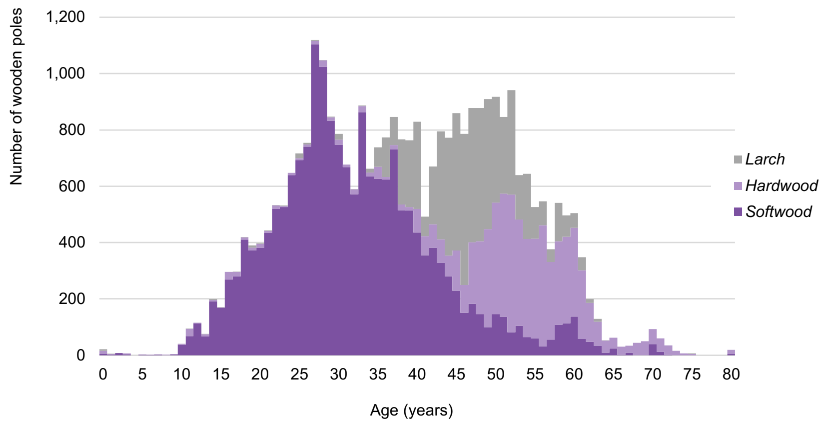
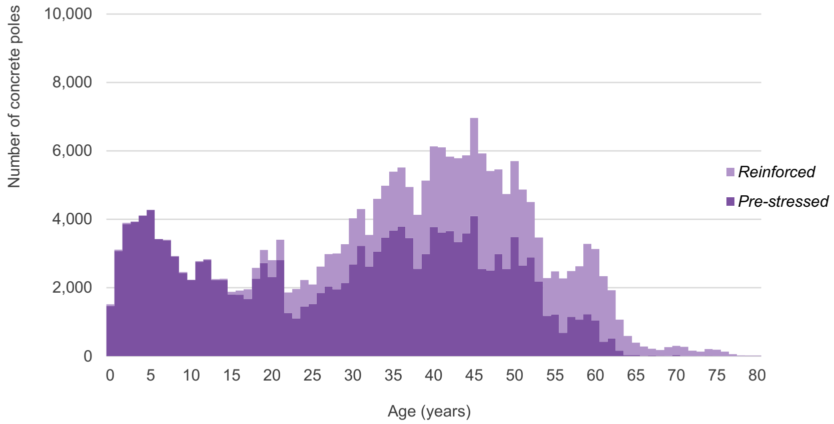


Figure 18.3: Concrete pole age profile



18.3.3 CONDITION, PERFORMANCE AND RISKS

In-service pole failure is a significant safety issue, potentially exposing the public and workers to hazards associated with falling network equipment, and electrical hazards associated with live conductors dropping on the ground or reduced clearances to ground.

In-service pole failure is also a significant reliability issue, as pole failure results in the loss of supply or network security. The reliability impacts can be extensive should multiple failures occur during extreme weather events causing extended restoration times.

Structural failure during maintenance or construction works is also a significant workplace safety hazard. Poles with a low AHI are replaced within our projected investments.

Meeting our portfolio objectives

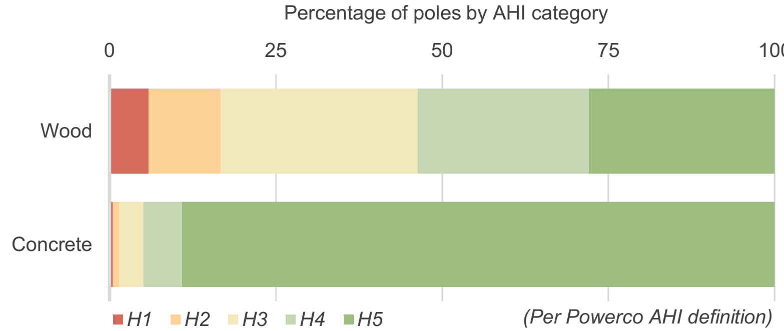
Safety and Environment: Poles are replaced using AHI information before failure, thereby minimising safety risks. Ensure replacements where possible are from sustainable sources.

It is important to rectify pole defects promptly. While most pole failures are caused by vehicle accidents, vegetation contacts and adverse weather, pole failures with existing condition defects or a manufacturing type issue can be triggered under stress, for example through heavy snow falls and wind loading.

Pole asset health

As outlined in Chapter 10, we have developed AHI that reflect the remaining life of an asset based on a set of rules that is consistently reviewed. Figure 18.4 shows current overall AHI for our population of concrete and wooden poles.

Figure 18.4: Wooden and concrete pole asset health as at 2020



Pole condition

We carry out regular inspections of our poles to verify their condition and to identify defects.

The main pole AHIs differ by pole type. Some common examples are set out in Table 18.3. Our inspection process allows us to identify the pole fleet's AHI. This allows planned and coordinated pole replacement with investment planning.

Table 18.3: 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. This loss of strength can lead to unexpected structural failure during adverse weather or maintenance or construction.
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 because of the significant residual strength of the pole there would need to be a large amount of spalling before replacement is warranted.
Steel	Corrosion of steel poles occurs over time at a rate dependent on environmental conditions. This is relatively easy to assess through inspection, although internal corrosion of tubular steel poles and underground corrosion is sometimes more difficult to assess.
Hardwood	Decay in hardwood poles can occur near the ground line and at the pole head.
Softwood and larch	Decay in softwood and larch poles typically occurs from the inside out.

Our current inspection and defect process has been in place since 2008 and is constantly under review.

We have also conducted research to assess the residual strength of legacy concrete pole types. This has identified type issues, which have been added to our AHI assessment criteria.

Our inspection programme is ongoing, and we expect to find further failure modes as we monitor our pole fleet, our pole fleet ages, and the condition of the pole fleet degrades. The target level is based on a three-year replacement stock, which allows time for replacement coordination to ensure efficient delivery.

The defect pool contains no urgent 'red' defects – these poles are replaced as a priority because of associated safety risks.

Wooden pole inspections

To inform our AHI forecasts, we have trialled a variety of techniques to improve the accuracy of our predictive models. We have adopted acoustic resonance tools in conjunction with traditional pole inspection techniques for wooden pole condition assessment.

Meeting our portfolio objectives

Operational Excellence: We have trialled and are implementing improved pole condition assessment techniques to improve AHI accuracy and asset renewal timing.

Type issues

In addition to condition-related replacements, we also have several pole type issues[67] within the fleet. These poles are targeted for replacement and are replaced during any investment works.

Pre-stressed concrete poles

We have identified that by design and manufacture, some pre-stressed concrete pole types have a very low strength compared with modern construction and design standards. They are replaced in pole and conductor renewals investment.

For example, some early manufacture (1960s) of pre-stressed poles used an internal reinforcement spreader between the ground section and the above ground section. The spreader has initiated cracking that has allowed moisture ingress, resulting in corrosion of the pole tendons.

Visually these poles appear in good condition, but internally the tendons have corroded, reducing strength to the point that they may fail under normal or climbing loads.

Reinforced concrete poles

Type issues have also been identified within the reinforced concrete pole fleet – primarily premature spalling exposing the reinforcement bars.

Reinforced concrete poles were made by a variety of manufacturers using local materials, such as gravels and sands, with varying degrees of quality control.

Typically, the poles spall at a rapid rate, exposing the reinforcing bars. When this type issue is identified, the poles are replaced in the renewal investment areas.

67 A type issue is a problem affecting the reliability or safety or design life of a subset of equipment, often related to a particular design or manufacturing issue.

18.3.4 DESIGN AND CONSTRUCT

Most new poles installed on our network are pre-stressed concrete.

When performing minor maintenance or renewal works, such as replacing a single pole or crossarm, we use a like-for-like approach.

When performing larger overhead line works, we undertake design analysis to ensure the new asset is compliant with our design and construction standards, which comply with external rules and standards such as AS/NZS 7000 – Overhead Line Design and ECP34.

Pre-mature pole replacement – often poles that have a high AHI score – occurs during conductor renewals, as design loads may increase, and for compliance with AS/NZS 7000 – Overhead Line Design Standard.

18.3.5 OPERATE AND MAINTAIN

Concrete 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.

Timber poles are inspected, and their condition assessed, as part of overall overhead network inspections. Timber poles that meet life extension criteria are selected for pole staking. We continue to explore the technology available to perform diagnostic testing on our wooden pole fleet that is easy to implement in the field and will enhance the quality of our asset data.

Our preventive pole inspections are summarised in Table 18.4. The detailed regime for each type of pole is set out in our maintenance standards.

Table 18.4: Pole preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Yearly
Visual inspection of all subtransmission poles as part of overhead network inspections. Alternates between a rapid inspection, which requires no digging at ground line, and a more detailed condition assessment 5 yearly.	2.5 yearly
Inspection of distribution and Low Voltage (LV) poles as part of overhead network inspections, completing a detailed condition assessment.	5 yearly
Aerial condition photography to provide identification of condition and defects from a top-down view. Ground inspection cannot provide this detail. Pole top photography is only carried out on the rural pole fleets.	5 yearly

The structure inspection frequency is based on a combination of historically legislated time periods, industry practice and our experience with identifying in-pole types and pole condition.

All poles need regular inspection because they may be damaged or compromised by a third-party action, age, poor ground conditions or land movement.

A key component of our routine inspections is identifying defects and reporting on asset condition. Where a defect is detected, the defect is assessed for failure likelihood and prioritised for repair or replacement.

Pole asset health (AHI) is the key factor in overhead renewal projects. Monitoring pole AHI allows us to develop long-term robust pole renewal programmes.

The pole-top photography is currently based on a five-year cyclical programme to complement the ground-based inspections. As more information becomes available, this will be optimised based on the network risk profile to ensure our assets remain in serviceable condition.

18.3.6 RENEW OR DISPOSE

Renewal of poles is primarily determined by asset health.

SUMMARY OF POLES RENEWAL APPROACH	
Renewal trigger	Proactive condition-based and AHI
Forecasting approach	AHI
Type issues	Identified and confirmed by pole type testing

Meeting our portfolio objectives

Asset Stewardship: We are increasing the use of diagnostic condition assessment tools and models to inform and verify renewal investments. Investigating different material and design to build resilient overhead networks.

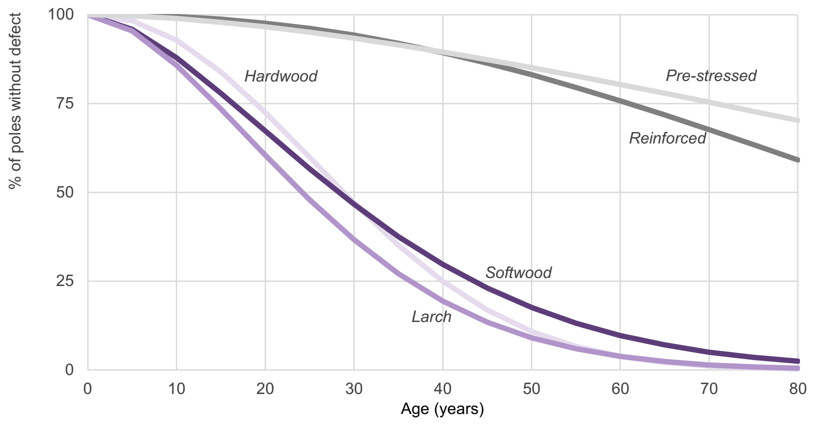
Because of our increasing conductor renewal programme, each new section of conductor renewal is designed to AS/NZS 7000, which may require poles that have a high AHI score to be replaced because the new design loads exceed the existing pole strength.

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 renewal quantities.

A forecasting approach that incorporates condition history and AHI is more robust than a purely age-based approach. Figure 18.5 shows our typical pole survivor curves. Each curve indicates the percentage of population remaining at a given age.

Figure 18.5: Pole survivor curves



The survivor curves show that poles require replacement over a wide range of ages. In addition to type, this is influenced by factors such as location, design and manufacture quality.

Our wooden poles tend to require replacement at a similar age to the industry expected life, although with a very wide distribution. Volumes of pole renewals are forecast to increase during the next two years and to plateau after three to five years.

Pole disposal

Poles are disposed of when they are no longer needed because of asset relocation (eg undergrounding), asset replacement, or following failure. When a pole fails, we carry out diagnostic inspection and testing to assess the root cause of failure. As trends emerge from the failure analysis, we incorporate them into our pole fleet asset strategy approach.

Requirements for recovery and disposal include safe work and site management processes and appropriate environmental treatment of scrap material. CCA treated softwood poles need to be disposed of at an appropriately licensed facility.

Pole life extension

As land use changes in the remote networks, such as shifts from livestock farming to forestry and honey production, we are observing that connection density on some remote feeders is declining. Extending the life of the poles in the remote networks will allow deferral of major renewal investments until a time when either further deferral is not practicable or alternative standalone power supplies become more cost effective. We have started a programme of pole life extension using a strapped steel truss that is expected to extend the life of a timber pole by more than 10 years.

Pole reinforcement

Having completed a trial in early 2020, we are now commencing an annual programme of pole reinforcements. A pole reinforcing truss is attached to the pole using high-strength steel banding, and no pole drilling is required. Each installation is designed and certified to provide ground line capacity against loading conditions specified by the current version of AS/NZS 7000.

The work does not require a planned outage and therefore doesn't impact our customers. Reinforcement defers renewal for 10+ years, allowing us to minimise investment in our remote rural networks that are potentially suitable for alternative solutions in the future. We are also considering this technology as an option to quickly rectify high-risk defects identified on timber poles.

Coordination with network development projects

Pole replacements can be triggered by a need to upgrade or thermally upgrade the conductor that the poles are supporting, for load growth. These upgrades put higher mechanical loads on the poles, often forcing an accompanying replacement to ensure the new conductor is safely supported in accordance with AS/NZS 7000.

As part of these upgrade projects, we also identify poles with low health scores and coordinate their replacement alongside the conductor upgrade to ensure efficient delivery and to minimise customer disruption. The detailed requirements for each individual upgrade project are confirmed by a full detailed design.

Meeting our portfolio objectives

Customers and Community: Replacement works are coordinated across portfolios to minimise customer interruptions and ensure efficient delivery.

18.4 CROSSARMS

18.4.1 FLEET OVERVIEW

A crossarm assembly is part of the overall pole structure. Its 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 can be mounted, such as insulators, high voltage fuses, surge arrestors, vibration dampers, bird spikes, earthing systems, armour rods, binders and jumpers, and arm straps.

From this point, the term crossarm refers to a crossarm assembly including all components.

A pole may have more than one crossarm, such as when 11kV and 400V circuits share the same structure. There are significant safety and performance risks associated with crossarm failure.

Figure 18.6: Different crossarm configurations

Our crossarms are typically made from hardwood and steel. Hardwood crossarms have insulating characteristics that limit fault currents. Hardwood crossarms can be easily drilled, allowing for simple installation of ancillary components. Steel crossarms are an alternative for high-strength requirements.

Crossarm components

Ancillary components may be replaced through the defect process as reported (this is treated as maintenance Opex).

However, it is, on average, more cost effective from a lifecycle perspective to replace the entire assembly when the crossarm has a low AHI because of the expense of mobilisation and other fixed costs.

The purpose of insulators is to support the conductor while providing electrical separation, through insulation properties, of the live conductor from the crossarm and pole structure. There are many types of insulators. Those on our network are generally pin, post, shackle or suspension/strain types made from glazed porcelain, glass or polymer.

Binders secure the conductor to the insulator. The modern method to ‘bind’ conductors to insulators is to use pre-formed ties. Armour-rod wraps are also used around the conductor, protecting the conductor from chafing on the insulators as well as providing some dampening for conductor vibration.

18.4.2 POPULATION AND AGE STATISTICS

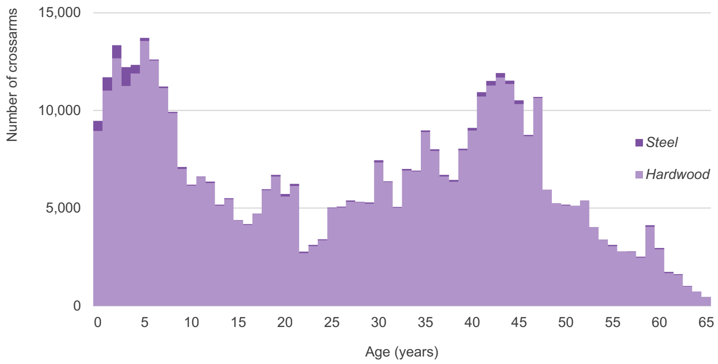
We have approximately 434,000 crossarms in service, of varying sizes and configurations.

Table 18.5: Crossarm population by type and voltage

CROSSARM TYPE	VOLTAGE	COUNT	% OF TOTAL
Wood	Subtransmission	16,435	3.8
	Distribution	251,013	57.8
	Low Voltage	158,867	36.6
Steel	Subtransmission	2,317	0.5
	Distribution	2,791	0.6
	Low Voltage	2,580	0.6
Total		434,003	

Figure 18.7 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 a lower AHI score increases rapidly.

Figure 18.7: Crossarm age profile



We have compiled the crossarm age profile from different data sources. Age and voltage class are reliably recorded for crossarms installed since 2000, but this information has had to derived for some older crossarms. 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 when crossarm age is not recorded.

18.4.3 CONDITION, PERFORMANCE AND RISKS

In-service failure of a crossarm can lead to dropped conductors or spans lowered to unsafe clearances, presenting a significant safety risk to the public.

Hardwood crossarms typically fail from age-related deterioration causing loss of strength, or from fungal decay, usually starting on the upper side as a result of exposure to moisture and other contaminates. Wooden crossarms also fail because of burning caused by electrical tracking from insulation degradation. Failure modes and rates of decay are strongly influenced by environmental conditions.

Crossarm components also fail. Binders fatigue over time and can loosen or break, allowing the conductor to swing free from the crossarm, usually resulting in an outage. These issues are repaired as needed, reactively.

We have identified problems with some types of subtransmission and distribution insulators. Some insulators of two-piece porcelain construction are prone to cracking at the join, leading to separation. Because of the potential safety consequences of these failures, we are proactively replacing crossarms that have these insulators. [68]

[68] It is cost effective to replace the whole crossarm assembly not just the insulators. These crossarms would need to be replaced in the medium-term anyway.

Meeting our portfolio objectives

Safety and Environment: Crossarms are replaced proactively using AHI 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 pollution, for example salt laden air. These issues are fixed as needed, reactively.

Crossarm asset health

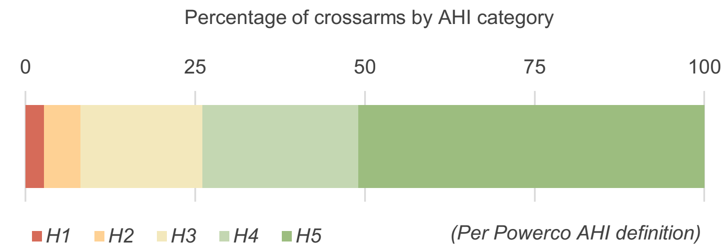
As outlined in Chapter 10, we have developed AHI that reflect the remaining life of each asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules.

For crossarms, we define end-of-life as when the crossarm is at the end of its predicted service life, or the insulators can no longer provide adequate insulating capability and the crossarm assembly shall be replaced.

The AHI is based on our survivorship analysis.

Figure 18.8 shows current overall AHI for our crossarm population.

Figure 18.8: Crossarm asset health



Approximately 3% of crossarms require renewal in the short term (H1). This is primarily because of the crossarm condition pool and our replacement programme of crossarms with insulator type issues.

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.

Crossarm condition

We carry out regular inspections of our crossarms to assess their condition and to identify defects. We are focused on improving the condition assessment regime for crossarms. We have changed the inspection methods for crossarms, the measures to address data gaps, provided additional training for field staff and have greater confidence with pole-top photography for the overall crossarm condition and AHI.

18.4.4 DESIGN AND CONSTRUCT

While the crossarms on our network are typically made of hardwood, we are exploring the use of fibreglass in the longer term. The initial cost is higher, but they are likely to have lower lifecycle costs because they last longer, are easier to inspect, and their condition can be assessed with greater confidence.

We also specify post type insulators rather than pin type insulators to avoid the failure modes of hole elongation caused by wind loading, as well as the potential for failure at the cement pin interface.

Crossarm configurations are designed to AS/NZS 7000 and ECP34.

18.4.5 OPERATE AND MAINTAIN

We undertake various types of inspections on crossarms, as set out in Table 18.6. 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.

Using pole-top photography will allow a higher standard of crossarm health assessment.

Pole-top photography

Visual inspections have traditionally been ground-based. The top side of the crossarm cannot be seen and therefore cannot be accessed for defect or condition. This is also true for the individual components that are supported by the crossarm, such as insulators and conductor binders. Aerial photography will provide more accurate identification of defective equipment, which can be prioritised for repair or replacement. Aerial photography will also provide an assessment of the asset health of the overhead network components for asset renewal planning. Aerial pole-top photography cannot be used in urban settings by helicopter - drone technology is being considered.

Table 18.6: Crossarm preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Yearly
Visual inspection of subtransmission crossarms as part of overhead network inspections. Alternates between a rapid inspection and a more detailed condition assessment.	2.5 yearly
Aerial condition photography to provide identification of condition and defects from a top-down view. Ground inspection cannot provide this detail. Pole top photography is only carried out on the rural pole fleets.	5 yearly
Visual inspection of distribution and LV crossarms as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

Crossarm faults usually occur because of age-related deterioration. Fault and defect repairs involve replacement of individual components or complete crossarm assembly replacement. Typical corrective work includes:

- Replace broken, rotten, or cracked arms.
- Replace broken or damaged arm braces and bolts.
- Replace individual cracked or failed insulators.

18.4.6 RENEW OR DISPOSE

Historically, we have taken a mainly reactive approach to crossarm renewal, as determined by the reported condition and known defects. We now take a proactive approach to crossarm renewal considering the current condition, and risk to all stakeholders on the Powerco footprint. Additional replacements are also undertaken during pole and conductor replacement projects.

SUMMARY OF CROSSARM RENEWALS APPROACH	
Renewal trigger	Proactive condition-based, type
Forecasting approach	AHI
Cost estimation	Cost models

We use the Overhead Renewal Planning Tool utilising AHI information to prioritise renewal work programmes.

In the short to medium term, our works will focus on replacing crossarms already marked with low AHI, and crossarms with insulator type issues. Where possible, we will deliver these renewals as large investments to ensure cost effectiveness.

Renewals forecasting

Our crossarm replacement quantity forecast incorporates historical survivorship analysis. We are developing enhanced AHI scores for all crossarms and will use this to forecast required renewal quantities in the future.

The analysis shows that crossarms require replacement over a range of ages. This is likely because of varying environmental conditions on our network and the inherent variability in the quality of hardwood crossarm timber species.

The volume of renewal has increased during the past three years, and is now at more sustainable levels, as indicated by the survivorship analysis. Renewals will transition to maintaining fleet health rather than improving it.

Meeting our portfolio objectives

Networks for Today and Tomorrow: Consider the use of alternative materials to improve reliability and network resilience to suit the economic and service performance of each investment.

Coordination with network development projects

Like poles, crossarms are often replaced as part of overhead line reconstruction projects, such as conductor upgrades as part of network development works. As a crossarm's expected life is short compared with a pole or conductor, its replacement for end-of-life reasons can often be coordinated with these works.

18.5 OVERHEAD STRUCTURES RENEWALS FORECAST

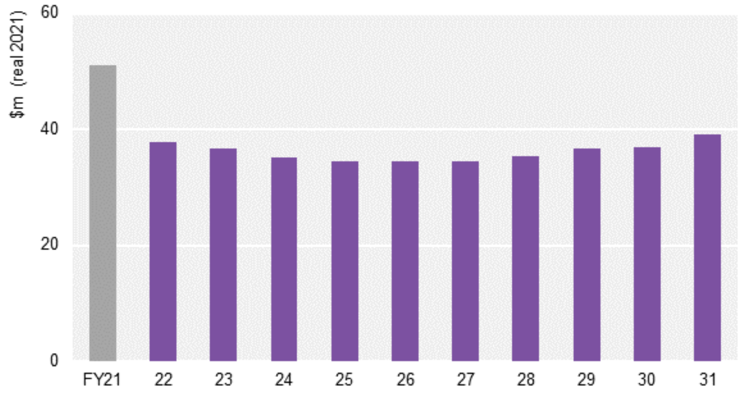
Renewal Capex in our overhead structures portfolio includes planned investments in our pole and crossarm fleets. This will require an investment of approximately $361m over the planning period.

A key driver for pole and crossarm replacement is managing safety risk and reliability, as pole or crossarm failure can cause conductor drop and reduce electrical clearance distances and disrupt electrical supply. Unsafe poles and crossarms also present significant safety risks to our field workforce.

Pole and crossarm renewal forecasts are derived volumetric estimates based on survivor curve analysis. Expenditure in this portfolio includes renewals of poles and crossarms to support our reconductoring programmes. More information on our reconductoring programmes is contained in Chapter 19.

Figure 18.9 shows our forecast Capex on overhead structures during the planning period.

Figure 18.9: Overhead structures renewal forecast expenditure



Having significantly lifted investment in this portfolio during the past three years, our forecast is to now continue with that increased level over the planning period. This forecast reflects the level of investment needed to manage renewals within the fleets and includes expenditure on crossarms that have known safety issues. A focus in the near term is to investigate changes to design standards and material specifications that still achieve the safety, reliability and resilience we want from our overhead network, but that also look to manage our costs and risks more optimally. Spend in this portfolio in FY21 is abnormally high as we have focused on completing additional overhead renewal projects because of deferrals in our Major Projects programme.

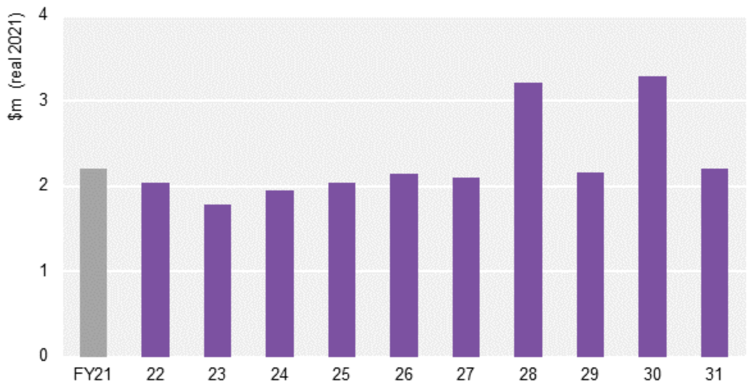
18.6 OVERHEAD STRUCTURES PREVENTIVE MAINTENANCE FORECAST

Our largest fleet accounts for approximately 20% of our preventive maintenance spend. This forecast includes all overhead line-related preventive maintenance and, therefore, this includes our overhead conductors fleet.

Acoustic resonance testing of the integrity of our wooden poles has proven to be invaluable. However, rather than deploying it as part of our routine inspections, we are using it in specialist applications only, such as informing our pole reinforcing programme. This is because of the specialist nature of the test and is reflected in a reduction in forecast expenditure compared with earlier projections. We continue to trial new techniques for a more suitable field test device to complement the current inspection regimes.

The increase in spend in FY28 and FY30 as shown in Figure 18.10 below is provision for the continuation of the pole-top photography programme, which is a key component of our renewal and defect management programmes.

Figure 18.10: Overhead structures preventive maintenance forecast expenditure



19 OVERHEAD CONDUCTORS

19.1 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
- Low Voltage (LV) overhead conductors

This chapter provides an overview of these assets, including their population, age and health. 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 $10m in 2022 to $19m in 2031. This portfolio accounts for 16% of renewals Capex during the planning period. The increase will be gradual to facilitate deliverability.

Increased investment is needed to support our safety and reliability objectives. Failure of overhead conductors can have a significant impact on our safety and reliability performance. This increase in renewals Capex is mainly driven by the need to replace end-of-life conductors because of their type, age and accelerated degradation due to environmental and reliability conditions.

We will:

- Continue to replace conductors in poor asset health.
- Ensure the ongoing safety and reliability of our conductor fleets.
- Continue to review material and design to build resilient overhead networks for the appropriate investment levels.
- Ensure conductor replacement meets current design standards.
- Identify and replace bare LV conductors with covered conductors to mitigate the public safety risk of bare conductor failure.

Below we set out the Asset Management Objectives that guide our approach to managing our overhead conductor fleets.

19.2 OVERHEAD CONDUCTORS OBJECTIVES

Overhead conductors are a core component of our network and connect our customers to the transmission system via grid exit points (GXPs). They enable the flow of electricity on circuits of varying voltage levels. Our network is long, predominantly rural, and most electrical circuits are overhead (76% of the total network length).

Our three overhead conductor fleets are defined according to operating voltages. The same conductor type (material) is often used across voltages, albeit of different sub-types and sizes. However, the risks and criticality differ by the operating voltage.

To guide our asset management activities, we have defined a set of portfolio objectives for our overhead conductor fleets. These are listed in Table 19.1. The objectives are linked to our Asset Management Objectives as set out in Chapter 4.

Table 19.1: Overhead conductors portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No condition-driven conductor failures resulting in injuries to the public or our service providers.
	No condition-driven conductor failures resulting in property damage, including fire damage.
	Dispose of a conductor responsibly when a conductor is replaced, including metal recycling.
	Construct a robust network to perform to the design lifecycle with consideration to the impacts of climate change.
	Continue to replace the bare LV conductor fleet with PVC-covered wire to mitigate the public safety risk that may be present when bare LV wire fails.
Customers and Community	Minimise planned interruptions to customers by coordinating conductor replacement with other works.
	Minimise landowner disruption when undertaking renewal work.
	Maintain a high standard of reliability.
Networks for Today and Tomorrow	Investment renewals are designed to current industry standards with consideration for future requirements for the network.
	Consider the use of alternative options and technology to improve customer experience and/or minimise network investment costs, such as remote area power systems.

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Asset Stewardship	Replace conductors with poor Asset Health Indices (AHI) scores to a sustainable level.
	Increase the use of conductor sampling and diagnostic testing to inform and verify AHI modelling.
	Continually monitor the performance and condition of the conductor fleets to identify trends for end-of-life characteristics.
Operational Excellence	Continually improve and refine modelling of AHI and risk for all the overhead conductor fleets to inform prioritised renewal plans.
	Improve our information of the LV overhead network, including conductor types, ages and failure mechanisms.

19.3 SUBTRANSMISSION OVERHEAD CONDUCTORS

19.3.1 FLEET OVERVIEW

Subtransmission overhead conductors are classified as the conductors used in circuits operating at 33kV and 66kV, connecting zone substations to GXPs, and interconnecting zone substations.

Figure 19.1: 66kV subtransmission overhead line in the Coromandel

Conductors used at subtransmission voltages are made of aluminium and copper, in various compositions. Hardened copper, which was highly conductive with good strength and weight characteristics, was the predominant type used on our networks until about 60 years ago.

During the 1950s, we started to use All Aluminium Conductors (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 with other types means that today it is only used in urban areas on shorter spans.

ACSR has become the most widely used conductor on our network. The ACSR conductor comprises an inner core of solid or stranded steel and one or more outer layers of aluminium strands. This construction gives the conductor a high strength-to-weight ratio, making it ideal for long spans, so it is widely used in rural areas of our network.

In the past five years, All Aluminium Alloy Conductors (AAAC) have been preferred to AAC conductors. AAAC has also recently become the most used conductor type in new installations, taking over from ACSR. AAAC has a greater tensile strength than AAC and is significantly lighter than ACSR. AAAC also has good conducting properties.

19.3.2 POPULATION AND AGE STATISTICS

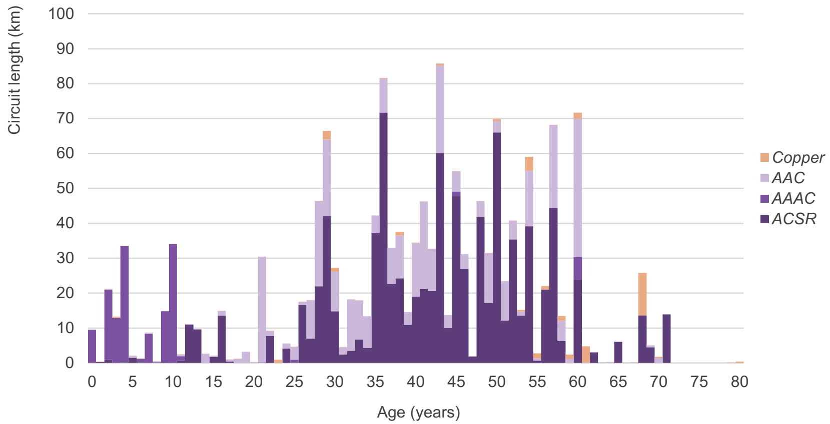
There are four types of subtransmission conductors, making up approximately 7% of our total conductor fleets. Table 19.2 shows that only small volumes of copper conductors remain in service.

Table 19.2: Subtransmission overhead conductor population by type

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	144	10%
AAC	416	28%
ACSR	908	60%
Copper	37	2%
Total	1,505	

Most of our conductors were installed in the 1960s, 1970s and 1980s. Figure 19.2 shows the age profile of our subtransmission conductors.

Figure 19.2: Subtransmission overhead conductor age profile



19.3.3 CONDITION, PERFORMANCE AND RISKS

Failure rates are lower within this fleet as subtransmission circuits are more robustly constructed than distribution and LV circuits. Subtransmission conductors are inspected more frequently because of their higher importance in maintaining a reliable supply. Subtransmission conductor failures can result in a high number of customers losing their electricity supply as subtransmission lines supply our zone substations.

Table 19.3 describes the failure modes relating to our conductor fleets, including distribution and LV. These failure modes inform our inspection programmes. The knowledge gained is used in our asset health modelling.

Table 19.3: Conductor failure modes for all conductor voltages

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, fault currents and design operating temperatures. As effects are cumulative, aged conductors may have relatively lower tensile strength. Copper, AAC and 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, salt contamination, is one of the 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' steel core(s) are prone to corrosion, this has been managed through galvanising and greasing on the steel core.
Fretting and chafing	Fretting and chafing is caused by conductor swing resulting in 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 chafing can occur between the conductor and binder or between strands of a conductor. This issue occurs more on homogenous conductors such as AAC, AAAC and ACSR. This has a reasonable level of impact on conductor failures on our network. Armour rods or line guards (sacrificial metal sheaths) are typically used on all aluminium conductors at the point of binding to an insulator to avoid this failure mechanism.
Fatigue	Conductor fatigue is caused by the flexing of conductor strains near the bind points. Continuous 'working' of the conductors causes brittleness over time, resulting in failures. Vibration dampers are fitted to mitigate the damage. Copper, AAC and AAAC conductors are more susceptible to fatigue than ACSR.
Foreign object strikes	Foreign object strikes, for example birds and vegetation, can break a conductor or weaken it to a point where it fails in high winds. Strikes can also cause conductor clashing, which usually results in the loss of conductor material because of the electrical arc. ACSR conductors are less susceptible to this issue because of the strength of the steel core. Large object strikes, for example a tree falling across the lines, can also cause complete mechanical failure of the conductor.
Binder failure	Binder failure enables the conductor to swing free from the insulators and crossarm, which means the conductor can contact an alternative phase or a support structure. The resultant arcing, due to the fault current, can cause the conductor metal to melt and the conductor to break.

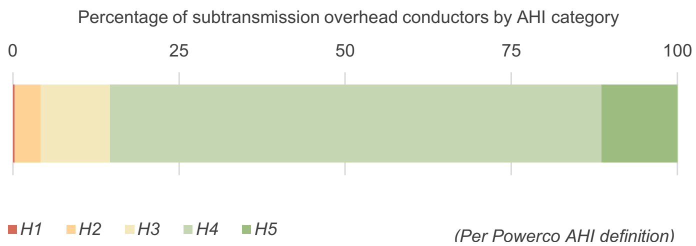
Subtransmission overhead conductor asset health

We have developed AHI modelling for the conductor fleets to enable us to predict the remaining life of the asset. In essence, our AHI models predict an asset's end-of-life and categorise their health score based on a set of rules.

We define end-of-life as when the assets can no longer be relied upon to safely carry their mechanical and electrical loads.

Figure 19.3 shows the current asset health for this fleet, based on conductor condition degradation using the Overhead Renewal Planning Tool (OHRPT) conductor model.

Figure 19.3: Subtransmission overhead conductor asset health as at 2020



Most of the subtransmission conductor fleet is aluminium types and, overall, the health of our aluminium conductors is acceptable – approximately 6% will require renewal during the next 10 years. The small number of copper conductors that remain will be replaced.

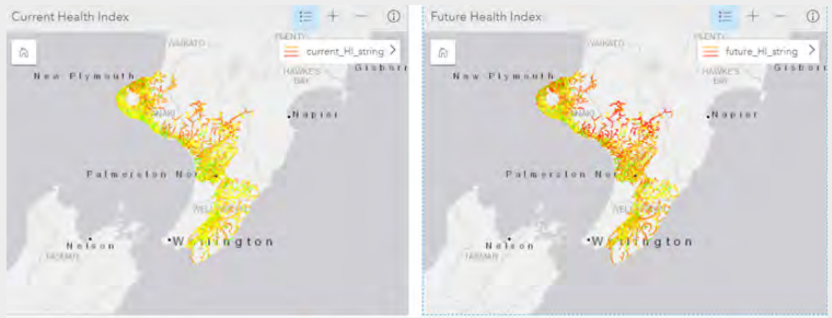
Conductor asset health modelling

On our network we have more than 100 types of conductors, installed from pre-1940 to 2020. The environment the conductors are located, ranging from inland alpine to coastal, and the conditions, including corrosion and windspeed, impact the conductor's expected life. Reliability factors also influence the expected life of conductors, including installation and construction methods, manufacturing faults, sustained fault currents and conductor vibration.

To understand our conductor asset health across all voltages, we have built a model using the Common Network Asset Indices Methodology (CNAIM) as a base. The model uses standard CNAIM inputs such as expected life, location, duty, type and age of the conductor. We also use additional health score modifiers where we have further information, such as from known defects, visual assessments, manufacturing faults, sample test results and fault currents. The combination of these inputs calculates an asset health score for each conductor span.

We are continuing to improve the quality of both the model inputs and outputs. Changes in source data are updated from field inspections and as-building. Field validation and conductor samples are used to verify the model parameters.

The model also allows us to forecast the ageing rates on the conductor fleets. The future AHI scores of the conductor fleets give us a good understanding for forecasting investments. This allows us to make improved renewal forecasts to keep the fleet in a stable health to maintain a safe and reliable network.



This figure shows a GIS map of current and forecast conductor health.

19.3.4 DESIGN AND CONSTRUCT

Any subtransmission conductor renewal investment includes a line design compliant with AS/NZS 7000 and associated national standards. The design considers reinstatement and worksite housekeeping issues to minimise impacts on landowners and the wider public, such as when working alongside a roadway.

Meeting our portfolio objectives

Customers and Community: The impact on landowners of overhead conductor renewal is anticipated and minimised during project design.

19.3.5 OPERATE AND MAINTAIN

Maintenance and inspection regimes applied to overhead conductors generally involve visual inspections and condition assessments. Table 19.4 summarises the preventive maintenance and inspection tasks. The detailed regime for each type of subtransmission overhead conductor is set out in our maintenance standard.

Table 19.4: Subtransmission overhead conductor preventive inspection tasks

INSPECTION TASK	FREQUENCY
Rapid inspections of critical subtransmission circuits, checking for key defects.	Yearly
Visual inspection of subtransmission overhead conductors as part of overhead network inspections standards.	2.5 yearly

Typically, conductors do not require routine servicing. However, they corrode and work-harden, becoming brittle because of wind-induced vibration and movement, and thermal cycling. Intrusive inspections are performed only when necessary, such as to support a major renewal decision.

There is a range of more sophisticated subtransmission conductor condition assessment tools available. These include thermography and acoustic testing to identify poor connections, failing joints and internal corrosion.

We are evaluating the use of these tools in our maintenance regimes across our conductor fleet. The evaluation includes comparing the additional costs to the benefits of more optimised replacement programmes and reduced failures.

19.3.6 RENEW OR DISPOSE

We use a condition-based renewal strategy for subtransmission overhead conductors, where our health score modelling indicates that replacement is required. We use visual inspections to verify the model results, for example the number of joints in a span can be an indicator of past failures because of a poor health score.

Meeting our portfolio objectives

Asset Stewardship: We will increase the use of diagnostic condition assessment tools, and use this information in our modelling 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 the level of network security of supply, the economic impact of conductor failure and the safety risk.

SUMMARY OF SUBTRANSMISSION OVERHEAD CONDUCTORS RENEWALS APPROACH	
Renewal trigger	AHI-based, considering risk and consequence
Forecasting approach	AHI and/or type
Cost estimation	Desktop project estimates

Renewals forecasting

Our AHI modelling provides us with a good understanding of the circuits that require replacement during the next three to five years. We expect to focus our renewals work on our remaining aged copper circuits, with the majority replaced by 2027. Forecast renewal quantities beyond this timeframe will be based on poor AHI from modelling, and this verified in the field by close inspection.

Coordination with Network Development projects

Subtransmission conductor works are also driven by load growth. An increase in conductor size is often needed to continue to meet demand. Our options analysis considers the costs and benefits of accommodating future demand by increasing conductor size alongside other options, such as 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 could involve replacing it with a conductor of larger size.[69] This means growth and renewal needs are integrated.

Conductor renewals always considers future load growth when selecting a new conductor size. This ensures that, as far as practicable, new conductors will not need to be replaced later because of load growth.

69 Work and expenditure in this chapter only relates to renewals.

19.4 DISTRIBUTION OVERHEAD CONDUCTORS

19.4.1 FLEET OVERVIEW

Our distribution network overhead conductors operate at voltages of 6.6kV, 11kV and 22kV. This fleet of conductors connects zone substations to distribution transformers and makes up the largest proportion of the overhead conductor portfolio.

Figure 19.4: 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[70] conductors.

The backbone of the main distribution network is formed of medium and heavy conductors.[71] There are significantly fewer failures on these conductors than the small diameter, lightweight types that are typically used on spur circuits.

19.4.2 POPULATION AND AGE STATISTICS

Approximately 65% of our total conductor fleets is at distribution voltages. Table 19.5 shows the five types of distribution conductors used on our network. As with subtransmission, the main conductor types are ACSR and AAC, although a higher proportion of copper conductors remain in this fleet. Since 2000, AAAC has been used as a replacement conductor in coastal sections of the distribution network as this type has a higher corrosion resistance.

Table 19.5: Distribution overhead conductor population by type

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
AAAC	1,141	8%
AAC	2,347	16%
ACSR	8,473	57%
Copper	2,495	17%
Steel wire	491	3%
Total	14,947	

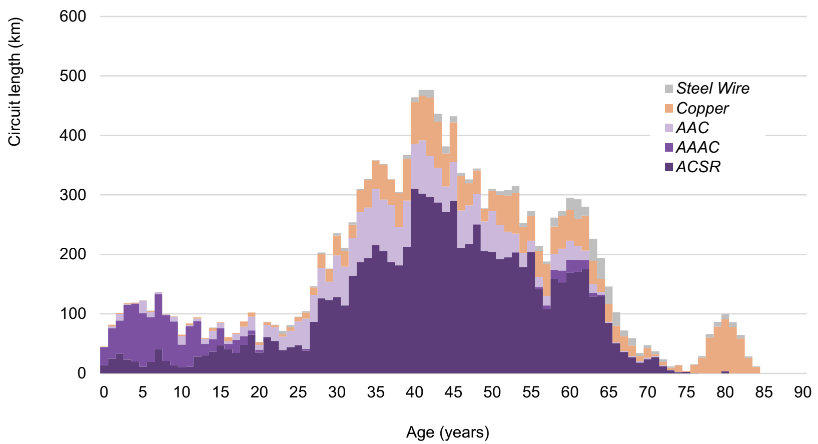
Most of the distribution network construction occurred in the 1960s and 1970s, primarily using ACSR and AAC conductors. The 11kV circuits make up most of the distribution network with smaller sections of network comprising 6.6kV and 22kV. Many different conductor types and sizes were used (100+).

Figure 19.5 shows the age profile of our distribution overhead conductors. A significant number of distribution conductors are approaching, or have already exceeded, their expected life of approximately 60 years. However, it is noted that conductors can exceed the expected life and still have a good AHI, therefore not requiring renewal. Since 2005, we have typically installed or replaced between 50km and 100km of distribution conductors per year, far less than the 300km to 400km installed in the 1970s and 1980s. Since 2019, we have considerably increased our replacement to more than 200km per year, and forecast this will increase to 300km.

70 Steel wire conductors (predominantly No 8 wire) are galvanised steel. They are typically installed in remote rural areas where only a low current capacity is required. They were predominantly installed during the 1950s and 1960s as a cost-effective alternative to ACSR and copper conductors.

71 Medium and heavy conductors are defined as those of >50mm^2 and >150mm^2 equivalent aluminium cross-sectional area respectively.

Figure 19.5: Distribution overhead conductor age profile



19.4.3 CONDITION, PERFORMANCE AND RISKS

Overhead conductors, by their nature, create risks to public, property and personnel, including:

- Lines falling, leading to an electrocution risk for people or livestock, either directly or indirectly – 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, for example someone undertakes tree trimming and accidentally touches 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.

Our distribution overhead conductor health analysis has identified conductor type, age, location and reliability factors as the main drivers of degrading condition. We expect the interaction of several factors, rather than a single factor, to result in faster degradation/poorer performance.

Poor construction methods in the past, for example not installing line guards or armour rods at the time of construction, have caused fretting and chafing of conductors on some circuits. The fretting and chafing leads to conductor failure over time.

Our renewal focus for this fleet uses a combination of these factors to prioritise replacement of distribution overhead conductors to reduce overall failure rates.

Conductor sampling

We have recently started a programme of conductor sampling and diagnostic testing, with the objective of improving our understanding of conductor end-of-life, and how it is influenced by type, age, inland versus coastal environments, attachment points versus mid-span, and other factors.

Samples will be taken from conductors of various ages, types, locations and from different points on the span. A variety of tests will be used that will enable us to build up a profile of each ageing characteristic – external damage, annealing, corrosion, fatigue – by conductor material, location, age and point of span.

This new information will enable us to enhance our conductor modelling tool. This will be used to improve asset health modelling and more effectively manage public safety and reliability risk while minimising cost through efficient replacement programmes.

Smaller distribution conductors tend to be less resilient than larger, heavier types. They have lower 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 (UTS) below 10kN tend to have much higher failure rates.

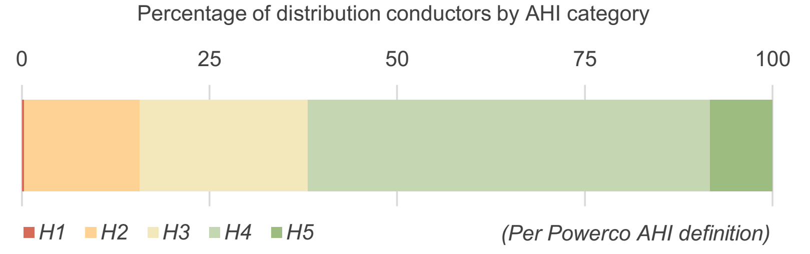
In general, small diameter ACSR conductors perform well, but performance of the smaller light homogenous copper and AAC conductors can be poor, regardless of age.

Distribution overhead conductor asset health

We have developed AHI that reflect the remaining life of an asset, using our OHRPT. In essence, our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For distribution overhead conductors, we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical and electrical loads.

Figure 19.6 shows current overall AHI for our distribution overhead conductor fleet. The AHI is based on known conductor types, age, environment, construction, fault current, poor manufacturing and expected condition degradation.

Figure 19.6: Distribution overhead conductor asset health as at 2020



The overall health of our distribution conductor fleet is satisfactory. Smaller and medium size conductors will need to be replaced during the next 10 to 20 years because of deteriorating health. Replacement will constitute approximately 30% of the fleet.

19.4.4 DESIGN AND CONSTRUCT

The renewal of distribution overhead conductors usually requires a portion of the existing poles to be replaced regardless of their condition or health as the poles do not comply with the modern design requirements of AS/NZS 7000 design standard.

Where large numbers of poles require replacement, we consider various options. This may include using smaller diameter, but stronger, conductor types, such as ACSR conductors, that require fewer pole replacements, or 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.

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 there is no damage. We may also consider realigning overhead lines to road reserves where practicable and cost effective or when land use has changed from farming to forestry.

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 are also considering different design methods and materials to construct a robust network within AS/NZS 7000 to meet all our portfolio requirements.

19.4.5 OPERATE AND MAINTAIN

Distribution overhead conductors are inspected less frequently than subtransmission conductors because of their lower criticality. Our inspection regime for distribution overhead conductors is summarised in Table 19.6. The detailed regime is set out in our maintenance standards.

Table 19.6: Distribution overhead conductor preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of distribution overhead conductors as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

Corrective maintenance tasks carried out on distribution overhead conductors are similar to those performed on subtransmission conductors.

Most conductor failure occurs during storms and high winds. Failure is most often caused by external contact or interference, such as trees or wind-borne debris (roofing iron etc), or where a conductor is weakened because of the loss of strands because of the lines clashing, for example bird strikes causing lines to clash.

Conductor failure because of condition can occur for several reasons, including annealing, corrosion, fretting and fatigue, or a combination of these conditions.

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. Physical access to poles and mid-span sections because of terrain and other factors can often be difficult, compounding repair/outage times.

Care is needed when re-terminating a conductor following a fault. Field staff must identify and use the correct preformed components. Some sizes of ACSR and AAAC are similar, but incorrect preformed component selection can result in an under-strength repair and subsequent failure under tension.

While we have standardised conductor types, a wide range of conductors are used on our network. Sufficient spare conductors and associated fittings are available at strategic locations to expedite fault repairs.

19.4.6 RENEW OR DISPOSE

Our conductor health modelling and analysis indicate that without further conductor replacement, failure rates may rise. Visual inspections can identify some defect types – some corrosion and foreign object damage. For other modes of failure, we must rely more on modelling all factors to predict risk and consequence.

SUMMARY OF DISTRIBUTION OVERHEAD CONDUCTOR RENEWALS APPROACH	
Renewal trigger	AHI-based, considering risk
Forecasting approach	AHI and/or type
Cost estimation	Desktop project estimates

We are targeting the replacement of distribution conductors of highest risk, identified from our OHRPT. Safety is our key concern regarding distribution conductor failure. We prioritise the renewal of conductors considering risks and consequences to all stakeholders.

Renewals forecasting

We forecast the amount of conductor renewal required to meet targets using our modelled asset health. This indicates the need to maintain the conductor replacement levels achieved during the Customised Price-quality Path (CPP) increase in Capex spend for conductor replacement.

Meeting our portfolio objectives

Asset Stewardship: We are increasing the use of diagnostic condition assessment tools and models to inform and verify renewal investments. We aim to maintain the conductor fleet for a long-term sustainable high safety and reliability standard.

Coordination with Network Development projects

Distribution overhead conductor upgrades and installations can be triggered by load growth, such as from residential infill or greenfield development. This often requires feeder backbone upgrades to a larger conductor, thereby increasing conductor capacity.

When planning the renewal of larger distribution lines, we consider forecast load growth and then appropriately size the conductor to meet credible foreseeable future needs. This reduces the likelihood of needing to upgrade the asset before it reaches its intended useful life. Voltage and backfeeding ability are also considered 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 remote area power supplies (RAPS). This is carried out instead of traditional conductor replacement where the economic benefits are positive.

Remote area power supplies (RAPS)

RAPS provide an option as a modern replacement asset at end-of-line on remote rural distribution feeders. In some situations, there may be just one, small customer connected to the end of a feeder that requires asset renewal. 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 with 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 installed approximately 20 RAPS units on our network, including new versions that use lithium-ion batteries for storage. This increases storage levels while reducing costs.

A RAPS unit with a 1.1kW photovoltaic array is shown below.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We are installing RAPS where appropriate on our network as an alternative technology to minimise the cost of asset renewal.

19.5 LOW VOLTAGE OVERHEAD CONDUCTORS

19.5.1 FLEET OVERVIEW

LV overhead conductors operate at 230/400V. The majority 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 are AAC, AAAC, ACSR, and copper. The conductors can be covered by an insulating sleeve or the conductor can be bare. LV conductors can either be constructed with their own poles or underbuilt, whereby the LV line is built under a HV circuit.

Our newer LV conductors are covered in a poly vinyl chloride (PVC) outer sheath, which provides some insulation protection.[72] This helps to mitigate safety risks to the public and reduces vegetation-related faults. The LV conductor fleet also includes overhead LV service fuse assemblies. These are the fuses located at the customer connection to protect customer premises and our network from faults.

Figure 19.7: LV overhead circuit

[72] The covering is not sufficient to classify the conductor as electrically insulated, but does provide some mitigation of safety risk by substantially reducing the likelihood of injury or death should accidental contact be made with the conductor.

19.5.2 POPULATION AND AGE STATISTICS

We have 6,261km of LV overhead conductors, of a variety of types, making up 297% of total fleet length. We also estimate we have over 230,000 overhead LV service fuse assemblies, although the exact number is currently unknown.

Table 19.7 summarises our LV overhead conductor population by materials. Half of our LV conductors are made of copper. AAC (PVC covered) is now the preferred conductor. Its lower tensile strength, compared with other types of conductor, is less of an issue than for HV conductors, as LV spans are typically much shorter than that of distribution, especially in urban areas.

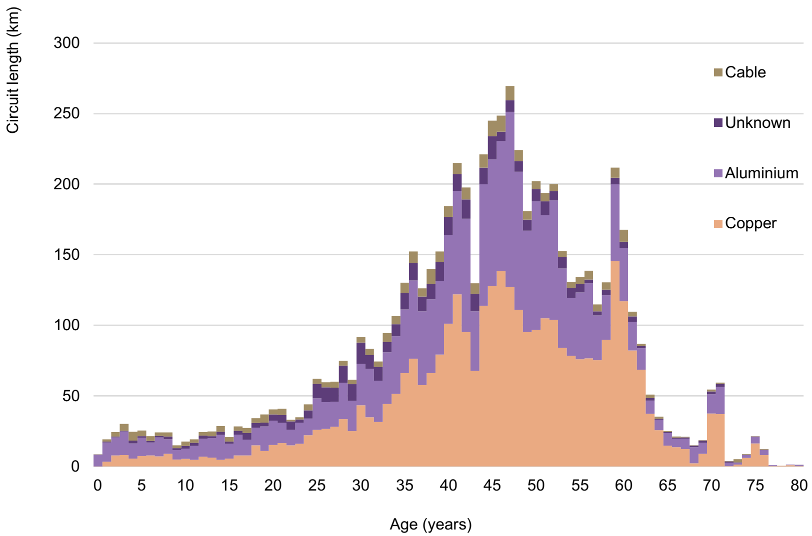
Table 19.7: LV overhead conductor population by material at January 2021

CONDUCTOR TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
Copper	3,434	52%
Aluminium	2,410	37%
Unknown	417	6%
Cable	328	5%
Total	6,261	

Our asset data is less complete for the LV fleet. We are aiming to increase the accuracy of that information through inspections. Some of the conductors recorded in our information systems are of unknown type or the material is unknown (6% of our LV conductors are of unknown material).

Figure 19.8 shows the age profile of our LV overhead conductors. The ageing population indicates that levels of renewal will need to increase.

Figure 19.8: LV overhead conductor age profile



As with the other fleets, significant investment was carried out in the period from 1960 to the mid-1980s constructing the LV network. Only a very small amount of new LV overhead network has been built in the past two decades. Most of the new LV build on our network has been constructed as underground circuits with almost no new LV overhead circuit construction.

Because of limitations on LV conductor data, we have estimated the age of about half our LV fleet using age data from associated poles.

19.5.3 CONDITION, PERFORMANCE AND RISKS

As discussed previously, failure of an overhead conductor creates large safety risks for the public. This is of particular concern as the majority of the LV fleet is in more densely populated urban areas. Bare LV conductors also pose a greater risk to all stakeholders than ‘covered’ conductors. Mitigating this risk is the 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 because of downed LV overhead conductors can be partially mitigated by covered conductors. Our standard requires the use of covered conductors, but there are rural and urban overhead LV circuits that still use legacy bare conductors.

Through our overhead line inspections, we identify high-risk LV circuits that have bare conductors, assess the public safety risk because of conductor or binding failure, and prioritise their replacement with covered conductors. These measures cannot completely mitigate the risks but help to bring it down to an ALARP level.

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.

LV overhead fuse assemblies

Historically, we have replaced LV fuse assemblies on a reactive basis, when the device fails. However, this causes inconvenience to customers and is not cost effective. There are also public safety risks with running these assets to failure.

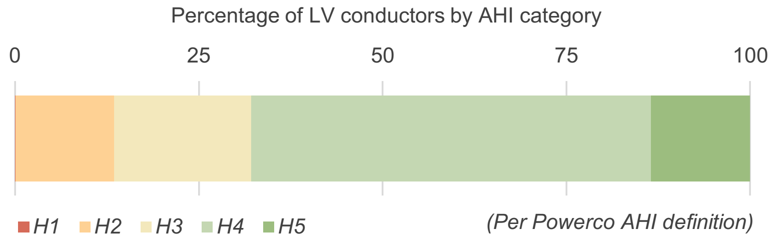
We plan to target replacement based on condition sampling and asset age. Areas to be targeted for replacement will be identified by analysing fault data and asset age, followed by condition sampling of the devices in the planned target areas.

LV overhead conductor asset health

We have developed AHI that reflect the remaining life of an asset, using our OHRPT. Our AHI models predict an asset’s end-of-life and categorise its health based on a set of rules. For LV conductors we define end-of-life as when the asset can no longer be relied upon to safely carry its mechanical and electrical loads.

Figure 19.9 shows overall AHI for our LV overhead conductor population. The overall AHI for this fleet is based on our understanding of the expected life and age of LV overhead conductors.

Figure 19.9: LV overhead conductor asset health as of 2020



The overall health of our LV overhead conductor fleet is satisfactory. Conductors with poor health will need to be replaced over the next 10 to 20 years. During this period, replacement is forecast for approximately 30% of the fleet, although with improved information on our LV conductors, we expect to refine this estimate.

19.5.4 DESIGN AND CONSTRUCT

Although not a new technology, we are investigating the use of Aerial Bundled Conductors (ABC) for use on our LV network. ABC has been used internationally 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 because of tree contact is no longer an issue and it will not arc if in contact with any earth point. Installation is also simpler, as insulators[73] and crossarms are typically not required. There is an additional cost for ABC and the visual impact differs from traditional four to six-wire systems.

We intend to trial ABC conductors on our LV network once research into New Zealand and international experience is complete. These trials will allow us to better understand the relative performance and cost of the product, and customers' visual preferences.

19.5.5 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.

[73] Insulated clamp brackets are still required.

Table 19.8: LV overhead conductor preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of LV overhead conductors, as part of overhead network inspections, completing a detailed condition assessment.	5 yearly

19.5.6 RENEW OR DISPOSE

Limited data on the condition of the LV overhead 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. Similarly, we are no longer satisfied with a reactive approach to replacement of LV fuse assemblies.

SUMMARY OF LV OVERHEAD CONDUCTOR RENEWALS APPROACH	
Renewal trigger	AHI, considering failure risk and uninsulated conductors
Forecasting approach	AHI and type
Cost estimation	Desktop project estimates

We believe conductor type issues are unlikely to be as prevalent for LV overhead conductors as with distribution voltage. However, environmental conditions, reliability factors and ageing influence failure rates.

We intend to plan for replacement of LV overhead conductors that have poor health and high-risk uncovered LV conductors. More detailed fault information will enable us to better target the replacement of conductors that have poor reliability. This includes particular types or those in challenging environmental conditions. This improved data will be fed into our OHRPT.

Our intention is to identify all bare LV conductors on the Powerco footprint. We intend to start a dedicated programme targeting replacement of bare LV conductors in high safety consequence parts of the network. Also, part of any renewal overhead fleet investments, including pole and crossarm replacement, is to identify any bare LV conductors within the project area. The bare LV conductors are replaced with covered conductors. We will also explore other potential options to reduce the safety risk posed by bare LV conductors.

Meeting our portfolio objectives

Safety and Environment: When prioritising conductor replacement and renewal works, public safety and property damage risks caused by potential conductor failures are always considered.

Similarly, for LV fuse assemblies, replacement planning will take into consideration fault data for an area, age of the assembly, and condition sampling.

Renewals forecasting

To forecast future renewal needs we have recently transitioned to using our LV conductor health model. Rather than using a simple 'birthday' type age model, we use a CNAIM 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 condition, type, environment and criticality of the conductor. We plan to slowly increase renewals of LV conductors during the planning period. This will enable us to refine our understanding of the step change required before committing to a large renewal programme.

In the case of LV fuse assemblies, we forecast renewals based on a steady state replacement programme. The focus on areas with older fuse assemblies and higher fault rates will result in improved asset health. With improved condition data we will be able to refine this forecasting approach.

The number of conductors to be renewed will increase, we suspect, as our data quality improves.

Coordination with Network Development projects

We coordinate LV overhead conductor renewals with development works through a consultation process. Very little new LV overhead network is constructed, and it is unusual for the LV network to be capacity constrained; we continue to monitor technological and customer changes in use of the network to ensure the LV network has the capacity for any future requirements. We will continue to coordinate growth and renewal investment and monitor developments as the use of grid edge technologies increases.

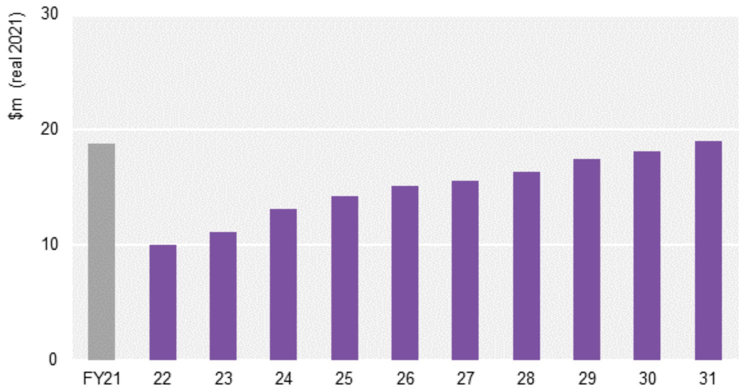
19.6 OVERHEAD CONDUCTORS RENEWALS FORECAST

Renewal Capex in our overhead conductors portfolio includes planned investments in our subtransmission, distribution and LV conductor fleets. During the planning period, we intend to maintain the conductor fleets to a sustainable level, targeting poor health conductors. The key driver for overhead conductor renewal is management of safety, risk and consequence by addressing declining asset health. Failure of an overhead conductor presents a significant public hazard, as well as reliability implications.

Subtransmission reconductoring projects can be scoped at a high level several years before implementation. This means we can carry out desktop cost estimates for each project, considering factors such as terrain difficulties, span lengths, and pole and crossarm renewals. Distribution and LV renewals forecasts are generally volumetric estimates. The work volumes are high, with the forecasts based on AHI.

Figure 19.10 shows our forecast Capex on overhead conductors during the planning period. [74]

Figure 19.10: Overhead conductor renewals forecast expenditure



[74] 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.

Our conductor renewals investment is forecast to gradually increase during the next 10 years. This forecast reflects the increased level of investment needed to renew distribution and LV conductors. However, compared with projections from previous AMPs, we have reduced our expected renewal volumes of conductors because of the increased knowledge gained from our conductor health modelling.

The additional spend in FY21 is primarily due to our complete network Light Detection and Ranging (LIDAR) scan, primarily to inform our vegetation strategy (refer to Chapter 25) but to also support the management of our overhead fleets. We are also completing additional overhead conductor replacement in FY21 than earlier forecast in order to balance our overall Capex delivery programme.

Renewals are expected to remain at these increased levels beyond the 10-year planning horizon, as more conductors built between the 1950s and 1970s require replacement.

During 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. We will also be investigating alternative construction methods that may allow for some cost savings.

20 CABLES

20.1 CHAPTER OVERVIEW

This chapter describes our cables portfolio and summarises our associated Fleet Management Plan. The portfolio includes three fleets:

- Subtransmission cables
- Distribution cables
- Low Voltage (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 forecast investment of $63m for renewing our cables fleets. This accounts for 7% of renewals Capex during the period. The forecast is has increased slightly compared to historical levels, in line with the aging of the fleet.

Our cable renewal programme focuses on addressing 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 ageing insulation and brittle lead sheaths
- First generation cross-linked poly ethylene cable (XLPE)
- Older oil-pressurised subtransmission cables

We are developing modelling to identify critical distribution circuits to facilitate better targeting of renewal investment capital. Our modelling will integrate data from condition assessment, diagnostic testing regimes and laboratory testing of faulted cable sections to assess condition and the root causes of failure.

Significant work was undertaken between FY17 and FY19 to replace failing oil-filled subtransmission circuits in the Palmerston North CBD. Our remaining oil-filled cables are stable and will be monitored for performance and further deterioration.

A number of years ago we embarked on a programme to replace LV pillars that have safety-related risks, such as metallic boxes that may become live when degraded and those with failure modes that lead to overheating and fire. We have been working to remove these types of LV boxes 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.

20.2 CABLES OBJECTIVES

Underground cable makes up approximately 24% of our total circuit length. Cable conductors come in various sizes and are usually made of copper or aluminium.

Aluminium is now used in most applications because it is less expensive than copper for the equivalent capacity. However, copper conductors offer a 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, generally in line with the changes in cable technology over time. These are XLPE, PILC, pressurised oil-filled cables, and poly vinyl chloride (PVC) insulated cables. Cables have one, three or four cores, and can be built with additional mechanical protection (armoured).

The fleets are generally direct-buried in native soil, although more recent installations may be ducted or installed in thermally stabilised backfill. We do have a number of unique installation types.

To guide our management of cable assets, we have defined a set of objectives listed in Table 20.1. The objectives are linked to our overall Asset Management Objectives in Chapter 4.

Table 20.1: Cables portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No public safety incidents from contact with our cable network.
	Minimise oil leaks from pressurised oil-filled cables.
Customers and Community	Minimise traffic interruptions when managing cable assets in road reserves NZUAG.
Networks for Today and Tomorrow	Investigate the use of real-time cable ratings using distributed temperature sensing.
	New cable sized to meet future demand
Asset Stewardship	Maintain the failure rate of cable assets at or below target levels.
	Proactive testing and renewal work on critical circuits
Operational Excellence	Improve our knowledge of the LV cable fleet.

20.3 SUBTRANSMISSION CABLES

20.3.1 FLEET OVERVIEW

The subtransmission cable fleet predominantly operates at 33kV, although we have several kms of 66kV cable in the Coromandel area. The assets include cables, joints, terminations (cable box or pole risers) and supporting systems. As this fleet is relatively young, it comprises primarily XLPE cables, although we do operate some older circuits of PILC in our New Plymouth, Palmerston North and Masterton networks, and pressurised oil-filled cables out of Bunnythorpe and Hawera GXPs, which include oil pressure vessels and in-ground pits.

20.3.2 POPULATION AND AGE STATISTICS

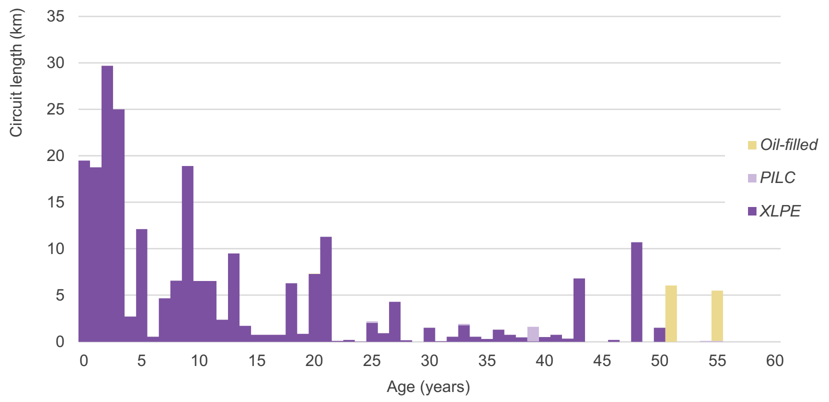
The majority of our 244km of subtransmission cable is XLPE cable. XLPE has been the preferred cable insulation technology for more than 30 years. Table 20.2 summarises our subtransmission cable population.

Table 20.2: Subtransmission cable population by type

INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	229	94%
PILC	2	1%
Oil-filled	13	5%
Total	244	

The subtransmission cable fleet is relatively young, with an average age of 14 years. Figure 20.1 depicts our subtransmission cable age profile.

Figure 20.1: Subtransmission cable age profile



The age profile shows the gradual change of cable technologies over time, from oil-filled cable at subtransmission voltages to PILC and eventually XLPE. XLPE cable requires less maintenance and is more environmentally acceptable.

Oil-filled cable has an expected life of 70 years and has generally given good service, however these assets require specialised oil management equipment to remediate any oil leaks. The diminishing availability of specialised equipment and expertise is seen as a major factor in determining the end-of-life of pressurised oil-filled cable circuits. With this in mind, a number of circuits have recently been retired because of ongoing issues with leaks and poor reliability.

20.3.3 CONDITION, PERFORMANCE AND RISKS

Pressurised oil-filled cable

We have recently retired three of the four 33kV oil-filled cable circuits located in the Palmerston North CBD. Insufficient conductor clamping strength led to their joints leaking oil because of thermal cycling. They required significant oil top-ups, and leakage into the environment exceeded acceptable levels. Repair was found to be uneconomic, so these have since been replaced with new XLPE circuits.

We have retained one Palmerston North circuit, Keith-Main 1, as an in-service backup while the PN subtransmission reconfiguration has been completed. While off-loaded, Keith-Main 1 has shown stable performance with no leaks recently. We will continue to monitor this situation.

The remainder of the oil-filled cable fleet – two 3km circuits from Hawera GXP and three 500m circuits from Bunnythorpe GXP – has had good performance. This is likely because our Hawera circuits are from a different manufacturer (Hitachi) and the Bunnythorpe circuits are short and without joints.

We will continue to monitor this and are developing plans for eventual replacement should the condition or reliability decrease.

Intrusive work on pressurised oil-filled cables requires specialised cable oil, oil management equipment, cable tapes, fittings etc. Expertise is also required from specialised cable technicians and oil technicians. Unfortunately, as the quantities of pressurised oil-filled cables in New Zealand dwindle as circuits are retired, and the subsequent declining numbers of jointers with capability to work with this type of cable, this has made technical expertise increasingly difficult to engage at short notice.

In the event of failure, this greatly increases the restoration time from days to many weeks, when comparing with XLPE cables. To shorten this time as much a possible, we hold spare joints, and have relationships with specialist service providers to repair these circuits.

Table 20.3 summarises the actions being taken with the affected pressurised oil-filled cable circuits.

Table 20.3: Subtransmission oil cable circuits

CABLE CIRCUIT	CIRCUIT LENGTH	ACTION
Keith St – Main St 1	5.7 km	In-service, to be decommissioned in FY22
Bunnythorpe GXP to Keith St x2 **Bunnythorpe GXP to Milson ("Gillespies")**	3 x 0.5 km	Conceptual design to be undertaken in FY22
Hawera GXP – Cambria x2 ("White" & "Black")	2 x 3.0 km	Replacement planned for FY28-30

Meeting our portfolio objectives

Safety and Environment: Subtransmission cable circuits with a history of oil leaks are being retired to minimise environmental impacts.

XLPE

Early generation (1960s to late 1970s) cable manufacturing processes were unable to produce cable of the same quality and consistency as modern cable, and this resulted in higher rates of insulation defects, shortening the overall life of the cable.

While the majority of the XLPE fleet is still relatively young, we do have some "second generation" XLPE in Tokoroa and Palmerston North. Recently, testing of our Baird Rd 33kV circuits in Tokoroa revealed a number of insulation defects, resulting in their replacement of the circuit.

As such, we expected that some early generation XLPE cables are likely to be approaching the onset of unreliability within the term planning period – we intend to monitor their performance closely and plan for their renewal when required.

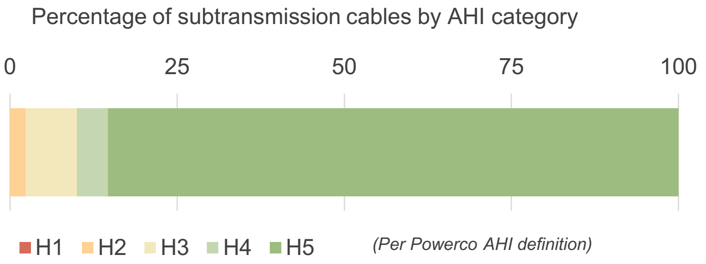
Terminations

A number of years ago we experienced a high incidence of premature insulation failures on newly installed 33kV heatshrink terminations because of the presence of voids between insulation layers. This was because of manufacturing or installation problems. We have been monitoring the remainder of the fleet, which has remained stable, so we expect it will continue to perform satisfactorily. We expect our monitoring programmes will detect this failure mode if it arises again. We no longer use this type of heat shrink.

Subtransmission cables asset health

As outlined in Chapter 10, we have developed Asset Health Indices (AHI) that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For subtransmission cables, we define end-of-life as when the asset can no longer be relied upon to operate reliably and without environmental harm, and the cable should be replaced. The AHI considers cable circuit reliability, environmental impacts and asset age. Figure 20.2 shows overall AHI for our subtransmission cable fleet.

Figure 20.2: Subtransmission cables asset health as at 2020



The health of the subtransmission cable fleet indicates that about 10% of the cables will require renewal in the next 10 years (H1-H3), as discussed earlier this comprises our remaining oil-filled circuits and some early XLPE cable. The rest of the fleet is in good health and no further replacement is expected in the next 10 years.

20.3.4 DESIGN AND CONSTRUCT

Most new subtransmission cable circuits utilise XLPE insulated cable with stranded aluminium conductors in two standard sizes – single core 300mm^2 and 630mm^2. Because of capacity requirements, engineering signoff has been given to a small number of projects for larger 800mm² and 1000mm² installations. Standardisation assists ongoing fleet management by reducing spares, simplifying the maintenance and repair process and reducing costs. In recent years, we have increased our standardisation for the selection of joints and fittings, as these are critical to the long-term reliability of cable circuits.

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 by taking into consideration conservative, near worst-case parameters for loading durations and environmental conditions. While this approach gives assurance that cable operating temperatures will not be exceeded, and that asset life will be achieved, it may underestimate the maximum allowable loading for short duration loads, or when environmental conditions are favourable.

We have been installing optical fibre with all of our new subtransmission cables and are testing distributed temperature sensing for the purposes of real-time rating applications.

Meeting our portfolio objectives

Networks for Today and Tomorrow: We will investigate and trial real-time cable ratings for subtransmission cables to increase their effective capacity, using distributed temperature sensing.

20.3.5 OPERATE AND MAINTAIN

While cables are generally maintenance free, we do perform inspections and diagnostic testing. Oil-filled cables require additional maintenance because of their pressurisation systems. Maintenance and inspections for subtransmission cables are summarised in Table 20.4.

Oil-filled cable circuits in Palmerston North are fitted with pressure monitoring equipment to provide alarms if the operating pressures drop below pre-set limits. Work is planned to fit alarms to the Hawera-Cambria circuits.

Table 20.4: Subtransmission cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Check and inspection of oil pressurisation systems.	Monthly
Cable route inspections. Inspection of cable terminations and surge arrestors. Thermography of exposed cable terminations on oil pressurised cable circuits.	Yearly
Sheath voltage limiter tests of XLPE and PILC cable.	2.5 yearly
Sheath integrity and earthing diagnostic tests.	5 yearly

We are investigating more intrusive Very Low Frequency (VLF) and Partial Discharge (PD) routine testing of earlier subtransmission circuits, as parts of the fleet approach the end of their expected service lives, so as to be able to accurately ascertain the health of the fleet and future renewal requirements.

Spares

Given the criticality and long repair time of pressurised oil-filled cable systems, we have purchased spare oil stop joint kits and have established contracts with specialist service providers in order to ensure timely repair. Given the lead times, we also hold length of 630mm² 33kV XLPE cable for repairs.

20.3.6 RENEW OR DISPOSE

We have identified the need to prepare plans for eventual replacement of our remaining pressurised oil-filled cable circuits, given the high maintenance and repair costs as these assets reach their end-of-life, and issues with similar vintage cables in the Palmerston North CBD. These circuits were summarised in Table 20.3.

During replacement of these cables, we cut in at key points and drain the oil, and then leave them capped in the ground.

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.

During the period, we expect to undertake increased monitoring and testing to inform future replacement requirements for our ageing XLPE cables.

Although undisturbed pressurised oil-filled cables inherently have low deterioration rates, their serviceability is vulnerable to the actions of events such as severe earthquakes, inaccurate excavations etc. Repairs to such outcomes may take several months to achieve.

We propose to replace the remaining pressurised oil-filled cable fleet on an age basis. In the meantime, we are preparing designs and consents for land easements to install new XLPE cable circuits for these routes, with these plans to be implemented in the event of a cable being seriously damaged and rendered unserviceable.

Coordination with Network Development projects

New subtransmission cable circuits require significant planning and lead time because of the need for consenting and securing of easements, and the time needed for cable manufacture. Easements for underground circuits are more straightforward than overhead circuits – many councils are restricting overhead lines in urban areas with underground cables the preferred solution.

Subtransmission cable planning involves 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 programme in Palmerston North. An optimal solution has been planned that provides considerable benefits over a like-for-like replacement solution.

20.4 DISTRIBUTION CABLES

20.4.1 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 more than 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 encased by an extruded lead sheath wrapped in an outer sheath of either tar impregnated fibre material, PVC, or poly ethylene.

PILC cables have a good performance record. Being a legacy technology, a potential risk with PILC cables is the limited jointing experience within our field workforce. Jointing and terminating these cables correctly without defects requires a high level of skill and experience, and most New Zealand cable jointers with this experience are nearing retirement. It is difficult for new cable jointers to gain and maintain this practical experience since there are few failures. For this reason, to avoid the need to install potentially unreliable XLPE-PILC transition joints, we may replace short runs of PILC when connected equipment needs to be replaced.

We have found that in some soil types, PILC sheaths can undergo accelerated corrosion, leading to lower fault capability and brittleness. Ageing may also cause the insulating paper to dry out, which makes the cables more difficult to work on and more prone to failure, particularly if the cable is moved or disturbed.

The first generation of XLPE cables was installed from the late 1960s to mid-1970s. These cables have a poor service record because of manufacturing quality problems, with failures caused by 'water treeing'[75] in the insulation, causing it to break down. We have found that some second generation XLPE cables have had premature corrosion of the wrapped screens, leading to failures and early replacement.

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.

20.4.2 POPULATION AND AGE STATISTICS

We have over 2,000km of distribution cable, of which about 14% is PILC and 86% is XLPE. Table 20.5 shows the breakdown of distribution cables by insulation type.

Table 20.5: Distribution cable population by type

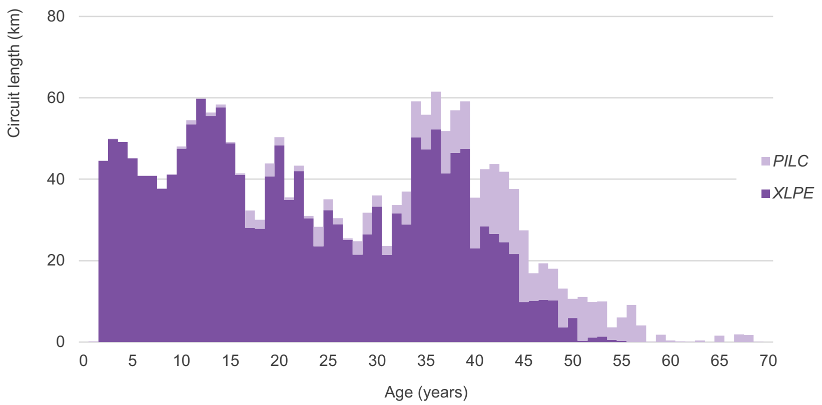
INSULATION TYPE	CIRCUIT LENGTH (KM)	% OF TOTAL
XLPE	1,842	86%
PILC	302	14%
Total	2,144	

We also have a small amount of submarine cable crossings in Whitianga, Tairua and out to Matakana Island. Additional discussion on these can be found in section 20.4.3.

Figure 20.3 depicts our distribution cable age profile. Most cable installed during the past 40 years has been XLPE, with PILC being the predominant type before that.

75 'Water treeing' results from condensed steam, which was used to assist the poly ethylene insulation to cure as part of the manufacturing process.

Figure 20.3: 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, most circuits operating well within the cables' expected life[76]. Significant levels of age-related replacement are therefore not expected for at least another decade.

However, we have two known 'type' issues within the fleet that will drive our short-term renewal plans. These are discussed in the next section.

20.4.3 CONDITION, PERFORMANCE AND RISKS

Cable degradation is impacted by a combination of factors including:

- Insulation type
- Outer sheath design
- Loading history
- Cable quality – manufacturing batch issues, transportation storage
- Fault currents through the cable
- Installation type eg in ducts or direct buried
- Armouring
- Soil type/environment
- Corrosion
- Age
- Third-party damage

Type issues

There are two main type issues that affect the distribution cable fleet.

Some of the early 11kV PILC cables installed in the New Plymouth networks have brittle lead sheaths that are prone to cracking during ground movement, including our circuits out of City Substation (New Plymouth), allowing water to enter. Any movement of the cables can cause cracking and potential failure. Additionally, where cables are grouped in a common trench, jointing for repairs is difficult, potentially extending restoration times.

The other type issue involves the first generation XLPE cables installed during the late 1960s to mid-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 this type problem. There is also some evidence of poor handling of cables during installation. These problems have resulted in sufficient failures to warrant progressive replacement. We see issues with this type of cable predominantly in our Tokoroa/Kinleith networks, as well as some areas of the Palmerston North network.

Special circuits

We also operate circuits whose operating environments present unique management risks:

- We operate several kilometres of 11kV submarine circuits near Tairua and Whitianga, and a crossing to Matakana Island. Through underwater inspections, we have identified that these cables may be prone to exposure because of movements of sandbanks over time, making them vulnerable to damage from boats and accelerated sheath degradation. Although we hold special submarine joints for emergency repairs, the availability of jointing staff and specialist cable barge means repair times are long. We are investigating starting more frequent inspections of these circuits to manage this risk.
- We operate approximately 30km of PILC and XLPE 11kV cable at the Oji Fibre Solutions pulp and paper Mill at Kinleith, of which a significant portion runs through Oji-owned tunnels. Given the high number of circuits adjacent to one another, and the high faults levels with proximity to the Kinleith GXP, these cables have increased risk of cascade failure (like the 2014 Penrose cable failure) and present a high arc flash risk for workers in the tunnels. Along with our 11kV switchboard upgrades, we are in the process of installing differential protection on these circuits to improve protection speed, minimising these risks. We hold spare cable and joints onsite to allow us to respond quickly to faults where they occur.

[76] Expected lives for distribution cables are 55 and 70 years for XLPE and PILC respectively.

Meeting our portfolio objectives

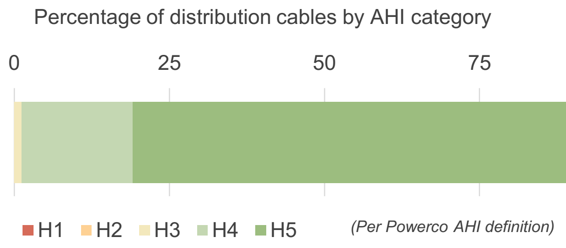
Asset Stewardship: Distribution cables with known high rates of failure are replaced to maintain overall fleet reliability and manage network SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index).

Distribution cables asset health

As outlined in Chapter 10, we have developed a set of AHIs that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For distribution cables, we define end-of-life as when the asset can no longer be relied upon to operate reliably and the cable should be replaced.

Figure 20.4 shows 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 20.4: Distribution cables asset health as at 2020



The health of the distribution cable fleet is generally very good, with more than 80% of the fleet not likely to require replacement in the next 20 years (H5). Our programmes to replace first generation XLPE are mostly complete, which has led to an improvement in the overall health of the fleet.

20.4.4 DESIGN AND CONSTRUCT

We use three standard sizes of distribution cable – 35mm^2, 185mm^2 and 300mm^2. These cables are multicore aluminium with XLPE insulation. Single core cables, copper core cables and other conductor sizes may be used for specific applications, such as when additional current rating is required or where there are issues with installation bending radii. This standardisation assists in our ongoing management of the asset fleet with terminations and joints, improving the ability to carry out repairs and replacements.

20.4.5 OPERATE AND MAINTAIN

Cables are generally low maintenance, as most of the length of cable is buried. We perform inspections, diagnostic acoustic and PD 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 defects, degradation or damage.

Our distribution cable maintenance tasks are summarised in Table 20.6. The detailed regime for each type of cable is set out in our maintenance standard.

Table 20.6: Distribution cable preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Cable riser terminations visually inspected. Thermography and acoustic diagnostic tests of cable riser and breakouts, cast metal potheads.	2.5 yearly

Cable faults most commonly occur because of 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 because of degradation.
- Fault repairs because of 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.

As part of the Transpower rebuild of Kinleith GXP, we are undertaking additional testing and sampling to ascertain the health of the tunnel cable fleets there, given their high criticality in supplying Oji Fibre Solutions. We are looking to identify strategic circuits in which this type of analysis is economic, to better refine our models of future replacement requirements.

We are investigating more regular visual inspections of our submarine circuits, which can be exposed to tidal movements, exposure and damage, after our Tairua river crossing cables were hit by a marine vessel in 2019.

20.4.6 RENEW OR DISPOSE

Our renewal approach for distribution cable is for replacement to be based on condition, including type issues and health. As previously mentioned, we have identified two type issues within the fleet – PILC cables with brittle lead sheaths and first generation XLPE cable that is prone to water treeing. We are developing modelling to identify circuits with elevated risk so that we can perform condition testing and, where warranted, proactively replace cables. We are also beginning a programme of post-fault cable sampling, and investigating the collection of cable data when we are cutting into circuits as part of renewal programmes. This will assist us in better understanding the health of our distribution cable fleet.

SUMMARY OF DISTRIBUTION CABLE RENEWALS APPROACH	
Renewal trigger	Proactive condition-based.
Forecasting approach	Type issues and age.
Cost estimation	Volumetric, adjusted for terrain.

Based on our current knowledge, distribution cable renewal volumes are expected to remain approximately constant during the next decade as the fleet is in good condition overall. In the longer term, we expect an 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.

Coordination with Network Development projects

We work with the councils and other utilities, particularly those with underground services located within the road reserve, to coordinate trenching works wherever feasible. 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, limit road traffic disruption and damage to pavement surfaces.

Road safety or widening projects initiated by the New Zealand Transport Agency often drive the need to relocate cables or to put underground an existing overhead line. This work is classified as asset relocation and is discussed further in Chapter 26.

Meeting our portfolio objectives

Customers and Community: Cable development and replacement is coordinated with other excavation works where practicable to minimise road traffic disruption and minimise cost.

20.5 LOW VOLTAGE CABLE SYSTEMS

20.5.1 FLEET OVERVIEW

The LV cable fleet operates at below 1kV (230/400V). The fleet consists of cables, link boxes, LV cabinets, service boxes and pillar boxes. We collectively refer to link boxes, pillar boxes and service boxes as LV boxes.

Customer service cables connect to a fuse supplied from our LV cable network. These service cables run between the customer's switchboard and a service box, which is usually located on the property boundary.

The integrity of LV boxes is a key public safety concern. We have a variety of styles and materials installed on our network – some typical examples are included in the figure below

Figure 20.5: LV boxes

20.5.2 POPULATION AND AGE STATISTICS

Our LV underground network consists of 6,870 circuit kilometres of cable. This includes 1,971km of dedicated street lighting circuits and 479km of hot water pilot circuits.

Data on our LV cable fleet is incomplete because before the year 2000 detailed information was normally not recorded. We are undertaking a programme of LV pillar and service box data capturing and labelling to fill the gap in our knowledge of the LV network. This programme is over 50% complete and will continue during the planning period.

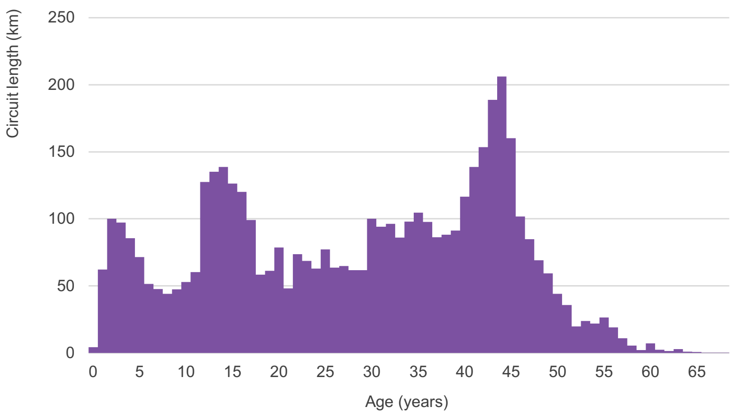
Meeting our portfolio objectives

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. Figure 20.6 shows the age profile of the LV cable fleet, excluding street lighting and hot water circuits. [77]

[77] About 10% of the fleet's age is unknown and has been excluded from the chart.

Figure 20.6: LV cable age profile



The average age of the LV cable fleet is 28 years. As the fleet is relatively young, we do not expect a need for significant condition-driven cable renewal.

20.5.3 CONDITION, PERFORMANCE AND RISKS

LV boxes are predominantly installed in urban areas to supply nearby loads.

As they are above ground and accessible, they can present a public safety risk if not properly maintained. The key public risk is loss of security because of damage, degradation or vandalism, exposing live terminals.

Type Issues

Some LV boxes of metallic construction can be inadvertently livened, causing safety risks. Affected LV boxes have been identified and replacement is occurring through our defects process. Early metallic 'mushroom' type LV boxes have caused concerns regarding livening of the metallic cover when the insulation on LV cables internally has degraded. A programme of replacement has removed most of this pillar type, and we continue to replace these as they are located.

In the Tauranga region, we have identified a type issue with approximately 30 in-ground LV link boxes. The boxes require special procedures to inspect, maintain and operate because of their design, which has exposed live parts with small clearances – a risk to our operators. These link boxes have failed explosively in other networks overseas, highlighting their potential risk to public safety. We have initiated a programme to replace these with above ground equivalents during the next 8-10 years. Replacement of these LV link boxes will enable us to greatly reduce the risk while improving the operability of the LV network within the Tauranga CBD.

Condition Issues

We have experienced a number of failures of LV boxes because of overheating of contacts and fuses. Older style pull-cap fuses have proven prone to overheating as corrosion occurs between the tinned copper cap and aluminium conductor. In the Tauranga region, where this problem is most prevalent, this has led to a number of pillar fires. We now have a programme to remedy these sites through our defects process.

Through our inspections and surveys we have also identified overcrowded LV boxes, typically at infill developments. These overcrowded LV boxes present a safety hazard to operators during servicing and can lead to overheating. We schedule the replacement of identified LV boxes through the defects process.

Third Party Damage

Many reported defects and faults are because of physical damage, often caused by vehicles. Although an LV box may initially have been placed in a safe location of a new development, new driveways or changes in walls/fencing can leave the boxes more vulnerable to damage. In these cases, solutions such as relocation or protective bollards can help prevent future failures. Where the risk cannot be mitigated, replacement with an underground style box has been utilised.

Through our inspections we are continuing to collect LV box defects. These LV boxes will be replaced as part of our ongoing LV safety-related investment programme.

20.5.4 DESIGN AND CONSTRUCT

We use three standard sizes of LV cable – 120mm^2, 185mm^2 and 300mm^2 stranded aluminium cable with XLPE/PVC insulation. Different sizes are used depending on the application and expected load. Voltage drop, fault current capacity and mechanical performance are considered when designing LV cable networks.

LV box types are carefully considered before being approved for use on the network. We use only products that have been through our approval process. We source LV boxes from two manufacturers.

20.5.5 OPERATE AND MAINTAIN

Maintenance of the LV cable fleet focuses on the inspection of LV boxes. The frequency of inspection is based on the safety criticality of the asset, with boxes in areas of higher risk inspected more often.

Table 20.7 summarises our inspections of the LV cable fleet. The detailed maintenance regime is set out in our maintenance standard.

Table 20.7: LV cable network preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Thermal imaging of CBD distribution boxes.	Yearly
Detailed inspection of LV boxes located near parks, public amenities, schools and business districts.	2.5 yearly
Detailed inspection of LV boxes not located near parks, public amenities, schools and business districts.	5 yearly

As part of our plan to improve our knowledge of the LV cable network, we are carrying out a programme of LV box data capture and labelling. Good progress has been made on this, and we are approximately halfway through the 10-year programme.

Table 20.8: Progress of LV box data capture and labelling

ZONE	% LABELLED AS AT NOV 2020
Tauranga	47%
Valley	81%
Taranaki	35%
Whanganui	57%
Palmerston	71%
Masterton	46%

This programme will ensure that each LV box is identified with a unique operating number, network connectivity is recorded and appropriate safety labelling is affixed. During this programme we will also conduct a detailed condition inspection, with the results fed into our defects management system.

Meeting our portfolio objectives

Safety and Environment: To minimise safety risks, LV boxes are being tracked and labelled to improve our management of assets that are in a public space.

20.5.6 RENEW OR DISPOSE

Renewal of buried LV cable is generally managed using a run-to-failure strategy, as the consequence of failure is low because of the low number of affected customers. Also the failure of buried cable poses very little safety risk.

As we improve our LV underground network condition information – primarily from improvements in capturing failure data from our Outage Management System (OMS) – we will be able to more proactively target cable known to be prone to failure. We forecast our LV cable expenditure based on historical trend analysis.

LV boxes present a safety risk to the public and their condition is more easily understood through visual inspection. We are continuing our programme of replacing LV boxes with a known type issue. There will also be an ongoing need to reactively replace LV boxes damaged by third parties. Forecasts are based on quantities of known defects and historical rates of replacement.

SUMMARY OF LV CABLE RENEWALS APPROACH	
Renewal trigger	Run-to-failure (cable) and condition/type (LV boxes).
Forecasting approach	Historical trend (cable) and defect rates (LV boxes).
Cost estimation	Volumetric average historical rate.

LV cable fleet renewal investment is expected to remain relatively constant during the next 10 years, at a similar level to our historically low replacement rate. After this, cable renewals may need to increase as larger quantities of cable reach nominal end-of-life. Condition and failure data analysis will help us better understand LV cable life expectancy and plan renewals.

Coordination with Network Development projects

The LV underground network is typically expanded through the addition of new subdivisions. As a greenfield installation, subdivision development costs are much lower than cable renewal. Traffic management costs are 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 because of load growth rather than poor condition.

As the level of photovoltaic (PV) and electric vehicle (EV) penetration increases, 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.

20.6 CABLES RENEWALS FORECAST

Renewal Capex in our cable portfolio includes planned investments in our subtransmission, distribution and LV cable fleets. During the planning period we will invest approximately $63m on cable renewal.

Managing safety risk is a key driver of expenditure for LV cable assets. Drivers for replacement of oil-filled subtransmission cables are a combination of environmental, reliability, cost, and poor condition. In the case of distribution cable, increasing failure rates because of deterioration of asset health from type specific issues are the key drivers for renewal.

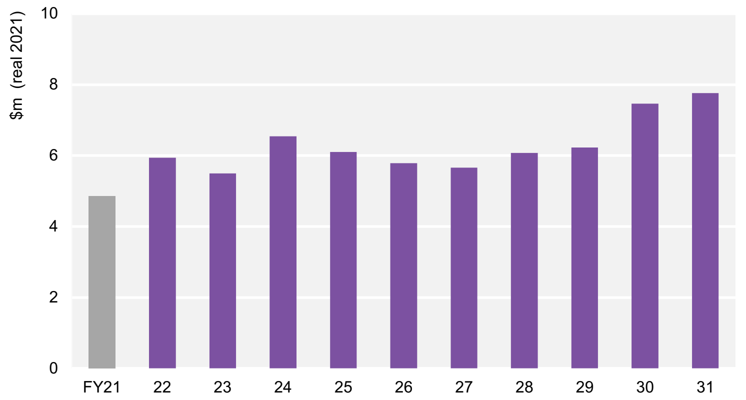
Our subtransmission cable renewals are generally derived from bottom-up models and expenditure is derived from cost estimates of planned projects. Distribution and LV cable forecasts are determined from volumetric estimates, which are explained in Chapter 28.

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.[78]

Distribution cable replacement is often coordinated with ground-mounted switchgear and transformer renewal.

Figure 20.7 shows our forecast Capex on cables during the planning period.

Figure 20.7: Cables renewal forecast expenditure



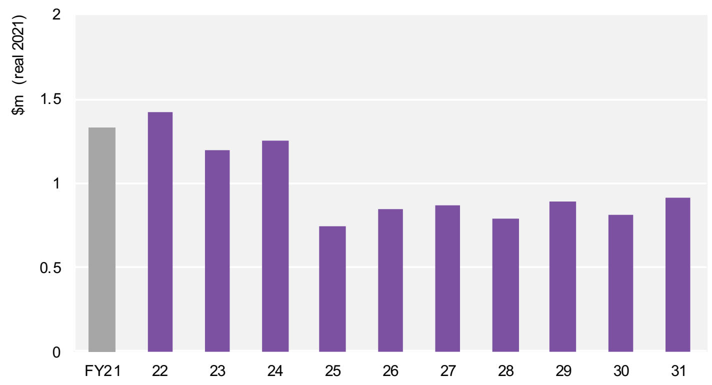
[78] As condition is the primary driver for the Palmerston North subtransmission cable replacement, this expenditure is classed as renewals.

The forecast renewal expenditure for the cable portfolio is in line with historical levels.

20.7 CABLES PREVENTIVE MAINTENANCE FORECAST

Underground cables account for 14% of our maintenance expenditure, with half of this allocated to the LV box data capture programme. As this programme comes to an end in 2024, expenditure levels are expected to decline.

Figure 20.8: Cables preventive maintenance forecast expenditure



21 ZONE SUBSTATIONS

21.1 CHAPTER OVERVIEW

This chapter describes the fleet management plans for our zone substations portfolio. This portfolio includes the following six fleets:

- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control injection 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 $119m in zone substation renewals. This accounts for 13% of our renewals Capex during the period.

We expect to sustain our current level of investment during the period to support the programmes we are undertaking in order to meet our safety and asset stewardship objectives. This level of investment was driven by the need to:

– Renew assets at the end of service life or in poor condition. The bulk of our expenditure in this portfolio is driven by the proportion of the fleet of power transformers, indoor switchboards and outdoor switchgear reaching the end of their service lives, with observable increases in levels of component failures and Do Not Operate (DNOs) tags on these critical assets.

– Stabilise asset health. Our condition-based risk management (CBRM) models indicate that we need to continue our level of expenditure in order to keep our network risk stable.

– Manage safety risk, particularly for field staff. Some 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, as well as replacing ageing oil breakers. In some cases, complete new switchrooms and switchboards are needed where simple retrofit or replacement options aren't suitable, typically for obsolescence, seismic risk or future development reasons.

Below we set out the Asset Management Objectives that guide our approach to managing our six zone substation fleets.

21.2 ZONE SUBSTATIONS OBJECTIVES

Zone substations take supply from the national grid (grid exit points) through subtransmission feeders. They provide connection and switching points between subtransmission circuits, step-down the voltage through power transformers to distribution levels, and utilise switching and isolating equipment to enable the network to be operated safely.

As major supply and control points, zone substations play a critical role in our network. The supply for many thousands of customers often depends on the performance of a few key assets within zone substations. As such, we design our sites to meet our security of supply standards – governing the levels of redundancy and spares. Prudent management of these assets is essential to ensure safe and reliable operation. As such, these have the highest levels of Supervisory Control And Data Acquisition (SCADA) monitoring, alarming, and protective zones of our networks. Zone substations provide the bulk supply of electricity for distribution to end users.

To guide our asset management activities, we have defined a set of portfolio objectives for our zone substation assets. These are listed in Table 21.1. The objectives are linked to our Asset Management Objectives set out in Chapter 4.

Table 21.1: Zone substations portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No lost time injuries resulting from arc flash incidents.
	No uncontained oil spills or SF_6 (sulphur hexafluoride) leaks from zone substation assets.
	No unacceptable noise pollution.
Customers and Community	Ensure design and aesthetics of zone substations integrate with the neighbouring community.
Networks for Today and Tomorrow	Support improved system security when renewing power transformers and switchboards, allowing for increased growth.
Asset Stewardship	Utilise the mobile substation to help minimise outages during maintenance or planned upgrade work.
Operational Excellence	Further develop our use of asset health and criticality to support renewal decision-making, including the use of CBRM approaches.
	Rationalise zone substation equipment for better spares management and operability.

21.3 POWER TRANSFORMERS

21.3.1 FLEET OVERVIEW

Zone substation transformers are used to transform power supply from one voltage level to another, generally 33/11kV, but some are 110/33kV, 33/6.6kV, 66/11kV or 11/22kV. Capacities range from 1.25 to 60MVA.

The major elements that comprise a zone substation power transformer are the core and windings, housing (or tank), bushings, cable boxes, insulating oil conservator and management systems, breather, cooling systems and tap changing mechanisms. These are mounted on pads and, because of the significant volumes of oil these carry, also include firewalls, bunding and oil separation systems.

Additionally, we have recently procured an 8MVA mobile substation to enable us to improve supply reliability when carrying out major maintenance or upgrades at our substations, particularly at our smaller rural substations which generally have limited 11kV backfeed for any major equipment outages.

Figure 21.1: Power transformer installation at Waharoa

21.3.2 POPULATION AND AGE STATISTICS

There are 198 power transformers in service on our network. Table 21.2 summarises our population of power transformers by rating.

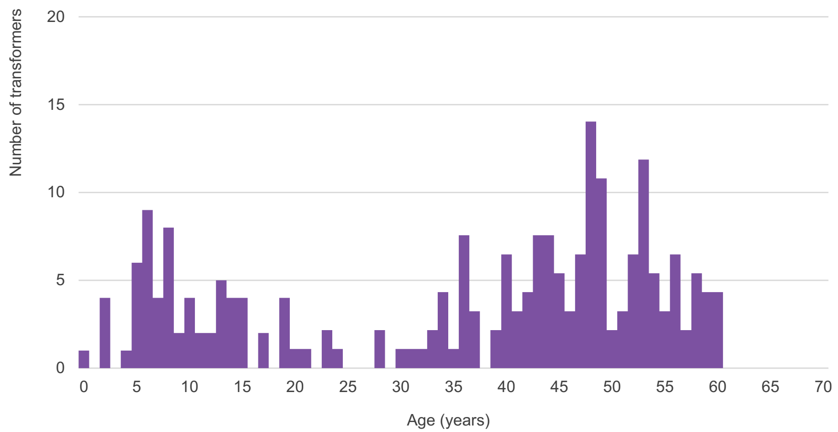
Table 21.2: Power transformer population by rating

MVA RATING	NUMBER OF TRANSFORMERS	% OF TOTAL
<5	21	11
≥5 to <10	86	43
≥10 to <15	18	9
≥15 to <20	45	23
≥20	28	14
Total	198	

Although we purchase standard sizes and configurations, we have some legacy orphan assets with unique vector groups or tapchangers with different tap steps. While this limits interchangeability and, therefore, operational flexibility during repair replacement, we have replaced the problematic units, such as autotransformers, and are grandfathering the remaining other types out of the network as appropriate.

Figure 21.2 shows our power transformer age profile. The average age of all our zone substation transformers is 36 years.

Figure 21.2: Power transformer age profile



We have increasing maintenance issues with power transformers that are approaching their expected 60-year service life. This indicates a steady volume of replacement to keep on top of the average transformer age. Other areas of transformer risk are addressed below.

21.3.3 CONDITION, PERFORMANCE AND RISKS

Power transformers are a mature technology, and major component failures are relatively rare. The main causes are manufacturing defects and on-load tapchanger component failures.

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.

Because of the number of predecessor power boards, each of our regions has differences in specific transformer makes, mounting arrangements and vector groups, which we are standardising over time to improve interchangeability.

A small number of our power transformers have inadequate or no oil containment facilities. A transformer that leaks oil may create an environmental hazard through soil contamination or, in more severe cases, runoff into water courses.

Through our existing bunding programmes we have addressed the highest risk sites, but throughout this planning period, where we don't already have near-term plans for upgrade or renewal, we will further reduce this risk by continuing to install or upgrade oil containment to include both containment (bunding) and separator systems. Implementing these measures may also reduce the risk of fire spreading in the event of a transformer failure.

In the past few years, we have seen an increasing trend of major failures of our older and refurbished transformers, primarily around their tapchanger components. Most recently we have seen tapchanger failures at our Livingstone, Bulls and Main St substations, and winding failure at McKee and Parkville. Our response is discussed further in the Operate and Maintain section.

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

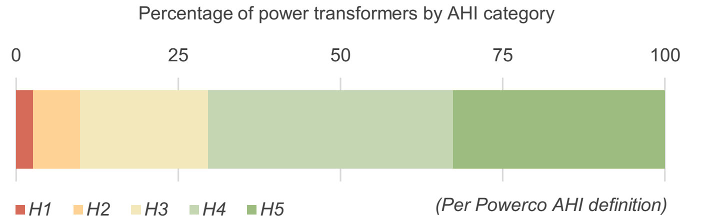
In our CBRM models for our power transformers, we have used a combination of the Asset Health Indices (AHI) and risk profile to determine the optimum replacement schedule.

The risk ranking takes into consideration the combination of the estimated likelihood and consequences of failure. We first prioritise renewal on the CBRM risk ranking followed by the AHI.

Our transformer health is stable, although we are beginning to see loss of reliability of some of our older refurbished units, particularly in relation to tapchangers. We are reviewing our approach to the location for these refurbished units as we continue our programme of replacement.

Figure 21.3 shows the overall AHI for our population of power transformers.

Figure 21.3: Power transformer asset health as at 2021



21.3.4 DESIGN AND CONSTRUCT

We have a range of controls during the procurement phase for power transformers which ensure we get quality assets from our suppliers. We work closely with a small panel of transformer manufacturers and conduct design reviews for all new transformers.

To ensure good operational flexibility across the network, we order transformers in standard sizes. Standard sizes[79] for 33/11kV transformers are:

- 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 from either the core or cooling fans. 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.

[79] Some units have two cooling ratings. They represent natural and forced, ie 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.

21.3.5 OPERATE AND MAINTAIN

Power transformers and their ancillaries, such as tap changers, undergo routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in Table 18.3.

To support our condition based maintenance strategy we will continue to evaluate non-intrusive test techniques and online monitoring to minimise disruption to our customers and ensure reliability is maintained.

Table 21.3: Power transformer preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of insulating systems, cooling, bushing and insulators, tap changer compartment, foundations and other ancillaries.	3 monthly
Service dehydrating breathers. External paintwork touch-ups. Automatic voltage regulator operation checks. Buchholz gas check. Acoustic emission, thermal imaging and external partial discharge diagnostic tests.	Yearly
Dissolved gas analysis (DGA) test, insulation and winding resistance tests. Tap changer service.	3 yearly

Mid-Life Refurbishment

When power transformers reach mid-life (25-35 years) we have historically undertaken major workshop-based overhauls – including major tap changer servicing, upgraded Buchholz relays and Pressure Release Valves (PRV), repaint and, if required, re-clamping and drying of the windings. This has generally been triggered by the paint systems reaching end of life at this time, or load growth requiring an upgrade of the transformers. While an overhaul is taking place, on site a new or recently overhauled transformer is installed in its place.

This approach has been successful in managing the aged transformer fleet, allowing transformers to be rotated through the network with older units moved to less critical sites where the consequence of failure is lower, allowing us to optimise the number of new transformers required on the network for growth reasons and extend the life of the transformer assets.

However, due to increasing difficulty in accessing spare parts and skilled service providers to service these older tapchangers, many of the overhauled units are now nearing the need for outright replacement, and we have been experiencing increased rates of failure, particularly in regards to the tap changer function.

As the cost of major overhauls has started to increase in relation to the new purchase cost, and the increasing serviceability issues of older units, the benefits of this programme have been lessened somewhat. As such, we are continually assessing the criteria used to determine the cost/risk implications of overhauling our aged power transformers. The decision to proceed with an overhaul will continue to be on a case-by-case basis.

Tapchanger Maintenance Audit

In response to the tapchanger servicing issues we have encountered, as part of the maintenance step change initiatives, specialist service providers have been engaged to ensure the older tapchangers remain serviceable by undertaking an intrusive maintenance audit. This will to identify any potential risks in the fleet and inform our maintenance and spares strategy which will ensure spare contacts, braids, divertor resistors and available to facilitate short restoration times.

Spares

In addition to parts, we also operate several whole transformer spares to support our N-security sites. As part of our strategic spares programmes, to support our mobile substation we have retained a moderate sized bushing transformer, as well as procuring a 7.5/10MVA unit with runner cables, that can be mobilised in the event of major transformer failure or our smaller single transformer substations.

Mobile substation

In line with our security of supply standards, many of our smaller rural zone substations have a single power transformer supply. In recent years, it has become increasingly difficult to arrange shutdowns because of diminishing distribution backfeed capability. Any maintenance or planned work requires significant network reconfiguration, extensive generation or, worst case, an outage for the communities supplied by these substations.

Mobile substations can reduce and, in some cases, eliminate the need for outages, and can be used as a temporary switchboard during major planned upgrades or under emergency failure of a major asset.

We completed procurement of a mobile substation in FY20, and have been cycling it through the network for upgrade projects. We have an ongoing programme to install permanent connection points and lay down areas at these key sites to allow straightforward connection of the mobile substation.

Meeting our portfolio objectives

Asset Stewardship: We have procured a mobile substation to help minimise outages during maintenance or planned installation work, and provide a backup option during major substation emergencies.

The mobile substation setup at Douglas zone substation.

21.3.6 RENEW OR DISPOSE

The overall condition and risk of network impact, via CBRM modelling, is used to schedule power transformers for renewal. Failure of power transformers is to be avoided because of the potential network impacts, depending on the security of the associated zone substation, and the 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

We use CBRM modelling to help us effectively forecast power transformer fleet renewal requirements and individual transformer replacement priority.

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 the CBRM power transformer fleet risk ranking, with final replacement timing and final size determined by coordination with network development plans for other zone substation primary replacements or upgrades.

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.

During the planning period we expect to replace three to four power transformers per year. This will ensure our higher risk transformers are replaced while managing the remaining fleet's health through its lifecycle.

Longer term, we expect the number of power transformer replacements to remain at a similar level. A significant number of transformers installed in the 1960s and 1970s will become due for condition-based renewal.

Coordination with Network Development projects

Power transformer refurbishments and replacements are coordinated with Network Development-related projects to develop an optimised programme.

A part of this coordination is the management of rotation of transformers because of load growth and condition. As an example, a load growth-related transformer replacement project might be coordinated by refurbishing the removed transformer and using it to replace a poor condition transformer at an alternative site. This policy of rotating transformers allows us to manage the loading and condition-related issues without investment in over-capacity.

Power transformer replacements are among the larger projects undertaken within a zone substation and often require civil works to upgrade oil bunding. For delivery and cost efficiency, we coordinate other zone substation works wherever practicable, such as outdoor switchgear replacements with transformer projects.

21.4 INDOOR SWITCHGEAR

21.4.1 FLEET OVERVIEW

Indoor switchgear comprises individual switchgear panels assembled into a switchboard. These contain circuit breakers, isolation switches, and 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. Since the late 1990s, when indoor 36kV rated switchboards became available, it has also been used for subtransmission switching applications. Indoor switchgear is generally more reliable than outdoor switchgear. It is more protected from corrosion as it is not exposed to environmental 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 housed within an appropriate building.

Figure 21.4: 11kV indoor switchboard at Main St, Palmerston North

21.4.2 POPULATION AND AGE STATISTICS

There are 142 subtransmission circuit breaker panels within 30 indoor switchboards, and 864 distribution circuit breaker panels within 108 indoor switchboards in service on our network. Most switchboards operate at 11kV, but we have a growing number of 33kV boards because of upgrade needs. As covered in Chapter 11: Growth & Security, we are starting to procure a number of 33kV switchboards as part of the Transpower Outdoor to Indoor (TP ODID) programme, which will enable us closer control of our subtransmission circuits out of those locations.

Table 21.43 summarises our indoor switchgear population by type and number of circuit breakers and switchboards.

Table 21.4: Indoor switchgear circuit breaker and switchboard populations by type

VOLTAGE CLASS	INTERRUPTER TYPE	CIRCUIT BREAKERS
Subtransmission	Oil	0
	SF_6	142
	Vacuum	0
Distribution	Oil	299
	SF_6	72
	Vacuum	493
Total		1,006

Indoor switchgear technology has evolved over time. Before the 1990s, most 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 Reyrolle LMT switchgear.

Modern switchgear uses vacuum or SF_6-based circuit breakers. We prefer these types because of lower lifecycle maintenance requirements, and improved switching characteristics. During the past 25 years, most of the switchgear we installed has been vacuum or SF_6-based.

Modern switchboards have been designed to IEC 62271-200 standards, which, compared to the older portions of the fleet, have much higher levels of safety features to mitigate the impacts of internal failure, greatly improving safety for our operators. They offer arc flash venting, racking through blast-proof switchgear doors, and are installed with dedicated arc flash protection to more quickly isolate arcing faults. Arc flash containment is now mandatory for new switchgear installed on our network.

Figure 21.5 and Figure 21.6 outline the age profile of the indoor switchgear fleet.

Figure 21.5: Subtransmission indoor switchgear (circuit breakers) age profile

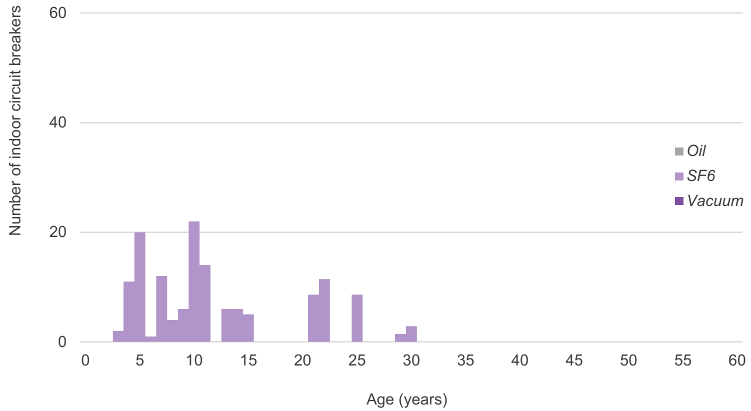
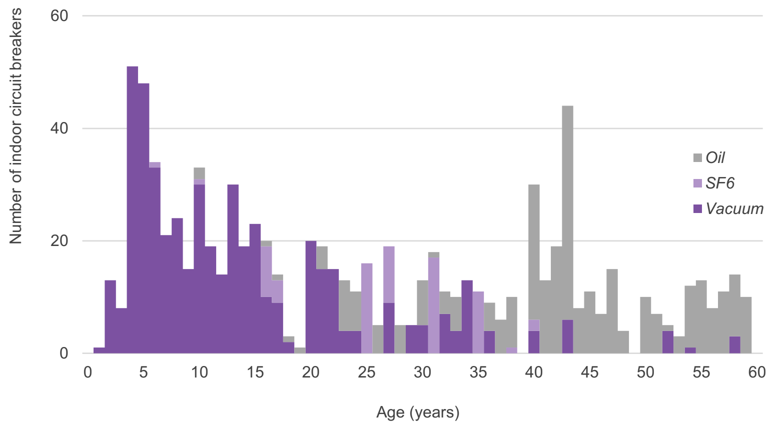


Figure 21.6: Distribution indoor switchgear (circuit breakers) age profile



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 during the next 5-10 years. At a small number of sites, there is mid-life degradation of ancillary assets, requiring intervention. This is discussed further in the following section.

21.4.3 CONDITION, PERFORMANCE AND RISKS

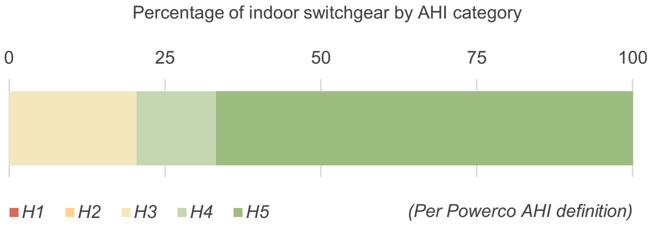
Indoor switchgear asset health

As outlined in Chapter 10, we have developed CBRM models that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules.

For indoor switchgear, we define end-of-life as when the asset can no longer operate reliably and safely and the switchgear should be replaced.

The AHI is calculated using CBRM. Figure 21.7 shows the AHI profile of the indoor switchgear fleet.

Figure 21.7: Indoor switchgear asset health as at 2021



About 20% of our indoor switchgear requires replacement during the next 10 years (H1-H3)[80].

Switchgear environment

We have experienced partial discharge issues with cast resin insulated instrument transformers in some of our early 33kV air insulated switchboards, now approaching 20 years of age. After consultation with the switchboard manufacturers, these issues are remediated either by replacing the defective components, building modifications to improve the weather-tightness or humidity control, or where discharge levels are not detrimental through online partial discharge monitoring.

The root of these issues is deficiencies in the original design of the switchgear buildings to provide the temperature and humidity control needed for 33kV air insulated switchgear. We are investigating initiating building weather tightness and environmental reviews of our 33kV switchgear buildings, to better understand where these issues are.

Orphan equipment

Some of our switchboards manufactured in the 1980s-90s era are no longer supported by manufacturers and we now consider these as orphaned equipment. Our current spares stock enables us to maintain operation of these switchboards at this time, however our ability to continue operation of these is regularly being reviewed. We have found that manufacturers' support for 33kV air insulated switchboards finishes much earlier than the equipment life; typically at about 20 years of age.

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 occurs when there is a phase-to-phase or phase-to-earth fault through the air, such as a flashover or accidental contact.

For well-maintained equipment, it is most likely to occur during work near live parts, such as racking operations, or during operation of switchgear. An arc flash can release a large amount of energy, which can prove fatal or cause serious, permanent injury. 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[81] to be no more than 8 cal/cm². We use this with characteristics specific to each switchgear type to categorise the arc flash risk. There are additional safety risks of secondary oil fire/explosion around switch failures in which the oil is involved.

We mitigate this risk through one of three approaches:

- Isolating and earthing adjacent circuits to the work position when performing maintenance or when work is taking place behind the switchboard.
- Reconfiguring the upstream network to reduce arc flash levels.
- Ensuring personnel working close to the switchboard wear appropriate arc flash rated personal protective equipment (PPE) gear.

As we have determined it is not possible to sufficiently mitigate arc flash risk associated with failure of oil equipment, we are progressively replacing or upgrading these switchboards in the short to medium term. We have approximately seven 11kV switchboards with oil that we estimate have arc flash energy above 8 cal/cm² under normal operating conditions. We plan to rectify all these sites within the next five years.

All newly installed switchboards have arc flash detection systems, arc containment and arc venting. We will also improve many of our existing switchboards by retrofitting various arc flash mitigations, such as blast doors, arc flash detection systems and arc venting.

80 The CBRM model assumes the fleet is in 'operational condition' and therefore calculates very little assets in H1 health. As the model runs forward in time, asset health degrades and the number of H1 assets increases.

81 Arc flash energy is described in calories per centimetre squared (cal/cm²). Our limit is based on the Electricity Engineers' Association's (EEA) '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 to reduce safety risks to our staff and service providers.

21.4.4 DESIGN AND CONSTRUCT

Our equipment class standards classify indoor switchgear as class A equipment because its function is critical to the reliable operation of the network. Before a new type of switchgear can be used on the network, it must undergo a detailed evaluation to ensure it is fit for purpose.

We predominantly specify withdrawable circuit breakers for indoor switchgear. We have installed a small number of switchboards that are non-withdrawable and these are giving good performance. On that basis, we are evaluating whether we should make further use of these types and expand these to our 33kV switchboards as well.

Withdrawable circuit breakers generally are mounted in removable 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, as well as potential issues introduced during maintenance.

Non-withdrawable breakers do not provide a visible break. Therefore, a key requirement for such equipment is that any indications are directly driven by the internal mechanism so that these can be relied upon to accurately reflect operating state.

The reliability of modern units has improved, and vacuum and SF_6 circuit breakers do not need to be serviced, therefore greatly improving both the lifecycle cost and reliability. However, the integral nature of these means individual panels cannot easily be replaced.

In addition, non-withdrawable units take up less space and can reduce the cost of new substations.

21.4.5 OPERATE AND MAINTAIN

Indoor switchgear undergoes routine inspections and maintenance to ensure its continued safe and reliable operation. These preventive tasks are summarised in Table 21.54.

Table 21.5: Indoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, cabinets and panels.	3 monthly
Operational tests on circuit breakers not operated in the past 12 months. Condition-test switchgear including thermal, partial discharge (PD) and acoustic emission scan.	Yearly
Insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. SF_6 gas pressure checks.	3 yearly
Vacuum circuit breaker diagnostic tests, eg High Voltage (HV) withstand. Switchboard partial discharge test.	6 yearly
Continuous online monitoring	Unscheduled

Partial discharge detection (PD) is a reliable condition monitoring technique for determining many insulation-related failures that can lead to disruptive failure. As part of the maintenance step change initiatives, we have recently increased the frequency of specialist diagnostic scans to a yearly task to detect the onset of PD and purchased four relocatable continuous online PD monitoring systems.

Continuous monitoring is utilised on a needs basis rather than being scheduled cyclically, and will be used to manage risk on boards with known issues until repairs can be carried out. If this regime proves to be effective for monitoring insulation breakdown, our standards will be adjusted accordingly.

Online monitoring

In 2018, we procured a set of online PD monitors to be used for condition assessment as well as real-time monitoring. These allow us to carefully observe partial discharge activity over time, and triangulate problem panels.

The use of these has been very beneficial in fault finding the internal discharge issues at our Keith St and Castlecliff substation 33kV.

Along with sharp observation from the field, this allowed us to draw a direct causality between poor switchroom environmental conditions and adverse electrical activity.

Meeting our portfolio objectives

Asset Stewardship: Use of these monitors greatly improved our ability to pin-point the source of issues, therefore allowing us to carefully manage supply and minimise outages while continuing to diagnose and make repairs.

Spares

Although switchboards, by design, generally deliver highly reliable service, they contain many components that are critical to their ongoing performance. We are working with suppliers to update our requirements for spares inventory, which is critical to maintaining serviceability. The availability of critical spares, where we can source them, is expected to improve our repair times on this type of equipment. For older types of equipment, we hold limited stock of older parts, and we are managing these switchboards as part of our obsolescence strategy.

21.4.6 RENEW OR DISPOSE

Indoor switchgear renewal decisions are based on a combination of factors, including:

- Switchgear condition – condition of the circuit breakers, busbars and other associated ancillaries.
- Known reliability type issues, such as cast-iron pitch-filled boxes.
- Equipment obsolescence, eg orphaned boards.
- Fault level interrupting capacity.
- Arc flash risk, accessibility.

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

When assessing Reyrolle LMT 11kV switchboards for renewal, we consider the feasibility of upgrading these switchboards by replacing their oil circuit breakers with vacuum circuit breakers. Arc fault containment doors, strengthening panels, control cables etc are also fitted as part of this work. These upgrade options often provide cost effective solutions to managing substation arc flash risks.

Renewals forecasting

Our indoor switchgear renewals forecast uses switchboard condition, reliability and arc flash risk information as inputs for the CBRM model of the fleet. Longer term, we also use age as a proxy for condition, to help us estimate likely future asset deterioration.

We have recently increased our investment in indoor switchgear renewals to mitigate arc flash risks and address the asset health of some switchboards. We expect to continue at this increased level during the planning period. We also expect to replace or retrofit approximately four switchboards per year for the next 10 years.

Coordination with Network Development projects

New zone substation projects typically use indoor switchgear because of the greatly reduced footprint required than an equivalent outdoor switchgear bay. For urban substations, switchgear is installed in buildings that visually integrate into the surrounding neighbourhood, providing as little visual impact as possible.

In some areas, network growth has driven requirements for additional feeders or modifications in network architecture. When undertaking switchboard renewals, future growth requirements are taken into account to ensure any newly installed boards will have sufficient future capacity to accommodate the forecast load growth in the planning period.

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 and switchboard replacement timing to minimise retiring protection equipment before the end of its useful life.

21.5 OUTDOOR SWITCHGEAR

21.5.1 FLEET OVERVIEW

The zone substation outdoor switchgear fleet comprises asset types associated with HV outdoor switchyards, including outdoor circuit breakers (CB), air break switches (ABS), 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 repairs.

Circuit breakers and reclosers provide protection and control, while fuses provide protection and isolation only. Load break switches control and isolate and are used to break load current.

While outdoor switchgear generally provides good flexibility for emergency replacements during equipment failure, as our sites become more space constrained we are progressively converting these to indoor switchboards.

Figure 21.8: Typical outdoor 33kV switchgear bay

21.5.2 POPULATION AND AGE STATISTICS

Table 21.65 summarises our population of outdoor switchgear by type. Circuit breakers are also categorised by interrupter type.

Table 21.6: Outdoor switchgear numbers by asset type at 2021

SWITCHGEAR TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Air break switch		932	68
Circuit breaker		183	13
	of which: Oil	113	
	SF_6	54	
	Vacuum	16	
Fuse		167	12
Recloser		83	6
Total		1,365	

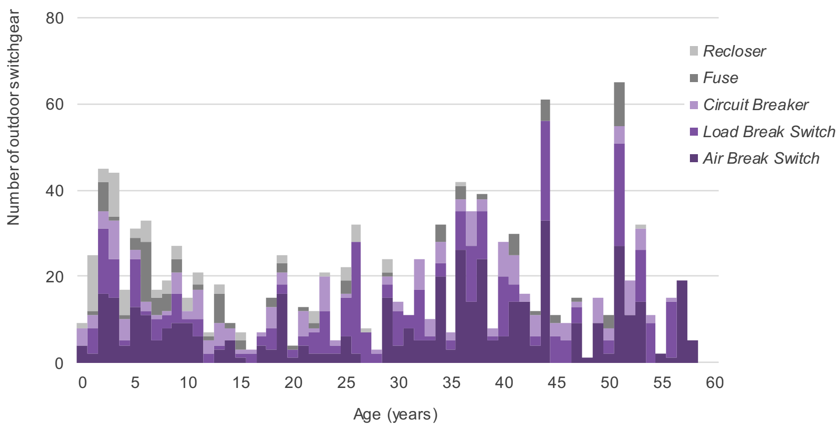
Installed from the 1960s to the 1980s, oil circuit breakers still make up the majority of the fleet. These circuit breakers have historically given good performance, but many are now exceeding their expected service life. Some are at advanced age – issues are described further in the following section.

We are progressively phasing out this type of circuit breaker and replacing it with either vacuum of SF_6-based types.

We also have a number of 11kV recloser structures, which we use for a number of our small rural sites. Where there are issues with space we are progressively converting these to indoor switchboards.

Figure 21.9 shows our outdoor switchgear age profile.

Figure 21.9: Outdoor switchgear age profile



We generally expect outdoor switchgear assets to require replacement at about 45 years of age. Therefore, more than 18% of the outdoor circuit breaker fleet is expected to require replacement during the next decade, noting that actual replacement decisions are made based upon asset condition and risk.

21.5.3 CONDITION, PERFORMANCE AND RISKS

Oil-based circuit breakers carry additional risks compared with their modern equivalents.

Switching operations, particularly operations to clear faults, degrade the switch contacts and oil, requiring out-of-schedule maintenance to maintain breaking performance.

Their large number of moving parts also means regular maintenance is required to avoid mechanisms slowing. In some cases, the delays in operation have been so severe that backup protection has operated. To minimise problems, 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.

The presence of oil as the interrupting medium also means that internal failure of these circuit breakers can result in hot oil or, in severe cases, explosions to occur, increasing the safety risk to any nearby workers.

Finally, as most oil circuit breaker types are now obsolete, replacement parts are difficult to source and, if available, can have very long lead times, resulting in support and availability problems. We have developed a systematic approach to the management of critical spares to help alleviate this issue as we continue through our programme of retiring these types.

“Dog-box” style circuit breakers typically comprise a SF_6 indoor breaker within a sheetmetal housing. There have been some historical issues with water ingress leading to internal tracking and breakdown. We will continue to monitor this failure mode.

Two-piece porcelain insulators used in many older 33kV air break and load break switches have been found to fail while the switch is being operated, creating a significant safety risk. We have placed operating restrictions on these switches to control the risk, and have initiated a programme to replace the faulty insulators. This is coordinated, wherever possible, with zone substation major maintenance.

Outdoor switchgear asset health

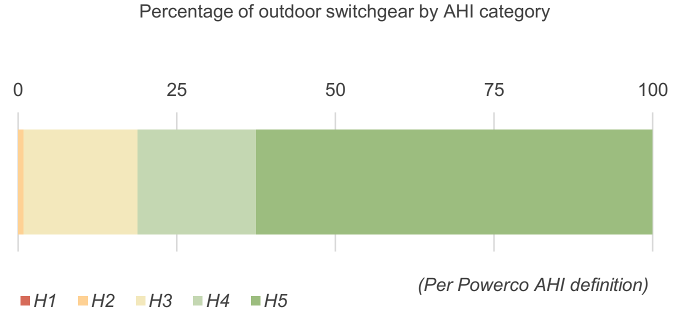
As outlined in Chapter 10, we have developed CBRM models that estimate the current and forecast health of our outdoor circuit breaker fleet, while the lower cost isolators are forecast by simpler age-based AHI measures.

For outdoor switchgear, we define end-of-life as when the asset can no longer operate reliably and safely, and the switchgear should be replaced.

The AHI for outdoor circuit breakers is based on CBRM.

Figure 21.10 shows the current overall AHI profile for our outdoor circuit breakers.

Figure 21.10: Outdoor switchgear (circuit breakers) asset health as at 2021



The overall health of the outdoor switchgear fleet indicates that approximately 37% of the fleet will require renewal during the next 10 years (H1-H3). A significant increase in renewal investment is required to restore the health of this fleet to preferred levels.

21.5.4 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.

For 33kV circuit breaker replacement, we have standardised on a small number of live tank SF_6 breaker, and a deadtank vacuum breaker. SF_6 circuit breakers are the industry standard for HV outdoor applications. Vacuum circuit breakers would help reduce our holdings of SF_6 gas and its associated environmental risks. As we hold more than 1,000kg of SF_6, we are classified as a major user of SF_6 [82] and are subject to specific reporting requirements.

Meeting our portfolio objectives

Safety and Environment: We continue to monitor developments in non-SF_6-based switchgear and, when mature, will consider its application to reduce the potential environmental harm from SF_6 gas leaks.

[82] Annual reporting requirements to the Ministry for the Environment include: 1) The amount of SF_6 added to the network; 2) The amount used in maintenance top ups; 3) The difference between total weight of gas in decommissioned equipment compared with nameplate weight; 4) Total SF_6 holdings.

Whenever possible we manage outdoor switchgear replacements at the bay level. This ensures delivery efficiency. Where practicable, replacements are also typically planned to coincide with power transformer replacements.

Figure 21.11: Live tank SF_6 outdoor 33kV circuit breaker

21.5.5 OPERATE AND MAINTAIN

Outdoor switchgear undergoes preventive maintenance to ensure safe and reliable operation. We also undertake preventive maintenance based on circuit breaker fault operations for oil type breakers to mitigate against failure modes associated with excess duty.

Our various preventive maintenance tasks are summarised in Table 21.76. The detailed regime for each asset is set out in our maintenance standard.

Table 21.7: Outdoor switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of circuit breakers, air break switches and reclosers.	3 monthly
Operational tests on CB not operated in the past 12 months. Condition-test circuit breakers, including thermal, PD and acoustic emission scan.	Yearly
Circuit breaker insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. Air break switches thermal scan. Recloser thermal and oil insulation tests.	3 yearly
Air break switches 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

For oil-filled circuit breakers, more intensive oil sampling and analysis requirements have been implemented in our three-yearly maintenance to provide further insights into the remaining life of the breaker and ensure continued reliable operation under fault conditions.

To identify the early onset of slowing CB mechanisms and to support our condition-based maintenance strategy, we will be evaluating online monitoring options through the intelligent electronic device (IED) relay. This can detect any fatigue in the mechanism and trigger a maintenance intervention. In the interim, more stringent control of lubrication and lubrication types to be used on the mechanisms will be introduced.

Outdoor switchgear requires more preventive and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

Experience has shown that the service life of outdoors circuit breakers is often determined by external corrosion issues and the availability of service and repair technical expertise.

21.5.6 RENEW OR DISPOSE

Our approach is to replace circuit breakers and other outdoor switchgear equipment on a condition and risk basis. We aim to avoid equipment failure, as network consequences can be large and failure modes can be explosive, creating a safety hazard, 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 circuit breaker renewals quantity forecast uses CBRM-projected AHI and risk as a base for replacement need – our air break and load break switches using 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 leading to slower operating speeds, which can increase fault clearance times.

Our renewals forecast also considers that older designs of switchgear generally have fewer safety features, are maintenance heavy, and are less reliable. These problems are compounded as skills and expertise for maintaining these types of equipment decrease, and spare parts become harder to obtain. Our expenditure forecast is based on forecast renewal quantities and average historical unit rates.

Outdoor-to-indoor (ODID) conversion project[83] planning considers a range of drivers on top of the typical considerations of condition, safety and criticality. These additional drivers include environmental pollution and corrosion conditions, site aesthetics, site space/layout and equipment maintenance requirements. 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 our like-for-like versus indoor conversion decision-making.

We have identified several substation candidates for ODID conversion. These substations generally have 33kV switchgear in poor condition, are subjected to industrial or environmental pollution, or have cramped overhead buswork. These projects are discussed in more detail in Appendix 8.

Coordination with Network Development projects

Most new zone substations use indoor switchgear as a preference to outdoor switchgear because of its cost, footprint, reliability and safety benefits. We also review existing zone substations for possible conversion to indoor switchgear when undertaking major development work. Where possible, renewal plans are coordinated to accommodate any future architecture or subtransmission feed requirements and changes in architecture.

83 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.

Whangamata battery energy storage facility

Whangamata is a resort township located in the western Bay of Plenty on the picturesque beach of the same name. During holiday periods and special events (Whangamata's famous Beach Hop for example), the population can swell from a few thousand to several tens of thousands. Whangamata's economic health relies on a reliable power supply, as its business community is dependent on holiday custom to survive the remainder of the year.

After consultation with business leaders in the Whangamata community, Powerco's Network Development Team decided to improve the security of supply by installing a 2MW/MWh battery energy storage system (or BESS), coupled to a 2.5MVA diesel generator. While provision of back-up power to vulnerable businesses was the primary objective, a secondary objective was to reduce subtransmission peak demand and provide dynamic voltage support to the wider Whangamata area.

Meeting our portfolio objectives

Customers and Communities: Minimise the impact of unplanned outages, provide backup power during maintenance operations, alleviate transmission line capacity constraints, and provide voltage support.

21.6 BUILDINGS

21.6.1 FLEET OVERVIEW

Zone substation buildings mainly house indoor switchgear and supporting control and monitoring equipment such as protection relays, SCADA, DC systems and communications.

Given the critical and sensitive nature of the equipment housed, zone substation sites need to be environmentally controlled, secure and resilient. Buildings and equipment must be well secured for earthquakes and designed to minimise the risk of fire or harm to operating staff.

Figure 21.12: Masonry constructed building

21.6.2 POPULATION AND AGE STATISTICS

We have 165 buildings[84] at our zone substations. These are built of various materials including concrete, timber and masonry.

[84] This excludes 'minor' buildings, such as sheds.

21.6.3 CONDITION, PERFORMANCE AND RISKS

Seismic risks

As building standards have evolved, the requirements for seismic performance have changed. Older buildings, particularly those made of unreinforced masonry and concrete, are well below today's strength standards.

The seismic performance of our zone substation buildings is important for the safety of our people who work in them, and to maintain electricity in the event of a large earthquake – remaining fully operational and safe to access to allow for quick restoration.[85]

In 2012, we started a programme to seismically assess all our substation buildings. To date, we have assessed 128 of our zone substation buildings[86] against the New Zealand Society of Earthquake Engineering (NZSEE) grades. Our standard requires all zone substation buildings to be at least 67% of the new building standard (NBS), equivalent to B grade or better. The study indicated 43 of our buildings require seismic strengthening. A programme has been put in place to strengthen these buildings within the next 10 years.

Where buildings are found to be earthquake prone or an earthquake risk (<67% NBS), we have been progressively strengthening them targeting those most at risk. Where equipment within the building has reached end of its service life, the suitability of the building to meet future demand is assessed before completing any reinforcement works. If the building is no longer suitable for the future growth of the network or replacement equipment because of lack of space, a new building is constructed.

Table 21.87 shows our zone substation buildings by NZSEE seismic grade.

Table 21.8: Zone substation buildings by NZSEE seismic grade

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS	% OF TOTAL
A+	>100	7	4
A	80-100	50	31
B	67-79	25	16
C	34-66	36	23
D	20-33	12	8
E	<20	10	6
Not assessed[86]		20	13
Total		160	

85 Zone substation buildings are considered a 'frequented location', and carry considerable community importance due to our function as a lifeline utility. Therefore, these buildings are of an importance level 4 in accordance with AS/NZS 1170.5, along with buildings used for medical emergency and surgery functions and emergency services.

86 Some zone substation buildings were excluded from this assessment as they had previously been assessed, had recently been strengthened, or had been constructed in the past 10 years. These buildings are assumed to be at least at grade B.

Asbestos

Sixteen substations have been confirmed to contain asbestos materials, and a further 18 are presumed or strongly presumed to have asbestos-containing materials.

Approximately another 56 substations fit the age profile of having a high likelihood of containing asbestos material but have not yet been surveyed. This may lead to increased compliance costs as we work through our building programmes.

If the material is in a non-friable state and well inspected and maintained, then if not disturbed, asbestos cannot be inhaled and so may remain in place.

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.

Weather tightness

We have recently found a small number of mid-life buildings have issues with proper sealing and moisture ingress, which has resulted in accelerated tracking and degradation of their cast-resin components. We are investigating engaging building inspectors to carry our weather tightness and environment control reviews, in addition to our scheduled seismic performance and earthing reviews.

21.6.4 DESIGN AND CONSTRUCT

When designing new zone substation buildings, we carefully consider the aesthetics of the environment within which they are to be built. While our rural substations still follow more traditional block building designs, in urban areas we make our sites as unobtrusive as possible and design the building to fit in with the surrounding neighbourhood.

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 21.13: Urban zone substation building

21.6.5 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 preventing unauthorised access.

Table 21.9: Building preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of building. Check emergency lighting system.	3 monthly
Detailed visual inspection, including weather tightness, checks of structure, roof, plumbing, drainage, electrics and fittings. Check safety equipment and signs.	Yearly
Engineering review of zone substation buildings – condition and seismic assessments.	10 yearly

We are planning additional maintenance on our older buildings to improve their internal environment. This will improve the operating conditions for indoor switchgear, minimising the need for maintenance interventions.

21.6.6 RENEW OR DISPOSE

Zone substation buildings that do not meet our standard for seismic compliance are part of a seismic strengthening programme scheduled 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	Historical rates

Our aim is to have all our zone substation buildings up to B grade standard or better by the end of the planning period, although more case-by-case detailed work may show we require more full replacements versus strengthening, which could increase the costs associated with these works. 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 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.[87]

Coordination with Network Development projects

Zone substation buildings are typically built for new indoor switchgear, either a complete switchboard renewal or a switchboard extension to serve additional feeders.

Planning for these two fleets is therefore done at the same time. We also schedule seismic upgrades to coincide with switchgear works to ensure upgrades are designed with the requirements of the new switchgear in mind.

New greenfield zone substation buildings are planned and designed to meet the needs of the overall development.

21.7 LOAD CONTROL INJECTION PLANT

21.7.1 FLEET OVERVIEW

Load control has been used in New Zealand for the past 60 years. Load control systems are used to manage the load profiles of customers with controllable loads, eg hot water or space heating.

Load control involves sending audio frequency signals through the distribution network from ripple injection plants at zone substations. Ripple receiver relays located at customer main distribution boards receive the signals and turn the ‘controlled load’ on or off.

87 Note that the cost of new buildings or building extensions is covered within the forecasts for the related asset, eg indoor switchgear.

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 21.14: Load control injection plant

21.7.2 POPULATION AND AGE STATISTICS

We operate 26 load control injection plants on our network, comprising both modern and aged equipment. Significant work undertaken since 2008 has resulted in a system that, while still containing some older technology plants, is able to be supported with readily available spares and technical support contracts.

Table 21.109 summarises our load control injection plant population by type.

Table 21.10: Load control injection plant by type

TYPE	PLANT	% OF TOTAL
Modern ripple plant	21	81
Aged ripple plant	5	19
Total	26	

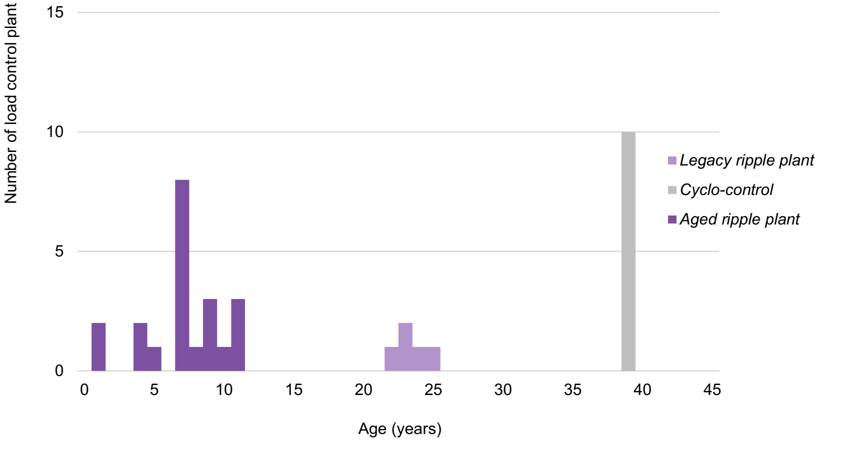
We continue to operate a CycloControl[88] system, which is a voltage distortion system used in the Stratford and Huirangi regions. Its method of transmitting load control commands differs from all other systems on our networks and has more faults. As this system operates at 11kV, each plant has less reach than we have with our GXP-based ripple plants.

These plants have now been superseded by newly installed ripple injection plants. The CycloControl system will be decommissioned in the near term once relay owners have migrated to the new standard.

Other aged load control plants are compatible with our modern plants, and component replacement is handled on a case-by-case basis.

Figure 21.15 shows the age profile of our load control fleet.

Figure 21.15: Load control injection plant age profile



In 2008, we undertook a modernisation programme to address issues with our legacy assets, such as the 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 older technology plant will be upgraded in the near future, and we plan to undertake consultation with receiver owners supported by the CycloControl plants, originally installed from the mid-1970s through to the mid-1990s, which will allow these plants to be decommissioned.

88 We have 10 CycloControl plants left in operation.

21.7.3 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 CycloControl, use obsolete code formats. Obtaining spares and manufacturer support is very difficult for these CycloControl plants.

21.7.4 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, and we are in the process of rolling out DECABIT format signals in Tauranga. 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 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 in the transition.

21.7.5 OPERATE AND MAINTAIN

Because of the specialist nature of load control plant, as part of our new maintenance programmes we have established 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 21.11: Load control injection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General visual inspection of plant. Operational tests.	3 monthly
Diagnostic tests, such as resonant frequency checks, signal injection levels and insulation resistance.	Yearly

21.7.6 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 been 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 lack spares and are difficult to support. Once these are replaced or retired, we expect little further renewal in this planning period. Some future replacements of modern plants will be driven by GXP transformer upgrades and network reconfiguration undertaken by Transpower.

SUMMARY OF LOAD CONTROL INJECTION PLANT RENEWALS APPROACH	
Renewal trigger	Obsolescence
Forecasting approach	Type
Cost estimation	Average historical rate

Coordination with Network Development projects

Load control plant continues to play a role on our network in managing peak loads. However, past distribution price structures and instantaneous gas hot water options have eroded the base of switchable load on the electrical network.

The use of our load control plant is in a state of transition. However, we see traditional load control continuing to play a role, alongside new non-network solutions, as alternatives to traditional network capacity upgrades.

21.8 OTHER ZONE SUBSTATION ASSETS

21.8.1 FLEET OVERVIEW

The other zone substation assets fleet comprises outdoor bus systems, fencing and grounds, earthing, lightning protection systems, security systems, and access control systems. We have 120 zone substations and 12 switching stations that contain outdoor buswork, fencing, earthing, lightning protection systems and support structures.

Outdoor bus systems are switchyard structures comprising steel or concrete structure, 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 surge arrestors for equipment bushings and indoor sites.

21.8.2 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 needs 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. Several older sites do not have adequate fencing and security systems compared with modern zone substations. Some fencing needs replacing as the asset is at end-of-life, such as because of corrosion. We intend to bring all sites up to our fencing and security standards during 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 surge arrestors on the terminals of high-value equipment, such as power transformers.

Modern buswork requires flexible conductors or sliding contacts in connection to primary plant to accommodate movement between fixed points during seismic events. A small number of 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.

21.8.3 OPERATE AND MAINTAIN

Our general zone substation preventive maintenance tasks are summarised in Table 21.1211. The detailed regime is set out in our maintenance standards.

Table 21.12: Zone substation general preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Site vegetation work – mowing, weeding. Check waterways.	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.	Yearly
Detailed inspection of busbar connections, insulators, and bushings. Detailed condition assessment of outdoor structures.	6 yearly

21.8.4 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 until at least FY27.

SUMMARY OF OTHER ZONE SUBSTATION ASSETS RENEWALS APPROACH	
Renewal trigger	Safety and reliability risk
Forecasting approach	Programmes
Cost estimation	Historical rates

21.9 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 injection plant
- Other zone substation assets

During the planning period we plan to invest $119m in zone substation asset renewal.

A key driver for the replacement of our switchgear assets is managing safety risk, particularly to our field staff. Managing reliability risks from potential equipment failure, indicated by asset condition and health, is a further driver. As noted, a portion of our power transformer fleet has reached end of service life, so we will continue replacing this as well.

The combination of our six fleet forecasts, derived from bottom-up models, drives our total zone substations renewal expenditure. Although initially forecast 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, such as power transformers.

We also coordinate zone substation projects with protection relay replacements (covered by our secondary systems portfolio).

Figure 21.16 shows our forecast Capex on zone substation renewals during the planning period.

Figure 21.16: Zone substation renewal forecast expenditure

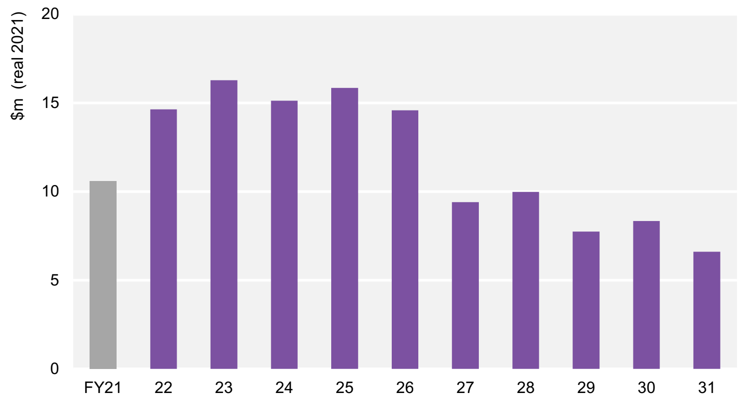
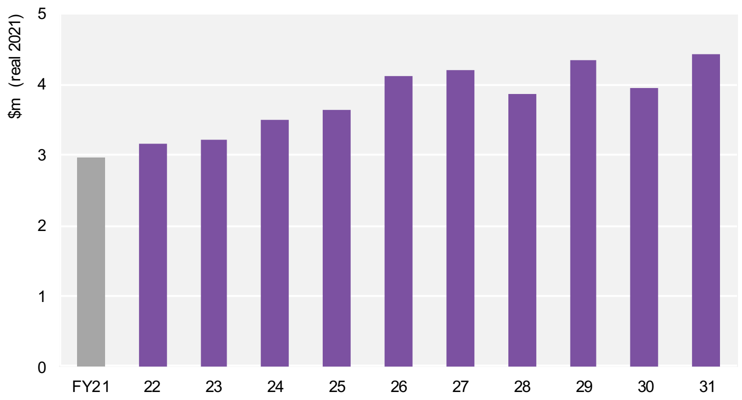


Figure 21.17: Zone substation preventive maintenance expenditure forecast



The forecast renewal expenditure for the zone substation portfolio represents a step change increase relative to historical levels of five years ago. Most of the increase is because of power transformer, indoor switchboard and outdoor switchgear renewal programmes. In recent years, we have lifted investment levels and intend to continue at $10-15m per annum for the first half of the planning period.

While historically some replacement has been coordinated with growth augmentations, the current condition of the portfolio means that substantial renewal investment continues to be warranted.

Further details on expenditure forecasts are contained in Chapter 28.

21.10 ZONE SUBSTATIONS PREVENTIVE MAINTENANCE FORECAST

The critical role zone substations play in our network is reflected in how we maintain these assets to ensure continued safe and reliable operation. Approximately 30% of our preventive maintenance spend is allocated to zone substations to ensure the assets meet their end-of-life requirements. The increased expenditure from 2024 is an indication of the focus we are placing on the use of more specialised services for critical assets, such as power transformer tapchangers.

22 DISTRIBUTION TRANSFORMERS

22.1 CHAPTER OVERVIEW

This chapter describes our distribution transformers portfolio and summarises our associated fleet management plan. This portfolio includes three fleets:

- Pole-mounted distribution transformers
- Ground-mounted distribution transformers
- Other distribution transformers, which include voltage regulators, capacitors, conversion and single earth wire return (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 10% of renewals Capex during 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 have reached, or are approaching, end-of-life.

The investment supports our safety and reliability objectives. Renewal works are driven by the need to:

- Reduce the risk related to some large pole-mounted transformers not complying with standards for seismic resilience, safety, or electrical clearances mandated by ECP34 (New Zealand Electrical Code of Practice for Electrical Safe Distances), focusing on larger units in urban areas first.
- Continue our distribution transformer replacement programmes, prioritised using asset condition, defect information and Condition-Based Risk Management (CBRM) modelling.
- Continue our programme to improve the safety of pole-mounted transformers by installing low voltage (LV) isolation via LV fuses (expected completion FY23).
- Continue a programme to manage risk and ensure legislative compliance associated with unauthorised public access to our ground-mounted transformers through replacement of 14,000[89] non-standard, ageing or damaged padlocks (expected completion FY23).

[89] Further replacements will occur in other portfolios, primarily ground and pole-mounted switchgear.

Below we set out the Asset Management Objectives that guide our approach to managing our distribution transformers fleets.

22.2 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. Our transformers are oil-filled, which carries some environmental and fire risk. Proper lifecycle management of our distribution transformers assets, including correctly disposing of these assets when they are retired, is important for safeguarding the public and mitigating potential environmental harm from oil spills.

To guide our asset management activities, we have defined a set of objectives for our distribution transformers. These are listed in Table 22.1. The objectives are linked to our Asset Management Objectives as set out in Chapter 4.

Table 22.1: Distribution transformers portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reposition pole-mounted transformers to limit risks related to working at heights.
	Achieve electrical clearances mandated by regulation and consistent with industry good practice.
	No explosive failures of, or fires caused by, distribution transformers.
	Installations compliant with seismic codes to avoid injury and property damage.
	Install compliant LV fusing on pole-mounted transformers.
	No significant oil spills.
Customers and Community	Minimise planned interruptions to customers by coordinating replacement with other works.
	Minimise landowner disruption when undertaking renewal work.
Networks for Today and Tomorrow	Consider the use of alternative technology to improve reliability or reduce service cost eg transformer monitoring units.
Asset Stewardship	Expand the use of asset health and criticality techniques to inform renewal decision-making.
	Ensure our critical distribution substations are seismically compliant.
Operational Excellence	Improve and refine our condition assessment techniques and processes.

22.3 POLE-MOUNTED DISTRIBUTION TRANSFORMERS

22.3.1 FLEET OVERVIEW

There are approximately 26,000 pole-mounted transformers on our network. These are usually located in rural or suburban areas where the distribution network is overhead. The capacity ranges from less than 15kVA to 300kVA.

Our standards set the maximum allowable capacity for a new pole-mounted transformer at 200kVA[90]. This means any pole-mounted transformers greater than 200kVA that require replacement are likely to be converted to a ground-mounted equivalent, or split into multiple transformer sites, if practical.

Following a major change to national seismic standards in 2002, some larger pole-mounted transformer structures are no longer compliant. Those single or H-pole-mounted installations often do not meet the ECP34 clearance and safety requirements. We intend to continue to replace these with compliant pole-mounted or ground-mounted units.

Meeting our portfolio objectives

Safety and Environment: Larger pole-mounted transformers are being reviewed for seismic and ECP34 compliance and those that do not meet the objectives are scheduled to be replaced with compliant pole-mounted or 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 small number of customers. Suitable spare transformers are held in stock at service provider depots. This ensures a fast response time to return service.

90 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 1,600kg must not be pole-mounted. A 200kVA transformer weighs just over 1,000kg.

Figure 22.1: 100kVA pole-mounted transformer

22.3.2 POPULATION AND AGE STATISTICS

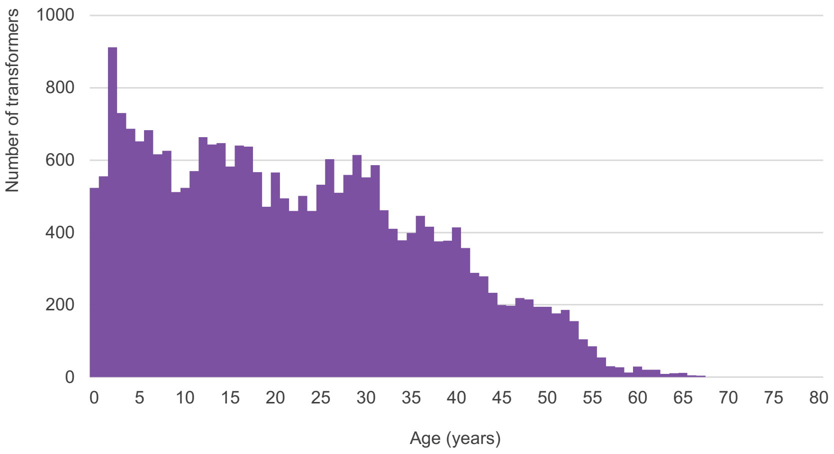
Table 22.2 summarises our population of pole-mounted distribution transformers by kVA rating. Most are very small, with almost 40% at 15kVA or below. A transformer of this size typically supplies a few houses in a rural area.

Table 22.2: Pole-mounted distribution transformers population by rating and voltage

RATING	6.6 KV	11/6.6 KV	11 KV	22 KV	33KV	TOTAL
≤ 15kVA	309	95	9,798	116		**10,318**
> 15 and ≤ 30kVA	189	56	8,449	34	2	**8,730**
> 30 and ≤ 100kVA	89	44	5,959	28	5	**6,125**
> 100kVA	3		6690	4		**697**
Total	**590**	**195**	**24,896**	**182**	**7**	**25,865**

Figure 22.2 shows our pole-mounted distribution transformer age profile. The expected life of these units typically ranges from 45 to 60 years. The fleet age profile indicates that an increasing number of transformers will require replacement during the planning period.

Figure 22.2: Pole-mounted distribution transformers age profile



22.3.3 CONDITION, PERFORMANCE AND RISKS

Failure modes

The main reasons for replacing pole-mounted transformers are age, environment-related deterioration, and random failures caused by third parties eg vehicle accidents or lightning strikes. The predominant causes of equipment degradation are:

- Accumulation of moisture and contaminant concentrations in insulating oil.
- Overloading over time.
- Oil leaks through faulty seals.
- External tank/enclosure damage and corrosion.

Some of these factors, such as tank corrosion or oil degradation (for some ground-mounted units) inform our Asset Health Indices (AHI) to forecast and prioritise replacement.

Risks

Some of our larger pole-mounted transformer structures do not meet modern seismic standards or meet requirements for electrical clearances documented in ECP34. Non-compliance with seismic requirements creates a safety risk and reduces network resilience should there be a seismic event.

Some of our older pole-mounted transformers do not have LV fuses, which means there is no direct protection against LV faults. When a fault occurs on the LV, either the HV fuse operates and clears the fault, or it is not cleared until it is manually isolated. This increases the possibility of live LV conductors to be accessible to the public during a wire down or other fault event.

Because of the large number of failures from lightning storms, particularly in the Taranaki area, we are revising our surge/lightning protection requirements on transformers and other types of equipment.

In 2013, we initiated a programme to install LV fuses on approximately 6,700 pole-mounted transformers, predominantly in our Taranaki, Valley and Wairarapa networks, where historical designs relied on upstream HV protection. This programme will be completed by 2023.

Meeting our portfolio objectives

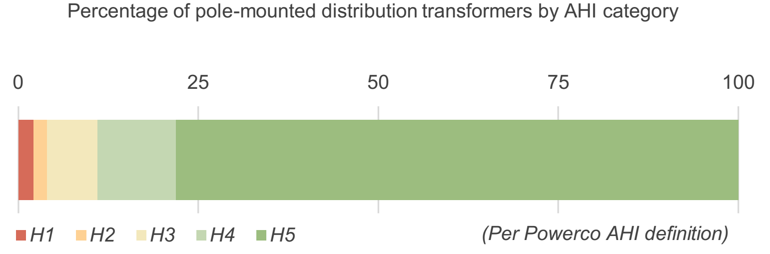
Safety and Environment: Where not already present, LV fuses are being installed on our pole-mounted distribution transformers to improve public safety in the event of a fault on the LV network.

Pole-mounted distribution transformers asset health

As outlined in Chapter 10, we have developed AHIs that reflect the remaining life of an asset. Our AHI models predict an asset's end-of-life and categorises its health based on a set of rules. For pole-mounted transformers we define end-of-life as when the asset fails because of condition. The overall AHI is based on survivorship and defect analysis.

Figure 22.3 shows current overall AHI for our population of pole-mounted distribution transformers.

Figure 22.3: Pole-mounted distribution transformers asset health as at 2021



The overall health of the pole-mounted transformer fleet is generally good, with few assets requiring replacement. Because of our run-to-failure approach with smaller pole-mounted distribution transformers, we expect to retain a sustainable level of H1 assets to be replaced under reactive/defect processes.

22.3.4 DESIGN AND CONSTRUCT

To improve seismic compliance, where practical, a pole-mounted transformer above 200kVA is replaced with a ground-mounted transformer of equivalent/greater size, or where space on the ground is not available, split into multiple sites and the LV reconfigured. Refer to Section 22.3.3 for more details. Smaller pole-mounted transformers are replaced like-for-like.

We intend to fit distribution transformer monitors on certain existing and new pole-mounted transformers.

22.3.5 OPERATE AND MAINTAIN

Pole-mounted transformers do not require intrusive maintenance. Maintenance is generally limited to visual inspections, with repair or replacement initiated on an on-condition basis. Pole-mounted distribution transformers usually supply a smaller number of customers, and as such are less critical than their ground-mounted equivalents. It is often cost effective to replace them when they are close to failure, rather than carry out rigorous maintenance to extend life. Our preventive inspections are summarised in Table 22.3. The detailed regime is set out in our maintenance standard.

Table 22.3: Pole-mounted distribution transformers preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Inspect tank and general fittings for corrosion and inspect earthing connection.	5 yearly

The five-yearly inspection interval for the pole-mounted transformer fleet is based on defects analysis and historical mandated requirements. The interval also coincides with our pole inspection programme providing cost efficiencies.

The pole-top photography programme initiated this year will complement the traditional ground-based inspection by providing detailed condition data from an aerial perspective. Learnings from this will be used to further develop the Maintenance Strategy.

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 may be repaired or refurbished in the workshop and managed through a rotating pool of spares. An appropriate level of spares is kept for each part of the network at service provider depots.

Fault response generally involves replacing transformers that have internal, tank or bushing damage. Defective pole-mounted transformers are taken to spares warehouses where they are assessed for workshop-based repairs or overhaul. A new unit replaces the defective unit.

Repair and overhaul work is undertaken according to our specifications and evaluation criteria 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.

22.3.6 RENEW OR DISPOSE

Pole-mounted transformer renewal is primarily based on condition and legacy design problems, such as inadequate electrical clearances. We accept some in-service failures associated with failure modes that cannot be detected by visual inspection. These failure modes typically do not present a significant safety hazard and the impact on the customer is limited. Renewal of pole-mounted transformers usually involves replacement of the pole, crossarm and ancillaries at once, to minimise the need for future outages.

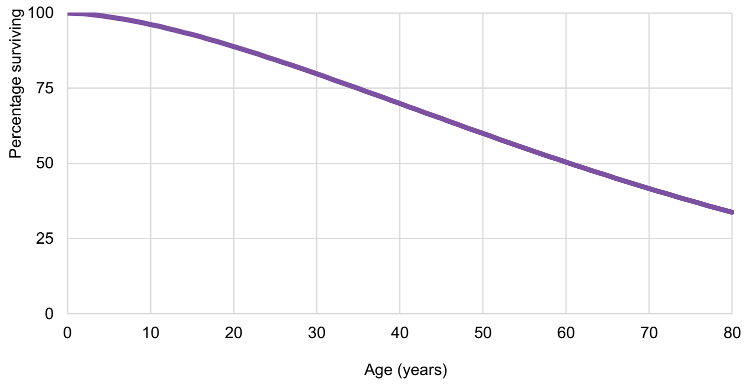
SUMMARY OF POLE-MOUNTED DISTRIBUTION TRANSFORMERS RENEWALS APPROACH	
Renewal trigger	Reactive and condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

Our pole-mounted distribution transformer replacement quantity forecast incorporates historical survivorship analysis. We have developed a survivor curve and use this to forecast expected renewal quantities.

Figure 22.4 shows a pole-mounted distribution transformer survivor curve. The curve indicates the percentage of transformer population remaining at a given age.

Figure 22.4: Pole-mounted distribution transformers 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 and inherent durability. The survivorship forecasting approach is therefore more robust than a purely age-based approach.

We have also identified larger pole-mounted distribution transformers on pole structures that may be at risk of failing during seismic events. As described in the Condition, performance and risks section, most of the identified transformers also do not comply with the standards for electrical clearances mandated by ECP34. While this is not retrospective, we have taken a targeted approach to address those that do not meet this standard.

Further review of the smaller overhead pole-mounted transformers identified smaller transformers in the fleet that do not meet the requirements of ECP34. Combined, this accounts for approximately 459 transformers sites that may be at risk.

Given the large number of sites, we prioritise based on risk, for example those within urban areas, next to major roads etc. We expect to continue this programme, either rebuilding these sites to modern design requirements or converting to ground-mounted installations, ensuring they meet today's safety standards for both seismic events and safety clearances.

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 in Section 22.3.3, our pole-mounted transformer fleet is maintained in good health by our condition-based renewal programme.

Pole-mounted transformers refurbishment

Suitable units that are taken off the network, eg for growth reasons, undergo minor repairs such as repainting, re-gasketing etc before entering the rotable pool of spares.

Pole-mounted transformers disposal

Pole-mounted distribution transformers are decommissioned and disposed of when they are replaced. The principal transformer components of steel, copper and oil are recycled.

The oil in pre-1970 transformers often contained polychlorinated biphenyls (PCB), which is now known to be carcinogenic. We believe we have removed all models containing PCB. However, we continue to test older models for PCB before removing oil. Should we find PCB, a specialist disposal company would be employed to undertake removal.

Coordination with Network Development projects

Pole-mounted transformer replacement can be instigated by a range of growth-related factors, including new developments or increases in customer load through customer-initiated works (CIW).

In some cases, this can involve larger overhead line projects, including renewal reconductoring and pole replacements. Where possible, pole-mounted transformer renewal is coordinated with larger line upgrade/rebuild 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.

22.4 GROUND-MOUNTED DISTRIBUTION TRANSFORMERS

22.4.1 FLEET OVERVIEW

There are approximately 8,700 ground-mounted distribution transformers on our network. These are usually located in suburban areas and CBDs with underground networks, or supply large commercial or industrial sites. Ground-mounted transformers are generally more expensive to install and maintain than pole-mounted transformers, and serve larger and more critical loads compared with pole-mounted transformers.

The size of ground-mounted transformers depends on load density, but they are generally 50 or 100kVA in rural areas, 200 or 300kVA in newer suburban areas, and 500kVA to 1.5MVA in CBD and industrial areas. Larger units of the fleet – ranging from 2-3MVA and above – are predominantly installed at industrial sites.

The majority of the fleet are berm-mounted, either within a road reserve or in their own easement, and are stored in a variety of legacy lightweight steel or cast concrete enclosure types, or newer all-in-one single pad solutions containing the transformer and LV panel (from about 1980). Recently, we have approved some of the new enclosure types that include provision for HV switchgear. Small numbers of these have now been installed on our network.

Figure 22.5: 300 kVA ground-mounted transformer

In urban areas, some transformers are enclosed in a customer's building, housed in standalone concrete block enclosures or, at a small number of outdoor sites, in fenced-off areas. We have about 400 "building" kiosks, generally housing the HV switchgear, transformer, LV panel and associated cabling.

Figure 22.6: Concrete block distribution substation

22.4.2 POPULATION AND AGE STATISTICS

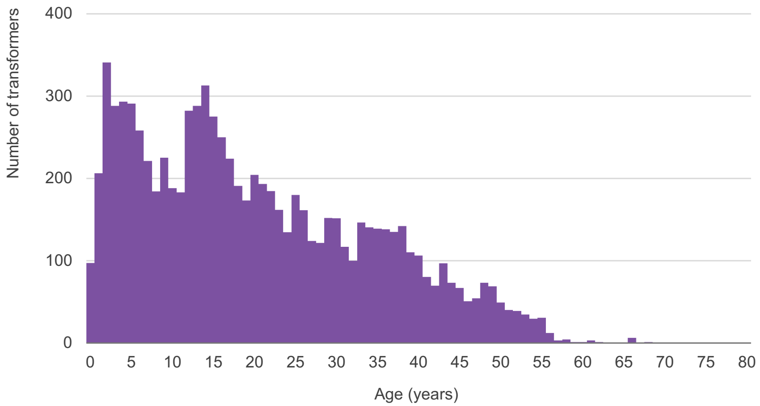
Table 22.4 summarises our population of ground-mounted distribution transformers by kVA rating. The smallest units have a size of approximately 100kVA, with larger units used for higher capacity installations.

Table 22.4: Ground-mounted distribution transformers population by rating

RATING	6.6 KV	11/6.6 KV	11 KV	22 KV	33KV	TOTAL
≤ 100kVA	12	6	2,292	5	5	**2,957**
> 100 and ≤ 200kVA	13	10	2,062	3		**2,088**
> 200 and ≤ 300kVA	19	10	2,068	4	9	**2,110**
> 300kVA	6	3	1,534		4	**1,547**
Total	**50**	**29**	**8,593**	**12**	**18**	**8,702**

Figure 22.7 shows our ground-mounted distribution transformer age profile.

Figure 22.7: Ground-mounted distribution transformers age profile



The ground-mounted transformer fleet is relatively young, with an average age of 20 years. Ground-mounted transformers generally have longer expected lives – 55 to 70 years – than pole-mounted units, particularly those we have located within buildings. This is because they are more frequently maintained due to their accessibility and higher criticality, and are often located inside enclosures, providing greater protection from environmental degradation. Because of this, we expect only a relatively small number of condition-based renewals during the planning period.

22.4.3 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, such as vehicle damage. The predominant causes of equipment degradation are:

- Accumulation of moisture and contaminant concentrations in insulating oil.
- Thermal failure because of overloads.
- Oil leaks through faulty seals.
- External tank/enclosure damage and corrosion.

LV panels

We manage LV panels as separate assets. Renewals of LV panels can occur separately to the transformer unit, typically in the case of reactive replacement following a failure or as part of our type issue replacement programmes. LV panels fail mainly because of overheating or insulation failure, and can often result in a fire. While rare, we have had failures of LV boards. Any failures are investigated to better detect and identify these points of failure at sites before they occur.

Some legacy LV board types present an increased risk of failure because of bare LV buses, ageing cables and connections, and the presence of deteriorating J-type fusing. There are approximately 107 porcelain J-type fused boards of 300kVA and above across the network. We are improving our inspections to identify these types of boards and taking a proactive approach to replacing these.

Type issues

Some of our older lightweight kiosk types make it difficult to properly inspect transformers for oil leaks or rust. We are generally including these for renewal when doing work on the network. We have approximately 71 “T-blade” transformers that are a type of compact transformer with inbuilt 3-way switches, used heavily in our Valley networks. Due to historic reliability issues with these switches, we no longer operate the switchgear, and we have a prioritised plan to replace these sites with modern fusing arrangements where these are directly on the main trunks of our feeders. We expect to complete this towards the end of the current planning period.

Distribution substation buildings

We have found that some of our older building kiosks do not have the seismic strength we require to ensure these distribution switching sites do not suffer damage during a major seismic event. As an extension to our zone substation building seismic strengthening programme, we have identified the distribution substation buildings that supply customers essential for disaster recovery following an earthquake, including: hospitals; Civil Defence centres; Three Waters.

We are investigating the seismic capability of these buildings to ensure we address any weaknesses via strengthening or renewal programmes to ensure we meet our commitments as a lifeline utility. More on our general resilience strategy can be found in Chapter 6.

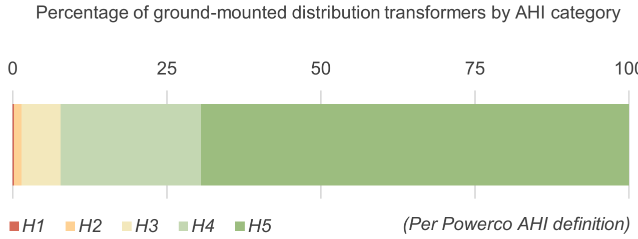
Meeting our portfolio objectives
Customers and Community: We are embarking on a programme to investigate the seismic capability of distribution substation buildings to ensure we address any weaknesses via strengthening or renewal programmes to ensure we meet our commitments as a lifeline utility.

Ground-mounted distribution transformers asset health

As outlined in Chapter 10, we have developed CBRM models that reflect the health and risk of our asset fleets. For ground-mounted transformers, this defines end-of-life as when the asset fails because of condition drivers.

Figure 22.8 shows current overall AHI for our population of ground-mounted transformers as calculated by our CBRM model.

Figure 22.8: Ground-mounted distribution transformers asset health as at 2021



As with the pole-mounted fleet, the overall health of our ground-mounted transformers is generally good. CBRM modelling shows an acceptable level of risk against the fleet, with few assets requiring replacement in the short term to maintain current risk levels. The criticality approach that this modelling allows us to apply has also shown that we may tolerate some additional deterioration of smaller ground-mounted transformers before replacement.

Meeting our portfolio objectives

Asset Stewardship: We are continuing to refine our asset health and criticality approaches to improve our asset renewal decision-making.

Locks and keys

Ground-mounted distribution transformers, and distribution switchgear assets, are made secure by padlocks. We have several legacy padlocking systems that have been inherited from previously separate networks. We do not have complete control over key access to these padlocks as not all keys have been returned by departing staff. Therefore our register of legacy key holders is incomplete. This raises the risk associated with unauthorised public access and prevents us from complying with legislative obligations.

Because of the need to ensure access to our assets is appropriately controlled, we are standardising all padlocks and keys using a high-security type that cannot be copied without authorisation. This work will be completed by the end of FY23.

22.4.4 DESIGN AND CONSTRUCT

The scope of the transformer monitoring initiative discussed above in Section 22.3 also includes the ground-mounted fleet. Some ground-mounted distribution transformers may be fitted with monitors when renewed.

To ensure distribution transformer monitors can be retrospectively installed, we will specify new ground-mounted distribution transformers house LV frames with sufficient space to mount a monitoring device, have pre-wired LV equipment fuses, and pre-installed CTs for each LV circuit.

22.4.5 OPERATE AND MAINTAIN

Ground-mounted transformers are more accessible to the public and, because of their size, are more critical as a greater number of customers are usually connected. Additionally, industrial and commercial customers are usually supplied from ground-mounted transformers. Because of this, ground-mounted transformers undergo more maintenance.

Our distribution kiosks have additional maintenance requirements, such as inspections of the doors, gutters, and vents. Since these usually house a combination of HV switchgear, distribution transformers, LV panel and associated cabling, these schedules are generally coordinated.

Our various preventive maintenance tasks are summarised in Table 22.5. The detailed regime is set out in our maintenance standard.

Table 22.5: Ground-mounted distribution transformers preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Ground-mounted distribution transformers	Visual safety inspection – check asset is secure.	6 monthly
	General visual inspection, check transformer tank, fittings for corrosion and damage. Thermal scan of connections and log Maximum Demand Indicator (MDI) readings.	Yearly
	Detailed inspection, thermal scan of connections and condition assessment. Oil sample on units >499kVA.	5 yearly
Distribution transformer kiosks and buildings	General visual inspection of the kiosk/ building – access or security, weather tightness, associated infrastructure, vegetation waterways are in good order.	6 monthly
	Detailed condition assessment and general clean of the kiosk/ building – access or security, weather tightness, associated infrastructure, vegetation waterways.	Yearly

Ground-mounted transformers are managed through a rotating spare pool strategy. Service provider depots have an appropriate stock of spares for each part of the network. Spares are available for fault response and for condition-based replacement.

Defective ground-mounted transformers are taken to the spares warehouses where they are assessed for workshop repairs or overhaul. A new or refurbished unit is used to replace a defective unit. Repair and overhaul work is undertaken according to our standards. Cost criteria are used to ensure the repair or overhaul works are cost effective. If they are not, the unit is disposed of, and a new unit is added to the spares stock.

Typical corrective work following inspections includes:

- Re-levelling base pads.
- Replacing blown fuses.
- Removing vegetation from enclosures.
- Removing graffiti.

22.4.6 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.

For our building kiosks, given the criticality of these sites, where assessed as seismically prone, we will either strengthen the buildings, or in cases where the cost of replacement/remediation can be prohibitive, we rebuild the site as a modern compact substation.

Meeting our portfolio objectives

Safety and Environment: We proactively replace ground-mounted distribution transformers before they fail, reducing public safety risks.

SUMMARY OF GROUND-MOUNTED DISTRIBUTION TRANSFORMERS RENEWALS APPROACH	
Renewal trigger	Proactive condition-based
Forecasting approach	Survivor curve
Cost estimation	Historical average unit rates

Renewals forecasting

We have recently developed CBRM models to assist in replacement forecasting and replacement prioritisation. This analysis allows us to manage the fleet on a condition and risk basis. We can maintain the current level of risk without further increasing expenditure by prioritising higher risk assets for replacement and deferring replacement of lower criticality assets.

LV panels are sometimes renewed reactively and not in conjunction with the associated ground-mounted transformer. Our forecast allows for some replacement of LV panels based on historical levels. As part of our drive to improve inspections, we are planning to better identify these types of installations and include these in our renewal programmes, where appropriate.

As previously discussed, replacement of many of the locks securing our ground-mounted transformers is warranted. Our forecast allows full replacement of all locks and keys that have not already been replaced, with the standardised, high-security units during the five-year period FY19-23.

Ground-mounted transformers 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. As with the pole-mounted transformer fleet, good condition units that have been removed from the network because of non-condition reasons, eg network growth and CIW, undergo minor repairs, such as repainting or re-gasketing before entering the pool of rotable spares.

Ground-mounted transformers disposal

Ground-mounted distribution transformers are decommissioned and disposed of when they are replaced. The principal transformer components of steel, copper and oil are recycled.

As with pole-mounted transformers, the oil in pre-1970 transformers often contained PCB, which is now known to be carcinogenic. We believe we have removed all models containing PCB. However, we continue to test older models for PCB before removing oil. Should we find PCB, a specialist disposal company would be employed to undertake the work.

Coordination with Network Development projects

Ground-mounted transformer replacement can be instigated by a range of growth-related causes but is most often driven by specific customer requirements through CIW.

An alternative solution to replacing a transformer for load growth reasons would be to relieve loading by installing an additional transformer. New customer connections, such as new residential subdivisions, are usually underground and the associated distribution transformers are ground-mounted.

22.5 OTHER TYPES OF DISTRIBUTION TRANSFORMERS

22.5.1 FLEET OVERVIEW

This section covers our remaining distribution voltage regulating equipment, such as conversion and SWER isolation transformers, capacitors and voltage regulators. The population of this sub-fleet is a relatively 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 like a distribution transformer but is typically of higher capacity and supplies a larger downstream distribution network than a typical distribution transformer. Therefore it has a higher reliability impact than a distribution transformer. These can be found in the remaining parts of the 6.6kV network we have in Taranaki, and the small amount of 22kV network in our Rangitikei area.

SWER isolating transformers convert from 11kV phase-to-phase to a SWER 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 two or three-bank, 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, but we do have some mobile units that can be used to assist in voltage support during distribution backfeed situations.

Figure 22.9: Collection of other distribution transformers

Capacitors — Voltage regulator — SWER isolation transformer

22.5.2 POPULATION AND AGE STATISTICS

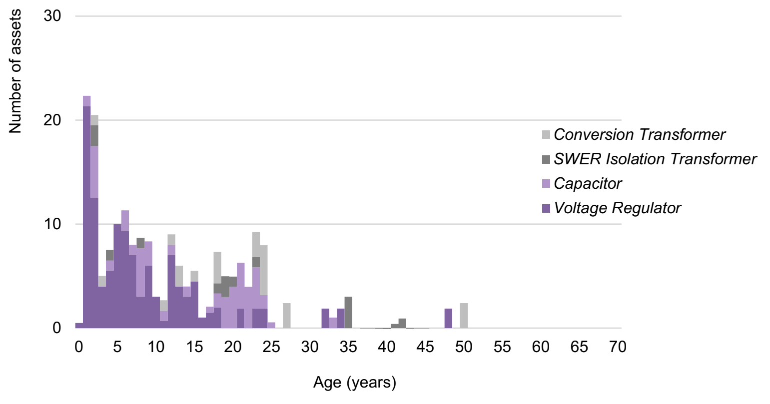
Table 22.6 summarises our population of other distribution transformers by type. Voltage regulators make up the largest portion of the fleet. We have been installing these devices during the past 15-20 years to manage voltage on the network.

Table 22.6: Other distribution transformers population by type

TYPE	NUMBER OF ASSETS	% OF TOTAL
Voltage regulator	117	60
Capacitor	44	22
Conversion transformer	22	11
SWER isolation transformer	13	7
Total	196	

Figure 22.10 shows the age profile of our other types of distribution transformers. The population is young, with an average age of 12 years. This is largely because of the recent prevalence of voltage regulators and capacitors technologies to help manage voltage. 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 22.10: Other distribution transformers age profile



22.5.3 CONDITION, PERFORMANCE AND RISKS

These transformers are of similar construction to pole or ground-mounted distribution transformers and, apart from capacitors, their failure modes are similar. Although rare, capacitors can suffer catastrophic failure, which may pose a safety risk to the public. Therefore, they undergo a more comprehensive set of tests than pole-mounted transformers.

Similar to other secondary systems assets, such as protection relays and Supervisory Control And Data Acquisition (SCADA) Remote Terminal Units (RTU), we expect controllers for voltage regulators will need replacement much earlier than primary equipment, so we have included an allowance in our forecast.

Given the young age of the fleet, its condition is relatively good with no known type issues. We do not anticipate a need for a significant renewals programme and, for now, envision replacing these transformers when they approach the end of their expected service life.

Spares

Given the long lead times for voltage regulators and their controllers, we hold a number of 200kVA and 300kV regulator tanks as critical spares to keep repair response times short.

22.5.4 DESIGN AND CONSTRUCT

We have processes in place that ensure ratings, installation configuration, and range of operation are 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.

22.5.5 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. Voltage regulators, however, contain mechanical switching devices and electronic controls and require a more thorough maintenance regime.

Capacitors are built differently than transformers and have different types of failure modes. They have their own maintenance regime.

Our various preventive maintenance tasks are summarised in Table 22.7. The detailed regime is set out in our maintenance standards.

Table 22.7: Other distribution transformers preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Capacitors	Thermal imaging scan of connections and leads.	2.5 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.	2.5 yearly
	Inspect tank and general fittings for corrosion. Carry out oil dielectric strength, acidity and moisture testing.	5 yearly
	Winding insulation tests, tapchanger operational checks	15 yearly
SWER and conversion transformers	See pole and ground-mounted distribution transformer maintenance.	

22.5.6 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 are immediately replaced to minimise the impact on customers.

SUMMARY OF OTHER DISTRIBUTION TRANSFORMERS 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 approximately constant during the planning period and in line with historical quantities.

Coordination with Network Development projects

There are several alternative 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 Remote Area Power Supply (RAPS) if the line also requires renewal.

As rural businesses grow, such as the dairy sector, 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 during the planning period.

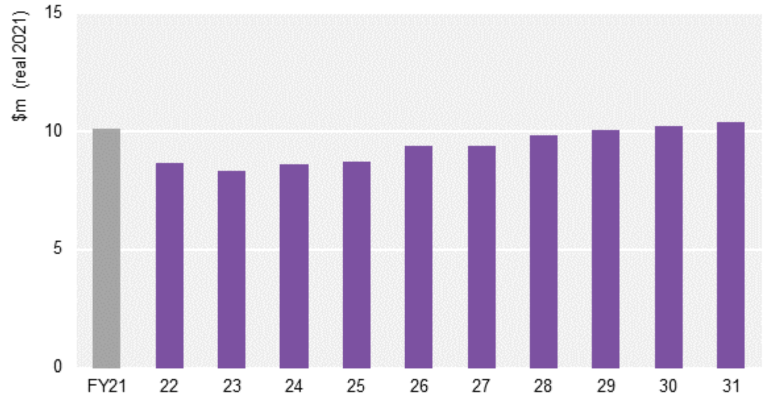
22.6 DISTRIBUTION TRANSFORMERS RENEWALS FORECAST

Renewal Capex in our distribution transformers portfolio includes planned investments in our pole-mounted, ground-mounted and other distribution transformers fleets. During the planning period we plan to invest approximately $94m in distribution transformers renewals

Renewals are derived from bottom-up models. These forecasts are volumetric estimates, which are explained in Chapter 28. 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.

Figure 22.11 shows our forecast Capex on distribution transformers during the planning period.

Figure 22.11: Distribution transformers renewal forecast expenditure

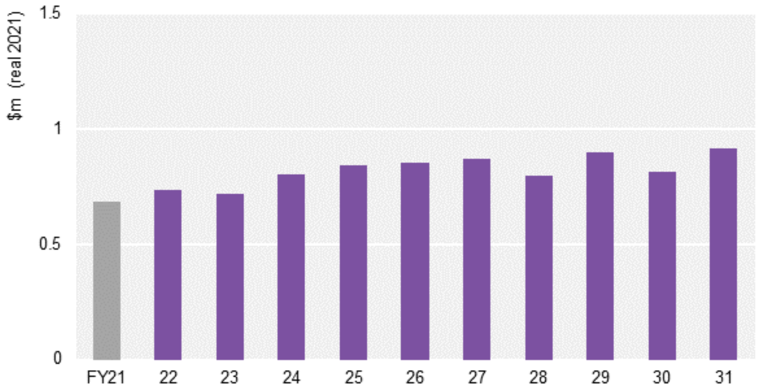


Forecast renewal expenditure is generally in line with historical levels.

22.7 DISTRIBUTION TRANSFORMERS PREVENTIVE MAINTENANCE FORECAST

Our fleet is well maintained with most maintenance activities focused on regular safety inspections and corrosion prevention. Major maintenance is predominantly driven by performance and reliability, allowing us to manage costs.

Figure 22.12: Distribution transformers preventive maintenance forecast



Distribution transformers account for approximately 7% of our preventive maintenance spend, which targets corrosion management and public safety. The deployment of the LV monitoring strategy will add further to the condition assessment knowledge of these assets, which may see their maintenance approach evolve in the future.

23 DISTRIBUTION SWITCHGEAR

23.1 CHAPTER OVERVIEW

This chapter describes our distribution switchgear portfolio and summarises our associated fleet management plan. Distribution switchgear refers to switching equipment generally located externally to zone substations. The portfolio includes four fleets:

- Ground-mounted switchgear, typically ring main units (RMUs)
- Pole-mounted fuses
- Pole-mounted switches
- Circuit breakers, reclosers and sectionalisers

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 plan to invest $99m in distribution switchgear renewal. This accounts for 11% of renewals Capex during the period.

Continued investment is needed to support our safety and reliability objectives. Renewal Capex is driven by:

- Replacement of older, type-issue KFME and OYT reclosers, which have been showing increasing levels of maloperation, leading to nuisance trips or delayed fault isolation – estimated completion FY23.
- Continuation of our locks standardisation programme, to reduce risk of unauthorised public access to our switchgear through replacement of non-standard, ageing or damaged padlocks – estimated completion FY23.
- Continuation of our programme of arc flash safety upgrades on our older 11kV switchboards at the Kinleith pulp and paper mill – estimated completion FY27.
- To manage public safety risk, continued investment to renew our outdoor oil RMU fleet, which does not meet our modern requirements for arc flash containment.
- Replacement of older orphaned switchgear types to standardise our fleet.

We have also forecast a substantial uplift in our intrusive maintenance programmes for this type of equipment, to ensure that these can continue to be operated safely to the end of their service lives.

Below we set out the Asset Management Objectives that guide our approach to managing our distribution switchgear fleets.

23.2 DISTRIBUTION SWITCHGEAR OBJECTIVES

The distribution switchgear portfolio contains a diverse population of assets with a wide range of types and manufacturers. Switchgear technology has evolved over time, with general improvements to operator safety and reliability, and reductions in intrusive maintenance requirements, particularly in the movement from oil quenched switchgear, to gas and vacuum interrupter types.

While oil switchgear is no longer used for new installations, because of the age of the network we still have large quantities of oil-based switchgear – around half of the ground-mounted switchgear fleet is oil-based.

We mitigate the failure risk of the fleet through routine maintenance, condition monitoring, operating procedures and, where necessary, operating restrictions. Where they are available, we also require the use of remote switching or portable actuators to reduce the likelihood of operator injury.

To guide our asset management activities, we have defined portfolio objectives for our distribution switchgear fleets. These are listed in Table 23.1. The objectives are linked to our Asset Management Objectives as set out in Chapter 4

Table 23.1: Distribution switchgear portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	No injuries or incidents from explosive failure or maloperation of switchgear.
	No significant oil or SF_6 (sulphur hexafluoride) leaks from distribution switchgear assets.
Customers and Community	Minimise interruptions to customers through equipment failure or maloperation.
	Ensure that switchgear is available to be used as intended, providing the required network flexibility to minimise customer interruptions during network switching and to facilitate rapid restoration of outages.
Networks for Today and Tomorrow	Increase use of Supervisory Control And Data Acquisition (SCADA) and remote switching to further improve fault isolation and restoration times for customers.
	Continue to evaluate new switchgear technology for general or specific use on the network, with a view to improving network operation and safety, and managing lifecycle cost.
Asset Stewardship	Ensure that fleets are safe to operate and do not place the community at risk.
	Reduce fleet diversity over time to optimise asset whole-of-life costs and improve safety and reliability by reducing human factor related problems.
Operational Excellence	Complete development of criticality frameworks for distribution switchgear.

23.3 GROUND-MOUNTED SWITCHGEAR

23.3.1 FLEET OVERVIEW

Ground-mounted switchgear provides distribution network isolation, protection and switching facilities. Ground-mounted switchgear includes RMUs, switches, fuse switches, links and associated enclosures. In general, ground-mounted switchgear is associated with our underground network, although some supports overhead sections.

The fleet comprises a range of makes and models with various insulating media associated with advances in technology over time. During the past five years we have predominantly installed SF_6 switchgear, but we also continue to operate a large fleet of oil-filled and cast resin switchgear.

Ground-mounted switchgear is installed within purpose-built switchrooms, on road-side berms, or within smaller, lightweight kiosks.

Figure 23.1: Ground-mounted switchgear

23.3.2 POPULATION AND AGE STATISTICS

Table 23.2 shows our population of ground-mounted switchgear by configurations and insulating media.

There is significant diversity within this fleet because of the age profile and historical predecessor companies, with more than 20 manufacturers represented.

This diversity increases maintenance and servicing costs, as well as the amount of training required for field personnel. This has the potential to affect operator safety when maintaining and operating this equipment.

In addition, older switchgear does not meet our modern requirements around arc flash mitigation, which presents a risk to operators and public.

As such, our replacement strategies include removal of older and less represented models from the fleet.

Table 23.2: Ground-mounted switchgear population by type

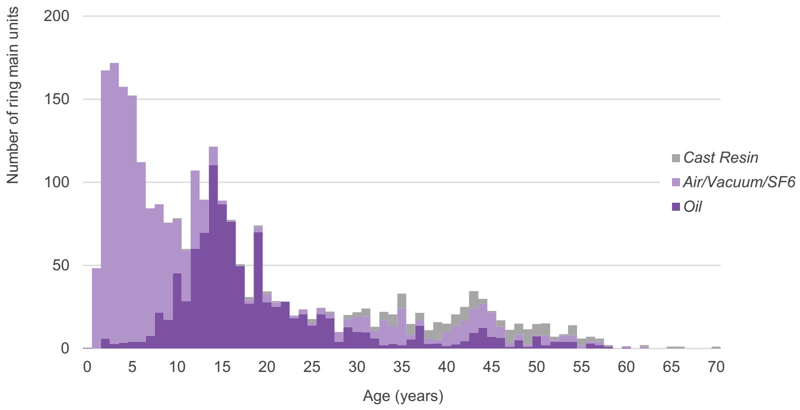
INSULATION TYPE	NUMBER OF RING MAIN UNITS	NUMBER OF INDIVIDUAL SWITCH UNITS
Oil	1,014	1,129
Air/Vacuum/SF_6	1,363	199
Cast resin	172	24
Total	2,548	1,352

Meeting our portfolio objectives

Asset Stewardship: Asset replacement over time will remove older oil types, replacing them with safer, lower maintenance modern types. Our replacement programme will also reduce diversity in the ground-mounted switchgear fleet, helping us to manage whole-of-life costs and reduce the incidence of operator-induced errors.

Figure 23.2 shows the age profile of our population of RMUs.

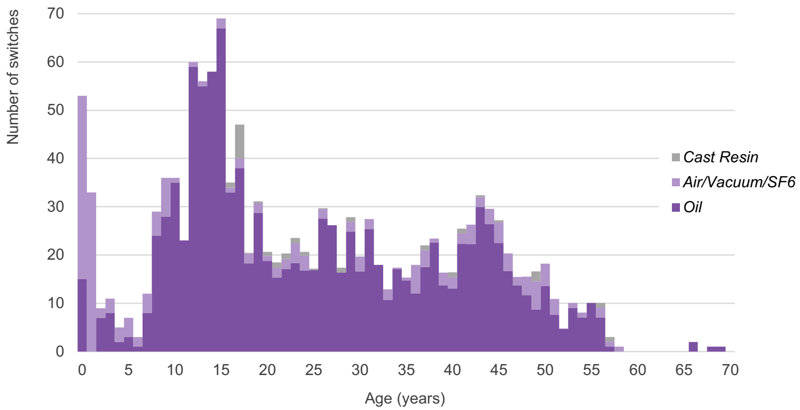
Figure 23.2: RMU age profile



We now install predominantly SF_6 RMUs for improved safety and reduced maintenance requirements compared with older types.

Figure 23.3 shows the age profile of our population of individual ground-mounted switches. These assets are generally older than the RMUs because of past design practices, and they have a much greater level of manufacturer diversity.

Figure 23.3: 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.

23.3.3 CONDITION, PERFORMANCE AND RISKS

While in generally good condition, because of the quantities of switchgear we operate, the proximity to operators and public, and the high impacts of failure, it is important that potential failure modes are understood and appropriately mitigated.

Details of potential issues and mitigation measures for each general type are discussed below.

Cast resin switchgear

Cast resin switchgear performs satisfactorily if located in dust-free, dry environments and regularly maintained. If installed in cubicles without heating or in a dusty environment, surface condensation results in electrical tracking and degradation of the cast resin surfaces. This issue is prevalent in our coastal networks in Taranaki, Thames Valley and Waikato.

The design of cast resin switchgear also creates issues because of the way each phase is switched individually, often with many units in series with each other. This can result in operational constraints when transferring load. Replacing cast resin switchgear with other switchgear is costly and difficult because alternative switchgear tends to have a larger footprint requiring extensive modification to the substation site.

Oil switchgear

Oil switchgear, installed from the early 1960s to the mid-2000s, is relatively cost effective and simple in design for high voltage (HV) protection and switching, which is why it represents a significant portion of our current operating fleet. However, it has onerous and costly intrusive maintenance requirements compared with other switchgear types, and has the potential to fail explosively if not maintained properly. Additionally, because of the age of the fleet, some types are often no longer supported by their manufacturers, and many are past their expected service life.

Some types of oil switchgear have minimal designed electrical clearances within their tanks, which makes them more susceptible to failure because of internal deterioration. We have experienced a small number of explosive failures of these types.

We have also experienced a high rate of failure on some earlier busbar extension chambers that were not originally designed with adequate insulation or voltage stress control, resulting in internal flashover and lost supply of the feeder.

A series of recent operating incidents in our industry has caused some concerns about the safety of personnel when operating oil switchgear – particularly switchgear in confined spaces. We have adopted remote operating devices, such as mechanical actuator units or lanyards when operating oil switchgear.

Risk is also impacted by installation context. We have subdivided our oil RMU fleet into two major sub-categories:

Outdoor RMUs

A significant proportion of our ground-mounted switchgear fleet is located outdoors, with much of it located in road berms. We have found switchgear degrades faster in outdoor environments because of rust, particularly in our coastal networks in Tauranga and Taranaki, and types that are susceptible to moisture ingress issues. Given the high impact low probability (HILP) potential failure modes, we schedule replacement based on type, condition and location, to manage public safety risk.

Indoor RMUs

The indoor switchgear fleet is generally older than our outdoor fleet, as building kiosks normally service the older parts of our network. Generally, these are in good condition for their age. In some older distribution substations, arc flash risk combined with a restricted operating position can limit effective egress, presenting a risk to our operating field staff. We are prioritising remedial work for these situations according to their risk profiles.

Given the risks of this fleet, we are undertaking a range of steps to significantly improve safety around this equipment. This is covered in more detail below.

Improvements to ground-mounted switch management

In March 2018, we had an independent consultant carrying out a review of our ground-mounted switchgear management practices. This review raised a number of improvement areas that we are addressing through the following:

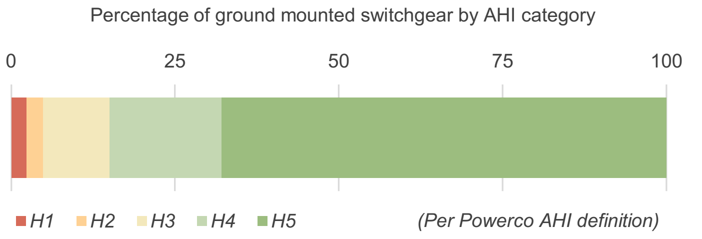
- Continued refinement of our operating restrictions on certain models of oil switchgear.
- Introduced remote operating devices, such as lanyards and actuator operating requirements, on this type of equipment.
- Updated maintenance practices to ensure they are more consistent with international good practice and adequately mitigate risk.
- Increased our maintenance requirements for these types of switchgear, intended to improve our understanding of the condition of this fleet, and inform replacement priority (discussed in more detail in the operate and maintain section below).
- Progressed data quality programmes to improve our classification of types and installation context for our ground-mounted switches, to better understand risk.
- Introduced condition-based risk management (CBRM) modelling to improve our ability to prioritise our renewal programmes to maximise risk reduction.

Ground-mounted switchgear asset health

As outlined in Chapter 10, we have developed CBRM models that reflect the remaining life of each asset. These models categorise each asset's health based on a set of rules allowing the prediction of end-of-life.

For ground-mounted switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely. The Asset Health Indices (AHI) is based on multiple data sources, including asset age, environmental situation, condition, historical performance and known type issues. Figure 23.4 shows current overall AHI for our ground-mounted switchgear fleet.

Figure 23.4: Ground-mounted switchgear asset health as at 2020



A small proportion of the fleet is assigned health grades of H1 and H2. This is primarily comprised of poor condition switchgear, which we are planning to replace.

Locks and keys

There are risks associated with the legacy padlocking systems used to protect our ground-mounted switchgear from unauthorised access.[91] To manage these risks we have a programme to replace all locks and keys with standardised, high-security types.

23.3.4 DESIGN AND CONSTRUCT

Ground-mounted distribution switchgear is classified as class A equipment and any new equipment undergoes a detailed evaluation process to ensure it is fit for purpose on our network.

Given the safety risk that switchgear failure presents to both operators and the public, we require new switchgear to be rated for either class A or class B internal arc flash containment (IAC).

IAC class B is equipment that is accessible by the public, and IAC class A is equipment in Powerco-controlled locations accessible only by authorised personnel wearing appropriate personal protective equipment (PPE).

91 For more detail, refer to the same section in the ground-mounted transformers fleet within Chapter 22.

IAC-rated switches and enclosures have been type tested to ensure that in the event of internal failure, arc flash heat and blast energies are diverted or dissipated to such a level that any people near the switch are safe.

Oil switchgear was not tested for internal arc flash containment and, accordingly, does not have an IAC classification.

New installed switchgear is specified to enable future automation and remote operation capability. Remote operation reduces switching/restoration times and provides greater safety for operators. As remote operation may allow equipment to be operated without an observer, to ensure the area around the switch is clear from members of the public, this type of automation is only applied to new installations with enclosures that are designed with full arc flash containment.

23.3.5 OPERATE AND MAINTAIN

Regular inspection and maintenance of our ground-mounted switchgear is required to ensure the safe operation of our distribution network. As this switchgear is often located in areas accessible to the public, it is vital the enclosures are always locked and secure.

Our various preventive maintenance tasks are summarised in Table 23.3. The detailed regime is set out in our maintenance standards.

Table 23.3: Ground-mounted switchgear preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
General inspection of switchgear buildings/enclosures.	6 monthly
General inspection of switchgear condition. Partial discharge and acoustic diagnostic tests.	Yearly
Switchgear service and operating checks. Diagnostic thermal scan.	5 yearly
Major maintenance, oil sample test and oil replacement for oil switchgear.	10 yearly

Maintenance requirements have been determined from manufacturers' recommendations, combined with our experience in maintaining and operating each asset type within our local operating environments. The six-monthly and yearly inspections are non-invasive safety driven inspections.

Switchgear components degrade over time and with the number of individual operations they perform. Older style oil switchgear requires more maintenance than SF_6 or vacuum gear.

We are undertaking an intensive maintenance programme on our oil-filled RMU fleet, which includes oil analysis, oil replacement, internal inspection and minor repairs in order to:

- Ensure the fleet can operate safely and reliably until end-of-life.
- Supplement our current condition data to better inform our replacement programme.
- Proactively identify any underlying type issues with our older fleet.

To align with our condition-based maintenance strategy and build on this maintenance programme, we are investigating suitable online oil condition monitoring devices. We anticipate a pilot rollout early FY22 in conjunction with the maintenance programme. These will potentially provide better insights into the continued performance of the fleet to complement our renewals programme.

Switchgear is generally berm-mounted and therefore exposed to weather deterioration and damage from vehicles. We minimise the incidence of damage by carefully choosing the location of switchgear and, in some cases, by installing protective bollards.

Corrective actions for switchgear include:

- 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.

23.3.6 RENEW OR DISPOSE

Renewal plans for ground-mounted distribution switchgear are now developed using our CBRM models.

Renewal decisions are made on a risk prioritised basis combining both the condition and likelihood of failure with the consequences of failure, considering safety, customer service, lifecycle costs and the environment.

This approach prioritises expenditure towards equipment with the highest combined likelihood and consequences of failure, predominantly older oil types situated in publicly accessible areas. Switchgear with industry known type issues is given high priority for replacement – these individual sites are then prioritised according to CBRM risk rankings.

Wholesale removal of our cast resin switchgear population is not necessary at this time, but we have established a prioritised replacement programme based on asset condition and potential network performance impact.

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

Renewals forecasting

Our CBRM models also allow us to develop forecasts of asset health and risk to determine our future renewal requirements.

Our planned investment will address existing assets identified as being industry known type issues, or those in poor health. Overall, in planning switchgear replacement programmes, we aim to retain our present overall risk profile.

As discussed previously in the condition, performance and risks section, the replacement of many of the locks securing our ground-mounted switchgear is required. Our forecast allows for replacement of locks and keys that have not already been replaced with the standardised, high-security units.

Coordination with Network Development projects

When existing ground-mounted switchgear is replaced, we use modern equivalent SF_6 or vacuum type RMUs because they have lower ongoing maintenance requirements and have modern safety features.

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 disruption to customers and the community. New switches are procured with remote operation capability so, if required, this capability can be enabled to implement network automation schemes.

23.4 POLE-MOUNTED FUSES

23.4.1 FLEET OVERVIEW

Pole-mounted fuses provide protection and isolation for distribution transformers and, in rural areas, fault isolation for tee-offs supplying low customer density spur lines or cables.

Pole-mounted fuses are non-ganged, single pole devices that are mechanically simple, using mature and proven technology. Some early fuse types, however, are susceptible to corrosion, have insufficient clearance to meet standards for minimum approach distances, and may be susceptible to stress-cracking of insulators. Later and current models have addressed these issues.

Models with noted corrosion and compliance issues have largely been replaced. Models prone to cracking are replaced based on condition.

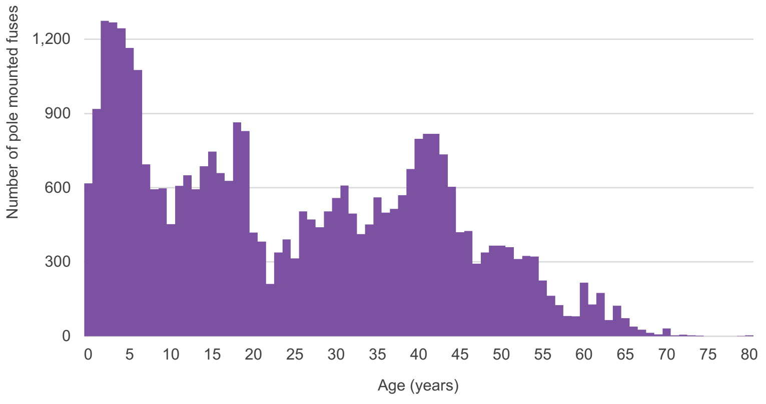
Figure 23.5: Pole-mounted drop out fuse

23.4.2 POPULATION AND AGE STATISTICS

The population of our pole-mounted fuse fleet is approximately 34,000. Many manufacturers are represented, but equipment is all very similar in design and function.

Figure 23.6 shows the age profile of our population of pole-mounted fuses.

Figure 23.6: Pole-mounted fuses age profile



The age profile indicates that a substantial portion of the fleet is older than a nominal asset life of 40 years, suggesting a need for continuing renewal expenditure. The profile also indicates a substantial number of assets less than five years of age, which is the result of new assets and recent renewal expenditure.

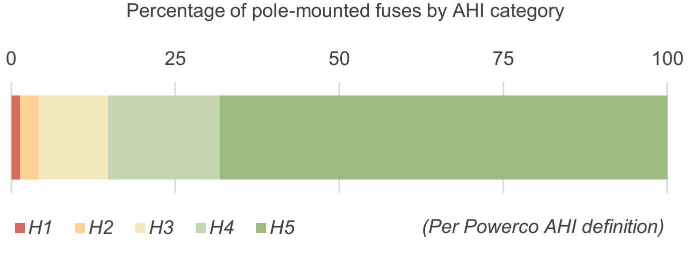
23.4.3 CONDITION, PERFORMANCE AND RISKS

Pole-mounted fuses asset health

As outlined in Chapter 10, we have developed AHIs that represent the remaining life of each asset. Our AHI models categorise asset health based on defined rules. For pole-mounted fuses our AHI is calculated using the combination of age profiles and survivor curves.

Figure 23.7 shows current AHI for our population of pole-mounted fuses.

Figure 23.7: Pole-mounted fuses asset health as at 2020



The AHI profile indicates that the fleet is broadly in good condition with approximately 10-15% likely to require renewal during the next 10 years (H1-H3). The AHI profile also shows some fuses require renewal in the short term (H1). These will be identified and rectified through our condition assessment and defect processes.

Risks

Certain types of pole-mounted fuses present fire risks when installed in dry areas as they can potentially cause sparks should the fuse operate. In the near term, we aim to prioritise the renewal of these fuses in areas of fire risk.

23.4.4 DESIGN AND CONSTRUCT

Fuse selection is based on the specific protection and operating needs of the network. When a distribution line is renewed, fuses supplying spur lines may be replaced with more effective devices, such as reclosers or sectionalisers, to enhance network operability and reliability.

The fuses used on our network must comply with industry standards. Before a new type of fuse can be used on the network it must be evaluated to ensure the equipment is fit for purpose.

23.4.5 OPERATE AND MAINTAIN

Our pole-mounted fuse fleet is inspected as part of our overhead line inspections, which check for damage, corrosion, and deterioration. Any remedial work is managed via our defect process. The inspection task and frequency is summarised in Table 23.4. The detailed regime is set out in our maintenance standard.

Table 23.4: Pole-mounted fuse preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection for corrosion and defects.	5 yearly

23.4.6 RENEW OR DISPOSE

Our renewal strategy for pole-mounted fuses is based on a combination of observed condition and known type issues. If an inspection identifies a defect, the fuse is scheduled for renewal as part of the defect management process. Alternatively, we may target the renewal of known problematic types or types nearing end-of-life during network renewal projects. Some fuses are replaced reactively after a fuse link operation because of their poor condition.

The consequences of failure are minor, and replacement can be carried out quickly. We also proactively replace ageing fuses as part of our overall pole replacement programme.

SUMMARY OF POLE-MOUNTED FUSES RENEWALS APPROACH

Renewal trigger	Reactive and condition-based
Forecasting approach	Survivor curve
Cost estimation	Volumetric average historical rate

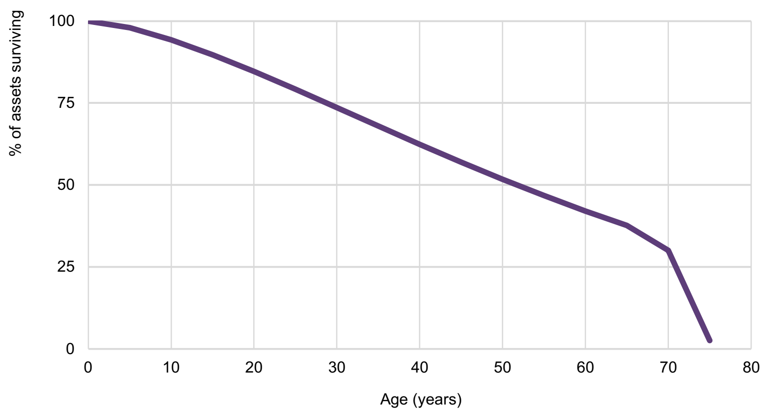
Renewals forecasting

Our pole-mounted fuse replacement quantity forecast is based on survivorship analysis using survivor curves developed from historical replacement data.

During the past 10 years, we have collected detailed information on the fuse disposals and failure modes. Our survivor analysis reveals that fuse replacement age varies, primarily because of 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.

Figure 23.8 shows the pole-mounted fuse survivor curve. The curve indicates the percentage of population remaining at a given age.

Figure 23.8: Pole-mounted fuse survivor curve



Because of the age profile (Figure 23.7) and the above curve, we expect annual pole-mounted fuse renewals to remain relatively constant during the planning period. As we inspect and replace further fuses we will use this data to refine our modelling.

Coordination with Network Development projects

Before renewing a network fuse, we review the ongoing need for equipment in that position. This review may find that a fuse should be upgraded to a recloser, installed elsewhere, or retired.

23.5 POLE-MOUNTED SWITCHES

23.5.1 FLEET OVERVIEW

The pole-mounted switch fleet comprises air break switches (ABS), vacuum insulated isolators and SF_6 gas insulated isolators.

Air break switches (ABS)

ABS are typically three-phase, ganged manual switches that can be operated using a handle mounted at ground level. They are used for network configuration, including sectionalising feeders to find and isolate faults, as open points between feeders, and for allowing worker access to the network for maintenance or construction works.

Because of the exposed nature of their mechanisms, these switches require regular maintenance to ensure they operate correctly.

A standard ABS has limited capacity to break load current. It is usually 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 to relatively light loads.

ABS have undergone various design and material specification improvements over time. Newer types have improved alignment, which has reduced maintenance requirements and operating issues, and they have better corrosion performance.

We continue to install ABS in applications where remote control capability is not essential and load break capability is not required. However, as the technology matures we expect to eventually stop installing new ABS and transition to either enclosed SF_6 or vacuum switches, because of lower lifecycle costs.

Vacuum and SF_6

Vacuum or SF_6 insulated switches are modern equivalents of ABS that have been used where remote control is required, and where high load currents need to be switched.

They are considered safer and more reliable to operate when compared with an ABS because, firstly, the mechanisms are enclosed leading to a much lower maintenance requirement than traditional ABS and, secondly, contact separation speed is assisted by use of springs and is not operator dependent.

There have been some early issues because of mounting design and tank corrosion, but this is expected to be resolved in the longer term. Our fleet of vacuum and SF_6 switches is relatively young. They can be specified with motorised operation and full automation capabilities.

Figure 23.9: Air break switch (ABS)

23.5.2 POPULATION AND AGE STATISTICS

We have approximately 5,000 pole-mounted switches on our network. There is significant diversity in our ABS fleet with many manufacturers represented. 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.

Table 23.5 summarises our population of pole-mounted switches by type.

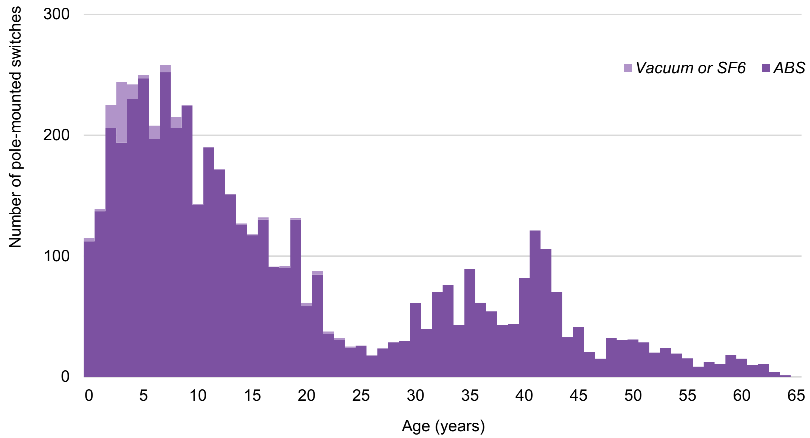
Table 23.5: Pole-mounted switch population by type

TYPE	NUMBER OF ASSETS	% OF TOTAL
ABS	5,062	97
Vacuum or SF_6	136	3
Total	5,198	

As we have only recently started installing vacuum and SF_6-based switches, the number in use is small – approximately 3% of the fleet population. As ABS are replaced with vacuum or SF_6 switches, their share will grow.

Figure 23.10 shows our pole-mounted switch age profile. Only a small proportion of pole-mounted switches exceed their nominal 45-year expected life.

Figure 23.10: Pole-mounted switch age profile



We have undertaken significant ABS renewal to replace poor condition switches and those with insufficient maintenance, in part because of the difficulty in obtaining shutdowns. This is reflected in the large number of younger ABS on the network.

23.5.3 CONDITION, PERFORMANCE AND RISKS

Risks

Pole-mounted switches have several known performance issues. Operating a defective ABS can cause failure, resulting in a flashover. Standard operating practice is to check the switch as thoroughly as practicable before operating. Operators are required to wear PPE.

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 failure mode does not present significant safety risk and is addressed either reactively or through routine maintenance.

Another issue relates to operating mechanisms that can seize up when switches are not operated. This is addressed through our maintenance regime, which specifies periodic operation of switches, coupled with scheduled maintenance.

Some older quadrant wire switch types, used in the Thames Valley and Tauranga areas, can have their operating wires deteriorate and break during operation, making the switch inoperable. In the worst case, this can leave the switch in a partially open state, leading to switching delays and larger outage areas. These are being included in replacement plans when located.

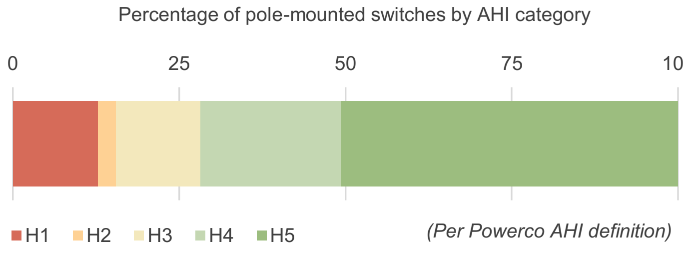
We have some installations where distribution ABS were installed underneath sub-transmission overhead lines. During load breaking operation of the switch, there is a risk that arcing during operation could lead to flashover to the circuits above, leading to explosive switch failure and loss of supply. (We are in the process of identifying high-risk sites that we will programme for replacement with enclosed switches).

Pole-mounted switches asset health

As outlined in Chapter 10, we have developed AHIs that reflect the remaining life of an asset. Our AHI models categorise asset 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 life.

Figure 23.11 shows current overall AHI for pole-mounted switch fleet.

Figure 23.11: Pole-mounted switches asset health as at 2020



The figure indicates that about 28 of our fleet will require renewal in the next 10 years (H1-H3). About 13% of pole-mounted switches have already exceeded their expected life and likely require replacement (H1) in the near term.

Locks and keys

There are risks associated with the legacy padlocking systems used to protect our pole-mounted switchgear from unauthorised access.[92] To manage these risks we will replace all locks and keys that have not already been replaced with the standardised, high-security units.

23.5.4 DESIGN AND CONSTRUCT

In addition to replacements with modern flicker-style ABS, we have started introducing vacuum and SF_6 switches in corrosion-prone areas in place of standard ABS. While these switches have a higher purchase cost, they have much lower intrusive maintenance requirement, are capable of interrupting higher load currents than standard ABS can achieve, and can be made remotely operable.

SF6 and vacuum pole-mounted switch types can be purchased in "automation ready" configurations. The installation of "automation ready" switches at critical interconnection sites in distribution networks provides additional benefits for remotely controlled network operations.

Switches equipped with internal isolators are preferred over those requiring external isolators, in order to satisfy our requirement for a visible gap when working on overhead networks.

Our updated reliability and automation strategy is discussed in Chapter 16.

When renewing an ABS, we will consider these additional benefits and select the best configuration for its function on the network. We are also trialling other modern switch types.

23.5.5 OPERATE AND MAINTAIN

Our ABS maintenance regimes differ depending on the location of the switch and the load it is serving. Switches in built-up areas undergo more frequent inspections and servicing compared with rural switches. Our preventive maintenance tasks for this fleet are summarised in Table 23.6. The detailed regime is set out in our maintenance standards.

Table 23.6: Pole-mounted switch preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
ABS – built-up area	Operation and major maintenance of contacts, pantographs, mechanisms. Contacts and jumpers thermal scan. (Both tasks done 5 yearly, but alternate 2.5 years apart).	5 yearly
ABS – rural area	Visual inspections of contacts, pantographs. Inspect, lubricate and operate switch.	5 yearly
	Operation and major maintenance of contacts, pantographs, mechanisms.	10 yearly
Vacuum and SF_6	External visual inspection and thermal scan.	5 yearly

We have recently considered potential areas of improvement to allow us to better ascertain switch condition. We are trialling alternative inspection methods, including acoustic testing and high-resolution aerial photography 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.

[92] For more detail refer to the same section in the ground-mounted transformers section of this chapter.

23.5.6 RENEW OR DISPOSE

Our renewal strategy for pole-mounted switches is condition-based replacement. Switches with identified defects are scheduled for replacement as part of the defect management process.

We are replacing aged ABS with modern low maintenance types of ABS or SF_6 and vacuum switchgear. These types of switchgear are expected to have service lives up to 45 years.

We are also collecting data on some poor performing types of ABS, such as the quadrant-wire models, which we will incorporate into our renewal plans. Should a switch fail, it is replaced immediately on a like-for-like basis to minimise the impact on customers.

SUMMARY OF POLE-MOUNTED SWITCHES RENEWALS APPROACH

Renewal trigger	Proactive condition-based and type issues
Forecasting approach	Age
Cost estimation	Volumetric average historical rate

Renewals forecasting

Our renewals forecast uses age as a proxy for condition. ABS are relatively simple mechanical devices that are exposed to the elements, and therefore their condition worsens over time through corrosion and mechanical wear.

We expect annual renewal expenditure for pole-mounted switches to remain approximately constant during the planning period.

Coordination with Network Development projects

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. We also take the opportunity to replace these switches with automation-capable devices where this aligns with the automation plan for the network.

23.6 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

23.6.1 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 includes relays for protection sensing and tripping, some of which can be programmed for distribution automation schemes. As with other types of switchgear, we operate a fleet with a mixture of models as technology has changed over time from oil to SF_6 and vacuum.

Circuit breakers

Circuit breakers, in the context of this fleet, are associated with distribution substations.[93] Circuit breakers are not widely used on the distribution network but are typically installed within major customer facilities.

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 circuits and equipment, and allow for access to the customer network for maintenance and construction works.[94]

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, therefore reducing the area affected by a fault. They can also be set to be more sensitive to downstream earth faults than feeder circuit breaker protection, which improves safety.

The term recloser refers to the device's ability to attempt to automatically restore supply for transient faults. 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.

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 typical of rural sections.

The technology for these devices has undergone a great deal of change over time. Most of the advances relate to the electronic control functionality, which now has greater capability to support distribution automation. The electronic controls require management of firmware and settings, and we expect the electronic control equipment will likely require replacement before the switchgear itself.

Sectionalisers

Sectionalisers are similar to reclosers in that they have some level of sensing, but are generally designed to work in coordination with an upstream recloser. As sectionalisers do not have the capability to interrupt fault current, they rely on the upstream circuit breaker or recloser to clear the fault, before opening. It then isolates the downstream portion of the feeder during the brief period when the feeder is de-energised. The upstream device then recloses to restore supply to the upstream portion.

93 Zone substation circuit breakers are discussed in Chapter 21.
94 Of note is the Oji Fibre Solutions and CHH site at Kinleith, which houses 26 switchboards, comprising approximately half of the distribution circuit breaker fleet.

Figure 23.12: A pole-mounted sectionaliser

23.6.2 POPULATION AND AGE STATISTICS

Table 23.7 summarises our populations of circuit breakers, reclosers and sectionalisers, split by interrupter type. This split is important because oil-based interrupters have higher safety risks under failure. In addition, older recloser types have limited protection functionality, reducing their flexibility.

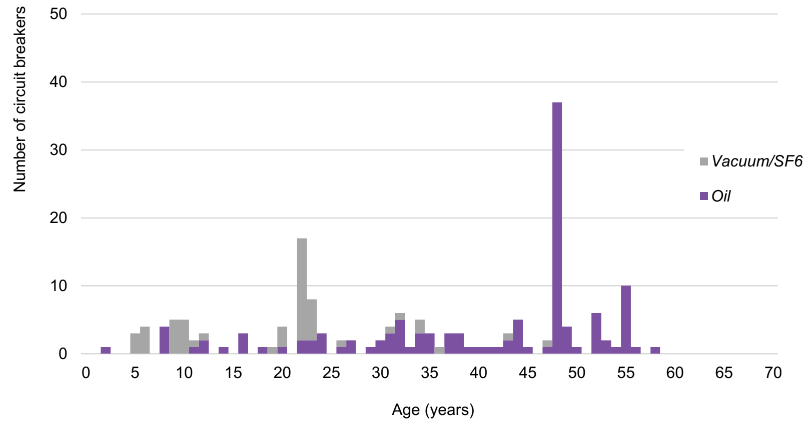
Approximately 70% of the circuit breaker fleet is oil-based, almost half of which is located at a single customer site at Kinleith.

Table 23.7: Circuit breakers, reclosers and sectionalisers population by type

TYPE	INTERRUPTER TYPE	NUMBER OF ASSETS	% OF TOTAL
Circuit breakers	Oil	145	20
	SF_6/vacuum	68	9
Reclosers	Oil	5	1
	SF_6/vacuum	344	48
Sectionalisers	Oil	9	1
	SF_6/vacuum	147	20
Total		**718**	

Figure 23.13 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.

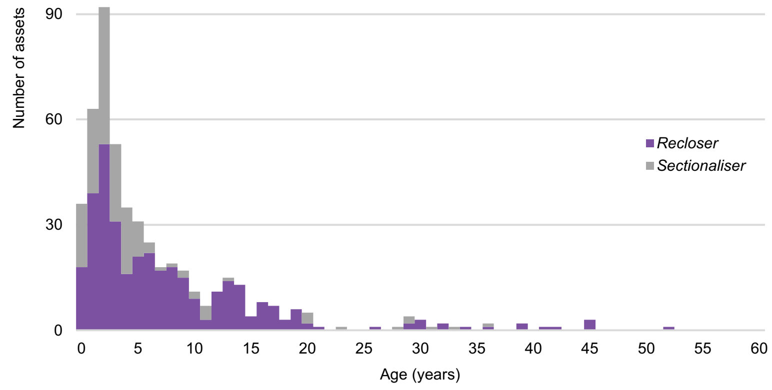
Figure 23.13: Circuit breakers age profile



Older assets in the age profile are mostly the oil-filled circuit breakers at the Kinleith site. A planned replacement programme at that site from 2020-27 will remove many of these. Oil-filled circuit breakers are no longer purchased. All new circuit breakers are SF_6 or vacuum types.

In contrast, our reclosers and sectionalisers are newer and many have been installed in the past 10 years as part of our automation programmes. We have been installing larger amounts of these devices to reduce the size of outage areas under fault scenarios. This fleet is therefore expected to require little renewal during the planning period. In the longer term, we expect replacement requirements to increase as the fleet ages and controllers require replacement.

Figure 23.14: Reclosers and sectionalisers age profile



23.6.3 CONDITION, PERFORMANCE AND RISKS

Oil type circuit breakers have proven, good reliability on our network, but the age of the fleet means there is increasing risk in regards to operator safety and loss of supply from explosion, fire, arc flash, arc blast and oil spills. The safety and loss of supply risks are significant at the Kinleith site because of the importance of the load, and the potential for non-Powerco authorised people to enter switchrooms with shared facilities not controlled by Powerco, such as low voltage (LV) reticulation, and other services.

The 11kV fault levels at Kinleith have recently been reduced as Transpower has installed neutral earthing resistors (NERs) and higher impedance power transformers. However, the deteriorating circuit breaker asset health, and the longer protection operating times prevalent at the site, present a high arc flash safety risk to operators. As a component of the 11kV switchboard upgrade programme, arc flash doors, end panels, arc flash protection and local remote CB operation are being installed. This will mitigate the arc flash safety risk.

Some of the oil type circuit breakers are manually operated. This is considered unsafe, especially given arc flash risk. Some switches have interlocked circuit earthing facilities for which we do not have information regarding the fault rating. We have prioritised these circuit breakers for replacement.

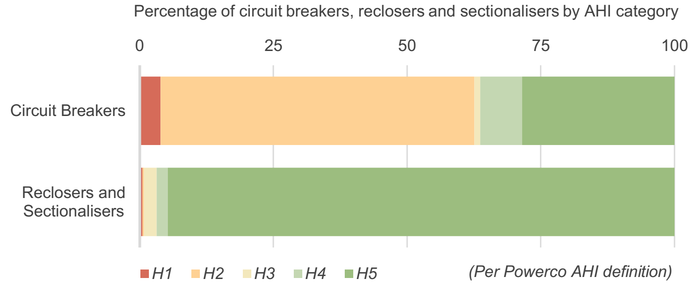
We have a small number of oil-immersed recloser types, such as early KFMEs or OYTs, that do not provide the functionality or visibility we require of modern reclosers and are beginning to show a number of issues in regards to their ability to adequately clear faults, extending restoration times. We have an existing programme to replace these with modern reclosers.

Circuit breakers, reclosers and sectionalisers asset health

As outlined in Chapter 10, we have developed AHIs that reflect the remaining life of each asset. Our AHI models predict an asset's end-of-life and categorise its health based on a set of rules. For circuit breakers, reclosers and sectionalisers we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switchgear should be replaced. The AHI is based on our knowledge of condition and reliability or safety issues, such as arc flash risk related to oil switchgear (discussed above), and asset age.

Figure 23.15 shows overall AHI for our population of circuit breakers, reclosers and sectionalisers.

Figure 23.15: Circuit breakers, reclosers and sectionalisers asset health as at 2020



The asset health of the combined recloser and sectionaliser sub-fleet is generally good. As mentioned in 23.6.3, we are working through a programme to replace our KFME and OYT type reclosers. Less than 5% (H1-H3) will likely require replacement in the next 10 years.

In contrast, the health of our distribution circuit breakers is considered to be poor and a significant risk – this is skewed by our large fleet of oil CBs at Oji, for which we are undertaking a significant renewal programme. This is based on our experience of operating this switchgear and the experience of others within the industry.

As such, we have categorised many of our oil circuit breakers as having type related issues requiring replacement.

There are also a considerable number of aged circuit breakers at Kinleith, where arc flash levels are high, that also require replacement. We are planning significant investment in this area to improve our circuit breaker asset health.

23.6.4 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. 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.

23.6.5 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.

Table 23.8 summarises our preventive maintenance tasks for this fleet. The detailed regime is set out in our maintenance standards.

Table 23.8: Circuit breakers, reclosers and sectionalisers preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Reclosers and sectionalisers	Inspections and tests of actuator/remote terminal unit (RTU) batteries. Communications check.	Yearly
	Thermal imaging scan.	2½ 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.	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

23.6.6 RENEW OR DISPOSE

Renewal of circuit breakers, reclosers and sectionalisers is based on asset condition and type-related safety or performance issues. Safety issues include certain types of oil circuit breakers that are prioritised for replacement either because of design issues with the equipment or stricter risk tolerances, such as for arc flash.

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. Over time, insulation degrades, mechanical components suffer wear and enclosures corrode. This makes age a useful proxy, also capturing that older designs of switchgear generally have fewer safety features, such as arc flash containment. The evolution in design of switchgear has improved safety and reliability. The renewal need for this fleet is higher than in the past. This is because of the need to renew oil circuit breakers that have safety issues, and the significant quantities of circuit breakers requiring renewal at Kinleith – we expect to complete this programme by FY27.

Additionally, we have a focused programme to replace our remaining KFME and OYT reclosers, which have reliability issues leading to trip failures. We expect to complete this replacement programme by FY23.

Once this has been completed, expenditure levels are expected to return to earlier levels.

Coordination with Network Development projects

The increasing use of network automation is a key part in the development planning of this fleet. Network automation seeks to improve network SAIFI and SAIDI performance. It improves the network's sectionalising capability following faults and through providing better network operational visibility. This is achieved through the targeted installation of additional reclosers and sectionalisers. Our network automation programme is discussed in more detail in Chapter 16.

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.

23.7 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.

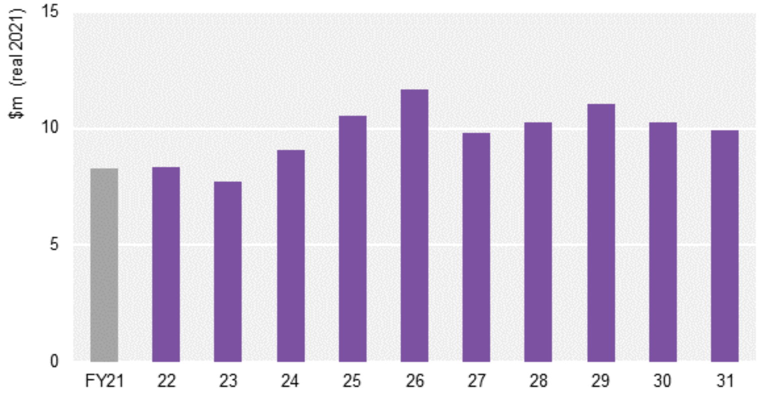
During the planning period, we intend to invest approximately $99m in distribution switchgear renewal. Safety is a key driver of renewal, particularly of our oil-filled ground-mounted switchgear and oil-filled circuit breakers.

Distribution switchgear renewals are derived from bottom-up models. These forecasts are generally volumetric estimates (explained in Chapter 28).

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.

Figure 23.16 shows our forecast Capex on distribution switchgear during the planning period.

Figure 23.16: Distribution switchgear renewal forecast expenditure

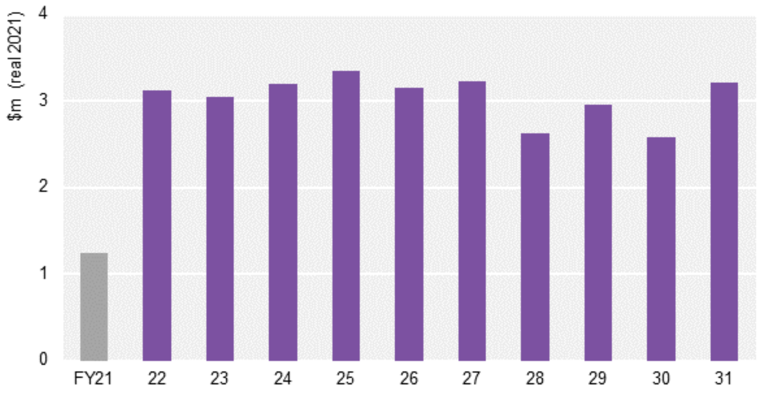


The forecast renewal expenditure is generally in line with historical levels. Further details on expenditure forecasts are contained in Chapter 28.

23.8 DISTRIBUTION SWITCHGEAR PREVENTIVE MAINTENANCE FORECAST

Our preventive maintenance expenditure for distribution switchgear accounts for 17% of our current budget, with a significant increase in FY22 as we begin the oil-filled RMU maintenance programme. Once the programme is in full execution, the overall maintenance budget will increase to approximately $3m per annum across this fleet, ensuring these assets remain fit for service and can be operated safely until their end of life.

Figure 23.17: Preventive maintenance expenditure forecast



24 SECONDARY SYSTEMS

24.1 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 explains our renewals approach and provides expenditure forecasts for the planning period.

Portfolio summary

During the planning period we expect to invest $53m in secondary systems. This accounts for 6% of renewals Capex during the period. This is an increase on our current spend, mainly driven by our Extended Reserves programme. Levels of renewal across the secondary systems fleets are in line with historical expenditure.

The main driver for asset replacement in the secondary systems portfolio is obsolescence and aged-based degradation. Capex is driven by the need to:

– Replace our legacy electromechanical and static protection relays, which suffer from increasing unreliability, a lack of spares, lack of support from manufacturers, and provide inadequate functionality compared with modern equivalents.

– Consolidate the communications protocols for our Supervisory Control And Data Acquisition (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 remote terminal units (RTU) that do not provide the functionality required for our network.

– Meet regulatory requirements in relation to the new Extended Reserves arrangements.

Below we set out the Asset Management Objectives that guide our approach to managing our secondary systems fleets.

24.2 SECONDARY SYSTEMS OBJECTIVES

Secondary systems are crucial for the safe and reliable operation of our electricity network, as they allow for control and operation of most primary equipment such as switchgear.

While their replacement cost is usually lower than the primary equipment that they control or monitor, they generally have shorter service lives. 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 Table 24.1. The objectives are linked to our overall Asset Management Objectives as set out in Chapter 4.

Table 24.1: Secondary systems portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Effective protection of primary systems.
	No injuries or incidents resulting from incorrect operation of protection systems.
	The SCADA system allows reliable control and monitoring of the electricity network at all times.
Customers and Community	High Voltage (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 Low Voltage (LV) networks to anticipate and effectively manage capacity and voltage pinch points, enabling increasing levels of distribution automation.
	Trial the use of smart devices to understand their potential operational, asset management and customer benefits.
Asset Stewardship	Direct Current (DC) supply systems provide their specified carry-over time in the event of an outage.
	Enable remote engineering access to modern numerical relays to allow us to retrieve disturbance records, helping identify the cause of faults and facilitate rapid restoration of supply.
Operational Excellence	Continue to use improved asset information gathered and recorded by modern numerical relays.

24.3 SCADA AND COMMUNICATIONS

24.3.1 FLEET OVERVIEW

The SCADA system provides visibility and remote control of our network. Its coverage includes major communication sites and zone substations, as well as distribution assets, such as voltage regulators and field pole-top and ground-mounted switches. A central master station communicates with RTUs over a communications system made up of various carriers, such as radio, microwave and fibre optic cable. RTUs interface with the network equipment, such as transformer control units and circuit breaker control systems.

The technology is diverse as it was installed by a range of preceding network companies with different standards and requirements. We have undertaken significant work to improve standardisation.

Master stations

The master station is essentially a central host computer server that manages the SCADA system. We have two master stations – the primary one located in New Plymouth and the backup in Auckland.

As our network is the result of amalgamating many networks, we previously ran multiple master stations from several vendors. During the past decade, we have standardised and consolidated the SCADA network into one OSI Monarch 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 with SCADA, such as transformer control units, DC supplies, protection relays, and recloser controls. They transmit telemetry data to the master station and relay communications from the master station to control connected devices.

A range of RTUs are used across our networks. With the consolidation of our master system, the majority of RTUs are modern devices, providing adequate service. However, a small number of devices in the Eastern region communicate via the Conitel protocol rather than the preferred DNP3 protocol. The remaining Conitel protocol devices will be transitioned to the new standard as their corresponding radios and base stations are replaced.

The change of communication protocol has allowed intelligent electronic devices (IEDs) installed on the network to now communicate directly with the SCADA master without the need for an interposing RTU. This has allowed the number of RTUs to remain relatively stable even though the number of SCADA devices continues to increase.

Figure 24.1: 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 implementing line differential protection between substations.

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 during 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, so this leaves only a small number of RTUs 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.

Remote Engineering Access (REA)

Our modern RTUs are capable of providing remote engineering access to our substation protection system. These allow us to provide much better response time during fault events where relay data and event files are needed to be accessed so that protection analysis can be carried out. The REA runs on a separate communications channel from the SCADA. This can be via our Powerco Transport Network (PTN) or through a cellular modem connection.

To date we have 88 zone substations with REA and the remaining zone substations will have REA when the protection relays and RTUs are planned for renewal.

Figure 24.2: Communications mast with associated radio antennae

24.3.2 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 from modern RTUs, which includes DNP connectivity and REA to substation protection relays.

Table 24.2 summarises our population of RTUs by type. [95]

Table 24.2: RTU population by type

TYPE	RTU	% OF TOTAL
Modern	310	99
Legacy	3	1
Total	313	

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 sparse, and is typically inferred from related assets, drawings of the installations, or eras of RTU types. We are working to improve our records of communications assets and record these in our asset information systems.

24.3.3 CONDITION, PERFORMANCE AND RISKS

Condition

Condition is generally not a significant factor in determining the replacement of RTUs, with functionality, technical obsolescence and supportability being the dominant factors.

A small number 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 that are more prone to failure, are difficult to maintain and troubleshoot, and require specialist knowledge to understand how they work.

95 This population excludes telemetered sites with IEDs directly connected to the SCADA network, such as those on modern automated reclosers.

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 several 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 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, such as 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 element of our Information and Technology Strategy and is discussed in more detail in Chapter 5.

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.

24.3.4 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 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 the easier transfer of data between systems. Internet-based inter-control centre communications protocol is a new technology that will allow us to see Transpower's circuit breaker status, 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 most of our numerical relays. REA allows our technicians and protection engineers to access relay 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 outages 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.

24.3.5 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 24.3: SCADA and communications preventive maintenance and inspection tasks

ASSET TYPE	MAINTENANCE AND INSPECTION TASK	FREQUENCY
Communications equipment, including RTUs	General equipment inspections to test asset reliability and condition. Transmitter power checks and frequency checks. Site visual inspection for dedicated communications sites, checking building condition and ancillary services. RTU operational checks.	6 monthly
	Visual inspection of communication cables/lines, checking for condition degradation. Attenuation checks. Antennae visual inspections, with bearing and polarity verified.	Yearly
SCADA master station	Maintenance covered by specialist team.	As required

24.3.6 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 that 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.

For these reasons, SCADA and communications equipment will generally need to be replaced at least once within the life of the primary equipment it supports. Currently, this is managed on a reactive basis but, over time as we gain a better understanding of the life of this equipment, we will move to more proactive replacement.

We hold a small quantity of RTU spares which allows us to replace these quickly when they fail. We also hold a range of older RTUs, which are no longer supported, to allow us to manage the impacts of failure before planned retirement.

Other communications assets, such as radio links and their associated hardware, are also typically replaced because of 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 15. 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 Conitel or other non-supported protocols.

The renewal forecast of supporting communications infrastructure has been estimated on a serviceable lifecycle replacement schedule, given the complexity of the PTN backhaul to service voice radio, SCADA and other services.

Longer term, we expect SCADA and communications renewals to remain at least at current levels. As the IED population continues to grow, we have allowed for an increasing level of replacement towards the end of the forecast period. Additionally, future capability requirements and an expansion of the communications network are likely to increase the renewal need long term.

Coordination with Network Development projects

The SCADA system already provides real-time monitoring and control at our zone substations. The system is largely mature and fully developed. As discussed above, our Eastern and Western systems are on a common platform.

Specific SCADA system needs are considered as part of Network Development. For example, a zone substation project includes developing the SCADA RTU, configuration and communications. Similarly, our network automation programme[96] is extending the control and monitoring capability to selected distribution switches.

96 We discuss the network automation programme in Chapter 16

24.4 PROTECTION SYSTEMS

24.4.1 FLEET OVERVIEW

Protection assets ensure the safe and appropriate operation of the network. These relays (or integrated controllers) are used to detect and measure faults on our HV electricity network, and through coordination with circuit breakers, clear and isolate faults. When working correctly and in coordination with other devices, they have a significant impact on minimising network damage and outage areas when the network faults.

Protection systems include auxiliary equipment such as current and voltage instrument transformers, communication interfaces, special function relays, auxiliary relays and interconnecting wiring.

Protection relay technology has 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 simple, legacy protection technology that have provided many years of reliable performance. While basic in design – each relay providing a specific function – they lack the flexibility in configuration and functionality of more modern protection technology. As their name suggests, they operate on electromechanical principles – coils and electromagnets driving mechanical components, such as rotating discs and relays, to define relay characteristics.

Figure 24.3: Electromechanical relays providing transformer protection

Electromechanical relays require ongoing calibration because of ‘drift’ of their mechanical 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 the oldest more than 50 years.

Static relays

Static relays gain their name from the absence of moving parts – in contrast to the electromechanical relays – instead relying on analogue electronic components to create the relay characteristic.

Being solid-state, they can have improved sensitivity, speed and repeatability compared with electromechanical relays. Electronic components, however, are susceptible to deterioration and drift because of time and temperature affecting the performance and reliability of relays.

Static relays have an expected life of approximately 20 years. Spare parts can no longer be sourced, and repair 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 in their configuration. 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 in functionality over previous technologies. These include SCADA integration, the ability for data to be accessed remotely, real-time and historical information about the power system, the protection and control systems, fault location and type, before, during and post fault currents and voltages.

Furthermore, these include self-testing features, which can alert network operations should the relay become non-functional. This near continuous testing substantially increases the overall availability of numerical relays when compared with electromechanical or static types.

Numerical relays are the universal 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 much 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 24.4: Modern numerical relays

24.4.2 POPULATION AND AGE STATISTICS

In recent years, substantial numbers of electromechanical and static relays have been replaced. Numerical relays are now the dominant relay type, making up 72% of the population.

As further systems are upgraded, there will also be a reduction in the total number of relays in the fleet, as numerical relays can be programmed to provide multiple protection functions that currently require several individual electromechanical relays.

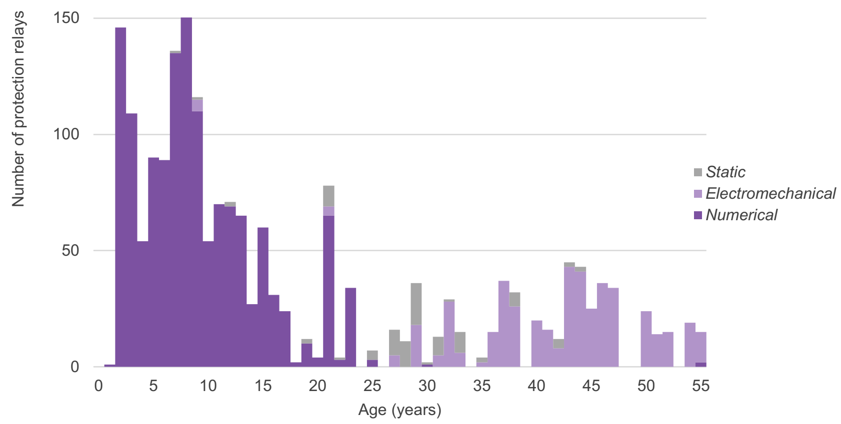
Table 24.4: Protection asset population by type

TYPE	RELAYS	% OF TOTAL
Electromechanical	465	23
Numerical	1451	72
Static	103	5
Total	2019	

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.

Figure 24.5 shows the age profile of our protection relays population. Many electromechanical relays exceed 40 years of life and are now due for replacement.

Figure 24.5: Protection relay age profile



24.4.3 CONDITION, PERFORMANCE AND RISKS

Condition

While electromechanical relays have a proven performance and long lives, having moving parts means they are subject to wear. 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.

The solid-state or static relays do provide additional functionality, such as a SCADA interface, however these relays still lack disturbance recording capability. Most of our static relay fleet are no longer supported by the manufacturer and spare parts are no longer available. Compared with other relay types, they experience a greater number of reliability issues because of component failure. In contrast, newer numerical relays can provide much greater functionality, richer information and higher reliability and system stability. However, they have a shorter life because of their microprocessor-based technology. Excessive heat may also cause them to fail, which we manage by substation air conditioning. Numerical relays generally provide an indication when they malfunction, which allows maintenance intervals to be extended.

Risks

Performance and reliability: The key safety risk for the protection fleet is that network faults are not detected and cleared because of a relay malfunction. These faults can then put the public or service provider in danger, can cause network equipment failure, extended outages, or overload. For these reasons, protection systems are designed with cascading backups, but these are designed to take longer to clear the fault to ensure protection discrimination and, being further upstream in the network, generally result in a larger outage area. As longer fault clearance times stress the network more, these can sometimes result in equipment damage, live power lines on the ground or fires.

Cyber security threats: It is also noted that the implementation of more numerical relays could pose higher risk exposure to cyber security. It is essential that security measures to address system vulnerabilities from cyber security attacks are in place.

Diversity: By limiting the type/model of the protection relay fleet, it is expected to have significant improvements in terms of whole-of-life support. This will reduce the number of protection standards/schemes that need to be supported, leading to a reduction in deployment and maintenance costs.

Meeting our portfolio objectives

Safety and Environment: We continually review our protection coordination to ensure faults are cleared in a fast but reliable manner.

Regulatory compliance

The Electricity Authority (EA) is implementing new requirements for Extended Reserves. The new requirements include tripping on the rate of frequency decay, which requires a more sophisticated relay unit. A very high percentage of our existing load shedding relays are many decades old and incapable of meeting the new specifications.

To meet our obligations, we need to replace and re-programme existing under-frequency relays at approximately 100 substations. This is forecast to occur during the 2023-25 period.

24.4.4 DESIGN AND CONSTRUCT

Protection system design must balance many competing requirements to ensure the overall system is effective. These requirements include:

- **High reliability** − the protection equipment must operate correctly when required, despite not operating for most of its life.
- **Stability** − the protection equipment must remain stable when events that look like faults occur eg power swings and current reversals, and continue to operate the way it should during the length of its life.
- **Dependability** − relays should always operate correctly for all faults for which they are designed to operate.
- **Security** − relays should not operate incorrectly for any fault eg an out-of-zone fault.
- **Sensitivity, speed and selectivity** − individual protection equipment must operate with the appropriate speed and coverage as part of an overall protection scheme.
- **Safety and reliability of supply** − the protection scheme must provide safety to the public and field staff, as well as minimising 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.
- **Lifecycle 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.

24.4.5 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 because of their mechanical nature and possible degradation in performance. Numerical relays require less detailed and fewer frequent checks, so cost less to maintain. They are also able to provide alerts regarding their condition, prompting a maintenance callout if necessary.

Our preventive maintenance schedule for protection relays is outlined in Table 24.5. The detailed regime is set out in our maintenance standards.

Table 24.5: Protection preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of protection assets, checking for damage, wear and tear. Any alarms, flags and LEDs reset.	3 monthly
Detailed condition assessment and operational checks for **electromechanical and static relays**. Perform diagnostic tests relevant to relay function eg overcurrent, distance.	3 yearly
Detailed condition assessment and operational checks for **numerical relays**. Perform diagnostic tests relevant to relay function eg overcurrent, distance.	6 yearly
AUFLS relays - regulatory compliance testing	3 yearly

24.4.6 RENEW OR DISPOSE

Our strategy is to replace electromechanical and static relays on the basis of functional obsolescence, reliability, and availability of effective vendor support.

Older technology relays continue to work but, unlike numerical relays, do not provide the modern functionality 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).

We have observed increasing component failures in our first generation numerical relays, which are now reaching end of service life at 20 years. This, combined with the limited functionality these provide compared with more modern numerical relays, means we are starting to replace our oldest relays of this type within the planning period.

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. This allows 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, although the likelihood is low.

Our forecast identifies relay renewal quantities and accounts for projects where associated primary assets are replaced eg switchboard replacements, to ensure efficient delivery. This may mean some relay replacements are brought forward or deferred for a period.

The forecast also includes expenditure from 2023-25 for the replacement of load shedding relays, to ensure compliance with the new Extended Reserves requirements. The forecast is based on desktop assessments of our zone substation load shedding needs, the number of feeders, and a bottom-up engineering estimate of the costs of a replacement system.

Forecast renewals are higher than historical levels because of the need to retire our electromechanical and static relays and replace them with modern numerical devices, and the significant expenditure for the replacement of load shedding relays from 2023-25.

Longer term, protection renewals, excluding load shedding replacement, are expected to remain at these levels as increasing numbers of first generation numerical relays require replacement. In addition to providing better functionality, numerical relays have lower maintenance costs.

Duplicate protection

Our HV circuits require a fast and reliable protection system and, therefore, protection duplication is required. This is included in the relay renewals forecast and will be done alongside HV switchboard renewals.

Coordination with Network Development projects

Protection relay replacement work is, as far as practical, coordinated with zone substation works – typically power transformer or switchboard replacements. Where this work is driven by Network Development requirements, the protection systems may also be replaced, depending on the technology and condition of the existing relay assets.

24.5 DC SUPPLIES

24.5.1 FLEET OVERVIEW

Our DC supply systems are required to provide a reliable and efficient DC power supply to the vital elements within our network, such as 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 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 24.6: DC charger and battery bank

24.5.2 POPULATION AND AGE STATISTICS

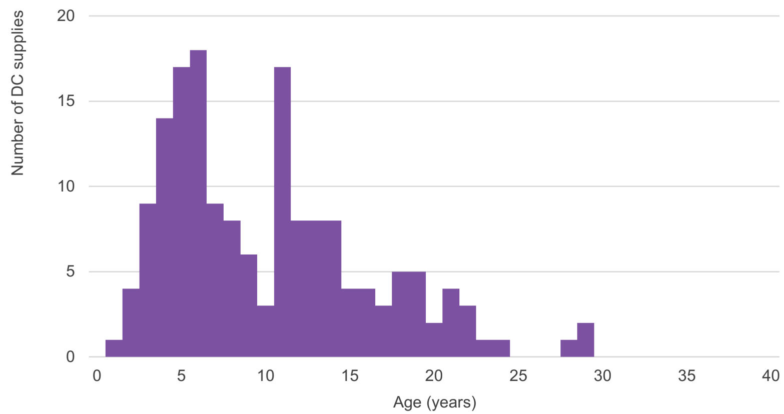
Table 24.6 summarises our population of DC supply systems by type. DC systems have been installed using many supply voltages because of different load requirements and network amalgamation. We expect the diversity to reduce as we replace non-standard voltage systems with modern equivalents.

Table 24.6: DC supplies population by voltage

VOLTAGE	DC SYSTEMS	% OF TOTAL
110V	85	51
48V	17	10
36V	1	1
24V	61	37
12V	1	1
Total	165	

Figure 24.7 shows the age profile of our population of DC supplies. The DC supply system batteries typically get renewed every eight years for Valve-Regulated Lead Acid (VRLA) type or 10 years for Absorbent Glass Mat (AGM) / Gel type. The charger/rectifiers are expected to last up to 20 years. A small number of DC system types have recently been identified with an increasing risk of failure – these will be prioritised for replacement.

Figure 24.7: Zone substation DC supplies charger/rectifier age profile



24.5.3 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 modes 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.

24.5.4 OPERATE AND MAINTAIN

We undertake regular inspections and testing of our DC supply systems to ensure they operate reliably and provide backup supply during outages. Our preventive inspection regime for DC supply systems is outlined in Table 24.7. The detailed regime is set out in our maintenance standard.

Table 24.7: DC supplies preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of **zone substation** DC systems. Check batteries for distortion, correct electrolyte levels and secure connections. Charger alarms operational, giving correct status.	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 status.	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.	Yearly
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.	2.5 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.

24.5.5 RENEW OR DISPOSE

DC supplies are critical assets as failure means we potentially lose visibility and control of our field sites. It is essential that these are scheduled for renewal as they reached the end of their life. The DC supplies are also being reviewed as part of the protection relay and/or SCADA/comms renewal to ensure that these can still provide the functionality expected or the capacity required.

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 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[97] 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.

24.6 METERING

24.6.1 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 GXPs. We have replaced most of the older and unsupported meters that were used for monitoring network load at our GXPs. Because of their technology, the few remaining older meters are limited to providing only kWh data in the form of impulse to the SCADA and load management systems.

Modern GXP meters are able to communicate via the DNP3 protocol and provide remote access functionality and rich data eg peak and average kVA, and power factor.

97 ‘Carry-over time’ means the time the DC system can supply the connected load in the event of an outage.

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 ring main units (RMU) 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.[98]

24.6.2 POPULATION AND AGE STATISTICS

Table 24.8 summarises our population of GXP meters by type. Our GXP meter replacement programme has upgraded the majority of metering units to modern ION meters.

Table 24.8: GXP metering population by type

TYPE	SUB-TYPE	GXP METERS
ION meter		28
Total		28

In addition to the GXP meters, we have 125 HV metering units and approximately 1,500 ripple receiver relays.

Figure 24.8 shows the age profile of our GXP meter population. The young age of the GXP metering fleet reflects recent modernisation of the assets.

Figure 24.8: GXP metering age profile

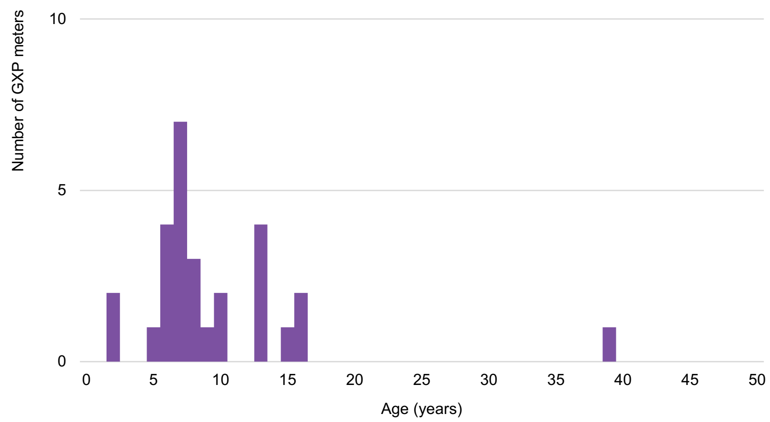
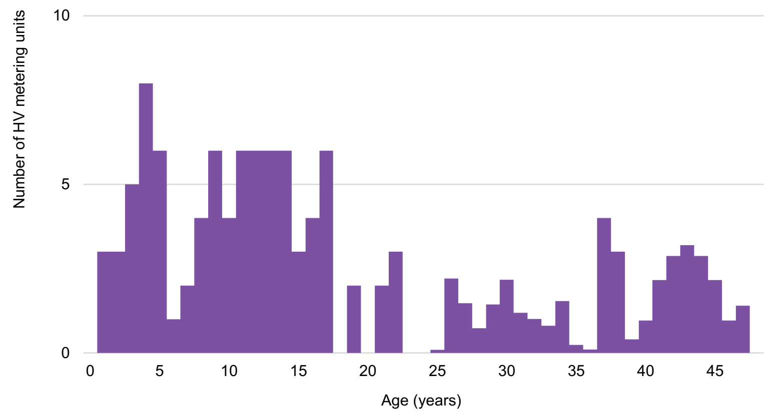


Figure 24.9 shows the age profile of our HV metering unit population. The HV metering unit fleet is relatively young. Experience has shown that life spans of more than 20 years are common for most metering units, with replacement or upgrade normally being related to changes in the load profiles of connected 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.

Figure 24.9: HV metering unit age profile



98 We discuss our load control plant fleet in Chapter 21.

24.6.3 CONDITION, PERFORMANCE AND RISKS

HV metering unit accuracy is important as the units 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 we own that are used for this purpose are compliant. These assets are therefore in good operable condition.

24.6.4 OPERATE AND MAINTAIN

We regularly inspect our metering assets to ensure their ongoing reliability. The re-calibration tests carried out on HV metering units every 10 years are particularly important. They must be conducted to ensure compliance with the participation code. These tests are only carried out by certified service providers.

Our preventive metering inspection tasks are summarised in Table 24.9. The detailed regime is set out in our maintenance standards.

Table 24.9: HV metering preventive maintenance and inspection tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of metering units installed within switchboards. Check cabling for damage and ensure secondary terminal block enclosure is sealed.	Yearly
Detailed inspection of ground and pole-mounted metering units. Check external condition and signage. Check cabling for damage and ensure secondary terminal block enclosure is sealed.	5 yearly
Perform metering equipment re-calibration tests to comply with participation code.	10 yearly

GXP meters do not undergo preventive maintenance but provide alerts when they are faulty.

24.6.5 RENEW OR DISPOSE

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 do 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 during the next two years. After this, the entire fleet will consist of modern devices and we expect no further renewal during 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.

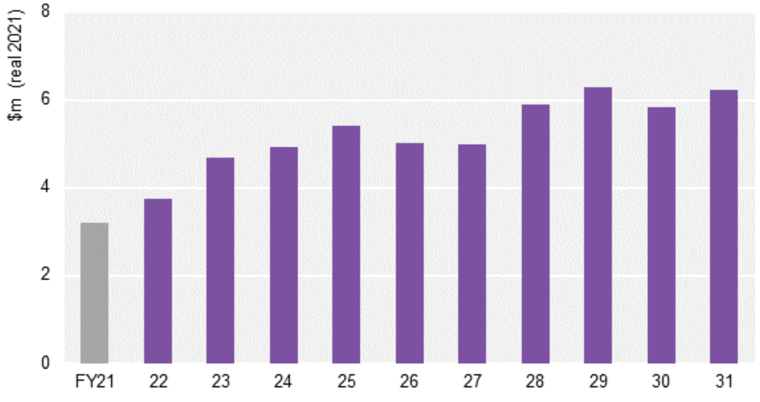
24.7 SECONDARY SYSTEMS RENEWALS FORECAST

Renewal Capex in our secondary systems portfolio includes planned investments in the SCADA and communications, protection, DC supplies, and metering fleets. During the planning period we intend to invest $53m in secondary systems renewals. Key drivers are functionality, meeting regulatory requirements, and investing in smart ripple receiver replacements.

Most renewals are derived from bottom-up models, based on identified replacement needs, asset age and historical replacement rates. These forecasts are generally volumetric estimates, which is explained in Chapter 28. We typically use averaged unit rates based on analysis of equivalent historical costs, along with building block costs for protection replacements.

Figure 24.10 shows our forecast Capex on secondary systems during the planning period.

Figure 24.10: Secondary systems renewal forecast expenditure



Renewal expenditure is expected to increase during the planning period. This is primarily because of:

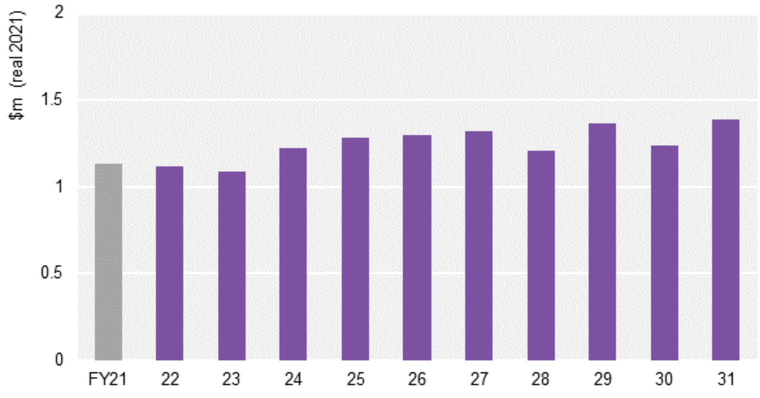
- Our programme of load-shedding relay replacements in FY23-25, to meet compliance with the Extended Reserves scheme.
- Increasing protection relay replacements, particularly of early numerical relays.
- A programme of duplicate protection investments, to improve the resilience of our protection systems, in particular to a cyber attack.

Other expenditure forecasts within this fleet are generally in line with historical levels.

24.8 SECONDARY SYSTEMS PREVENTIVE MAINTENANCE FORECAST

Secondary systems maintenance accounts for 10% of our preventive maintenance expenditure. This level of expenditure is expected to remain relatively consistent, although the electromechanical relays will be phased out and maintenance intervals can be increased to six-yearly.

Figure 24.11: Secondary systems preventive maintenance forecast



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25 VEGETATION MANAGEMENT

25.1 OVERVIEW

25.1.1 COMPLIANCE

Vegetation in proximity to power lines is a significant hazard with the potential to impact safety, quality of supply and Opex. Network operators, while not owning vegetation near power lines, have obligations regarding its management. These are documented in the Tree Regulations[99], which prescribe the minimum distance that trees must be kept from overhead lines[100], and sets out the responsibilities for tree trimming.

Trees in proximity to lines are declared by landowners as either being of interest, or no interest to them. For trees they have a declared interest in, tree owners have an obligation to keep them maintained and clear of our network. Powerco has an obligation to notify owners so they can maintain trees before they infringe clearance zones. These requirements are logistically complex when considered in the context of Powerco's large overhead network.

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 owner's and our responsibilities with regard to actions and cost.

Powerco discharges its obligations under the regulations through a cyclical tree trimming programme. The network is surveyed within a defined time period and landowners are notified of their obligations. The tree trimming programme is then developed incorporating optimal cutting plans and methods. Cycle times vary based on the network environment and criticality. Because of the volume of vegetation present near our overhead network and the available budget, our approach has focused on providing a vegetation profile maximising the length of power lines that is compliant with minimum clearance zone requirements.

This approach, by necessity, prioritises short-term compliance over long-term performance and cost by limiting our ability to:

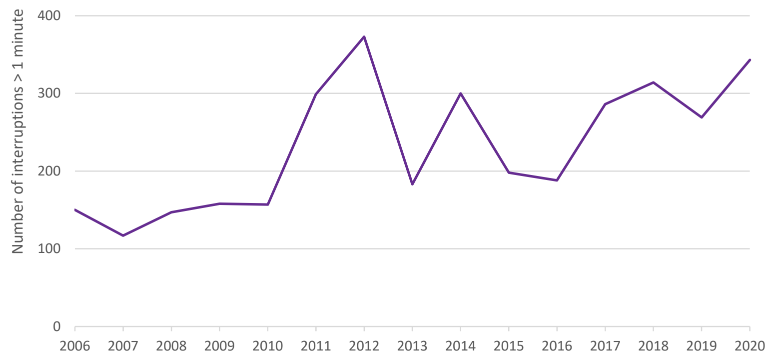
- Remove rather than trim trees
- Implement long-term methods such as spraying and mulching
- Address at-risk trees that are outside of the prescribed clearance zone.

99 Electricity (Hazards from Trees) Regulations 2003 (SR 2003/375)

25.1.2 PERFORMANCE

Outages caused by vegetation are a significant contributor to our overall System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). The trend of vegetation-related outages is shown in Figure 25.1.

Figure 25.1: Number of vegetation-related events causing >1 min outages



Our cyclical strategy is consistent with good practice, however developments in Light Detection and Ranging (LiDAR) surveying, vegetation analytics and risk-based planning may provide opportunities to improve the safety, performance and cost effectiveness of our vegetation management activities. We are currently executing a LiDAR survey covering the entire overhead network, which will create improved visibility of network vegetation and risk as discussed in the Future Improvements section.

100 The New Zealand Electrical Code of Practice for Electrical Safe Distances (NZECP 34) sets minimum safe electrical distance requirements for overhead lines, including the minimum safe approach distances for the public, and requirements for workers who need to work within this distance.

25.2 OBJECTIVES

To guide our strategy and activities during the planning period we have identified the following high-level objectives for vegetation management.

Table 25.1: Vegetation management portfolio objectives

ASSET MANAGEMENT OBJECTIVE	PORTFOLIO OBJECTIVE
Safety and Environment	Reduce the potential risk of incidents involving tree owners who undertake trimming work. This is to improve public safety and comply with regulations.
	Reduce safety hazards by prioritising higher risk trees.
Customers and Community	Minimise landowner disruption when undertaking tree management.
	Improve relations with tree owners to better align incentives around the timing and scale of vegetation management.
	Provide a resilient network by endeavouring to supply all customers at all times by managing avoidable faults.
Networks for Today and Tomorrow	Reduce the number of vegetation-related faults on our network to avoid interruptions (intermittent and permanent) that may affect increasing quantities of sensitive, smart equipment.
Asset Stewardship	Reduce damage to network assets caused by vegetation to enable assets to achieve expected life.
	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 utilising data such as LiDAR to direct investment. Improve the quality of vegetation fault information to better understand trends from vegetation-related outages.

25.3 ONGOING VEGETATION MANAGEMENT INITIATIVES

Powerco is implementing a range of ongoing improvement initiatives, which are discussed in Table 25.2.

Table 25.2: Vegetation management improvement initiatives

INITIATIVE	UPDATE
Risk-based approach Develop a risk-based approach for trees beyond the mandated clearance limits.	Definition of the risk-based approach to vegetation assessment is under way, including considering industry guidelines with a view to achieving greater than mandated clearances, based on assessed risk for targeted sites. This is expected to progress further with the addition of LiDAR information.
Improved stakeholder engagement	We are working with our service providers to improve stakeholder engagement, with the objective of encouraging landowners to proactively manage or remove vegetation on their properties before it approaches infringement zones. In particular, we are working closely with the forestry industry and other electricity industry representatives to educate forest owners and harvesters about adequate set-backs in order to protect power lines while also ensuring their crops are profitable to harvest.
Improved public education Develop an enhanced public safety programme.	We continue to run campaigns to educate rural communities on the risks of trees outside of the regulatory growth limit zones. There is an ongoing need to educate tree owners about safety issues, their responsibilities and the effects they have on the communities they live in.
Trimming and felling efficiency improvements	We are continuing to work with our contractors to apply innovative, safer and more efficient tree management practices. Equipment now used as standard includes large diggers with tree shears, tracked all-terrain elevated work platforms, shelter trimmers and mulchers as well as heli-spraying to manage regrowth and maintain corridors.

Figure 25.2: Improved vegetation management practices

Tree shears provide controlled felling near power lines.

A tracked all-terrain elevated work platform allows easy access to trees as well as minimising the impact on surrounding land.

25.4 FUTURE IMPROVEMENTS

Central to our LiDAR survey is the development of vegetation analytical tools. Once completed, the survey will provide an objective and complete inventory of the vegetation that is in proximity to our power lines. Analytics will allow an estimation of the risk that it presents. We will use this information to develop a sustainable long-term strategy that moves our programme from a cyclical programme, based on achieving a minimum clearance compliance, to a more efficient programme that achieves compliance and targets critical sections of the network while:

- Reducing long-term costs
- Improving reliability through the targeted removal of out-of-profile vegetation
- Remaining dynamic to achieve a defined overall risk profile

Achieving a sustainable strategy and optimal long-term savings may require a short-term increase in expenditure.

Key initiatives to achieve this are outlined in Table 25.3.

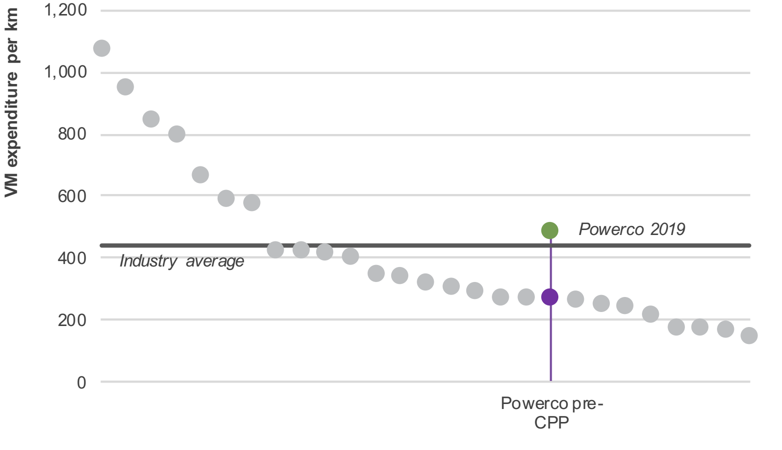
Table 25.3: Future vegetation management improvement initiatives

INITIATIVE	COMMENT
LiDAR information	LiDAR technology provides accurate distance assessment of vegetation encroachment on the electricity line network. It also provides accurate distance assessment of any physical items, such as buildings. We are implementing a whole of network LiDAR survey and will utilise data to plan works.
Strategy Review	We will use the data produced by the LiDAR survey to conduct a comprehensive review of our vegetation management strategy and its implementation. The availability of objective data will enable analysis to determine the optimal balance between the short-term cost of investing in tree removals and longer-term benefits of reduced cyclical trimming costs.
Risk-based treatment of out-of-zone trees	We will continue to identify instances where out-of-zone trees that are a risk can be cost effectively treated. For example, senescent or diseased trees near critical sections of the network that have high customer density.

25.5 VEGETATION MANAGEMENT OPEX FORECAST

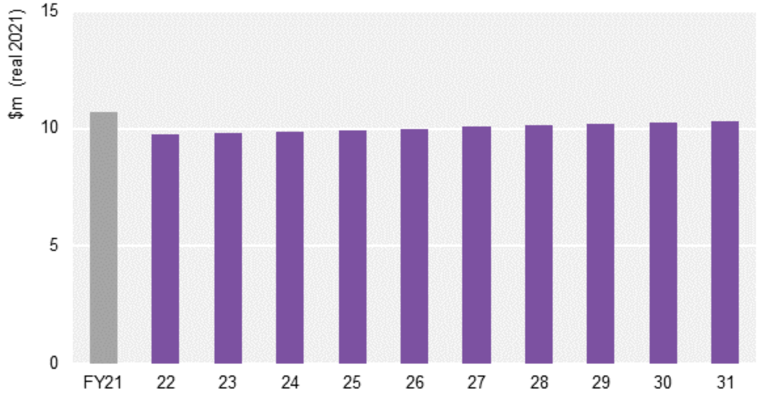
Figure 25.3 compares our previous (purple dot) and new (green dot) vegetation management expenditure per kilometre of overhead line with other Electricity Distribution Businesses (EDB). Before increasing our investment in 2019, our vegetation expenditure was low compared with other EDBs. Our recent increase has brought us in line with the industry average.

Figure 25.3: Vegetation Opex per km of overhead line compared with other EDBs (FY15-19 average)



Our vegetation management Opex forecast is based on our current strategy for the planning period, shown in Figure 25.4. We anticipate that our review of the vegetation strategy and its implementation will result in changes to this forecast when complete.

Figure 25.4: Vegetation management expenditure



26 ASSET RELOCATIONS

26.1 CHAPTER OVERVIEW

This chapter explains our approach to relocating assets on behalf of customers and other stakeholders. It includes an overview of typical relocation works, our process for managing these works, and how they are funded. Our forecast Capex, net of capital contributions, during the planning period is also discussed.

Further detail on our stakeholders and how they affect our investment plans can be found in Appendix 3.

26.2 OVERVIEW OF ASSET RELOCATIONS

The assets that most often need to be relocated are poles, overhead conductors and underground cables. These are often located alongside other infrastructure, such as roads, water pipes, and telecommunications cables. A common example is moving poles and lines to accommodate the widening of a road.

Asset relocations Capex is driven by third-party applications, which typically fall in one of the following four categories:

- **Roading projects** – road widening and realignment projects by the New Zealand Transport Agency (NZTA) and councils require our assets to be relocated.
- **Infrastructure projects** – infrastructure owners may need us to relocate our assets as part of their developments eg stormwater pipelines, electricity transmission lines or telecommunications assets.
- **Development** – 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 ask that electricity lines disrupting their views 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.

26.3 OUR ASSET RELOCATION PROCESS

Our asset relocation process allows flexibility to facilitate development by other utilities, our customers and third parties.

The process for small relocation works is usually an externally managed design and build approach. We find this provides the most customer-centric service. When a customer seeks asset relocation, we provide a list of approved service providers. During the design and pricing stage, the customer may choose to work with more than one contractor to create a competitive environment. The customer's contractor then works with us to deliver the relocation work. In this process, the contractor works for the customer to meet their needs, while we ensure the contractor complies with our technical, safety and commercial requirements. Typically, we undertake between 75 and 125 relocation projects each year.

In most circumstances we receive contributions from the third party requesting the relocation, reducing the amount of our investment in these projects. For roading and other infrastructure projects, the level of our investment is governed by legislation, which often requires us to fund the materials portion of the project.[101] 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.

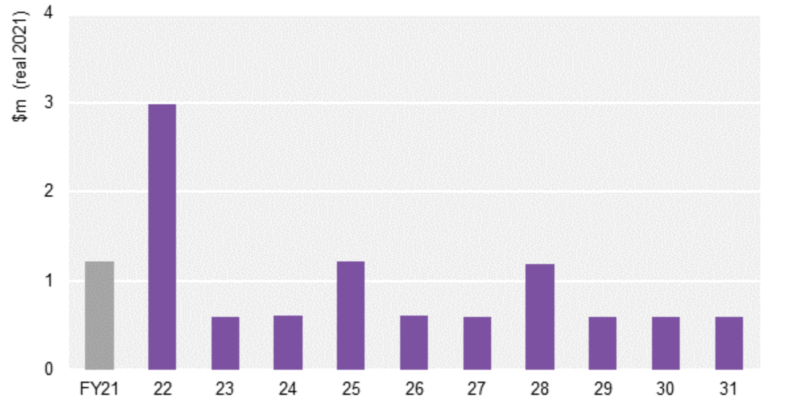
26.4 FORECAST EXPENDITURE

Because asset relocations are customer driven, often with short lead times, our ability to forecast this expenditure on a volume or project basis is limited and we also have limited ability to smooth the expenditure across years. In prior AMPS we have used the preceding financial years values as the basis of our forecasts.

However, we foresee an increase in roading investments by local councils and the NZTA as the nation tries to recover from the economic impact of COVID. Therefore for this AMP we have identified significant roading project expenditures on our network region, in consultation with councils and the NZTA, and assumed that these projects will run in a 2-3 year cycle.

Figure 26.1 shows our expected investment, net of contributions, in asset relocation works during the planning period.

Figure 26.1: Forecast asset relocation Capex (net of contributions)



[101] Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act 1989.

27.1 CHAPTER OVERVIEW

Non-network assets include assets that support the operation of the electricity business, such as information and communications technology (ICT), asset management data and facilities. This chapter describes the investments that are required to enable the wider Asset Management Plan and Network Evolution. It also discusses our data quality improvement programme and other non-network assets, such as office buildings and vehicles.

Investment in ICT and data quality is forecast to grow during the planning period, driven by the need to reduce technology risk and strengthen our core business operations through the delivery of foundational business practices and technology. At the same time, these investments enable new capabilities, such as the operation of distributed energy resources, cyber security, and advanced analytics.

This chapter is structured as follows:

- 27.2 – Data quality
- 27.3 – Planned ICT initiatives and investments during the period
- 27.4 – ICT expenditure forecasts
- 27.5 – Facilities portfolio approach and forecast

27.2 DATA QUALITY

All major network programmes (Reliability, Vegetation Management, Advanced Distribution Management etc) are hugely data intensive. Poor data quality reduces decision confidence, resulting in reporting inaccuracies, contention over which data is appropriate/trusted and sub-optimal decisions based on incorrect definitions.

In Chapter 13 we outlined the role of our Data Governance Group to ensure good stewardship of our data. Our goal is to improve our data management capability so that data quality is championed, measured and incrementally improved.

The programme of work under way to improve our data and data management capabilities is described in the following sections.

27.2.1 DATA MANAGEMENT

Data management consists of the practices, techniques and tools for achieving consistent delivery of data to meet the requirements of all applications and business processes.

Better data management is essential to improving our data quality for the long run. We are implementing the following initiatives alongside ICT projects that deliver the enabling technology.

Asset Information Standards

We are creating a suite of Asset Information Standards and data dictionaries to ensure that information is collected, categorised and made available to end users in an agreed format, to agreed levels of quality and to agreed timescales. The Asset Information Standards will align with our existing engineering standards and procedures. They will also account for external regulatory and stakeholder requirements.

The key Asset Information Standards include:

- **Asset Information Standard:** A high-level standard that describes the key asset information objects we need, including structured records as well as unstructured documents.
- **Asset Register Standard** (including condition and criticality measures)**:** A consolidated view of our asset information requirements for each asset class.
- **Job Plan and Preventive Maintenance Standard:** Documents business rules, best practice and governance arrangements to set up Job Plan and Preventive Maintenance Records in our Enterprise Resource Planning (ERP).
- **Work Order Standard:** Defines the information required to initiate, manage and record both planned and unplanned work activity.
- **Content Management Standard:** A consolidated set of requirements for the storage, access, update, archiving and deletion of unstructured documents, including technical records, drawings and Management System documents.

We will phase the development of Asset Information Standards and the implementation of information quality audits based on the business priorities and requirements.

Information Steward

We are implementing software to provide data profiling and monitoring and information policy management. This will help us to gain a better understanding of data quality and assist data governance, resulting in:

- Improved visibility of data quality metrics.
- Enforcing consistent processes with consistent validation rules and guidelines.

Data Catalogue

We have multiple sources of data in current and legacy systems. The quantity of data available is going to increase as we transition to an intelligent, open-access network. The challenge of managing this data increases along with the amount of data we collect.

We are implementing a data catalogue to make working with data easier for end users by allowing for active data curation that will improve speed and quality of data analysis by assisting in:

- **Dataset searching:** Natural language search capabilities allowing use by non-technical users. Ranking of search results by relevance and by frequency of use.
- **Dataset evaluation:** Evaluate suitability of data for an analysis use case, including the ability to preview a dataset, see all associated metadata, visualise other use cases and view data quality information.
- **Data Access:** Limiting access to restricted datasets to specific approved users and preventing the combination of certain datasets. This will help ensure security, privacy and compliance of our customers' sensitive data.

27.2.2 INSTALLATION CONTROL POINT (ICP) RECONCILIATION

As we prepare for the transition to an intelligent, open-access grid, the need to improve information about our customer connections becomes more important. The ICP Reconciliation programme will improve our ICP records by:

- Sifting through corrupted registry records and validating incorrect information and archiving de-commissioned ICPs.
- Updating our information with feedback from the field to get a more accurate record for each customer.

27.2.3 ASSET DATA

Along with more accurate customer records, better information on our assets is a building block for our distribution system operator (DSO) future. We have programmes of work in place to improve the data quality of the following key asset attributes.

Low Voltage (LV) network

Alongside our ICP reconciliation programme, we need accurate LV network information. The LV network has historically been the largest blind spot for utilities in New Zealand and we are working to plug this gap through our LV connectivity programme.

Conductor information

High Voltage (HV) and LV overhead conductors form a large portion of our fleet. However, planning for their renewal has been difficult because of low-quality asset information. Having knowledge about the capacity of the network gets more important as we increase the amount of automation we deploy on the network. Our conductor information programme is a focused effort between the asset information teams and field service providers to improve information in this area.

Nameplate data

Our nameplate data collection programme is aimed at improving the data quality of our more critical assets. This includes zone substation assets (power transformers, circuit breakers - CBs and switchboards) as well as underground distribution assets (ring main units - RMUs).

27.3 PLANNED ICT INIATITIVES AND INVESTMENTS DURING THE PERIOD

The main ICT investments comprising each I&T strategic programme are described below.

27.3.1 DIGITAL WORKPLACE PROGRAMME

In recent years, we have modernised our employee experience services – replacing legacy workstations with modern laptops, upgrading office tools, enabling secure remote working, as well as major upgrades of our video conferencing and telephony systems.

While we have delivered new tools, our focus is on upskilling our staff to use the tools more effectively and improving how we collaborate. Our plans also include bringing more structure and process to the management of unstructured information.

Lifecycle upgrades to these services are planned during the remainder of the planning period.

27.3.2 CONNECTING WITH CUSTOMERS PROGRAMME

We are reviewing the processes and systems to improve how we communicate with customers during planned and unplanned outages. Implementing these improvements will require a new website platform with support for multi-channel communications so that customers can get the information they need, wherever they are, whenever they want it.

Later in the planning period, we will undertake an advanced customer interaction project to manage and automate customer service requirements individually as their service requirements become increasingly varied. This is not possible with our current tools, which segment customer interaction in terms of the engineering characteristics of our network rather than customer preferences.

27.3.3 ERP PROGRAMME

The "New Foundations" ERP programme comprises the largest proportion of planned ICT expenditure. The pre-built integration between work and asset management available in our modern ERP (and related other business activities) will simplify the task of aligning work management to changing customer and asset needs. It will also improve our ability to provide accurate and timely information about the condition and state of all our assets. Ultimately, this will allow us to implement advanced analytic approaches to asset management and maintenance planning.

New Foundations Phase 1 comprising the finance and asset management core was implemented in 2019. It was the most complex project ever undertaken in Powerco's history, and this complexity caused significant delays, with consequent budget impacts. While we have continued with part of the Phase 2 plan, implementing a new Asset Investment Planning and Management (AIPM) system in 2020, a significant effort has gone into the stabilisation and business adoption of Phase 1 functionality. We have taken the decision to slow down the programme to ensure new functionality is fully embedded before introducing further change. This means that the programme will extend well into the next regulatory period.

A new AIPM solution (Copperleaf C55) was implemented in 2020 to optimise our asset-related expenditure against the value of the services that it delivers and the risks and costs of doing so. We will continue to refine these models during 2021.

Looking ahead, our legacy billing system will require a lifecycle upgrade. The replacement tools are expected to allow us to bill for use of the system at an ICP level using cost-reflective prices. As part of this project, we will retire legacy point solutions for customer billing, moving their functionality into the ERP.

New Foundations will also establish new systems for customer works, customer contact, customer/contractor websites integration, customer complaints and customer relationship management that we can use to synchronise all the interactions that we have with our customers, regardless of which part of Powerco they are dealing with.

Table 27.1 lists the activities that we will be undertaking during the three phases of our ICT systems upgrade process.

Table 27.1: Proposed ERP phasing (completed functionality shown in bold)

PHASE 1	PHASE 2	PHASE 3
Plant maintenance	**Asset investment planning and management (AIPM)**	Advanced analytics for predictive maintenance
Business-to-business integration with suppliers	Customer Relationship Management (CRM)	Human resources (part 2)
Geographic information integration	Human resources (part 1)	Enterprise health and safety
Mobility (part 1)	ICP management and billing	Real estate (including easements)
Project management	Business planning and consolidation	Quality management
Materials management		Treasury
Service management		Mobility (part 2)
Purchasing		Risk management
Sales		Contract management
Finance		
Asset accounting		
Accounts payable		
Accounts receivable		
Human resources (baseline)		

27.3.4 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS) PROGRAMME

In 2018, we implemented a new voice console system for the Network Operations Centre (NOC), completed the implementation of a new digital mobile radio network to provide reliable communications coverage across our rural networks, and also completed the first phase of automating our network operations with a major upgrade to the Outage Management System (OMS). Because of essential lifecycle upgrades to these systems, the Switch Order Management project has been deferred to 2022. At the same time, we will develop a more detailed network model and implement mobility solutions to give staff and service providers a real-time view of our network status.

During the next regulatory period, we will implement an Advanced Distribution Management System (ADMS) to provide the core smart grid platform that will allow us to maintain network quality and reliability as our customers take increasing advantage of distributed energy resources, such as solar photovoltaic (PV) generation and local battery storage.

Alongside the growth in our communications network infrastructure, we need a real-time data platform to process increasing volumes and variety of data from a proliferation of sensors, both in real-time for network operations and also to enable trending and forecasting for asset management.

In 2020, we completed a major upgrade to our data historian so that it can enable this analysis for the growing number of sensors on our network.

Looking ahead, Internet of Things (IoT) data services will be an area of continued focus throughout the planning period.

27.3.5 DATA & ANALYTICS PROGRAMME

We rely upon a highly complex data warehouse environment comprising multiple data repositories, technologies and manual processes for our reporting and analysis needs. We will migrate from the legacy environment to a new enterprise reporting platform, which will fulfil the majority of our business reporting needs and provide insight to business performance.

In 2019, we implemented a new cloud-based advanced analytics platform. We will continue to extend this platform with new capabilities that will provide the data science capabilities required to obtain the customer and asset insight Powerco needs to plan for the future of our network.

In addition, we have implemented data governance and data cataloguing software to enable the data quality initiatives described in section 27.2. Work to configure and adopt these systems is ongoing.

27.3.6 CYBER SECURITY PROGRAMME

Cyber risk is one of Powerco's more significant risks, and our business strategy to increase network monitoring and automation will increase our risk. In recent years, we have worked hard to reduce our cyber risk from high to medium by implementing new tools and practices.

Given that what is a good cyber security position now will probably not be in two years' time as cyber threats evolve, we will continue to invest similar amounts going forward. The current strategy, spanning 2021 and 2022, brings a focus on Cyber Risk Management, ISO-27001 certification for sensitive information, as well as improved cyber incident response.

27.3.7 IT TRANSFORMATION PROGRAMME

We have invested extensively in our infrastructure services in the past few years as part of our risk management and service standardisation initiatives.

While our data centre investment remains valid in the long term to support our real-time operational systems, we have developed a Cloud Acceleration Strategy to map the journey to the cloud for our corporate systems. Our new ERP is hosted in the cloud and we will complete the migration of our other corporate systems in 2021. This will reduce the on-premises systems footprint, so we are reviewing options for our secondary data centre.

We are investing in automation for new cloud services in order to speed up delivery of new services and increase standardisation, as well as a new generation of monitoring tools better suited to cloud services that enable proactive management and improved troubleshooting.

In 2021, we will replace the legacy service management system to improve service delivery and enable user self-service support.

We began adopting Agile methodologies two years ago to help speed up delivery of new services and we will continue to build our Agile maturity with frameworks and tools.

The remainder of the expenditure is to fund the lifecycle replacement of ICT services.

27.4 ICT EXPENDITURE FORECASTS

27.4.1 OVERVIEW

We distinguish between two ICT portfolios.

- **ICT Capex:** Portfolio includes investments in ICT change initiatives and network-related ICT. It covers the ICT programmes and projects that ensure our processes, technology and systems help deliver our Asset Management Objectives.
- **ICT Opex:** Portfolio covers ICT costs associated with operating our business. It covers software licensing, software support, public cloud services, data centre costs and network running costs.[102]

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.

Investments in communications infrastructure to enable network automation and control are profiled in Chapter 15.

27.4.2 TRENDS IN ICT EXPENDITURE

There are two main trends that will impact ICT expenditure during the planning period – the evolution to an intelligent grid and the adoption of cloud services.

Evolution to an intelligent grid

Powerco's strategy to evolve a more intelligent grid and open-access network will come with a commensurate increase in ICT costs, both Capex and Opex, during the planning period. This will increase communications network, data services and cyber security costs.

Examples of new requirements:

- Make power quality and protections device data from substations available to network planning so that they can see power quality trends and transients to build and respond to those events.
- Automated field network recovery via smart assets so that unplanned outage durations are minimised.
- Thousands of field devices constantly feeding measurements back to Powerco data services, so that we can manage power flows and constraints on the network right down to LV level.
- Devices as close as practicable to our customers, so we can view what's happening at the fringes of our grid.

[102] ICT Opex is included as part of our business support expenditure forecasts (refer to Chapter 26).

- Increased cyber security risks arising as our traditional mechanical electricity network evolves to a connected, intelligent digital grid. The additional cyber security investment is essential to support safe and secure network operations.

In most cases, the trend is for the new communications, data processing and cyber security capabilities to be purchased as a service with a commensurate increase in operating costs. In the event that we are able to use capital intensive solutions, there will still be an increase in operating costs associated with operating and maintaining these systems.

At this stage, it is difficult to fully quantify with any accuracy the impact on our future operating costs. For example, cyber security Opex is forecast to grow 225% between FY20 and FY22, while operational costs for our communications fleet will increase by approximately 5% per year during this Customised Price-quality Path (CPP) period, continuing to grow at this rate or higher through the next regulatory period.

Public cloud services

Since approximately 2010, computer applications and infrastructure have been made available as services from one or more public cloud providers. Cloud services are attractive because they reduce the time to implement new technology capabilities, increasing business agility, and also provide many IT operational and cyber security benefits. In many instances today, and increasingly in the future, the cloud will be the only method of consuming application or infrastructure services.

Utilities have been slow to adopt cloud services but are now rapidly moving their corporate applications to the cloud. In 2018, Powerco established a "Cloud First" Strategy, which will see all new solutions implemented using cloud services and most of the remaining corporate systems migrated to the cloud. For example, Powerco implemented MYOB PayGlobal software as a service in 2016 and recently migrated its email and personal file storage to Microsoft Office365. The new ERP system uses a combination of infrastructure and software as a service (SaaS).

Cloud services change the ICT Opex/Capex by:

- Avoiding the need for upfront capital expenditure on hardware and software, replacing it with a subscription fee paid for the services used.
- Increasing communications costs (leased) as more network capacity is required between Powerco's offices and the cloud providers.

While investment is shifting from traditional Capex to Opex (hardware purchase replaced by infrastructure as a service), the overall total cost of ownership is neutral to positive and provides additional benefits relating to implementation time, flexibility, scalability, cyber security and automation.

It is important to note that our approach for real-time systems, which includes operational technologies such as SCADA and NOC communications, is to continue to host these in our own data centres. There is no current proven cloud model for these services.

The target is for the majority of Powerco's corporate applications to be migrated to public cloud by mid-2021.

As Powerco is still relatively new to cloud services, it is difficult to predict the impact of the cloud on our operational expenditure. In FY18, Powerco spent 1% of total ICT budget on public cloud services. This had doubled to 2% by FY21. An IT benchmark of 112 utilities from around the globe (Gartner, December 2020) shows that, on average, utilities spend 3% of total ICT budget on public cloud services, and Gartner predicts that public cloud spending is expected to grow at a compound annual growth rate (CAGR) of 16.5%.

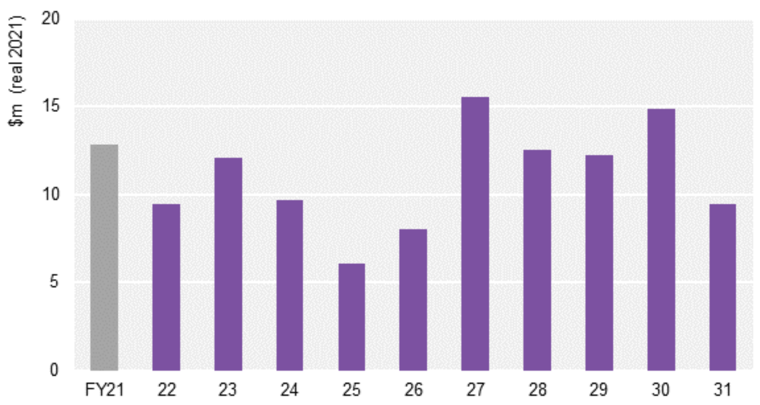
While we have been able to offset some of the Opex impact by entering into pre-payment contracts, which allow us to capitalise the cost of the Powerco-dedicated computer resources (also attracting a significant discount reducing overall expenditure), increases in SaaS, public cloud computing and associated network spend will gradually shift ICT Capex to Opex.

Given the benefits of cloud, the regulatory framework needs to be updated to reflect this shift for the overall benefit of customers.

27.4.3 EXPENDITURE FORECASTS

Figure 27.1 shows our forecast ICT capital expenditure for the planning period.

Figure 27.1: ICT Capex forecast



The increase in capital expenditure in the remaining two years of this regulatory period is due largely to higher than anticipated costs to upgrade our ERP and the addition of network modelling solutions required for our ADMS.

Following this, annual average capital expenditure will return to historical levels before increasing again in line with further ERP and ADMS investments.

27.5 FACILITIES PORTFOLIO APPROACH AND FORECAST

27.5.1 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 and efficient to operate.

We have five major regional offices in four cities that match our broad geographical coverage and ensure we are close to our assets and the work being undertaken across our network. In addition to this, we have a New Foundations project office, as the project was not able to be accommodated in existing facilities.

Our corporate office is in the New Plymouth CBD (Liardet St) and we have a second location on the outskirts of New Plymouth (Junction St), where most of our New Plymouth staff are located. Our five major regional offices and our depot locations are shown in Table 27.2.

Table 27.2: Office and depot facilities

LOCATION	OWNERSHIP
Junction St office and depot (New Plymouth), Mihaere Dr office and depot (Palmerston North). Depots – Coromandel, Masterton, Pahiatua, Taihape, Raetihi.	Owned
Grey St office (Wellington), Liardet St office (New Plymouth), Tauranga office, Te Aroha office, New Foundations project office (New Plymouth), Whanganui office, Palmerston North office (future).	Leased

Increased staff and contractor numbers to deliver the CPP programme has placed added pressure on many of the facilities. Therefore, our facilities strategy remains focused on addressing these demands to ensure we are providing environments that support our teams.

Junction St will continue to be upgraded, accommodating the increase in numbers and providing facilities for project teams. The Kaimai Building at Junction St will be refurbished and delivered FY22, providing modern office space for up to 70 people.

Tauranga growth will be addressed with a new part-floor in the existing leased building to accommodate current and future requirements.

The Palmerston North team will be provided with a new office building in the CBD that relieves current pressures and allows for future growth.

27.5.2 VEHICLES

There are 58 vehicles in our fleet that are dedicated solely to the Electricity Division. Another 11 vehicles support corporate functions.

The number of vehicles isn't forecast to increase going forward. If anything, the business will look at ways to rationalise and finetune the existing fleet to reduce where possible.

A recent Powerco commitment to transition to a full electric vehicle (EV) fleet by 2030 is already in motion and a roadmap is being created to guide vehicle acquisition and disposal during the next 10-year period.

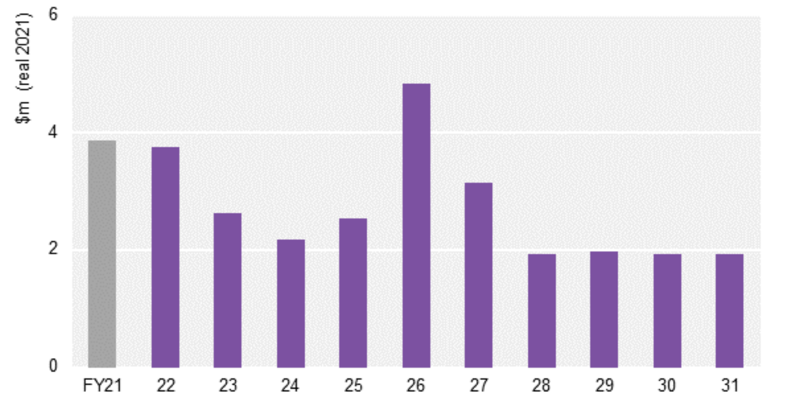
All but four vehicles are leased on full maintenance lease terms.

The vehicles have been selected based on several criteria, including safety, fit for purpose, and cost, and with input from our drivers. All vehicles are fitted with the EROAD GPS system to encourage and promote positive driver behaviours and help ensure compliance and effective vehicle utilisation.

27.5.3 EXPENDITURE FORECAST

Figure 27.2 shows our facilities Capex forecast.

Figure 27.2: Facilities Capex forecast



One of the key drivers of facilities Capex continues to be the upgrade of the Junction St facility to accommodate the continued growth at this office and ensure that the facilities can accommodate scalable operational needs.

The upgrade of the Junction St offices and new offices in the Palmerston North and Tauranga regions will ensure our staff are well supported in modern and productive environments. To allow for expansion and modernisation, there is an allowance in

FY26 for an office refurbishment and potential office extension within the Junction St site.

Another driver for the increase in facilities Capex is the introduction of the new IASB standard, IFRS 16 Leases, which came into effect on 1 January 2019. This requires leases to be recognised as Capex on the balance sheet.

Expenditure Forecasts

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

28.1 CHAPTER OVERVIEW

This chapter provides a summary of our expenditure forecasts during the planning period. It is structured to align with our internal expenditure categories and forecasts provided in earlier chapters.

We supplement our expenditure forecasts by providing high-level commentary and context for our forecasts, including key assumptions. We also discuss our cost estimation methodology and how this has been used to develop our forecasts for the planning period.

Note on expenditure charts and tables

The charts depict in-year forecasts (grey column) for our 2021 financial year (2020-21) and our forecasts (purple columns) for the remainder of the planning period.

Expenditure is presented according to our internal categories in this section. Expenditure is also provided in Information Disclosure categories, which differ in minor ways, in Schedules 11a and 11b in Appendix 2.

All dollars are denominated in constant price terms using FY21 dollars. The schedules in Appendix 2 also show expenditure in FY21 constant price terms.

28.2 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 have provided cross references to chapters with more detailed information.

28.2.1 CAPEX

Our forecast for total Capex is fairly stable with a slight upwards trends in the second half of the planning period. It represents our current best view, based on our Asset Management Strategies and using available network information.

Total Capex includes the following four expenditure categories:

- **Growth and security Capex** – discussed in Chapters 15 and 16
- **Renewals Capex** – discussed in Chapters 18-24
- **Other network Capex** – discussed in Chapters 15[103], 17, and 26
- **Non-network Capex** – discussed in Chapter 27

The slight forecast increase during the later years of the planning period relates almost entirely to network expenditure. There is a decrease in non-network Capex following the completion of our investments in systems and capability. Figure 28.1 sets out our total forecast Capex for the planning period.

Figure 28.1: Total forecast Capex for the planning period

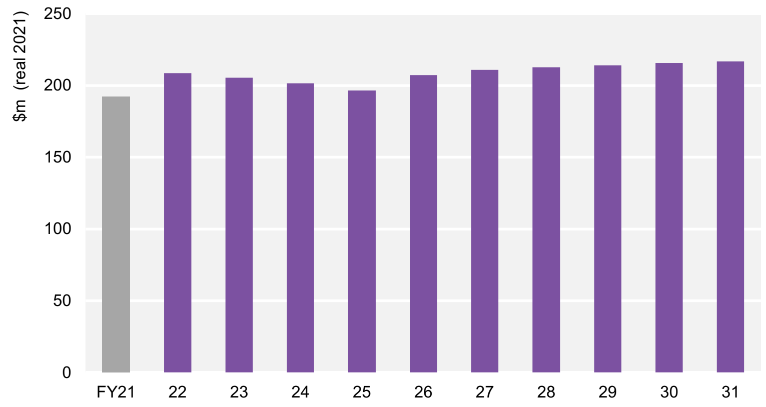


Table 28.1: Total forecast Capex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
192.5	208.5	205.5	201.6	197.0	207.2	210.9	212.7	214.1	215.7	216.8

Our Capex profile reflects the underlying network needs discussed in this AMP. The general stability of our investment profile is underpinned by our traditional network investments, with the rate of increase in later years reflecting the adoption of new network strategies as described in Chapter 6.

28.2.1.1 GROWTH AND SECURITY CAPEX

Our network development Capex is split into three portfolios. These are:

103 Network evolution is discussed as an area of Growth and Security investment in Chapter 15. To remain consistent with our CPP application, the Network Evolution expenditure forecast is included in the Other Network Capex expenditure category.

- Major projects
- Minor growth and security works
- Reliability

The combined expenditure in these portfolios is shown in Figure 28.2.

Figure 28.2: Total growth and security Capex for the planning period

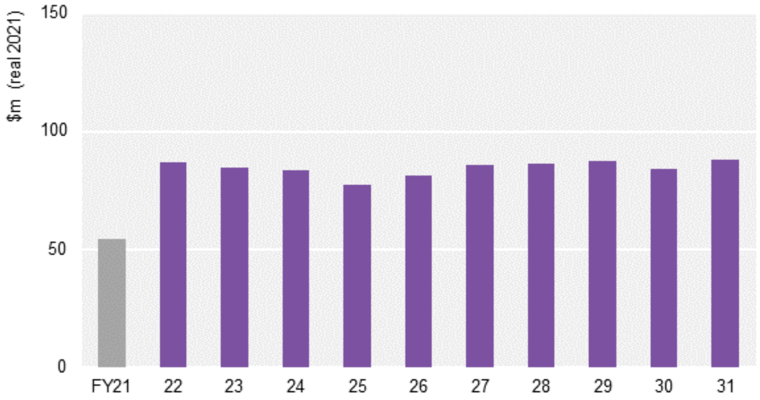


Table 28.2: Total growth and security Capex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
54.3	87.0	84.8	83.7	77.6	81.2	85.6	86.5	87.8	84.4	88.3

Network growth investment is forecast to increase in the final two years of CPP (FY22-23) to support delivery of the Customised Price-quality Path (CPP) major projects. This higher level of expenditure is forecast to be sustained from FY24 onwards because of increasing levels of investment in Low Voltage (LV) network visibility and performance, network automation, and the impact of decarbonisation.

28.2.1.2 RENEWALS CAPEX

As discussed in Chapters 18 to 24, our fleet management Capex is split into seven portfolios. These are:

- Overhead structures
- Overhead conductors
- Cables
- Zone substations
- Distribution transformers
- Distribution switchgear
- Secondary systems

The combined expenditure in these portfolios is shown in Figure 28.3.

Figure 28.3: Total renewals Capex for the planning period

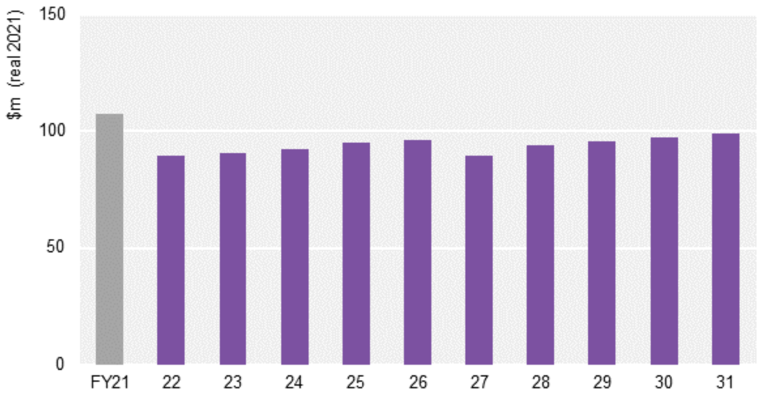


Table 28.3: Total renewals Capex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
107.5	89.2	90.4	92.5	95.3	96.1	89.4	93.9	95.5	97.1	99.1

Renewals expenditure has increased from historical levels to address deteriorating condition and asset health trends, and to accommodate an increasing percentage of our assets reaching the end of their practical service life. Expenditure is forecast to remain fairly constant during the later years of the planning period to maintain the health of our asset fleets. Expected efficiencies arising from improved asset management practices are expected to help offset increasing costs in other areas.

28.2.1.3 OTHER NETWORK CAPEX

Other network Capex is split into three portfolios. These are:

- Network evolution
- Customer connections
- Asset relocations

The combined expenditure in these portfolios is shown in Figure 28.4.

Figure 28.4: Total other network Capex for the planning period

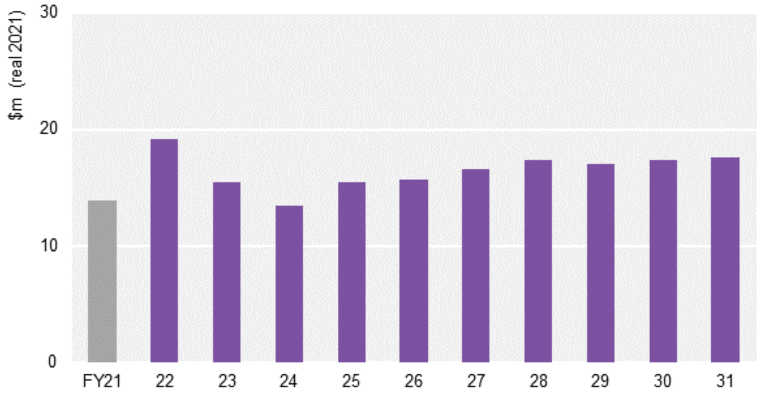


Table 28.4: Total other network Capex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
14.0	19.2	15.5	13.5	15.5	15.7	16.6	17.4	17.1	17.4	17.6

The profile for other network Capex is influenced by the variability in customer connections, and large one-off customer projects. Network evolution expenditure is fairly stable over the duration of the planning period.

28.2.1.4 NON-NETWORK CAPEX

As discussed in Chapter 27, our non-network Capex is split into two portfolios. These are:

- Information and Communications Technology (ICT) Capex
- Facilities Capex

The combined expenditure in these portfolios is shown in Figure 28.5.

Figure 28.5: Total non-network Capex for the planning period

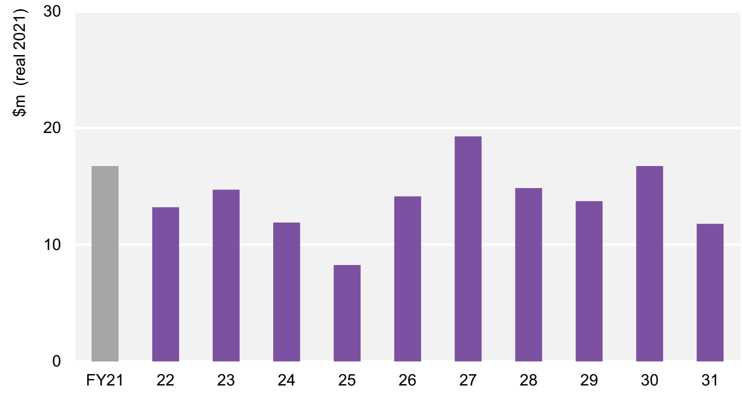


Table 28.5: Non-network Capex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
16.7	13.2	14.7	11.9	8.3	14.1	19.3	14.9	13.7	16.7	11.8

ICT investments during the planning period include advancements in cyber security and analytics capabilities, and support the evolution of an intelligent grid and the cost of maintaining an increased number of digital capabilities upon which our business now depends.

Facilities Capex includes investment in new office space and upgrades to better accommodate the increased levels of staff and contractors, and to ensure our staff are well supported in modern and productive environments.

These non-network investments are critical enablers of capacity and capability improvements needed to efficiently deliver increased work volumes and lift asset management capability.

28.2.2 OPEX

Total Opex includes the following two expenditure categories:

- **Network Opex**[104]
- **Non-network Opex**

[104] System Operations and Network Support (SONS) is part of our Network Opex category.

In Figure 28.6 we set out our forecast for total Opex during the planning period. Our Opex profile reflects the underlying network needs discussed in this Asset Management Plan (AMP) and represent our best forecasts using available information.

Figure 28.6: Total Opex for the planning period

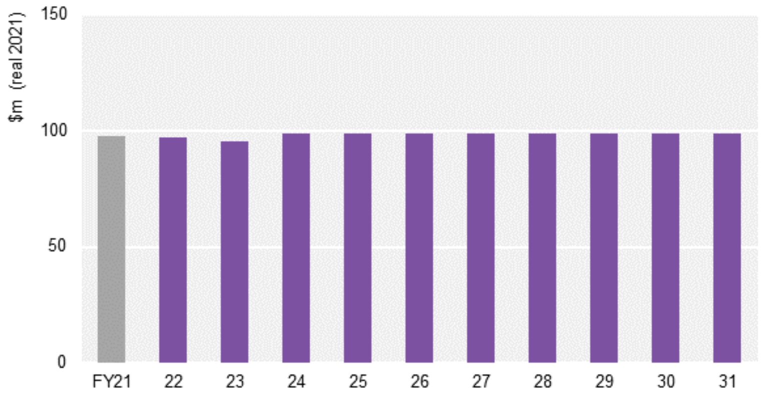


Table 28.6: Total forecast Opex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
98.0	97.3	95.6	98.8	98.9	98.8	98.9	98.8	98.8	98.8	98.7

Opex is forecast to be relatively stable during the planning period. We intend to achieve this stable expenditure despite significant upward pressure on operating expenses, resulting mainly from a shift towards a cloud-based ICT solution, major field service contract uncertainty, and improved identification of asset defects.

28.2.2.1 NETWORK OPEX

Our network Opex forecast includes expenditure in the following portfolios:

- **Preventive maintenance and inspection** – Is scheduled work, including servicing to maintain asset integrity, and inspections to compile condition information for subsequent analysis and planning.
- **Corrective maintenance** – Restores assets that have aged, been damaged, or do not meet their intended functional condition. It is undertaken to ensure assets remain safe, secure, and reliable.
- **Reactive maintenance** – Activities required to restore the network to a safe and operational state following asset failures, faults and other network incidents.
- **Vegetation management** – Encompasses all tree trimming activities and support tasks, such as customer liaison and inspections to determine the work required to keep trees clear of our overhead network.
- **System Operations and Network Support (SONS)** – Comprises our engineering staff and others who directly support electricity network operations. It also covers related network support expenses, such as professional advice, engineering reviews, quality assurance, and network running costs.

The combined expenditure in these portfolios is shown in Figure 28.7.

Figure 28.7: Network Opex for the planning period

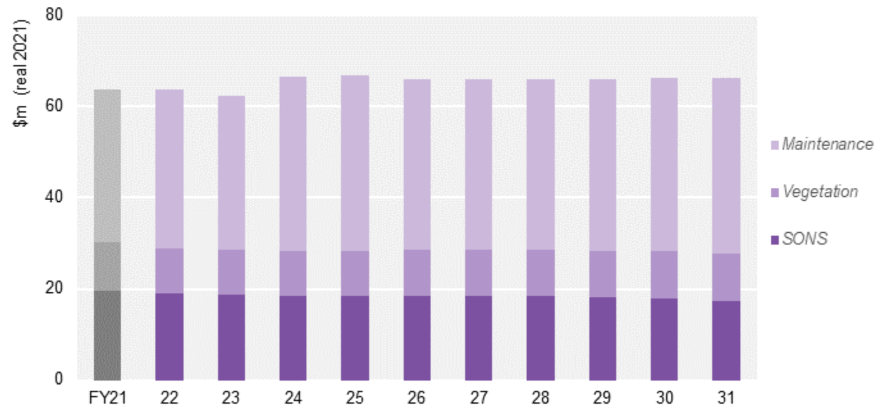


Table 28.7: Network Opex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
63.8	63.6	62.3	66.6	66.7	66.0	66.0	66.0	66.0	66.1	66.1

Opex levels are forecast to remain at about CPP levels (FY19-23) with upwards pressure expected from the renegotiation of our major field service contracts in FY24, and the increasing discovery of asset defects associated with improved and expanded inspection activities.

We expect to maintain our current levels of vegetation Opex and deliver a proactive vegetation management programme.

Our SONS forecast reflects ongoing investment in developing our people and their capabilities to support more advanced asset management maturity.

28.2.2.2 NON-NETWORK OPEX

Our non-network Opex forecast includes expenditure related to the divisions that support our electricity business. It includes direct staff costs and external specialist advice. The other material elements are office accommodation costs; legal, audit and governance fees; and insurance costs. A portion of our non-network Opex is allocated to our gas business, in accordance with our cost allocation policy, and is excluded from the forecasts in this AMP.

Figure 28.8: Non-network Opex for the planning period

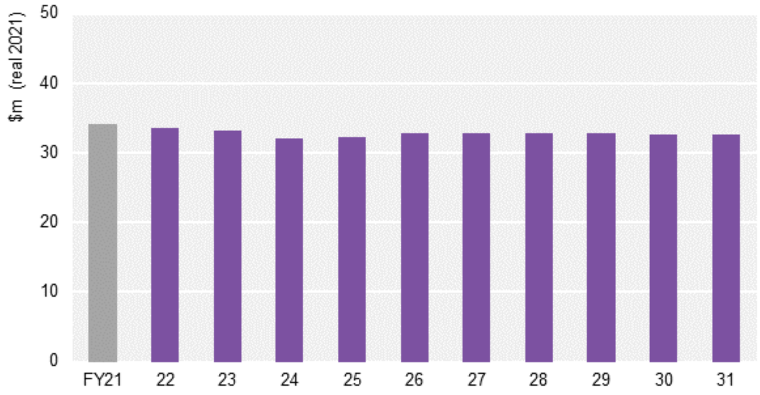


Table 28.8: Non-network Opex for the planning period ($m real 2021)

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
34.2	33.7	33.3	32.2	32.2	32.9	32.8	32.9	32.8	32.6	32.6

Our forecast expenditure is consistent with historical costs during the planning period. Increases in Opex because of a transition to cloud-based services and increases to cyber security costs are largely offset by increased efficiencies in other areas of non-network Opex.

28.3 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 followingtwo categories:

- Inputs and assumptions relating to our forecasts and underlying forecasting approaches.
- Our approach to escalating our forecasts to nominal dollars, including our estimates of capitalised interest and the timing of commissioning.

28.3.1 FORECASTING INPUTS AND ASSUMPTIONS

Table 28.9 sets out the main inputs and assumptions underpinning our forecasts for the planning period.

Table 28.9: Forecasting inputs and assumptions

INPUTS AND ASSUMPTIONS	DISCUSSION
Work volumes	
Historical asset failure rates provide an appropriate proxy for expected asset fleet deterioration (used in our survivorship analysis).	Except where specific type issues or localised accelerated deterioration have been identified, we have assumed that asset condition will degrade at similar rates to historical evidence when accounting for age and type. Through survivorship analysis, we can then use this information to estimate likely quantities of future asset replacements. In some cases, such as 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 to Chapters 18-24.
Expected asset lives, based on experience operating our network, provide an appropriate proxy for longer term asset replacement forecasting.	For longer term forecasting, at times we 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 to Chapters 18-24.
Historical relationships between load growth and related drivers (local GDP, installation control point – 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 in the medium term. In the longer term, the increasing adoption of new technologies (see Chapter 6) 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 over-investment.

INPUTS AND ASSUMPTIONS	DISCUSSION
An open-access network will be the new norm for network operations.	We forecast that distribution networks globally will commence the transition to an open-access platform. This is to ensure that our customers can maximise their energy options. The shift to open-access networks would require a deeper insight of the LV feeders on our networks, new analytical and operational capabilities and commercial arrangements.
Embedded generation will not have a material impact on network investment in the planning period.	We have assumed that the installation of photovoltaics (PV) and energy storage will not materially affect peak load growth and related investments during 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 because of embedded generation. We note that industry studies, including Transform, which was carried out by the Electricity Networks Association (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. Therefore our assumption is conservative.
Brownfield asset replacement quantities are based on like-for-like replacement.	For volumetric fleets we assume that the quantity of assets forecast for replacement will be replaced with an equal number of assets, except where consolidation strategies are in place, such as with ground-mounted switchgear. Actual replacement may involve quantity variances, such as during line construction where the number of poles may increase or decrease. However, these variances are assumed to balance out, resulting in an appropriate forecast.
Customers do not expect our network performance to degrade over the long term.	Customer surveys indicate they want us to at least maintain current performance levels (also considering price impacts). Our work volume models are therefore designed to ensure no reduction in performance during the planning period. In practice, there are parts of our network that will require more investment to ensure appropriate safety outcomes, or to reflect changing customer needs and demographics.
Unit rates (costs)	
Historical unit rates are appropriate for use in volumetric forecasts.	Historical unit rates for volumetric works reflect likely future scopes and risks, on an aggregate or portfolio level. While we continue to target efficiency in all aspects of our work delivery and have made some allowances for this later in the planning period, our experience has shown that increased efficiency tends to be offset by increased safety related costs, such as traffic management, and increased costs associated with accessing the road corridor and private land.
Current network Capex unit rates reflect likely costs during the planning period.	We expect historical unit rates for capital works to reflect costs during the planning period, except where we have identified specific areas of potential cost saving (eg overhead construction design, discussed in Chapter 18).
Current maintenance unit rates reflect likely costs during the planning period.	We expect historical unit rates for maintenance to reflect costs during the planning period.

INPUTS AND ASSUMPTIONS	DISCUSSION
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 during 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.

28.3.2 ESCALATION OF FORECASTS

During the planning period we will face different input price pressures to those captured by a general measure of inflation, such as the consumers price index (CPI). We expect that the input price increases we face during the planning period will be greater than CPI because of factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.[105]

Our approach to developing cost escalators involves applying different cost escalators to our real price expenditure forecasts. Our escalators have been developed using:

- Independent forecasts of input price indices that reflect the various costs we face, including material, labour and overhead components.
- CPI forecasts consistent with the Commerce 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.[106]

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.

28.4 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

105 The Default Price-quality Path (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.

106 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.

- Linked to out-turn 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 during the planning period. Instead, we have sought to develop forecasts to a confidence level of P50.[107]

Our forecasts beyond two years use a combination of the following approaches:[108]

- **Customised estimates (Capex)** – Used for large single projects (>$500,000) that require individual tailored investigation.
- **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)** – Mainly used for forecasting network and non-network Opex. It is also used for certain trend-based Capex forecasts, such as asset relocations.

These estimate types are discussed below.

28.4.1 CUSTOMISED ESTIMATES

This approach involves developing cost estimates based on project scopes, with larger projects supplemented with cost estimates from external consultants. Project scopes are determined from desktop reviews of asset information, such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities.

Activity costs are based on historical costs, service provider rates, quotes, and external reviews. Material costs are determined with reference to supply contracts and historical installation costs contained in our price-book. Installation costs are informed by similar previous projects and updated with current prices from service providers.

There are risks associated with estimating projects up to 10 years in advance. The costs that are subject to material estimation risk will vary by project type. In general, the main cost items that lead to estimation risk include:

- Site location, eg remoteness of the 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.

28.4.2 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 out-turns 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[109] 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, such as IT hardware, we have used expected volumes and unit rates informed by discussions with vendors and historical out-turns.

28.4.3 BASE-STEP-TREND

We have used a ‘base-step-trend’ approach to forecast part of our expenditure.[110] The approach is used by many utilities and economic regulators for forecasting expenditure that is recurring.[111] Figure 28.9 sets out the steps in developing base-step-trend forecasts.

[107] The P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.

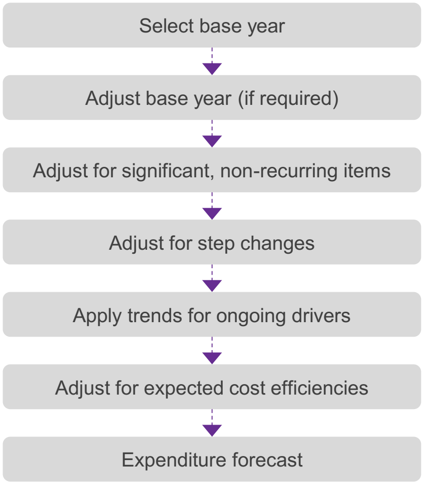
[108] Budgeting for the earlier part of the period is based on tendered work, detailed project-specific estimates, or maintenance delivery plans.

[109] The net impact of cost variances will tend to diminish in a portfolio containing a large number of P50 estimates.

[110] This includes reactive maintenance and SONS. It is also used to a lesser extent for non-network Opex and certain Capex forecasts, such as asset relocations and customer connections.

[111] 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 Commerce Commission’s approach to Opex used in setting DPPs in 2012 and 2014.

Figure 28.9: Base-step-trend forecasting steps



The base-step-trend approach starts with selecting a representative base year. The aim is to identify a recent year that is representative of recurring expenditure that is expected in future years. If there are significant events, such as a major storm, an adjustment is made to remove their 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 because of ongoing drivers, and expected cost efficiencies.

28.4.4 COST ESTIMATION PRICE-BOOK

Our Capex cost estimation process is built around a cost estimation ‘price-book’. Using this, we can develop robust cost estimates using a centrally managed dataset. We continue to improve our processes to capture actual project cost and feed it into relevant future cost estimates.

28.5 INFORMATION DISCLOSURE CATEGORIES

28.5.1 NETWORK CAPEX

For the purposes of Information Disclosure in Schedule 11a, we use the following network Capex categories. These differ somewhat from the categories we have used in our Capex expenditure forecasting, and which are discussed in this AMP. We use our categories as they better reflect the way we manage the associated assets, but we maintain mappings to allow us to meet our disclosure requirements[112].

- **System growth** – These investments are classified under our growth and security category, excluding reliability investments, and also includes our network evolution investments. The investment plans are described in detail in Chapters 15 and 16.
- **Asset replacement and renewal** – These investments are classified under our renewals category. The investment plans are described in detail in Chapters 18-24.
- **Reliability, safety and environment** – Safety and environment capital investments are generally managed as part of our renewals processes but are separately identified to reflect their particular drivers. The investment plans are described in detail in Chapters 18-24. Reliability investments include our automation programme (part of growth and security), discussed in Chapter 16.
- **Customer connections** – Our customer connections portfolio is consistent with the Information Disclosure definition. These investments are discussed in Chapter 17.
- **Asset relocations** – Our asset relocations portfolio is consistent with the Information Disclosure definition. These investments are discussed in Chapter 26.

[112] Our non-network Capex categories align with the disclosure requirements and are discussed in Chapter 27.

28.5.2 NETWORK OPEX

As with network Capex, for the purposes of Information Disclosure in Schedule 11b, we use the following network Opex categories. These differ somewhat from the categories we have used in our Opex expenditure forecasting.

- **Service interruptions and emergencies** – This category is consistent with our reactive maintenance portfolio.
- **Vegetation management** – Our vegetation management portfolio is consistent with the Information Disclosure definition.
- **Routine and corrective maintenance and inspections** – This category covers expenditure from our preventive maintenance and inspection portfolio, as well as the Commerce Commission's 'corrective' work within our corrective maintenance portfolio.
- **Asset replacement and renewal** – This category is generally consistent with our corrective maintenance portfolio, although our corrective maintenance portfolio also includes the corrective work from the Commission's routine and corrective maintenance and inspections category.
- **System operations and network support** – Our SONS portfolio is consistent with the Information Disclosure definition, although we classify SONS as network Opex.

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Appendices

This section provides additional information to support our AMP. It includes our Information Disclosure schedules.

APPENDIX 1 GLOSSARY OF KEY TERMS

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.

ABC means Aerial Bundled Conductor.

ABS means Air Break Switch, which is a type of equipment used for isolating parts of a circuit.

ACSR means Aluminium Conductor Steel Reinforced, which is a commonly used type of overhead conductor.

Adequacy means the ability of the electrical power network to meet the load demands under varying steady state conditions while not exceeding component ratings and voltage limits.

ADMD means After Diversity Maximum Demand. This refers to the average maximum demand assigned to a customer or load for network dimensioning purposes during design. Typical domestic ADMDs are in the order of 4kVA at reticulation level and 2kVA at feeder level.

ADMS means Advanced Distribution Management System.

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. Should also include explanation of the H1-H5 scale.

ALARP means As Low As Reasonably Practical and is one of the principles of risk management.

AMI is Advance Metering Information, which includes meter information outside of that available through the registry.

AMMAT means Asset Management Maturity Assessment Tool.

Asset fleet describes a group of assets that share technical characteristics and investment drivers.

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.

BaU is Business as Usual.

BESS means Battery Energy Storage System.

Capex refers to capital expenditure, investments to create new assets or to increase the service performance or service potential of existing assets.

CAGR is Compound Annual Growth Rate.

CB is a Circuit Breaker. These are critical switching devices on our network

CBD means the Central Business District.

CBRM means Condition-Based Risk Management.

CCA is Copper Chrome Arsenic, a treatment method for softwood poles.

CDEM is Civil Defence and Emergency Management.

CDR is a Conceptual Design Report

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.

CNAIM means Common Network Asset Indices Methodology. It is the UK standard for modelling asset risk and degradation.

Contingency means the state of a system in which one or more primary components are out of service. The contingency level is determined by the number of primary components out of service.

CPI means the Consumers Price Index.

CPP is Customised Price-quality Path.

Critical Spares are specialised parts that are stored to keep an existing asset in a serviceable condition. Critical spares may also include entire asset spares in case of serious failures.

CRM is the Customer Relationship Management system.

CT means Current Transformer

CIW means Customer-initiated Works

CWMS means Connections Works Management System, which is an online workflow management system that facilitates and tracks the processes associated with customer connection applications, approvals, and works completion.

DAS means Distribution Automated Switches, one of the many HV devices that can help us develop a network of the future.

DC means direct current....

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.

DFA means Delegated Financial Authority.

DGA means Dissolved Gas Analysis, which is a type of oil test, typically carried out on transformers. It analyses the different gas traces found inside the oil. Different levels and combinations of gas traces provide an indication of the internal condition of the transformer.

DG/ESS is Distributed Generation/Energy Storage Systems.

DMS means Distribution Management System.

DNO is a Do Not Operate notice is assigned to assets deemed unsafe for operators to switch without extra operational precautions.

DNP3 is Distributed Network Protocol version 3, which is our standard communications protocol.

DP or Degree of Polymerisation is a type of test carried out on a transformer's paper insulation. This test provides an indication of insulation condition.

DPP means Default Price-quality Path.

DRAT is Powerco's Defect Risk Assessment Tool, a tool that is used to systematically analyse defects and the risks presented by them.

DSI is Distribution System Integrator. It 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.

DSO is Distribution System Operator. It is a utility that has all the functionality of a DSI, but is also involved in managing all the transactions of energy and alternative services on the network.

EA is the Electricity Authority

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.

ECP34 is the New Zealand Electrical Code of Practice for Electrical Safe Distances.

EDGS means the Electricity Demand and Generation Scenarios produced by MBIE.

EEA is the Electricity Engineers' 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.

EHV means Extremely High Voltage

Emergency Spares means holdings of equipment to provide a level of protection against a catastrophic failure of assets.

EMS means Environmental Management System.

ENA is the Electricity Networks Association.

EPR means Earth Potential Rise (or Ground Potential Rise), which occurs when a large current flows to earth through an earth grid impedance and creates a change of voltage over distance from the point of injection. EPR can be hazardous to the public and field staff and is an ongoing safety concern.

ERP means Enterprise Resource Planning, which is a suite of applications that collect, store, manage and interpret data.

ESCP is Powerco's Electricity Supply Continuity Plan.

ETS is the Emissions Trading Scheme.

EV means Electric Vehicles.

EWP means Electricity Works Plan, which is our two-year rolling Electricity Works Plan scheduled works plan.

Failure means an event in which a component does not operate or ceases to operate as intended.

FIDI is Feeder Interruption Duration Index, which means the total duration of interruptions of supply that a customer 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 because of one or more network component failures.

GIP means Grid Injection Point.

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 work.

GXP means transmission Grid Exit Point.

GWh means gigawatt hours.

HILP means High Impact Low Probability events.

HPI means High Potential Incidents.

HV refers to High Voltage, which is associated with assets on our network above 1,000 Volts.

IAC is internal arc flash containment.

iPaaS means integration Platform as a Service.

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 customer to our network.

ICT means Information and Communications Technology.

Incipient faults are faults that slowly develop and can result in catastrophic failure if not monitored and acted on appropriately.

ID means Information Disclosure, which suppliers of electricity lines services are subjected to under regulatory requirements by the Commerce Act.

IED means Intelligent Electronic Device.

Interruption means an unplanned loss of electricity supply of one minute or longer, affecting three or more ICPs, because of an outage on the network.

IoT means Internet of Things.

ISO 55001 is an internationally recognised standard for asset management. It replaced PAS 55.

ISSP means Information Services Strategic Plan.

JDE means JD Edwards, which is our maintenance, work management and financial system.

kV refers to kilovolt – 1,000 volts.

LIDAR which stands for Light Detection and Ranging, is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances) to the Earth

LFI means Line Fault Indicator.

LoRaWAN is Long Range Wide Area Network, a long-range wireless communication protocol.

LPWAN is a low-power wide area network

LTI means Lost Time Injury.

LTIFR means Lost Time Injury Frequency Rate, which is calculated as the 12-month rolling number of LTIs per 1,000,000 hours worked.

LV refers to Low Voltage, which is associated with parts of our network below 1,000 volts.

MBIE is the Ministry of Business, Innovation and Employment.

MD means maximum demand

MDI means Maximum Demand Indicator

MECO is Materials, Energy, Chemicals, Other lifecycle considerations.

MfE is the Ministry for the Environment.

MPLS refers to Multi-Protocol Label Switching which is a routing technique in telecommunications networks that directs data from one node to the next based on short path labels rather than long network addresses, thus avoiding complex lookups in a routing table and speeding traffic flows.

MV is mega volts or 1,000 volts

MVA refers to mega volt amp.

MW is megawatt.

N-1 is an indication of power supply security and ‘N-1’ specifically means that in the event of one circuit failing, there will be another available to maintain the power supply, without interruption.

NAPA means Network Access Planning Application

NAT means Network Approval Test process, which is applied to assess the suitability of equipment for use on the network.

NER is a Neutral Earthing Resistor, which is attached to power transformers to reduce fault currents on the network.

NBS is New Building Standard. We use this seismic standard to determine which of our substation buildings require strengthening.

NOC is our Network Operations Centre, which is responsible for dispatch, coordinating/planning works, restoring supply and operating our network.

NOM is the Powerco Network Operations Manual. A comprehensive group of standards and forms that provide internal operational rules and guidance for work carried out on Powerco Electricity networks.

NZSEE is the New Zealand Society of Earthquake Engineering.

NZTA is the New Zealand Transport Agency.

NZUAG is the New Zealand Utilities Advisory Group

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.

OHRPT means Overhead Renewal Planning Tool

Outage means a loss of electricity supply.

P50 cost value is an estimate of the project cost based on a 50% probability that the cost will not be exceeded.

PAS 55 is Publicly Available Specification 55, which is an asset management standard published by the British Standards Institution in 2004. While still in use, it has been superseded by ISO 55001.

PCB is Polychlorinated Biphenyls, a carcinogenic substance contained in the oil of pre-1970s transformers.

PD is Partial Discharge testing.

PHEV means Plug-in Hybrid Electric Vehicle.

PILC means Paper Insulated Lead Covered, which is a type of power cable.

PMI means Preventive Maintenance and Inspection.

PMO means Project Management Office.

PPE means Personal Protective Equipment.

Protection Discrimination is a coordinated electrical protection system that isolates part of the network circuit due to faults while keeping the remaining parts in service.

PQM is a Power Quality Meter

PTN means Packet Transport Network.

PV means Photovoltaics.

PVC means Poly Vinyl Chloride, which is a type of outer sheath on some of our cable and overhead conductor.

R – L1, L2, L3 is NOC's storm response level, categorised in terms of an R – Readiness, L1 – Level 1, L2 – Level 2, or L3 – Level 3.

RAPS means Remote Area Power Supply, which provides a cost effective alternative for replacing long, end of line, remote rural distribution feeders.

RCM means Reliability-Centred Maintenance.

Refurbishment means activities to rebuild or replace parts or components of an asset, to restore it to a required functional condition and extend its life beyond that originally expected. Refurbishment is a Capex activity.

REA means Remote Engineering Access. This is provided by the latest standard RTUs, and allows remote download of engineering information such as on faults.

R&D means Research and Development.

RFI/ROI means Request for Information and Registration of Interest

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.

RTS means Real-Time Systems.

RTU means Remote Terminal Unit, which is a device that interfaces our network devices to our SCADA system.

SaaS means Software as a Service.

SAIDI means System Average Interruption Duration Index. This is the average length of time of interruptions of supply that a customer experiences in the period under consideration.

SAIFI means System Average Interruption Frequency Index. This is the average number of interruptions of supply that a customer experiences in the period under consideration.

SAP (Systeme, Anwendungen und Produkte in der Datenverarbeitung, "Systems, Applications & Products in Data Processing") is a German-based European multinational software corporation that makes enterprise software to manage business operations and customer relations.

SCADA means Supervisory Control And Data Acquisition. This is a system for remote monitoring and control that enables us to operate our network in a safe and reliable manner.

Scheduled Outage or Planned Outage means a planned loss of electricity supply.

Security means the ability of the network to meet the service performance demanded of it during and after a transient or dynamic disturbance of the network or an outage to a component of the network.

Service provider means a contractor or business that supplies a service to us.

SF_6 means sulphur hexafluoride.

SMC means the Service Management Centre operated by our service providers.

SMEI is the Safety Manual for the Electricity Industry

SONS means System Operations and Network Support.

SPS means Special Protection Scheme.

SSDG means Small Scale Distributed Generation.

STATCOM refers to a Static Synchronous Compensator. It is a shunt device of the that uses power electronics to control power flow and improve transient stability on power grids

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.

TCO is the Total Cost of Ownership when conducting lifecycle assessments for assets

VoENS is Value of Energy Not Served calculations for feeder capacity.

VAR stands for Mega Volt*Amps Reactive, also known as the apparent power.

VLF means Very Low Frequency spectrum

VRP refers to our Voice and Radio Platform

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.

3LoD is the Three Lines of Defence model to assist with the risk management decision-making process.

3Ds means decarbonisation, decentralisation and digitalisation.

A2.1 SCHEDULE 11A

Included below is our Schedule 11A disclosure. Constant price figures in this schedule are in 2021 real dollars.

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
9		**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10		Consumer connection	39,997	44,394	39,844	34,925	39,212	43,528	48,054	50,117	52,398	54,877	57,201
11		System growth	45,501	83,649	82,747	78,255	73,446	71,665	76,120	78,152	80,221	77,915	84,921
12		Asset replacement and renewal	100,325	86,493	87,119	91,206	96,366	103,835	99,258	106,808	110,671	114,560	121,031
13		Asset relocations	1,976	5,562	1,143	1,174	2,399	1,224	1,251	2,550	1,304	1,335	1,363
14		Reliability, safety and environment:											
15		Quality of supply	9,341	7,834	8,066	12,541	13,672	21,849	24,817	26,487	28,539	29,386	30,601
16		Legislative and regulatory	-	163	1,634	1,758	1,801	-	-	-	-	-	-
17		Other reliability, safety and environment	7,176	4,447	5,153	5,085	5,506	3,613	3,315	3,754	4,801	6,002	5,284
18		**Total reliability, safety and environment**	16,517	12,444	14,853	19,384	20,979	25,462	28,132	30,241	33,340	35,388	35,885
19		**Expenditure on network assets**	204,316	232,542	225,706	224,944	232,402	245,714	252,815	267,868	277,934	284,075	300,401
20		Expenditure on non-network assets	16,737	13,340	15,084	12,399	8,754	15,292	21,231	16,698	15,742	19,569	14,051
21		**Expenditure on assets**	221,053	245,882	240,790	237,343	241,156	261,006	274,046	284,566	293,676	303,644	314,452
22													
23	*plus*	Cost of financing	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078
24	*less*	Value of capital contributions	28,553	32,840	27,407	23,948	27,295	29,726	32,762	34,821	35,804	37,397	39,039
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	194,578	215,120	215,461	215,473	215,939	233,358	243,362	251,823	259,950	268,325	277,491
28													
29		Assets commissioned	164,220	181,589	288,938	196,944	216,006	228,690	238,233	250,595	253,007	275,254	271,433
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 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
32			$000 (in constant prices)										
33		Consumer connection	39,997	43,739	38,695	33,353	36,652	39,811	43,052	43,950	44,975	46,098	47,032
34		System growth	45,501	81,725	79,566	73,850	67,321	63,935	66,194	66,283	66,408	62,949	66,545
35		Asset replacement and renewal	100,325	84,711	83,884	86,086	88,579	92,881	86,496	90,682	91,527	92,290	94,981
36		Asset relocations	1,976	5,467	1,106	1,112	2,221	1,106	1,104	2,198	1,097	1,098	1,094
37		Reliability, safety and environment:											
38		Quality of supply	9,341	7,686	7,770	11,842	12,606	19,549	21,634	22,485	23,594	23,669	24,018
39		Legislative and regulatory	-	160	1,568	1,648	1,646	-	-	-	-	-	-
40		Other reliability, safety and environment	7,176	4,353	4,965	4,800	5,078	3,234	2,892	3,191	3,971	4,851	4,143
41		**Total reliability, safety and environment**	16,517	12,199	14,303	18,290	19,330	22,783	24,526	25,676	27,565	28,520	28,161
42		**Expenditure on network assets**	204,316	227,841	217,554	212,691	214,103	220,516	221,372	228,789	231,572	230,955	237,813
43		Expenditure on non-network assets	16,737	13,202	14,723	11,908	8,259	14,146	19,279	14,865	13,740	16,745	11,787
44		**Expenditure on assets**	221,053	241,043	232,277	224,599	222,362	234,662	240,651	243,654	245,312	247,700	249,600
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											

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
Difference between nominal and constant price forecasts		**$000**										
Consumer connection		-	655	1,149	1,572	2,560	3,717	5,002	6,167	7,423	8,779	10,169
System growth		-	1,924	3,181	4,405	6,125	7,730	9,926	11,869	13,813	14,966	18,376
Asset replacement and renewal		-	1,782	3,235	5,120	7,787	10,954	12,762	16,126	19,144	22,270	26,050
Asset relocations		-	95	37	62	178	118	147	352	207	237	269
Reliability, safety and environment:												
Quality of supply		-	148	296	699	1,066	2,300	3,183	4,002	4,945	5,717	6,583
Legislative and regulatory		-	3	66	110	155	-	-	-	-	-	-
Other reliability, safety and environment		-	94	188	285	428	379	423	563	830	1,151	1,141
Total reliability, safety and environment		-	245	550	1,094	1,649	2,679	3,606	4,565	5,775	6,868	7,724
Expenditure on network assets		-	4,701	8,152	12,253	18,299	25,198	31,443	39,079	46,362	53,120	62,588
Expenditure on non-network assets		-	138	361	491	495	1,146	1,952	1,833	2,002	2,824	2,264
Expenditure on assets		-	4,839	8,513	12,744	18,794	26,344	33,395	40,912	48,364	55,944	64,852

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Consumer types defined by EDB**		**$000 (in constant prices)**					
All Consumers		39,997	43,739	38,695	33,353	36,652	39,811
**include additional rows if needed*							
Consumer connection expenditure		39,997	43,739	38,695	33,353	36,652	39,811
less Capital contributions funding consumer connection		27,803	30,000	26,250	22,500	24,750	27,000
Consumer connection less capital contributions		12,194	13,739	12,445	10,853	11,902	12,811

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	13,160	41,927	32,785	11,099	13,506	12,925
Zone substations	9,700	22,191	27,317	34,723	27,935	25,121
Distribution and LV lines	5,402	2,639	2,886	4,998	4,395	4,411
Distribution and LV cables	6,142	4,000	5,829	9,193	7,809	7,798
Distribution substations and transformers	2,762	1,780	688	2,451	2,390	1,015
Distribution switchgear	5,555	2,816	3,021	5,114	4,828	4,985
Other network assets	2,780	6,372	7,040	6,272	6,458	7,680
System growth expenditure	45,501	81,725	79,566	73,850	67,321	63,935
less Capital contributions funding system growth						
System growth less capital contributions	45,501	81,725	79,566	73,850	67,321	63,935

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
	$000 (in constant prices)					
Subtransmission	7,073	4,033	2,836	2,342	2,299	2,276
Zone substations	10,831	15,793	16,569	14,544	15,485	16,665
Distribution and LV lines	57,916	42,462	43,750	44,495	44,967	47,128
Distribution and LV cables	6,887	5,795	5,338	6,344	5,909	5,399
Distribution substations and transformers	8,937	7,350	7,053	8,056	8,179	8,740
Distribution switchgear	7,690	8,139	7,502	9,427	10,863	11,799
Other network assets	991	1,139	836	878	877	874
Asset replacement and renewal expenditure	100,325	84,711	83,884	86,086	88,579	92,881
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	100,325	84,711	83,884	86,086	88,579	92,881

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	**$000 (in constant prices)**					
**include additional rows if needed*						
All other project or programmes - asset relocations	1,976	5,467	1,106	1,112	2,221	1,106
Asset relocations expenditure	1,976	5,467	1,106	1,112	2,221	1,106
less Capital contributions funding asset relocations	750	2,500	500	500	1,000	500
Asset relocations less capital contributions	1,226	2,967	606	612	1,221	606

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	**$000 (in constant prices)**					
**include additional rows if needed*						
All other projects or programmes - quality of supply	9,341	7,686	7,770	11,842	12,606	19,549
Quality of supply expenditure	9,341	7,686	7,770	11,842	12,606	19,549
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	9,341	7,686	7,770	11,842	12,606	19,549

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26

11a(vii): Legislative and Regulatory

*Project or programme**	$000 (in constant prices)					
Secondary systems (relay replacement for extended reserves)	-	160	1,568	1,648	1,646	-
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	160	1,568	1,648	1,646	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	160	1,568	1,648	1,646	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26

11a(viii): Other Reliability, Safety and Environment

*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment	7,176	4,353	4,965	4,800	5,078	3,234
Other reliability, safety and environment expenditure	7,176	4,353	4,965	4,800	5,078	3,234
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	7,176	4,353	4,965	4,800	5,078	3,234

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26

11a(ix): Non-Network Assets

Routine expenditure						
*Project or programme**	$000 (in constant prices)					
ICT capex	5,151	3,922	4,810	5,956	4,612	6,476
Facilities	451	1,319	838	260	394	351
Leases	1,066	1,677	1,677	1,677	1,677	1,677
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	6,668	6,918	7,325	7,893	6,683	8,504
Atypical expenditure						
*Project or programme**						
ICT capex (new capability)	7,728	5,534	7,293	3,781	1,107	2,825
Facilities	2,341	750	105	234	469	2,817
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	10,069	6,284	7,398	4,015	1,576	5,642
Expenditure on non-network assets	16,737	13,202	14,723	11,908	8,259	14,146

A2.2 SCHEDULE 11B

Included below is our Schedule 11B disclosure. Constant price figures in this schedule are in 2021 real dollars.

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031

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
8	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	6,954	7,826	7,938	8,958	9,175	9,423	9,667	9,918	10,175	10,438	10,709
11	Vegetation management	10,724	9,905	10,115	10,350	10,613	10,912	11,206	11,509	11,820	12,139	12,467
12	Routine and corrective maintenance and inspection	14,074	16,772	16,231	18,501	18,848	18,969	19,431	19,684	20,286	20,787	21,717
13	Asset replacement and renewal	12,506	10,593	10,436	12,484	12,757	12,295	12,588	12,888	13,195	13,510	13,832
14	**Network Opex**	44,258	45,096	44,720	50,293	51,393	51,599	52,892	53,999	55,476	56,874	58,725
15	System operations and network support	19,499	19,347	19,333	19,273	19,562	20,107	20,299	20,620	20,690	21,036	20,773
16	Business support	34,194	34,002	34,079	33,488	34,160	35,512	36,172	36,930	37,614	38,145	38,878
17	**Non-network opex**	53,693	53,349	53,412	52,761	53,722	55,619	56,471	57,550	58,304	59,181	59,651
18	**Operational expenditure**	97,951	98,445	98,132	103,054	105,115	107,218	109,363	111,549	113,780	116,055	118,376

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
20	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	6,954	7,717	7,713	8,558	8,601	8,645	8,689	8,734	8,778	8,823	8,868
23	Vegetation management	10,724	9,767	9,827	9,888	9,949	10,011	10,073	10,135	10,198	10,261	10,324
24	Routine and corrective maintenance and inspection	14,074	16,543	15,786	17,693	17,692	17,432	17,496	17,367	17,537	17,608	18,024
25	Asset replacement and renewal	12,506	10,449	10,149	11,939	11,975	11,299	11,335	11,371	11,407	11,443	11,479
26	**Network Opex**	44,258	44,476	43,475	48,078	48,217	47,387	47,593	47,607	47,920	48,135	48,695
27	System operations and network support	19,499	19,146	18,870	18,510	18,455	18,601	18,433	18,357	18,058	18,001	17,427
28	Business support	34,194	33,650	33,262	32,162	32,227	32,852	32,846	32,877	32,829	32,640	32,616
29	**Non-network opex**	53,693	52,796	52,132	50,672	50,682	51,453	51,279	51,234	50,887	50,641	50,043
30	**Operational expenditure**	97,951	97,272	95,607	98,750	98,899	98,840	98,872	98,841	98,807	98,776	98,738
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*											

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
40	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	109	225	400	574	778	978	1,184	1,397	1,615	1,841
43	Vegetation management	-	138	288	462	664	901	1,133	1,374	1,622	1,878	2,143
44	Routine and corrective maintenance and inspection	-	229	445	808	1,156	1,537	1,935	2,317	2,749	3,179	3,693
45	Asset replacement and renewal	-	144	287	545	782	996	1,253	1,517	1,788	2,067	2,353
46	**Network Opex**	-	620	1,245	2,215	3,176	4,212	5,299	6,392	7,556	8,739	10,030
47	System operations and network support	-	201	463	763	1,107	1,506	1,866	2,263	2,632	3,035	3,346
48	Business support	-	352	817	1,326	1,933	2,660	3,326	4,053	4,785	5,505	6,262
49	**Non-network opex**	-	553	1,280	2,089	3,040	4,166	5,192	6,316	7,417	8,540	9,608
50	**Operational expenditure**	-	1,173	2,525	4,304	6,216	8,378	10,491	12,708	14,973	17,279	19,638

A2.3 SCHEDULE 12A

Company Name	**Powerco Limited**	
AMP Planning Period	**1 April 2021 – 31 March 2031**	

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**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.	0.47%	0.97%	3.72%	6.06%	88.78%	-	4	2.46%
11	All	Overhead Line	Wood poles	No.	6.51%	10.82%	29.80%	27.50%	25.36%	-	4	23.13%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	39.75%	60.25%	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.30%	3.90%	10.40%	74.00%	11.40%	-	4	4.61%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	5.25%	4.77%	89.98%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	44.28%	55.72%	-	-	-	4	-
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	-	-	-	9.96%	90.04%	-	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.	6.94%	33.33%	17.36%	32.64%	6.25%	3.47%	3	15.28%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	1.90%	98.10%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	1.19%	21.43%	23.21%	54.17%	-	4	29.17%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	91.30%	8.70%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	21.69%	4.11%	13.26%	18.98%	41.97%	-	4	11.23%
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.	-	-	26.32%	10.53%	63.16%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	23.97%	14.60%	61.44%	-	4	20.26%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	3.77%	7.55%	88.68%	-	4	-
35												

	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)							
36–38					H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2.59%	7.25%	19.69%	37.82%	32.64%	-	4	7.25%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.30%	15.40%	22.40%	53.60%	8.30%	-	3	7.24%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	20.00%	80.00%	-	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	1.33%	19.05%	79.62%	-	3	2.13%
44	HV	Distribution Cable	Distribution UG PILC	km	-	0.04%	0.18%	10.89%	88.89%	-	3	0.67%
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.	0.47%	0.63%	2.05%	2.21%	94.64%	-	4	8.36%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.59%	56.98%	1.12%	7.82%	28.49%	-	4	75.42%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3.75%	2.76%	11.51%	18.96%	63.02%	-	3	7.16%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	13.98%	4.06%	15.79%	24.33%	41.83%	-	4	13.23%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.40%	2.43%	10.19%	17.15%	67.85%	-	4	5.68%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.02%	1.91%	7.25%	11.56%	76.27%	-	3	5.44%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.22%	1.14%	6.40%	22.83%	69.41%	-	4	4.40%
53	HV	Distribution Transformer	Voltage regulators	No.	-	1.59%	-	3.18%	95.23%	-	4	3.42%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.49%	1.55%	5.99%	9.91%	81.07%	-	3	3.52%
55	LV	LV Line	LV OH Conductor	km	0.06%	13.42%	18.64%	54.43%	13.45%	-	2	6.71%
56	LV	LV Cable	LV UG Cable	km	0.21%	0.35%	4.06%	27.21%	68.17%	-	2	1.19%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	2.29%	2.69%	12.36%	25.35%	57.31%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	4.40%	2.32%	24.88%	26.02%	42.38%	-	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	31.01%	5.35%	16.15%	47.50%	-	3	23.28%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	42.49%	26.84%	28.12%	2.56%	-	2	25.56%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	2.08%	64.58%	33.33%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	27.78%	-	13.89%	58.33%	-	4	-
63	All	Load Control	Relays	No.	6.19%	36.02%	1.29%	3.99%	52.51%	-	1	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Notes:

1. We interpret Grade 1 condition as assets requiring replacement within one year, based on our asset health models. This does not mean the assets are at imminent risk of failure, but rather have reached the end of their useful life. With appropriate risk mitigations (such as operating constraints for switchgear), these assets can safely continue in service for more than one year, though we do not consider this a sustainable practice over the longer term.
2. The '% of asset forecast to be replaced in next 5 years' for Zone Substation Buildings is based on our seismic strengthening programme. The buildings will be strengthened via various means, but typically not replaced. This ensures consistency with our renewal Capex forecasts.
3. The '% of asset forecast to be replaced in next 5 years' is based on a denominator of operational network sites, whereas disclosure schedules 9a and 9b additionally include spares.

A2.4 SCHEDULE 12B

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031

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	4	1	N-1	1	858%	1	447%	Subtransmission circuit	Single 66kV circuit. Proposed backup distributed generation project. Removal of tee at Kaimarama (with the GIS switching station project) to improve reliability.
10	Kerepehi	10	-	N-1 SW	2	-	8	139%	Subtransmission Circuit	Single 66kV circuit. Proposed backup distributed generation project
11	Matatoki	5	-	N	2	-	-	-	Transformer	Single Tx. 2nd transformer proposed 2030
12	Tairua	9	8	N	-	119%	8	122%	Transformer	Tx firm capacity constraint. New substation pre 2023 to offload some load. Also proposed backup 11kV link with Whangamata.
13	Thames T1 & T2	12	-	N-1	2	-	19	62%	No constraint within +5 years	66kV upgrade removes binding constraint
14	Thames T3	2	7	N-1 SW	7	25%	7	25%	No constraint within +5 years	Customer agreed security. No load increase indicated.
15	Whitianga	16	-	N	-	-	16	107%	Transformer	New substation pre 2023 to offload some of Whitianga load.
16	Paeroa	8	6	N	2	132%	10	80%	No constraint within +5 years	Managed operationally. Transformer upgrades pre 2021.
17	Waihi	17	16	N-1	-	104%	16	107%	No constraint within +5 years	Customer agreed security.
18	Waihi Beach	6	3	N	3	174%	3	182%	Subtransmission Circuit	Single 33kV cct. 2nd Transformer planned pre 2023. Proposed backup ditributed generation post 2023. Removal of tee near Waihi pre 2022 to improve reliability.
19	Whangamata	10	5	N	1	210%	5	214%	Subtransmission circuit	Battery & Generator recently commissioned. Proposed backup 11kV link
20	Aongatete	4	7	N-1	2	60%	8	62%	No constraint within +5 years	Planned renewal of Aongatete substation
21	Bethlehem	9	8	N	8	116%	24	42%	No constraint within +5 years	Single transformer Substation - 2nd Tx planned 2023-2025
22	Hamilton St	16	22	N-1	12	72%	22	73%	No constraint within +5 years	Recently commissioned Sulphur Point substation offloaded Hamilton Street substation.
23	Katikati	9	5	N	5	185%	11	81%	No constraint within +5 years	Second transformer and second circuit to be completed by end 2021
24	Kauri Pt	3	2	N	2	167%	2	174%	Subtransmission Circuit	Single Tx and subtransmission circuit. Removal of the tee at Katikati to improve reliability
25	Matua	9	7	N-1 SW	8	119%	7	121%	Subtransmission circuit	Single Tx limits security. Second transformer planned 2026-2028. Sufficient 11kV backfeed
26	Omokoroa	10	13	N-1	3	79%	13	85%	Transformer and Subtransmission c	Both transformers approaching firm load. New third 33kV circuit planned for 2021-2023. Substation upgrade planned 2023-2028 (dependant on timing of NZTA highway development)
27	Otumoetai	15	14	N-1 SW	11	108%	14	113%	Transformer	Minor constraint - managed operationally. Matua and Bethlehem second transformer projects will relieve Otumoetai
28	Pyes Pa	10	12	N-1	8	89%	24	51%	No constraint within +5 years	Possible constraint depending on the rate of commercial/industrial growth. New Belk Road substation planned 2022-2027 to offload Pyes Pa.
29	Waihi Rd	21	24	N-1 SW	10	89%	24	92%	No constraint within +5 years	33kV reinforcement planned 2030-2032
30	Welcome Bay	23	21	N	4	107%	21	115%	Transformer and Subtransmission c	Managed operationally. New Oropi substation planned 2024-2027 will relieve constraints at Welcome Bay.
31	Matapihi	13	24	N-1	14	54%	24	55%	No constraint within +5 years	
32	Omanu	12	24	N-1	12	49%	24	52%	No constraint within +5 years	Partial load transfer from Triton as a result of routine growth projects. Does not limit firm capacity
33	Papamoa	16	21	N-1	10	73%	21	78%	No constraint within +5 years	11kV offload with new feeders from Wairakei substation
34	Te Maunga	10	10	N-1 SW	10	95%	10	104%	Transformer	Automated tie points progressively installed to improve reliability
35	Triton	20	21	N-1 SW	10	94%	24	86%	No constraint within +5 years	Transformers upgraded and load shift to Omanu

7	12b(i): System Growth - Zone Substations									
8	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
36	Wairakei	7	6	N	6	111%	24	35%	Transformer	2nd transformer 2022
37	Atuaroa Ave	8	-	N	7	-	-	-	Subtransmission Circuit	33kV second circuit 2026 and 2nd transformer 2025
38	Paengaroa	5	4	N-1 SW	4	133%	4	140%	Subtransmission Circuit	Second transformer 2024 and second circuit 2028 proposed for the future
39	Pongakawa	4	1	N-1	1	345%	3	187%	Subtransmission Circuit	Single circuit limited 11kV backfeed. Future diesel generator planned to provide backup
40	Te Puke	19	23	N-1	11	82%	23	85%	Subtransmission Circuit	Switchboard security upgrade planned 2023-2025
41	Farmer Rd	7	-	N	1	-	-	-	Subtransmission Circuit	Customer's planned load growth will exceed existing transfomer capacity and overload existing 33kV subtranmission circuit.
42	Inghams	4	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security
43	Mikkelsen Rd	13	19	N-1	4	66%	19	69%	No constraint within +5 years	
44	Morrinsville	9	-	N-1	2	-	8	121%	Transformer	2nd 33kV circuit ~2023. Future Sub upgrade post 2023.
45	Piako	13	15	N-1	7	86%	15	90%	Transformer	
46	Tahuna	6	1	N-1 SW	1	831%	2	406%	Subtransmission Circuit	Single 33kV circuit. Risk mitigated operationally via 11kV backfeeds
47	Tatua	5	-	N	-	-	-	-	Subtransmission Circuit	Customer's load growth will exceed the exisiting transformer capacity and overload 33kV subtransmission circuit.
48	Waitoa	12	19	N-1	-	64%	19	64%	No constraint within +5 years	
49	Walton	6	-	N	2	-	-	-	Transformer	Single Transformer. Risk managed operationally
50	Browne St	10	11	N-1 SW	7	93%	11	98%	Transformer	Very minor, low risk. Managed operationally
51	Lake Rd	6	2	N	2	382%	5	140%	No constraint within +5 years	2nd transformer planned in ~ 2021
52	Tirau	10	-	N	-	-	10	100%	No constraint within +5 years	Single transformer. Customer driven 2nd Tx proposed for 2021
53	Putaruru	12	-	N	1	-	17	70%	No constraint within +5 years	New GXP, Subtrans. & transf upgrades .
54	Tower Rd	8	17	N-1	5	50%	17	52%	No constraint within +5 years	GXP and Subtrans upgraded, & 2nd Tx added.
55	Waharoa Nth	4	3	N	-	148%	9	42%	No constraint within +5 years	Split sub restored to single sub again after 33kV & Tx upgrades
56	Waharoa Sth	5	-	N	-	-	9	56%	No constraint within +5 years	Split sub restored to single sub again after 33kV & Tx upgrades
57	Baird Rd	10	-	N-1	7	-	11	94%	No constraint within +5 years	Baird Rd & Maraetai Rd operating as 33kV closed loop.
58	Midway / Lakeside	4	-	N	-	-	-	-	No constraint within +5 years	Customer agreed security at both substations
59	Maraetai Rd	8	-	N-1	7	-	15	56%	No constraint within +5 years	Baird Rd & Maraetai Rd operating as 33kV closed loop.
60	Bell Block	16	25	N-1	9	63%	25	67%	Transformer	Load transfer planned post 2024
61	Brooklands	17	24	N-1	7	69%	24	72%	No constraint within +5 years	
62	Cardiff	2	3	N-1 SW	3	63%	3	66%	No constraint within +5 years	
63	City	17	20	N-1	12	82%	20	85%	Transformer	Capacity upgrade planned post 2027
64	Cloton Rd	10	13	N-1	1	76%	13	78%	No constraint within +5 years	
65	Douglas	2	2	N-1 SW	2	93%	2	95%	Subtransmission circuit	Single circuit. Very low risk. Most load can be backfed.
66	Eltham	10	11	N-1 SW	3	87%	15	66%	No constraint within +5 years	Transformer upgrade ~2021
67	Inglewood	5	6	N-1 SW	3	82%	6	86%	Transformer	Load transfer planned post 2025
68	Kaponga	3	3	N-1 SW	2	101%	3	105%	Transformer	Low risk of failure. Operationally managed.
69	Katere	14	21	N-1	11	66%	21	70%	No constraint within +5 years	
70	McKee	1	-	N	-	-	-	-	No constraint within +5 years	
71	Motukawa	1	1	N-1 SW	1	74%	1	77%	Transformer	Single transformer. Most load can be backfed.
72	Moturoa	18	24	N-1	7	76%	30	63%	No constraint within +5 years	New 33kV circuits and transformers 2019/20
73	Oakura	3	-	N	-	-	-	-	Subtransmission circuit	Single cct & Tx. 11kV backfed adequate till 2nd cct ~2025
74	Pohokura	5	9	N-1	-	57%	9	57%	No constraint within +5 years	

	12b(i): System Growth - Zone Substations									
8	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
75	Waihapa	1	2	N-1 SW	2	49%	2	49%	No constraint within +5 years	
76	Waitara East	5	10	N-1	4	46%	10	49%	No constraint within +5 years	
77	Waitara West	7	6	N-1 SW	8	104%	6	106%	Transformer	Risk of failure is low. Managed operationally.
78	Cambria	13	17	N-1	5	77%	17	79%	No constraint within +5 years	Transformer & Subtrans upgrade planned ~2026
79	Kapuni	6	7	N-1	4	79%	7	79%	No constraint within +5 years	
80	Livingstone	3	3	N-1 SW	1	88%	5	53%	No constraint within +5 years	Transformers scheduled for replacement (higher cap)
81	Manaia	6	5	N	5	126%	5	129%	Transformer	33kV Tee likely resolved ~2022. Single Tx bank (after renewal)
82	Ngariki	4	4	N-1 SW	4	98%	4	102%	No constraint within +5 years	
83	Pungarehu	3	5	N-1	2	66%	5	70%	Transformer	Low risk - operationally managed (e.g. backfeeds)
84	Tasman	7	6	N-1 SW	3	102%	6	104%	Transformer	Low risk - operationally managed (e.g. backfeeds)
85	Mokoia	3	4	N-1 SW	4	89%	3	-	Transformer	New Sub. Replaces Whareroa.
86	Beach Rd	10	16	N-1	3	61%	16	62%	No constraint within +5 years	Subtrans upgrades complete pre 2025.
87	Blink Bonnie	4	3	N	3	127%	3	130%	Transformer	Low risk of failure. Security upgrades planned post 2026
88	Castlecliff	9	9	N-1 SW	5	104%	13	72%	Transformer	Post 2024 plan to upgrade transformers
89	Hatricks Wharf	13	-	N	6	-	10	137%	Transformer	Single transf, but 11kV bus tie (Taupo Quay) mitigates risk
90	Kai Iwi	2	1	N	1	225%	1	235%	Subtransmission Circuit	Single 33kV cct & single Tx. Also N security GXP.
91	Peat St	14	-	N-1	6	-	-	-	Transpower	2nd 33kV circuit ~2021, but N secure GXP limits security
92	Roberts Ave	5	6	N-1 SW	6	78%	6	79%	Transpower	2nd 33kV circuit ~2021, but N secure GXP limits security
93	Taupo Quay	11	-	N	8	-	10	109%	Transformer	2nd 33kV circuit planned pre 2024. Single Tx with bus tie limits security.
94	Wanganui East	5	3	N	3	154%	3	155%	Subtransmission Circuit	Single 33kV cct and Tx. Post 2025 plan for 2nd cct and Tx.
95	Taihape	4	1	N	1	553%	1	564%	Transformer	Single transformer. 2nd Transformer post 2026
96	Waiouru	2	1	N	1	477%	1	460%	Subtransmission circuit	N secure GXP, 33kV & Tx. Post 2026 11kV upgrade.
97	Arahina	8	3	N	3	262%	3	267%	Subtransmission Circuit	N secure GXP, 33kV & Tx. Post 2026 2nd cct & Tx.
98	Bulls	6	2	N	2	286%	2	295%	Transformer	Post 2021 2nd 33kV. Post 2021 2nd transformer.
99	Pukepapa	5	2	N	2	287%	2	302%	Transformer	Single transformer. Limited backfeed. Post 2026 - 2nd Tx
100	Rata	3	1	N	1	407%	1	416%	Subtransmission circuit	Single 33kV cct and Tx. Post 2028 plan for 11kV Upgrade.
101	Feilding	22	24	N-1 SW	2	91%	24	95%	Transformer	Re-rateTransformers 2022 and post 2023 33kV upgrade and new zone substation
102	Ferguson St	11	-	N	15	-	24	47%	No constraint within +5 years	New Sub: 2019. 2021: 2nd Tx added & full N-1 33kV capacity.
103	Kairanga	18	19	N-1 SW	8	94%	24	78%	Subtransmission circuit	Transformers upgrade planned ~2023
104	Keith St	18	22	N-1	-	84%	22	87%	No constraint within +5 years	Upgrades offload 33kV circuits feeding Main and Keith St
105	Kelvin Grove	17	17	N-1 SW	5	99%	24	76%	Transformer	Transformers possible upgrade in ~2022. Potential new NEI substation post 2023.
106	Kimbolton	3	1	N	1	191%	1	199%	Subtransmission Circuit	Single 33kV circuit & single transformer. Remote Sub.
107	Main St	22	17	N-1 SW	13	128%	25	90%	No constraint within +5 years	New Sub & 33kV cables address ex. high risk constraints.
108	Milson	17	18	N-1 SW	5	93%	19	90%	Transformer	Posible TX and subtransmission upgrade post 2023
109	Pascal St	23	17	N-1 SW	12	133%	25	93%	No constraint within +5 years	New Sub & 33kV cables address ex. high risk constraints.
110	Sanson	8	-	N-1 SW	4	-	11	79%	Sub-transmission Circuit	33kV backfeed secures load. New Sanson-Bulls 33kV link and new Ohakea Sub
111	Turitea	14	-	N-1	5	-	-	-	Subtransmission Circuit	Switched 33kV security - Second 33kV circuit and TX upgrade post 2023
112	Alfredton	0	1	N	0	35%	1	35%	No constraint within +5 years	Single Transf. but adequate backfeed.
113	Mangamutu	12	13	N-1	1	96%	13	97%	No constraint within +5 years	Major customer largely determines security requirements.

12b(i): System Growth - Zone Substations

Row	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
114	Parkville	2	-	N	-	-	-	-	Transformer	Single transformer
115	Pongaroa	1	3	N	1	29%	3	30%	No constraint within +5 years	Single transformer, but adequate backfeed
116	Akura	13	9	N-1 SW	7	145%	15	90%	No constraint within +5 years	Txs replaced & section of 33kV circuit upgraded, pre 2022
117	Awatoitoi	1	-	N	-	-	-	-	No constraint within +5 years	
118	Chapel	12	10	N-1	5	120%	23	56%	No constraint within +5 years	Upgrade short section of 33kV cable pre 2022.
119	Clareville	9	9	N-1 SW	1	98%	9	103%	Transformer	Transformer and 33kV upgrade post 2024
120	Featherston	4	2	N	2	247%	2	259%	Transformer	Single transformer. 2nd bank proposed in longer term,, 2025 New Sub to increase transfer capacity
121	Gladstone	1	0	N	0	528%	0	547%	No constraint within +5 years	
122	Hau Nui	1	-	N	-	-	-	-	No constraint within +5 years	Generation site. Not economic to provide higher security
123	Kempton	4	0	N	0	1,059%	0	1,110%	Subtransmission Circuit	Post 2024:- 2nd 33kV supply & upgraded 2nd transformer,, 2025 New Sub to increase transfer capacity
124	Martinborough	5	0	N	0	4,953%	0	5,222%	Transformer	Single transformer. 2nd Tx planned post 2024, , 2025 New Sub to increase transfer capacity
125	Norfolk	6	1	N-1	3	451%	1	463%	Transformer	Risk is very low. Post 2024 upgrade planned.
126	Te Ore Ore	7	7	N	7	103%	7	106%	Transformer	Single transformer
127	Tinui	1	-	N	-	-	-	-	No constraint within +5 years	
128	Tuhitarata	4	0	N	0	2,269%	1	409%	Subtransmission circuit	Single 33kV circuit & single transformer, 2025 New Sub to increase transfer capacity
129										

130 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

A2.5 SCHEDULE 12C

Company Name	**Powerco Limited**
AMP Planning Period	**1 April 2021 – 31 March 2031**

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

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 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
11	*Consumer types defined by EDB**							
12	Small		4,770	4,770	4,770	4,770	4,770	4,770
13	Commercial		60	60	60	60	60	60
14	Industrial		20	20	20	20	20	20
15								
16								
17	**Connections total**		4,850	4,850	4,850	4,850	4,850	4,850
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		753	753	753	753	753	753
21	Capacity of distributed generation installed in year (MVA)		4	4	4	4	4	4
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 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
25	GXP demand		780	786	792	798	804	810
26	*plus* Distributed generation output at HV and above		140	141	142	143	144	145
27	**Maximum coincident system demand**		920	927	934	941	948	956
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		920	927	934	941	948	956
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		4,464	4,498	4,532	4,566	4,601	4,637
32	*less* Electricity exports to GXPs		161	162	164	165	166	167
33	*plus* Electricity supplied from distributed generation		1,014	1,022	1,030	1,038	1,046	1,054
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		5,318	5,357	5,398	5,439	5,481	5,523
36	*less* Total energy delivered to ICPs		5,041	5,079	5,117	5,156	5,196	5,236
37	**Losses**		277	279	281	283	285	287
38								
39	**Load factor**		66%	66%	66%	66%	66%	66%
40	**Loss ratio**		5.2%	5.2%	5.2%	5.2%	5.2%	5.2%

A2.6 SCHEDULE 12D

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031
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 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	83.7	98.2	99.3	94.1	90.2	91.3
12	Class C (unplanned interruptions on the network)	177.6	199.8	197.4	195.0	195.4	197.3
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.38	0.41	0.41	0.42	0.41	0.41
15	Class C (unplanned interruptions on the network)	1.93	2.28	2.27	2.25	2.26	2.28

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031
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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	83.7	98.2	99.3	94.1	90.2	91.3
12	Class C (unplanned interruptions on the network)	177.6	199.8	197.4	195.0	195.4	197.3
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.38	0.41	0.41	0.42	0.41	0.41
15	Class C (unplanned interruptions on the network)	1.93	2.28	2.27	2.25	2.26	2.28

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031
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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	83.7	98.2	98.2	99.3	94.1	90.2
12	Class C (unplanned interruptions on the network)	177.6	199.8	199.8	197.4	195.0	195.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.38	0.41	0.41	0.42	0.41	0.41
15	Class C (unplanned interruptions on the network)	1.93	2.28	2.27	2.25	2.26	2.28

A2.7 SCHEDULE 13

Company Name	Powerco Limited
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55001

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	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	We have an authorised AM Policy which is consistent with other policies in the business. Relevant personnel are aware and working in accordance with it. While we don't have a documented communication approach, it is featured on the intranet, available on our document management system and featured on the notice-board		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	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. It has reached a stage of requiring review. At the time of scoring, the refresh is underway, with an estimated completion date by the end of FY'21	Areas for improvement: a. More clearly identify how the end to end processes integrate into the AM System. b. Make more evident in the strategies how they are prioritised or tracked.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2.7	The Asset Strategy discusses the asset life cycle and its approach to this is summarised in this AMP. Specific asset life cycle strategies have been developed, and again, are summarised in this AMP.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management 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 continued to develop our suite of Fleet Management Plans that include work volumes across relevant time periods for all asset types, aligned to the asset information systems. The fleet plans identify inspection regimes and renewal programmes and future needs based on assessment of condition, age and trends in defects and failures.	The Regulatory AMP has been updated to include more details within the area plans and fleet plans from previous years. There is an area of fleet planning whose documentation has not been updated for some time.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management 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?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	2.6	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.	We don't have a defined approach for communicating our plan(s). The AMP is published on our website, hard copies are made available to key internal and external stakeholders. Fleet plans are available internally for fleet managers on SharePoint.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.7	There is a range of documents that detail asset management responsibilities. These include Powerco's Business Plan, business unit tactical plans, governance structures and position descriptions. 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.	Areas for improvement: a. More clearly articulate the requirements for an AMS and define the roles and responsibilities for governance of the AMS. b. Further refinement needed with definition of roles and responsibilities, and how they are understood and communicated.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2.6	Our field contract arrangements have been arranged to provide demonstrable cost efficiency. Deliverability is central to asset management, and our processes consider the skills and competencies needed to ensure cost effective delivery.	Powerco has a field service contract arrangements, and is reviewing the procedures for delivery of works as part of its ERP implementation. Resource and skill needs to meet works plans delivery are being developed and our supply chain management strategy is being reviewed.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What 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?	3	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. However we tend to be better at response, rather than reduction and readiness. We have reviewed our emergency spare holdings and are reviewing the management of the spares. Lastly, we are continuing our work on developing contingency plans for key zone substations.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management 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)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What 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?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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)?	3	Powerco reviews its organisational structure on a periodic basis to ensure it meets the changing needs of the business. Each restructure is followed by a review of the roles and responsibilities. The responsibilities of ownership are outlined in staff position description. Governance committees have been established with specific responsibilities agreed on.	Area of improvement: a. Review of org structure and people capability against the AM needs b. RASCI against the business needs	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.8	Powerco have established a programme group that review the resource requirement for delivering our AMP. There are established methods for forecasting resource needs at a work-type and financial level. The 2 yr rolling works programme is used in the ongoing management of contract service providers. We are constantly reviewing the impact of COVID on our supply chain to manage any disruptions to the works plan.	Area for improvement: a. Prepare a clear overall resource strategy. b. Review capability of human resource in resource strategy	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.6	The importance of ISO55001 certification has been recognised by at senior management. This includes re-defining the scope of Asset Management in the business, and including the wider organisation in the process. The intent of senior management is to communicate the business plan after completion of this AMP.	Areas for improvement: a. Develop a formal AM comms plan.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.9	Powerco's selection process includes ISN reviews of new service providers. We also provide stand over monitoring for service providers that we have not approved but are deemed competent to work on our network. Our competency framework for ensuring individuals within the contractor's teams are suitably qualified.	Tiered operational meetings between us and field contractors ensure work plans are understood and independent field auditors review workmanship and worksite safety.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint 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)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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)?	2.4	As part of our service provider contracts, we stipulate 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. There are position descriptions and ad-hoc/informal succession plans in the business	Area of improvement: a. Review of org structure and people capability against the AM needs b. Review worker competence standard	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	We have documented our internal competence requirements for staff as well as for field staff. An overall asset management competence and training framework, while being prepared, is still needed.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the 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	Same as above		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop 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)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the 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?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	2.2	Significant effort has been expended to develop operational dashboards to communicate asset management information, although these do not yet cover the full scope of AM activities. Standards and notifications are notified to service providers through the CWM portal. There is a dedicated internal comms team to help manage communication via the intranet.	There is no formal communication plan.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.8	There has been significant effort in preparing the following documents: - AM Manual - AM Capability Framework - AM Scope - AM Strategy		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2.8	There has been significant effort in preparing the Asset Information Standard. We have also established a formal Data Governance Group and corresponding Data Communities to oversee and manage our ongoing asset information needs.	We have an asset information policy, and are working on several data dictionaries.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	The Data Governance Group is responsible for identifying and delivering our data quality improvement initiatives. Over the past 2 years we have implemented our ERP system that has clear delegations and increased checks on data accuracy to ensure data quality now and into the future.	We are also reviewing our data collection process by ensuring data requirements are reflected in the field devices that our workers use.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.5	We have developed an Asset Information Strategy, but there is yet no clear ownership or review process identified. We have established an (IS) Architecture Review Board to ensure improvements to the IS Systems are aligned.	We are working on developing appropriate process to identify and develop the Asset Information Strategy on an ongoing basis. Needs and capabilities of individual applications are currently reviewed on an Ad-hoc basis.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management 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?	2.8	We have established the following: risk policy, risk management framework / process, assurance framework and risk matrix. These are being embedded as we roll them out across our business. We have also developed and are rolling out a new change management framework across our organisation.	We are working on improving the population of relevant risk registers for various types of risks.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.4	Our Change Management Framework is used to help identify training requirements for individual non-network projects. However it is applied inconsistently across the scope of the AMS.	Future improvements would include the training needs being updated into a formal competency framework.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3.2	Powerco has invested significant resource in the last few years in all aspects of legal and regulatory compliance. We have implemented ComplyWith to keep track of our ongoing legal obligations. We have been conducting legal compliance reviews through our Assurance team for a considerable period and can be considered competent in this area.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management 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?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	3	We have expended considerable effort in clarifying our end-to-end asset management processes and controls. Key initiatives include: - Development of our Asset Management Manual - Deployment of our ERP system - Mapping of our end-to-end capital works process These build on our existing contracts with external suppliers, commissioning and handover processes and project management methods.	There have been some temporary dips in performance as we switch from our legacy management system to our new ERP. We will be reviewing and improving our commissioning and maintenance processes.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
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?	3	The deployment of our new ERP has provided us opportunity to better manage our assets by reviewing the history of and controlling the implementation of our plans against each individual asset. This is currently in its initial stages, but the foundations laid by the ERP will be built on as we mature in its capabilities.	We have also created dedicated roles to ensure that the appropriate maintenance is carried out as outlined in our strategy and plans. This includes the preparation of maintenance procedures where required to supplement the standards	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	We have expended considerable effort to develop common network asset indices models (CNAIM) models to inform our decision-making models. These CNAIM models are informing our condition assessment requirements that will be deployed through our MyPM field devices.	We will continue to mature these systems as we roll out this approach for our entire fleet.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.9	We have developed a fault response standard, re-designed our incident investigation systems and processes, as well as continue to develop our contingency plans for key sites on our network.	The HSEQ team helps ensure that investigations occur, actions are taken and responsibilities are clear. We now also have automatic escalation built into our systems. We also have weekly incident meetings and Executive Health and Safety meetings to monitor our work in this area.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain 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?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that 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?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2.5	We have adopted the 3-lines-of-defence model for our AMS. This includes the development of an assurance framework that defines how we audit various parts of the AMS. We are working on identifying and developing plans where they may be gaps in our assurance activities.	We have developed better insights about the scope and range of external audits across our business. The results of these audits are now reviewed by our internal assurance team.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.5	Our field auditing a programme is delivered by an external provider on our behalf. It covers - Worker safety in the field - Quality of workmanship - Work planning - Documentation and record keeping - Assurance of critical work and public safety controls	We currently do not have a formal process for managing the outputs of audits on our systems.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.5	We have several feedback loops to inform our continual improvement requirements. These include processes such as: Log-an-idea, Project learnings, Standards feedback forms, safety observations and incident investigations. We have also established governance committees for specific functions within the AMS that are responsible for identifying improvement initiatives and reporting them to our newly formed Asset Management Steering Committee.	We do not have any coordinated continuous improvement action plan. This may be developed as our maturity in this area improves.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.7	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 Network Transformation team that leads research into this area. However a coordinated Asset Management Improvement plan has not been developed or approved.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

A2.8 SCHEDULE 14A – NOTES ON FORECAST INFORMATION

Below we comment on differences between our forecast capital expenditure (schedule 11a) and operational expenditure (schedule 11b) in nominal and constant prices:

- We explain our approach to forecast escalation in Chapter 28.
- We are required to identify any material changes to our network development plan disclosed in our previous AMP. We discuss our current plans in Chapter 15 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.
- We state our expenditure in constant prices in 2021 real dollars in the body of this AMP. Schedules 11a and 11b uses constant prices in 2021 real dollars, as per the Commerce Commission's information disclosure requirements for a 2021 AMP and for consistency with other electricity distributors' disclosures.

A2.9 MATERIAL CHANGES

This section discusses any material changes in the approach to the population of information disclosure schedules shown in the previous sections.

A2.1 MATERIAL CHANGES TO SCHEDULE 12A

The method for calculating our internal asset health indices (AHI), scored H1-H5, is consistent with the 2019 AMP for most fleets. This aligns with the EEA AHI 1-5 grades.

Since the 2019 AMP, we have developed improved asset health modelling for our overhead conductor fleets (described in further detail in Chapter 19). This has improved the evaluation of AHI for these fleets. These are also scored H1-H5.

Asset health is discussed in more detail in Chapter 10 and is used extensively throughout our fleet management chapters of this AMP.

A2.2 MATERIAL CHANGES TO SCHEDULE 12B

Installed firm capacities and transfer capacities have been fully reviewed, and a more consistent interpretation of our security standards has been applied.[113] Any changes to the metrics reported in 12b are due to adjustment made to the underlying parameters for a site.

[113] See Chapter 10 for a description of our security standards.

A2.3 MATERIAL CHANGES TO SCHEDULE 12C

Our forecasts of demand growth rates were developed at feeder level, and these then determine zone substation and GXP growth rates. This is consistent with the previous forecast methodology and as a result there are no significant adjustment in this schedule.

A2.4 MATERIAL CHANGES TO SCHEDULE 12D

Our SAIDI/SAIFI forecasting approach is generally consistent with the 2019 AMP. We use separate models to forecast unplanned and planned SAIDI and SAIFI. The forecasts are based on modelling historical fault data, and our planned work. Within our CPP period (ending in FY23) we intent to remain within our planned quality path limits, which is reflected in our forecast. The unplanned SAIDI and SAIFI forecasts are not normalised.

A3.1 APPENDIX OVERVIEW

The main objective of our Asset Management Plan is effective consultation with our stakeholders.

In Chapter 2 we provide an overview of our main stakeholders and their interests. Given the importance of our stakeholders to us, this appendix gives more details about each stakeholder, and provides insights as to what they tell us they want from our asset management.

A3.2 OUR CUSTOMERS

We exist to serve the needs of our customers. More than 800,000 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:

- 344,261 homes and businesses comprising:
  - Residential customers and small businesses ('mass market')
  - Medium sized commercial businesses
  - Large commercial or industrial businesses
- 13 directly contracted industrial businesses, including large distributed generators

Electricity is an indispensable part of modern economic and social life. As use and dependence on electricity has grown, so too has customers' expectation of the availability and quality of supply. In addition to excellent customer service, customers increasingly expect good, timely information about their service.

A3.2.1 STAKEHOLDER INTEREST

The interests of each of our main customer groups are described in Chapter 2. These are as identified through consumer surveys, meetings with customers and consumer groups, and feedback from our hotlines. Customers' interest can be summarised as:

- **Reliability** – Our customers want us to minimise the frequency and duration of supply interruptions, as well as ensuring quality of supply and network capacity.
- **Responsiveness** – Our customers expect us to respond quickly to issues on the network and reduce potential safety and reliability risks.
- **Cost effectiveness** – Our customers expect our investments are appropriate to meet their expectations and that we are constantly evaluating our approach to optimise these investments and their underlying costs.
- **Customer service and information quality** – Our customers value timely and accurate information about their supply, especially during supply interruptions. They want more real-time information available through digital channels.

A3.3 COMMUNITIES, IWI AND LANDOWNERS

With almost 28,000km of network circuits, we interact with a range of communities, iwi and landowners. We are also an active corporate citizen and involved in a range of community projects and activities.

We recognise the importance of consulting with iwi and communities on significant new projects, particularly development of new subtransmission line routes. We regularly meet with landowners, iwi and local community groups to ensure their views, requirements, values, significant sites and special relationship with the land are taken into account early in the project development phase.

- Affected landowners wish to be advised when maintenance crews enter their property and wish to be assured their property will not be damaged or put at risk.
- Communities expect us to be an active and responsible corporate citizen, supporting the areas where our staff live and our network operates.

A3.4 RETAILERS

We currently have 24 electricity retailers operating under multiple brands on our network. Of these, three serve 70% of our customers.

Like most electricity distribution businesses (EDBs), we operate an interposed model. This means retailers purchase our services, bundle them with energy supply and the cost of accessing the transmission grid, and provide a bundled price for delivered energy to their customers. Working with retailers to ensure a simple and effective energy supply for customers is a key part of what we do.

Retailer interest follows customer interest, as described above. In addition, retailers have an interest in:

- How we work with them to provide customers with information about outages and other information customers may require.
- Our pricing structure and pricing changes.
- How we resolve customer complaints, which may have been directed to the retailer.
- How we operate under the Consumer Guarantees Act.
- Our use of system agreement.

A3.5 THE COMMERCE COMMISSION

The Commerce Commission is the main agency that regulates us. It aims to ensure that regulated industries, such as electricity lines businesses, are constrained from earning excessive profits, and are given incentives to invest appropriately and share efficiency gains with consumers.

The Commerce Commission has responsibilities under Part 4 of the Commerce Act 1986, where it:

- Sets default or customised price/quality paths that lines businesses must follow.
- Administers the information disclosure regime for lines businesses.
- Develops input methodologies.

Part 4 of the Commerce Act requires the Commission to implement an information disclosure regime for EDBs. The regime places a requirement on businesses to provide enough information publicly, such as via regulatory accounts and various performance indicators, to ensure interested parties are able to assess whether or not the regulatory objectives are being met.

We meet regularly with Commissioners and staff to compare notes.

A3.6 STATE BODIES AND REGULATORS

The state bodies and regulators that have jurisdiction over our activities include the Ministry of Business, Innovation and Employment (MBIE), WorkSafe NZ, and the Electricity Authority.

MBIE administers the Health and Safety at Work Act 2015 and the Electricity (Safety) Regulations 2010. The Safety Regulations set out the underlying requirements the electricity industry must meet. In particular, lines companies must set up and maintain a Safety Management System that requires all practicable steps 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 NZ is the regulator for ensuring safe supply and use of electricity and gas. It conducts audits from time to time to ensure compliance with safety standards as well as accident investigations following serious harm or property loss incidents.

Radio Spectrum Management administers the radio licences needed for the operation of the Supervisory Control And Data Acquisition (SCADA) and field communication systems.

The Electricity Authority regulates the operation of the electricity industry and has jurisdiction over our activities as they relate to the electricity industry structure. These include terms of access to the grid, use of system agreements with retailers, as well as metering, load control, electricity losses and distribution pricing methodologies.

We are committed to supplying electricity in a safe and environmentally sustainable manner and in a way that complies with statutes, regulations and industry standards. In the electricity distribution network context, the most noteworthy legislation to comply with is:

- Electricity Act 1992 (and subsequent amendments)
- Electricity Industry Act 2010
- Electricity (Hazards from Trees) Regulations 2003
- Electricity (Safety) Regulations 2010 (and pursuant Codes of Practice)
- Resource Management Act 1992
- Health and Safety at Work Act 2015
- Electricity Industry Participation Code 2010
- Hazardous Substances and New Organisms Act 1996

A3.7 TERRITORIAL LOCAL AUTHORITIES

As the largest electricity distributor by geographical size, we cross a large number of local and regional councils.

These organisations are valued customers and have an interest in how electricity supports economic growth and how our activities interact with the Resource Management Act.

- **Implementation of the Resource Management Act** – Local councils have a role in promoting the sustainable management of natural and physical resources. We aim to be actively involved in debates about district and regional plan changes and take part in hearings and submissions on local issues as we deliver our works. We will aim to provide constructive feedback as we transition away from the RMA.
- **Economic growth** – Authorities have an interest in promoting economic growth in their communities, and we work with them to understand where we may need to invest to support this.
- **A valued customer** – Local councils are also often our customers, supplying lifeline utility services, such as water and sewerage systems. We work closely with councils to understand their supply needs and co-ordinate any outages.

A3.8 OUR EMPLOYEES

We have about 450 staff, based in offices in New Plymouth, Tauranga, Whanganui, Palmerston North and Wellington. The level of engagement with our teams and the strength of our culture is important to us. We regularly undertake engagement surveys to make sure we continually improve what we do.

Our employees wish to have interesting and varied careers, with the ability for career development. Safety, job satisfaction, working environment and staff wellbeing are key employee tenets.

Our teams have an interest in managing the network competently and doing the 'right thing', therefore it is of great importance that we effectively communicate our Asset Management Plan with them.

Employees need to have a safe environment to work in and we also need to ensure our assets are safe for contractors and the public. Safety in design principles are a key part of our design and construction standards.

A3.9 OUR SERVICE PROVIDERS

We operate an Electricity Field Services Agreement with Downer Limited, and have expanded the capital works contractor panel to include Northpower and Electrix. We also have a range of approved service providers who work on our network.

Our service providers require a sustainable and long-term relationship with us. As part of this relationship, we expect our service providers will be profitable, but efficient. This means having a foreseeable and constant stream of work to keep their workforces productively employed. Focus areas, from our perspective as an asset owner, are safety, competency, crew leadership and alignment of business models.

Given the anticipated expenditure during the AMP planning period, we will work closely with our service providers to ensure we are able to deliver the higher volume of work in the most efficient manner.

Workflow certainty allows our service providers to confidently build up the right level of resources to achieve efficient resource utilisation. It also allows service providers to achieve benefits of scale from their material purchases resulting in efficient pricing and a stable industry environment.

Electrical equipment is capable of causing serious harm and we take measures to ensure service provider employees work in a safe environment. This is accomplished through a competency certification framework, procedures and through audit processes.

These principles are discussed in more detail in Chapters 13.

A3.10 OUR INVESTORS

We are a privately owned utility with two institutional shareholders: Queensland Investment Corporation (58%) and AMP Capital (42%).

As the electricity distribution sector is regulated, regulatory certainty is a key issue that affects our owners' investment decisions. Our investment plans are subject to certain aspects of the regulatory regime being changed and clarified through the Commission's formal review of the Input Methodology rules. These cover:

- Productivity and commercial efficiency. Delivery of asset management in a productive, efficient and commercially prudent manner.
- Optimal utilisation of assets represents the best trade-off between capital expended on the assets and network risk.
- Risk management processes seek to identify, recognise, communicate and accept or control risks that arise in the asset management process.

Owners (as represented by the directors) have overall responsibility for Powerco and expect our management team to address this wide range of business drivers.

A3.11 OTHER STAKEHOLDERS

Other stakeholders with an interest in our asset management process include Transpower, the media, and groups representing the industry, such as the Electricity Networks Association and the Electricity Engineers Association.

Transpower supplies bulk electricity through their grid. Operational plans, such as 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.

APPENDIX 4 MAJOR CUSTOMERS

A4.1 APPENDIX OVERVIEW

We have 650 customers with demand greater than 300kVA, who we class as large commercial or industrial customers. Of this number, 109 sites have installed capacity of greater than 1500kVa, representing $67.5m of our annual revenue (including transmission). Such customers have more specific operational and service requirements than the mass market given the size, complexity and forward requirements.

Therefore, it's important that we understand the unique characteristics and requirements of these organisations and develop strong working relationships with a long-term view. Of increasing importance is understanding customers' growth needs and intentions, with regard to decarbonising or offsetting non-electric heat load. We are presently of the view that significant industrial customers are looking to biomass, while smaller boiler loads are more likely to electrify. We are seeing some smaller scale electrification transition, largely in the government sector, such as education and health. We are aiming to obtain an increasing amount of information from customers regarding plant renewals and load sizing to keep our planning teams as informed as possible and alerted to potential system constraints.

This appendix provides more details on our largest customers – defined as being an industry sector, or customer sites with installed capacity or a site portfolio greater than 1.5MVA.

These organisations have a significant impact on our network operations and asset management priorities, and it's very important to us that we seek to provide the highest levels of service.

A4.2 TIMBER PROCESSING SECTOR

Forestry is a significant industry in New Zealand, and we have significant timber and product processing operations and commercial forestry across our footprint.

Traditional timber processing facilities are often located away from other users, in remote areas with low network security. This means that outage planning may involve customer consultation, and 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
Juken Nissho	Claymark (Thames)
Taranaki Pine	Pukepine Sawmills
Kiwi Lumber (Masterton)	Carter Holt Harvey (Kopu)
Webstar Limited	Kiwi Lumber

A4.3 DAIRY SECTOR

Dairy farms are spread across our footprint and are particularly dominant in the Taranaki and Waikato regions.

At an individual farm level, in recent years increased cooling and holding standards have resulted in increased network uptake. While this drives need for effective network planning and operations, it is anticipated that further volume growth in this sector will be subdued while commodity prices remain soft.

Off-farm processing loads remain strong across our footprint.

The industry requires a reliable supply, so shutdowns for maintenance or network upgrade activities have to be planned to minimise farming disruption, and planned for the dairy low season.

Major dairy customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Fonterra – Mainland Products (Eltham)	Fonterra – Morrinsville
Fonterra – Pahiatua	Fonterra – Tirau
Fonterra – Longburn	Fonterra – Waitoa
Open Country Dairy Ltd – Whanganui	Open Country Cheese
	Tatua Dairy

A4.4 FOOD PROCESSING AND DISTRIBUTION SECTOR

Many of our larger customers are involved in food and beverage processing and/or retail. As demonstrated by the table below, across our network are a significant number of primary food industry processing plants (meat and poultry), coolstores, and food manufacturers such as bakeries, flour milling, and pet food.

The kiwifruit industry, which includes coolstores and post-harvest facilities, is expected to continue its growth trajectory, given the success of the SunGold variety. Coolstore operations 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. We continually seek to understand location and size of potential loads to understand requirements and effectively manage operational implications.

Major food processing customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
AFFCO NZ Feilding & Whanganui	Apata Coolstores
ANZCO Foods	AFFCO Rangiuru
Silver Fern Farms	Champion Flour
Tegel Foods	Eastpac Coolstores
Premier Beehive	Greenlea Meats
Yarrows	Inghams Enterprises
Ernest Adams	Silver Fern Farms Te Aroha
Foodstuffs	Seeka
Malteurop New Zealand Limited	Trevelyan's Pack & Cool
Ovation New Zealand Limited	Wallace Corporation

A4.5 INDUSTRIAL MANUFACTURING AND MINING SECTOR

We have a variety of large manufacturers and extractive companies connected to our network.

The manufacturing sector is dependent on prevailing economic conditions, particularly the conditions within the industry's niche. Therefore, the requirements on the distribution network can 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
Tasman Tanning Limited	Fulton Hogan
Nexans NZ Ltd	HR Cement Ltd
Iplex Pipelines NZ	J Swap Quarries
Waters & Farr	Waihi Gold

A4.6 TRANSPORTATION SECTOR

We have two major ports on our network – the Port of Tauranga and Port Taranaki. 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, volume is largely oil and gas condensates.

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, have squeezed the windows available for maintenance.

In July 2020, KiwiRail announced its Freight Transport Hub location in Palmerston North between Palmerston North Airport and Bunnythorpe. The demand needs of the facility (3-5MVA) will necessitate delivery of a zone substation in the next 2-3 years to meet demand growth and maintain security levels.

Major transportation customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Port Taranaki	Port of Tauranga

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 as to the installation of variable speed drives or alternative options.

Major chemicals customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Ballance Agri-Nutrients (Kapuni)	Ballance
Methanex NZ – Waitara Valley	Evonik
OMV Taranaki Limited – Oaonui	
Methanex NZ Waitara	
TAG Oil Stratford Production Station (Cheal)	

A4.8 GOVERNMENT SECTOR, EDUCATION AND RESEARCH FACILITIES

We serve a range of public sector organisations, including hospitals, sewerage and water plants, army and air force bases, universities, polytechnics and research facilities.

We recognise the impact a supply outage can have on these facilities. We work carefully with district health boards, local councils and the New Zealand Defence Force to ensure our service meets their current needs and that we can plan effectively to meet future requirements.

Given the critical nature of their activities, a number of government sector organisations require higher security of supply, and have on-site generation.

Government, education and research customers

WESTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY	EASTERN CUSTOMERS > 1.5MVA INSTALLED CAPACITY
Taranaki District Health Board	Chapel St Wastewater Treatment Plant
NZDF – Ohakea, Waiouru and Linton	Tauranga Hospital
Mid Central District Health Board	Thames Hospital
Massey University	Matamata-Piako DC Wastewater Treatment Plant
	Southern Cross Hospital
	Bethlehem College

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 2021 AMP.

In summary, we completed 90% of our scheduled capital works programme for FY20, and overall completed 106% of our scheduled maintenance programme. Any incomplete capital and maintenance work was carried over to the FY21 programme.

A5.2 DEVELOPMENT PROJECT COMPLETION

During FY20 we undertook a series of network development projects. These projects make up significant portions of our overall capital spend whilst delivering key advances in network security of supply and capacity growth.

In the North Western region of our network, we saw the commissioning of the 33kV Upgrade to the Moturoa Sub, along with great progress on the Inglewood line upgrade from 6.6kV to 11kV, these projects saw a combined spend of approx. $11M in the region. The Moturoa project did take a little longer than initially expected to complete, however commissioning was still met on target with only beautification works being outside of expectations, while the Ingle wood is well on track to meet future targets.

Our South Western region, Palmerston North, Wairarapa and the Manawatu saw early works and conceptual preliminaries gain momentum for the Fielding-Sanson-Bulls capacity upgrades as well as significant commissioned asset value with the completion of the Ferguson Sub upgrade which signifies the first stage completion of the major Palmerston North CBD upgrades, with a forecast spend of $24M. In these early stage's works have gone to plan and have been achieved within approved budget expectations. Initial route agreement issues with our Taupo Quay and *inherently linked* Peat street upgrade projects caused delays in spending on detailed design work, construction of these what not scheduled in FY20.

Our Eastern regional centres, encompassing the Tauranga and Valley regions saw the lion's share of the activity, with allot of early design and route investigation going into what will make up some our largest projects to come in future years.

The Valley region saw the completion of the Whangamata Battery Project, coming in at approx. $8M this project has meant that the Commercial and CBD areas of Whangamata can now be backed up by battery supply and still operate in the event of any major outage to the coromandel Spur. This project did come with allot of challenges as it was a very new concept, this did cause some delay's in completion and some cost variances but all together was well managed and still completed within the annual time frame set out.

The Tower road to Browne Street link was completed providing a critical cable link to the new Tower road transformer that was installed to provide a second unit to this area. Investment of $6M was completed with these two projects during FY19 and FY20.

Our Valley region still has a great number of active major projects, that are or were in the design and concept stages during FY20 these include an upgrade to the Waihi Beach Substation, upgrades to the Hinuera, Piako and Walton substations as well as our largest and most challenging projects, the Putaruru to Arapuni 100kV Line, Whenuakite 66kV line and the Kaimarama Substation and lines. There were some delays in early stage progress on these major projects which has caused a limit in expenditure for the FY20 period. These delays have been as a result of some challenging landowner agreement processes and in particular with our Kopu-Tairua project some substantial escalation in engineering estimate prompting alternate option investigations.

In the Tauranga region, our Kati Kati Second transformer and 33kV circuit upgrade was successfully completed, going very well against time and budget. A major project began in FY20 to relocate and upgrade our Omokoroa Substation and cables. This will ultimately see an investment of around $13M into the area, however it has had challenges with progress due to the fact it is inherently linked to the development of the new Northern Link Motorway by LTNZ. Early discussions have been good, and Powerco is in a good position to deliver, we are just waiting on green lighting from Government and NZTA.

A5.3 MAINTENANCE PROGRAMME DELIVERY

The FY20 maintenance programme faced some challenges due to COVID lockdown restrictions. Some maintenance was deferred, and the backlog has been appropriately re-allocated for next year's programme.

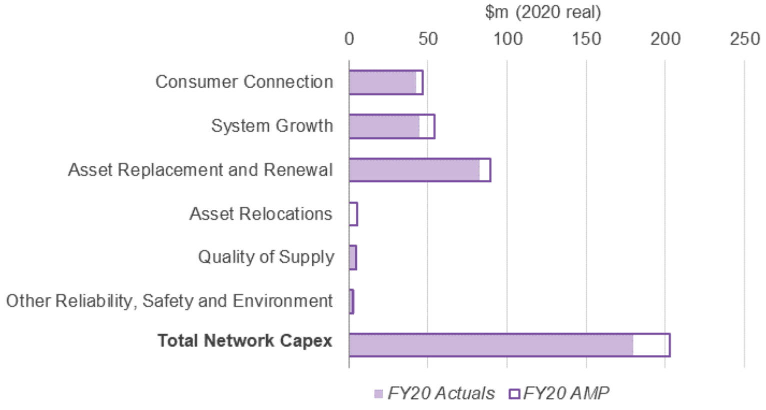
We have added some additional "step-changes" to our programme (oil RMU maintenance, steel lattice towers inspections and additional tap changer maintenance) which have been successfully completed.

A5.4 FINANCIAL PROGRESS AGAINST PLAN

A5.4.1 NETWORK CAPEX

Total network Capex for FY20 was below the 2020 AMP forecast by $23.0M (-11%). This underspend was across a number of expenditure areas with the largest variance in System Growth.

Figure A5.1: Network Capex variance FY20

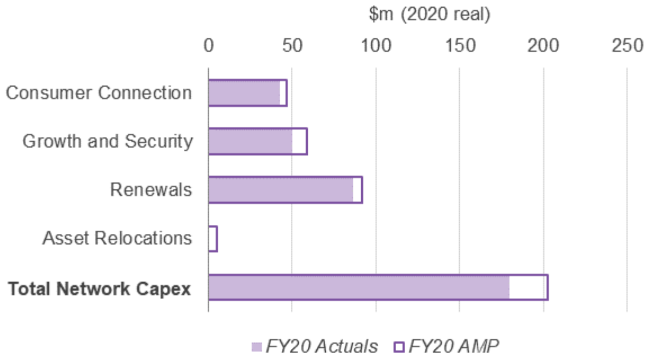


In the 2017 AMP we outlined our change in approach to Capex categorisation, when compared to the information disclosure categories. We are doing this to better support our expenditure tracking and justification by providing more consistency in expenditure categorisation, and removing unnecessary variability between years.

This re-categorisation included adding System Growth and Quality of Supply together to form 'Growth and Security', and to add Asset Replacement and Renewal and Other Reliability, Safety and Environment together to form 'Renewals'.

This approach aligns better with how the expenditure is forecast within the AMP.

Figure A5.2: Network Capex variance FY20, adjusted categories



Consumer connection expenditure was under target by $4.2m (-9%).

Growth and security expenditure was less than forecast by $9.0m (15%). The challenges involved with the delivery of several large-scale projects account for most of this variance.

Renewals expenditure was $5.4m or (6%) lower than forecast. This was primarily due to fewer and less severe storm events translating to a lesser requirement for reactive asset replacement and renewal on Powerco's network.

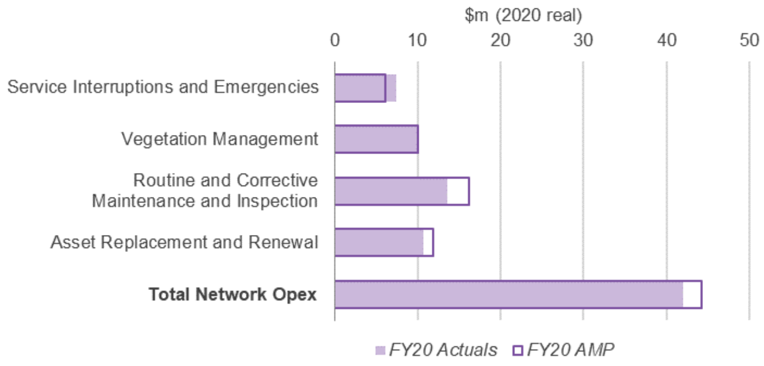
Demand for asset relocations from third parties was significantly over forecast by $4.4M, with only $0.7m in capital expenditure for FY20. Asset relocation expenditure was impacted by the cancellation or delays to several State Highway projects, particularly around the Tauranga region.

A5.4.2 NETWORK OPEX

The figure below shows our FY20 Opex actuals were on target against our AMP20 operational expenditure levels. Total Network Opex was below target by $2.3m (-5%).

This network opex underspend was primarily in Routine and Corrective Maintenance and Inspection, driven by a slower than forecast rate of progress on our CPP opex step change initiatives. FY20 activities focused on ensuring our core maintenance activities were delivered during our transition to CPP.

Figure A5.3: Network Opex variance FY20



APPENDIX 6 GENERAL NETWORK RISKS

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 many 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.

RISKS DESCRIPTION	INHERENT RISK SCORE	VELOCITY	CONTROL DESCRIPTION	CONTROLLED RISK SCORE
Fatality or serious harm to approved contractors working on Powerco network. Could result from: – Motor vehicle or road traffic incidents – Negligence and human error – Equipment failure – Asset failure e.g. pole – Lack of, or incorrect mix of competence – Lack of effective supervision of inexperienced crews or subcontractors	High	Immediate	– Contractor works manual includes network asset, procedural, HSE and quality requirements – Contractor approval system – only Powerco approved contractors permitted to work on our networks – Contractor competency system – named persons allowed to carry out specific tasks based on competency and training records – Safety-in-design considerations are further defined and integrated into the asset planning processes – HSE risk management framework hazard management including performance monitoring; ongoing hazard identification and review process – Asset strategy and planning processes including defect management process to manage end-of-life assets – Increased focus on risk-based assessment on potential of asset failure and carrying out increased numbers of preventative renewals on assets to improve safety around our assets – Field audits of approved contractors – technical, compliance and HSE requirements – Joint HSE forums with Powerco and service providers are held each quarter where topical issues are discussed and continuous improvement activity shared	Medium
Fatality or serious harm to member of the public on Powerco's network. This can result from the following: – Negligence or human error – Equipment failure, e.g. LV line down – Weather event, e.g. LV line down – Incorrect or inadequate information issued by Powerco – Public not aware of potential hazards, e.g. underground assets – Unauthorised access to the Powerco network – Vandalism This risk excludes car / pole fatalities.	High	Immediate	– Free cable and gas pipe location and stand-over service – Active public awareness programmes aimed at specific target audience, e.g. field days, seminars, art promoting safety in public places and Powerco website, videos, bus adverts – Signage and security around high risk assets – Compliance with NZs7901 including effective management of network defects and red tagged pole structures – external certification – Asset strategy and planning processes including defect management process to manage end of life assets – Increased focus on risk-based assessment on potential asset failure and carrying out increased numbers of preventative renewals on assets to improve safety around our assets – Safety-in-design considerations are further defined and integrated into the asset planning processes	Medium
Fatality or serious harm to Powerco employee. This can result from: – Motor vehicle or road incidents – Stress – Negligence or human error – Equipment failure – Lack of competence – Unawareness of potential hazards	Medium	Immediate	– Hazard registers, HSE committee information, health and safety management system, policies and procedures are widely available on the intranet – Wellness and occupational health service provision – Powerco staff cannot access network assets without the competencies required of field staff – typically Powerco staff role is supervisory only – Staff induction procedure includes hazard and HSE information and information on HSE representative and health monitoring – HSE training matrix is documented and competency is monitored for staff, manager, and HSE / warden / first aider roles – Employees are offered interactive on-line driver training and a practical driving assessment. In addition, there are advanced sessions for employees who drive more than 10,000 km a year as well as 4wd and quad bike training for employees who require this	Low

RISKS DESCRIPTION	INHERENT RISK SCORE	VELOCITY	CONTROL DESCRIPTION	CONTROLLED RISK SCORE
1. 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 Powerco's greatest exposure (refer to 2011 update of marsh & McLennan uninsured assets - catastrophe risk /loss report) 2. Eruption of Mt Taranaki which impacts the Taranaki region only 3. Major pandemic impacting Powerco and NZ in general rather than just one region Note: ENA and EEA facilitate service provider arrangements in event of a national disaster, e.g. Christchurch earthquake)	Medium	Immediate	– Business continuity framework, plans (BMS documents) and regular desktop exercises are reviewed / scheduled for improvement and training purposes – Backup NOC facilities are available at bell block in the event of a loss of the junction street site, and network oversight and control can be assumed from the Tauranga office (for network triage purposes) in the event that both New Plymouth facilities become inoperable – Materials damages and business interruption insurances are held for depots / offices and contents, zone substations and SCADA; special earthquake insurance cover is held for GMS, DRS, ground mounted transformers and ground mounted substations – $70m revolving cash loan maintained for an event where the network fails, and it is not covered by insurance, e.g. lines and pipes	Low
The DPP process was unable to provide the level of capital we require to effectively maintain and renew Powerco electricity assets in the long term. At current levels of expenditure an increasing proportion of assets will require operation beyond their target service lives, particularly our overhead network assets. There are also indications that underlying reliability performance at specific locations across our network is being impacted negatively by a combination of deteriorating condition, increasing age and model/type-related issues. The operational margin around our SAIDI/SAIFI quality targets is eroding at current levels of expenditure. The current CPP serves to alleviate the potential risk significantly over the medium to long term, but there is still a possibility that after reset the level of capital available may be insufficient to sustain the quality of the network. When transitioning off CPP, it is not clear how the commission will set Powerco's expenditure allowance levels. The risk is that capex and opex will be set at levels that are insufficient to maintain the network at the standard we believe necessary to meet quality, safety, and longer-term reliability levels. A result of a reduction in expenditure allowances would likely be that the RAB level drop below what is currently assumed in our financial model, hence leading to lower than forecast returns.	High	Slow	– The CPP process for the next 5 years will alleviate the potential risk significantly over the medium to long term, but there is still a possibility that it does not provide the level of capital needed – We continue a focus on maintaining relationships with the commerce commission – There is continued dedicated focus on lifting the level of asset management maturity within Powerco to support and maximise the likelihood of successful delivery of the CPP application – Powerco is engaging with the commission on how it will set the post-CPP expenditure allowances; this will step up after the DPP3 determination is finalised, and inform the regulatory approach post-CPP	Medium
Breach of the commerce act electricity and gas DPP (price and / or quality), CPP price setting and associated information disclosure requirements resulting in pecuniary penalties and reputation damage. The reducing quality targets imposed on Powerco over the CPP period are not considered by management to be achievable and pose a potential breach risk over the CPP period. The key risk remains as being a breach of unplanned SAIDI and SAIFI breach caps due to adverse weather. Without this the controlled risk level for this risk would be rated lower.	Medium	Slow	– A regulatory presence in wellington ensures a continued focus on maintaining relationships with the commerce commission and regulators – Active monitoring is in place to ensure that Powerco's position with respect to the CPP new quality-price incentives is tracked on a routine basis – The risk of inadvertent breach of annual information disclosure requirements is reduced through having tight controls on underlying processes and systems to ensure information quality; this is an area of ongoing management focus and is subject to regular internal audit and oversight by regulatory – The CPP decision should enable Powerco to progress investments necessary to ensure stable long-term network performance – Our CPP application proposed variations to quality targets to allow us to achieve the network work without potential to be penalised due to increased planned interruptions; we also proposed an annual delivery report against which investment progress and other factors are made public; assessment against these requirements will occur in 2019	Medium

RISKS DESCRIPTION	INHERENT RISK SCORE	VELOCITY	CONTROL DESCRIPTION	CONTROLLED RISK SCORE
Severe weather event which adversely affects Powerco's 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 into a CPP application – Cost of replacing uninsured assets requires funding by Powerco 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 delivery resources during extended storm events – The wide geographical spread of Powerco 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 Powerco vulnerable in some scenarios where the core operating centre at junction street is damaged or unable to be accessed	Medium	Immediate	– The scale of Powerco's capital programme means that we typically have high levels of staff and plant to respond to storms and other events – Practice of splitting to local 'hubs' for power rectification in major events reduces dependence on central control room co-ordination in peak events – Resource rotation and maximum hours worked policies (both Powerco and its service providers) are adhered to – Training of Powerco and downer employees in the CIMS process for improved responsiveness under a severe weather event. – Backup NOC facilities are available at bell block in the event of a loss of the junction street site, and network oversight and control can be assumed from the Tauranga office (for network triage purposes) in the event that both New Plymouth facilities become inoperable – Levels and locations of emergency and critical spares holdings are documented, also levels of general materials e.g. poles, cable and where these are located. There are contracts with some suppliers to hold contingency stock levels	Medium
Fatality or serious harm to external third parties working near the network. This can result from: – Negligence, human error or equipment failure or – Incorrect or inadequate information given by Powerco – Unawareness of potential hazards – Lack of competence	Medium	Immediate	– Free cable and gas pipe location and stand-over service, also close approach permits – Compliance with industry best practice in close approach excavation – Accurate GIS location data – Public awareness programmes in conjunction with local authorities – Compliance with NZs7901 – external certification – Asset strategy and planning processes including defect management process to manage end of life assets	Medium
The risk that inaccurate or incomplete as build data is received from service providers / contractors or that the as-built is incorrectly recorded by our in-house team and therefore adversely impacting our asset data quality.	Medium	Slow	– Contract standards and processes in place and regularly updated for recording of assets and as building requirements – EFSA KPI as built quality monitored and followed up monthly – Monitoring and follow up of work in progress to identify outstanding work packs and associated documents	Medium
Inaccurate and/or incomplete HV information being provided to service providers / contractors / third parties.	Medium	Rapid	– Waivers are issued with supplied data for plan issuers. – Safe working practices used in the field including stand-over requirement for excavations near Powerco underground cables and pipes. – Electricity strategic standard now in place – Jos is stopped if data supplied does not match what is in the field – Standards and processes in place and regularly updated for service provider recording of assets and as building requirements – HV connectivity is checked daily – Contractors required to provide corrected data if information supplied is inaccurate or incomplete	Medium
Falling demand driven by population, energy efficiency and/or changed network utilization. Notes: The likelihood of falling demand is low. Population growth will continue to be the biggest driver of demand for the foreseeable future Consequence/impact of demand changes will be muted in the first instance - this is because allowable revenue is set by building blocks methodology	Medium	Slow	– Design and implementation of a customer-led energy platform strategy to help position Powerco to ensure assets remain used and useful (i.e. avoid stranding) over a broad range of energy market scenarios	Low
Risk of data integrity issues within the oms application that is not detected and is used to produce incorrect SAIDI / SAIFI, CPP ADR and/or EFSA KPI disclosures.	Medium	Immediate	– Oms Eectra system has much improved data integrity than previous version – Internal and external assurance audits of both system and data disclosures completed annually – SAIDI / SAIFI audited annually – Data checked daily	Low

APPENDIX 7 DEMAND FORECASTS

A7.1 APPENDIX OVERVIEW

This appendix sets out our 15-year demand forecasts for our zone substations.

A7.2 DEMAND FORECAST FOR COROMANDEL AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coromandel	0.5	0.8%	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.8
Kerepehi	0.0	0.9%	10.0	10.1	10.2	10.3	10.4	10.5	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2	11.3
Matatoki	0.0	0.7%	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.9	4.9	4.9	5.0	5.0
Tairua	7.5	0.5%	8.9	9.0	9.0	9.1	9.1	9.2	9.2	9.3	9.3	9.3	9.4	9.4	9.5	9.5	9.6
Thames T1 & T2	0.0	0.3%	11.7	11.8	11.8	11.8	11.9	11.9	11.9	12.0	12.0	12.1	12.1	12.1	12.2	12.2	12.3
Thames T3	6.9	0.0%	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Whitianga	0.0	1.0%	16.5	16.7	16.8	17.0	17.2	17.3	17.5	17.7	17.8	18.0	18.1	18.3	18.5	18.6	18.8

A7.3 DEMAND FORECAST FOR WAIKINO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Paeroa	6.0	0.8%	7.8	7.9	8.0	8.0	8.1	8.1	8.2	8.3	8.3	8.4	8.4	8.5	8.6	8.6	8.7
Waihi	16.0	0.4%	16.7	16.8	16.8	16.9	17.0	17.1	17.1	17.2	17.3	17.3	17.4	17.5	17.6	17.6	17.7
Waihi Beach	3.3	0.9%	5.7	5.8	5.8	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5
Whangamata	0.0	0.4%	10.5	10.5	10.6	10.6	10.7	10.7	10.8	10.8	10.9	10.9	10.9	11.0	11.0	11.1	11.1

A7.4 DEMAND FORECAST FOR TAURANGA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Aongatete	7.2	1.6%	4.3	4.4	4.4	4.5	4.6	4.6	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.2	5.2
Bethlehem	8.0	1.6%	9.3	9.5	9.6	9.8	9.9	10.0	10.2	10.3	10.5	10.6	10.8	10.9	11.1	11.2	11.4
Hamilton St	22.4	0.4%	16.1	16.1	16.2	16.3	16.3	16.4	16.5	16.6	16.6	16.7	16.8	16.8	16.9	17.0	17.0
Katikati	4.6	1.0%	8.5	8.6	8.7	8.8	8.9	9.0	9.0	9.1	9.2	9.3	9.4	9.5	9.6	9.6	9.7
Kauri Pt	1.6	0.9%	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0
Matua	7.4	0.3%	8.8	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.2	9.2
Omokoroa	13.2	1.4%	10.4	10.6	10.7	10.9	11.0	11.2	11.3	11.5	11.6	11.8	11.9	12.1	12.2	12.4	12.5
Otumoetai	13.6	0.9%	14.7	14.9	15.0	15.1	15.3	15.4	15.5	15.7	15.8	15.9	16.0	16.2	16.3	16.4	16.6
Pyes Pa	11.7	3.4%	10.4	10.8	11.1	11.5	11.8	12.2	12.5	12.9	13.3	13.6	14.0	14.3	14.7	15.0	15.4
Tauranga 11kV	30.0	1.2%	24.4	24.7	25.0	25.3	25.6	25.9	26.2	26.5	26.8	27.1	27.4	27.6	27.9	28.2	28.5
Waihi Rd	24.1	0.6%	21.5	21.6	21.7	21.9	22.0	22.1	22.3	22.4	22.6	22.7	22.8	23.0	23.1	23.2	23.4
Welcome Bay	21.4	1.4%	22.9	23.2	23.5	23.9	24.2	24.5	24.9	25.2	25.5	25.8	26.2	26.5	26.8	27.2	27.5

A7.5 DEMAND FORECAST FOR MOUNT MAUNGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Atuaroa Ave	0.0	0.9%	8.2	8.3	8.3	8.4	8.5	8.6	8.6	8.7	8.8	8.9	8.9	9.0	9.1	9.2	9.2
Matapihi	24.1	0.5%	13.0	13.0	13.1	13.1	13.2	13.3	13.3	13.4	13.4	13.5	13.6	13.6	13.7	13.7	13.8
Omanu	24.3	1.3%	11.9	12.0	12.2	12.3	12.5	12.6	12.8	13.0	13.1	13.3	13.4	13.6	13.7	13.9	14.0
Paengaroa	3.6	1.0%	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	5.4	5.5
Papamoa	21.3	1.7%	15.5	15.8	16.0	16.3	16.5	16.8	17.1	17.3	17.6	17.8	18.1	18.3	18.6	18.9	19.1
Pongakawa	1.3	0.9%	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.9	4.9	4.9	5.0	5.0
Te Maunga	10.3	1.9%	9.8	9.9	10.1	10.3	10.5	10.7	10.9	11.0	11.2	11.4	11.6	11.8	12.0	12.1	12.3
Te Puke	22.9	0.8%	18.8	19.0	19.1	19.3	19.4	19.5	19.7	19.8	20.0	20.1	20.3	20.4	20.6	20.7	20.9
Triton	21.3	0.6%	20.0	20.1	20.3	20.4	20.5	20.7	20.8	20.9	21.0	21.2	21.3	21.4	21.6	21.7	21.8
Wairakei	6.0	5.3%	6.6	7.0	7.4	7.7	8.1	8.4	8.8	9.1	9.5	9.8	10.2	10.5	10.9	11.2	11.6

A7.6 DEMAND FORECAST FOR WAIKATO AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Browne St	10.6	1.1%	9.8	9.9	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.1	11.2	11.3	11.4
Farmer Rd	0.0	0.5%	6.9	6.9	6.9	7.0	7.0	7.1	7.1	7.1	7.2	7.2	7.2	7.3	7.3	7.4	7.4
Inghams	0.0	0.0%	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Lake Rd	1.7	1.5%	6.5	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.8	7.9
Mikkelsen Rd	19.2	0.8%	12.6	12.7	12.8	12.9	13.0	13.1	13.2	13.3	13.4	13.5	13.7	13.8	13.9	14.0	14.1
Morrinsville	0.0	0.7%	8.8	8.8	8.9	8.9	9.0	9.1	9.1	9.2	9.2	9.3	9.3	9.4	9.5	9.5	9.6
Piako	15.2	0.8%	13.1	13.2	13.3	13.4	13.5	13.6	13.7	13.8	14.0	14.1	14.2	14.3	14.4	14.5	14.6
Putaruru	0.0	0.6%	11.6	11.6	11.7	11.8	11.9	11.9	12.0	12.1	12.2	12.2	12.3	12.4	12.5	12.5	12.6
Tahuna	0.7	0.9%	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.4	6.4	6.5	6.5	6.6
Tatua	0.0	0.0%	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Tirau	0.0	0.5%	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.2	10.3	10.3	10.4	10.4
Tower Rd	0.0	1.0%	8.2	8.3	8.3	8.4	8.5	8.6	8.7	8.7	8.8	8.9	9.0	9.1	9.2	9.2	9.3
Waharoa Nth	2.5	1.2%	3.7	3.7	3.8	3.8	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3
Waharoa Sth	0.0	0.0%	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Waitoa	18.8	0.0%	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Walton	0.0	0.9%	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5	6.6	6.6

A7.7 DEMAND FORECAST FOR KINLEITH AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baird Rd	0.0	0.7%	10.2	10.3	10.4	10.4	10.5	10.6	10.7	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2
Maraetai Rd	0.0	0.4%	8.3	8.3	8.3	8.4	8.4	8.4	8.5	8.5	8.5	8.6	8.6	8.6	8.7	8.7	8.7
Midway / Lakeside	0.0	0.0%	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2

A7.8 DEMAND FORECAST FOR TARANAKI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bell Block	24.5	1.2%	15.6	15.7	15.9	16.1	16.3	16.5	16.6	16.8	17.0	17.2	17.4	17.5	17.7	17.9	18.1
Brooklands	24.0	0.7%	16.6	16.7	16.9	17.0	17.1	17.2	17.3	17.4	17.5	17.6	17.7	17.8	17.9	18.0	18.2
Cardiff	5.5	0.9%	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8
City	20.1	0.7%	16.5	16.7	16.8	16.9	17.0	17.1	17.2	17.4	17.5	17.6	17.7	17.8	17.9	18.1	18.2
Cloton Rd	13.0	0.6%	9.9	10.0	10.0	10.1	10.1	10.2	10.3	10.3	10.4	10.5	10.5	10.6	10.6	10.7	10.8
Douglas	1.7	0.4%	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7
Eltham	11.3	0.6%	9.9	9.9	10.0	10.1	10.1	10.2	10.2	10.3	10.3	10.4	10.5	10.5	10.6	10.6	10.7
Inglewood	6.2	1.1%	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.7	5.8	5.8
Kaponga	3.0	0.8%	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4	3.4
Katere	20.6	1.3%	13.6	13.8	13.9	14.1	14.3	14.5	14.6	14.8	15.0	15.2	15.4	15.5	15.7	15.9	16.1
McKee	0.0	0.3%	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Motukawa	1.3	1.0%	1.0	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	1.1
Moturoa	20.7	0.8%	18.2	18.3	18.5	18.6	18.8	18.9	19.1	19.2	19.4	19.5	19.7	19.8	19.9	20.1	20.2
Oakura	0.0	1.4%	3.4	3.5	3.5	3.6	3.6	3.7	3.7	3.8	3.8	3.9	3.9	4.0	4.0	4.0	4.1
Pohokura	9.2	0.0%	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Waihapa	2.4	0.0%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Waitara East	10.1	1.3%	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1	5.2	5.3	5.3	5.4	5.4	5.5
Waitara West	6.4	0.3%	6.7	6.7	6.7	6.7	6.7	6.8	6.8	6.8	6.8	6.9	6.9	6.9	6.9	6.9	7.0

A7.9 DEMAND FORECAST FOR EGMONT AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cambria	17.0	0.5%	13.1	13.2	13.2	13.3	13.3	13.4	13.5	13.5	13.6	13.7	13.7	13.8	13.8	13.9	14.0
Kapuni	7.0	0.0%	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Livingstone	3.0	0.3%	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Manaia	5.0	0.4%	5.9	6.0	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.3	6.3	6.3
Mokoia	3.1	0.8%	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.5
Ngariki	3.9	0.8%	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.3
Pungarehu	4.5	1.0%	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4
Tasman	6.4	0.5%	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.9	6.9	6.9	7.0	7.0

A7.10 DEMAND FORECAST FOR WHANGANUI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Beach Rd	16.2	0.3%	9.8	9.8	9.9	9.9	9.9	10.0	10.0	10.0	10.1	10.1	10.1	10.2	10.2	10.2	10.2
Blink Bonnie	3.0	0.5%	3.8	3.8	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1
Castlecliff	8.7	0.3%	9.1	9.1	9.1	9.2	9.2	9.2	9.2	9.3	9.3	9.3	9.4	9.4	9.4	9.5	9.5
Hatricks Wharf	0.0	0.4%	13.4	13.5	13.5	13.6	13.6	13.7	13.7	13.8	13.8	13.9	14.0	14.0	14.1	14.1	14.2
Kai Iwi	1.0	0.9%	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.5	2.5
Peat St	0.0	0.4%	14.1	14.2	14.2	14.3	14.3	14.4	14.4	14.5	14.5	14.6	14.6	14.7	14.7	14.8	14.8
Roberts Ave	5.8	0.4%	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Taupo Quay	0.0	0.1%	10.8	10.8	10.8	10.8	10.9	10.9	10.9	10.9	10.9	10.9	10.9	11.0	11.0	11.0	11.0
Wanganui East	3.4	0.2%	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.4	5.4	5.4

A7.11 DEMAND FORECAST FOR RANGITIKEI AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Arahina	3.1	0.3%	8.1	8.2	8.2	8.2	8.2	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.5	8.5	8.5
Bulls	2.0	0.6%	5.7	5.7	5.8	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1	6.2	6.2	6.2
Pukepapa	1.9	1.0%	5.5	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.1	6.2	6.2
Rata	0.7	0.4%	3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2
Taihape	0.8	0.4%	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7
Waiouru	0.5	-0.7%,-	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2

A7.12 DEMAND FORECAST FOR MANAWATU AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Feilding	23.7	0.9%	21.6	21.8	22.0	22.2	22.3	22.5	22.7	22.9	23.1	23.3	23.5	23.7	23.8	24.0	24.2
Ferguson St	15.0	0.4%	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4	11.4	11.4	11.5	11.5	11.6	11.6
Kairanga	19.1	0.7%	17.9	18.0	18.2	18.3	18.4	18.5	18.6	18.8	18.9	19.0	19.1	19.2	19.4	19.5	19.6
Keith St	21.9	0.6%	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5	19.6	19.8	19.9	20.0
Kelvin Grove	17.2	1.1%	17.0	17.2	17.4	17.5	17.7	17.9	18.1	18.3	18.5	18.7	18.8	19.0	19.2	19.4	19.6
Kimbolton	1.4	0.8%	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	3.0
Main St	17.0	0.4%	21.8	21.9	22.0	22.1	22.2	22.3	22.4	22.5	22.6	22.6	22.7	22.8	22.9	23.0	23.1
Milson	18.1	0.6%	16.8	16.9	17.0	17.1	17.2	17.3	17.4	17.5	17.6	17.7	17.8	17.9	18.0	18.1	18.2
Pascal St	17.0	0.4%	22.5	22.6	22.7	22.8	22.9	22.9	23.0	23.1	23.2	23.3	23.3	23.4	23.5	23.6	23.7
Sanson	0.0	1.2%	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9
Turitea	0.0	1.0%	14.0	14.2	14.3	14.5	14.6	14.7	14.9	15.0	15.2	15.3	15.5	15.6	15.8	15.9	16.0

A7.13 DEMAND FORECAST FOR TARARUA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alfredton	1.4	0.0%	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Mangamutu	12.8	0.3%	12.3	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.5	12.5	12.6	12.6	12.6	12.7	12.7
Parkville	0.0	0.3%	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Pongaroa	2.9	0.1%	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

A7.14 DEMAND FORECAST FOR WAIRARAPA AREA SUBSTATIONS

SUBSTATION	CLASS CAPACITY	GROWTH	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Akura	9.0	0.8%	13.0	13.1	13.2	13.3	13.4	13.5	13.6	13.7	13.8	13.9	14.0	14.1	14.2	14.3	14.4
Awatoitoi	3.0	0.9%	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5
Chapel	13.8	0.5%	12.4	12.5	12.5	12.6	12.7	12.7	12.8	12.9	12.9	13.0	13.1	13.1	13.2	13.3	13.3
Clareville	9.4	1.2%	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10.1	10.2	10.3	10.4	10.5	10.6	10.7
Featherston	0.1	1.0%	4.4	4.4	4.5	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.8	4.9	4.9	5.0
Gladstone	1.4	0.7%	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2
Hau Nui	0.0	0.5%	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Kempton	0.4	1.0%	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.8	4.8
Martinborough	0.1	1.1%	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.7	5.7
Norfolk	10.6	0.5%	6.3	6.4	6.4	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8
Te Ore Ore	6.8	0.6%	7.0	7.0	7.1	7.1	7.2	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.6
Tinui	1.3	0.8%	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2
Tuhitarata	0.0	1.2%	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5

A8.1 APPENDIX OVERVIEW

This appendix provides additional details for planned projects outlined in our Fleet Management and Network Development plans.

The appendix describes the constraints, technical options and preferred solution for the Growth and Security projects outlined in Chapter 15. In general, only projects scheduled to commence in the next five years are listed unless they are of significance to the overall zone substation or area plan. Towards the later part of the planning period, project needs and solutions are less certain. This is because of the volatility of the growth forecasts and impact of future technologies on demand. The listed 'future projects' are continuously reviewed against future demand forecasting. Available options, cost estimates and preferred solutions are expected to change, be refined over time and become firmer as the projects move closer to commencement.

This appendix also includes a description of our larger renewal projects. Only zone substation and subtransmission projects with expected costs exceeding $500,000 have been included and, again, only those that are scheduled to commence in the next five years. Like Growth and Security projects, our renewal projects are continuously reviewed against updated condition assessment and asset health information, and plans updated and adjusted.

The Electricity Distribution Information Disclosure Determination requires us to disclose our forecast expenditures under specific categories. The categories mostly used in this section include:

GRO - System Growth

ARR - Asset Replacement and Renewal

QoS - Quality of Supply

ORS - Other Reliability, Safety and Environment

A8.2 ORS – OTHER RELIABILITY, SAFETY AND ENVIRONMENTCOROMANDEL

A8.2.1 SUBTRANSMISSION NETWORK PROJECTS

A8.2.1.1 NEW KAIMARAMA 66KV SWITCHING STATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KAIMARAMA GIS SWITCHING STATION	GRO	$9,720	2021-2023

Network issue

The combined 2019 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage of the 66kV line between Kopu and Tairua, the section of 66kV line between Kaimarama and Whitianga is often overloaded during peak demand conditions. During an outage of either 66kV circuit from Kopu, the remaining network is voltage constrained at peak demand. These three substations therefore do not meet our Security of Supply Standard, which requires a no break N-1 supply (security class AAA).

In addition to the above constraints, the subtransmission network supplying the Coromandel, Whitianga and Tairua substations has a history of poor reliability because of the long overhead lines that cross rugged and exposed terrain, coupled with the existing meshed configuration and tee connections. The Coromandel area's subtransmission network is our worst performing area in terms of System Average Interruption Duration Index (SAIDI).

There is a particular issue with the Coromandel substation, supplied via a 66kV line that tees off the Tairua-Whitianga 66kV line. The implementation of a robust electrical protection system on this three-terminal network has been found to be difficult. Protection systems have been upgraded on the subtransmission circuits to allow the 66kV ring to be operated permanently closed. Future upgrades will involve high speed communication systems to enable fast inter-trip schemes to operate on the subtransmission network.

Options

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 110kV-capable switching station.

Preferred option

Currently, the preferred option is the installation of a new Kaimarama 110kV-capable switching station (option 6 above), based on the use of indoor gas insulated switchgear, enclosed in a switchroom designed to blend in with the environment. The landowners have signed an option agreement contract that secures Powerco the right to purchase the land to build the gas insulated switchgear switching station. The project is at the detailed design stage.

A8.2.1.2 KOPU-TAIRUA 66KV LINE UPGRADE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KOPU-TAIRUA LINE UPGRADE	GRO	$14,176	2021-2023

Network issue

The combined 2020 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage anywhere on the long 66kV line from Kopu GXP (grid exit point) through to Whitianga, the line between Kopu and Tairua does not have sufficient capacity to supply all three substations during peak loading conditions. The 66kV network would also experience voltage constraints at its extremities (ie Coromandel substation). These three substations therefore do not meet our Security of Supply Standard, which requires a no break N-1 supply (security class AAA) regarding the subtransmission network.

Options

1. Re-conductor existing Kopu-Tairua 66kV line.
2. Duplex the existing Kopu-Tairua 66kV line.
3. Build a second Kopu-Tairua 66kV line.
4. Alternative non-network solution (Project CORE) – distributed generation (DG).

Preferred option

Option 1, to re-conductor the existing Kopu-Tairua 66kV line, is preferred. However, the consenting and property issues of a new line are prohibitive through this area of sensitive landscapes and difficult physical access.

Moving to a non-standard (for the distribution industry) duplex construction represents high risk – conductor fittings are scarce and the technology largely unproven in post or pin type construction. In addition to the line upgrade, 66kV reactive support will be needed to address the voltage constraints eventually. This could occur as a separate project following the line upgrade.

Detailed design and engineers' estimates for option 1 have been completed and indicate that project cost is going to be much higher than the original estimated costs calculated a few years ago. Powerco is investigating DG as a non-network solution (option 4). Option 1 is still being worked on in parallel while the feasibility work is carried out for option 4.

A8.2.1.3 NEW KOPU-KAUAERANGA 110KV-CAPABLE LINE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KOPU-KAUAERANGA 110kV LINE	GRO	$9,900	2028-2030

Network issue

During 2019, the total load on the Thames substation was ≈13.3MW. The substation supplies medium-demand customers, including A and G Price ≈1.6MW, Thames Toyota and Goldfields shopping centre. Under normal operating conditions the supply to Thames is via a single 66kV circuit. If there is a fault on the normal Thames supply a second overhead 66kV supply line can be switched in. However, the second circuit is shared with the Coromandel/Whitianga/Tairua substations and the shared section (≈5km of Raccoon conductor between Kopu and Parawai) would be overloaded during peak loading conditions. Therefore, the existing supply network to Thames does not meet the requirements of our Security of Supply Standard, which recommends a no break N-1 supply network with a security class of AAA. The section of overhead line between Parawai and Kauaeranga is overloaded when supplying Whitianga, Coromandel and Tairua in the event of a Kopu-Tairua outage.

In addition, the subtransmission network in the Coromandel area has a long history of poor performance because of the long overhead lines that cross rugged terrain. This is compounded by the meshed configuration that involves several 66kV tee connections. The simplification of the existing network is expected to deliver significant benefits to customers in the Coromandel area.

Options

5. New 110kV-capable line from Kopu GXP to Kauaeranga initially operated at 66kV.
6. Thermal upgrade of the existing Kopu-Kauaeranga 66kV line.
7. 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 proposed Kaimarama switching station, from Kopu, via an 110kV supply line.

The proposed line route has been designated, and agreements are in place with most landowners. However, one block of land is subject to Treaty of Waitangi settlement claims and is likely to delay the project's construction start date. As an interim measure, to enable the deferral of the new line, the section of Mink conductor between Parawai and Kauaeranga has been re-conductored and the Kopu-Parawai section of Racoon thermally upgraded.

A8.2.1.4 WHENUAKITE 66/11KV SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHENUAKITE 66/11kV SUBSTATION	GRO	$13,820	2021-2023

Network issue

During 2019, the peak loading level on the Whitianga 66/11kV substation was 17.5MVA, which exceeds the existing (N-1) substation capacity. The 11kV backfeed from the adjacent 66/11kV substations is small, and the Whitianga substation does not meet Powerco's Security of Supply Standard which, given the size of peak demand, requires the substation to provide a no break N-1 supply.

At present, several 11kV feeders at Whitianga substation have an installation control point (ICP) count well in excess of the targeted maximum for their respective security levels. The constant growth in Whitianga requires a combination of more feeders and zone substation capacity.

The Cooks Beach/Hahei area is fed from the already constrained Whitianga substation and feeders. The feeders that supply Cooks Beach/Hahei have inherent performance and reliability issues, which cannot be rectified easily, and supply quality on the feeders into this area is poor.

Options

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Whenuakite substation (in and out 66kV configuration).
3. New Whenuakite substation (66kV tee connection).
4. New Whenuakite substation (66kV switching station).

Preferred option

Currently, the preferred option is to build a new Whenuakite substation, supplied via a new 66kV double circuit line that connects into the Tairua-Whitianga circuit using an in-and-out configuration (option 2 above). Detail design of option 2 is under way. This option will reduce the existing Whitianga substation feeder ICP count and shorten the length of the feeders and improve feeder performance. Future load growth in the region can be accommodated with the preferred option. Installing additional 11kV feeders from Whitianga substation, instead of a new Whenuakite substation, would face considerable consenting and construction challenges, and would not address load constraints at Whitianga itself. A tee connection for the proposed Whenuakite substation (option 3) would exacerbate the existing protection and operational constraints on the 66kV. Obtaining property and consents for both a substation and a switching station (option 4) would considerably add to costs and project complexity.

A8.2.1.5 MATARANGI 66/11KV SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATARANGI 66/11kV SUBSTATION	GRO	$10,000	2021-2023

Network issue

As noted for the Whenuakite constraints above, the 11kV feeders from Whitianga substation are long and heavily loaded, with ICP counts and feeder lengths exceeding our recommended standards. This impacts on reliability as more customers are affected and for a greater number of outages per year. Strong growth has been sustained in the past decade and is predicted to continue because of the area's continued popularity for holiday accommodation. Backfeed capacity on the 11kV is particularly constrained and secure capacity at Whitianga substation is exceeded.

The coastal townships to the north of Whitianga, including Matarangi and Kuaotunu, are supplied by two 11kV feeders as follows:

- Owera Rd feeder: A rural overhead line feeder that follows a path north-east from the Whitianga substation to Matarangi, a distance of ≈15km. During peak network loading periods (≈3.5MVA in 2019) a significant portion of the electrical load is at the end of this feeder and it is equipped with a voltage regulator and two pole-mounted capacitor banks to elevate delivery voltages.
- Kuaotunu feeder: Passes through the Whitianga township supplying some urban customer load before heading north-west to Kuaotunu. The 2019 peak load on the feeder was ≈2MVA.

The loads on the above two, long 11kV feeders are projected to continue to increase with ~300 lots proposed at Matarangi and ~80 lots approved at Opito Bay. The combined peak load of ≈5.5MVA on the two feeders cannot be supplied by a single feeder (ie during an outage of the other feeder).

Options

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.
4. Alternative non-network solution (Project CORE) – DG

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, constructing additional 11kV feeders out of Whitianga substation does not address the constraints on Whitianga substation itself.

Option 4 is also being investigated as part of Project CORE to install DG to test whether the solution is feasible and economical. This option will relieve thermal constraints on the 11kV feeders when required.

A8.2.2 ZONE SUBSTATION PROJECTS

A8.2.2.1 BACKUP SUPPLY TO KEREPEHI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KEREPEHI REFURBISH 11kV SWITCHBOARD	ARR	$700	2026
KEREPEHI 66kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$140	2024
BACKUP SUPPLY TO KEREPEHI SUBSTATION	GRO	$5,000	2022-2024

Network issue

The Kerepehi substation is supplied via a single 66kV circuit from Kopu GXP. During an outage of this circuit, there is limited 11kV backfeed from nearby substations to provide backup. This backfeed is not sufficient to provide the required security to Kerepehi substation.

Options

1. Reinstate an old 50kV line between Kerepehi and Paeroa energising it at 33kV and install a 33/11kV transformer at Kerepehi to back up the substation.
2. Construct a second 66kV circuit from Kopu.
3. Improve the distribution network and increase the 11kV backfeed capability.
4. Install backup distribution generation.

Preferred option

The current preferred solution is option 4, to install backup DG at Kerepehi substation. This will offer backup, peak lopping ability, and be future-proofed to provide grid scale microgrid capabilities. The original preferred option 1, to reinstate the 33kV line between Kerepehi and Paeroa in its current form will not be completed within the period because of access and consenting challenges, which will also add considerable cost to the project.

Powerco is undertaking a concept design option involving renewal or replacement of the indoor 11kV switchgear, and DG.

Fleet issue

The existing 11kV switchboard at Kerepehi substation does not meet modern arc flash standards and has oil quenched circuit breakers. The Kerepehi switchroom has recently been seismically strengthened. The outdoor 66kV circuit breaker is unreliable and is scheduled for replacement.

Options

1. Refurbish the existing Kerepehi 11kV switchboard including arc flash protection, arc flash doors and end panels. Replace the 66KV outdoor circuit breaker.
2. Install a new 11kV switchboard in the existing Kerepehi switchroom. Replace the 66kV outdoor circuit breaker.

Preferred option

The preferred option is to refurbish the existing Kerepehi 11kV switchboard and replace the 66kV outdoor circuit breaker.

A8.2.2.2 MATATOKI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATATOKI SEISMIC STRENGTHENING	ARR	$200	2024
MATATOKI REFURBISH 11kV SWITCHBOARD	ARR	$533	2024-2025
MATATOKI REPLACE 66kV CIRCUIT BREAKERS	ARR	$200	2026-2027
MATATOKI SECOND TRANSFORMER	GRO	$2,130	2029-2031

Network issue

Matatoki is supplied from a single 7.5MVA 66/11kV transformer. An outage on this transformer causes loss of supply to the substation. Existing 11kV backfeed capacity is insufficient to support the maximum demand load. This means that the substation does not meet Powerco's Security of Supply Standard.

Options

1. Install a second transformer at Matatoki substation.
2. Increase 11kV backfeed capacity to Matatoki.

Preferred option

The preferred solution is option 1, which is to install a second 7.5MVA 66/11kV transformer at Matatoki substation. This will provide backup to the existing unit. Option 2, to further increase 11kV backfeed capacity, will involve substantial 11kV infrastructure investment and is not economically attractive.

Fleet issue

The Matatoki 11kV switchroom has a seismic strength of 35% New Building Standard (NBS), below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Matatoki substation does not meet modern arc flash standards, has oil quenched circuit breakers and electromechanical relays.

Options

1. Seismically reinforce the existing switchroom and refurbish the existing 11kV switchgear. Replace the 66kV outdoor circuit breakers
2. Build a new switchroom and install new 11kV switchgear in the new switchroom. Replace the 66kV outdoor circuit breakers

Preferred option

The preferred option is to reinforce the existing switchroom and refurbish the existing 11kV switchgear, as this will optimise risk reduction vs capital expenditure. Separately replace the outdoor 66kV circuit breakers.

A8.2.2.3 TAIRUA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$235	2026

Fleet issue

The existing switchroom building is at 50% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom to 67% NBS.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom and carry out a switchboard arc flash upgrade.

A8.2.2.4 THAMES SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
THAMES SEISMIC STRENGTHENING, REPLACE 11kV SWITCHBOARD AND REPLACE 2x66kV OUTDOOR CIRCUIT BREAKERS	ARR	$3,039	2023-2024

Fleet issue

The Thames 11kV switchroom has a seismic strength of 19% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Thames substation does not meet modern arc flash standards and is a switchboard type, which is only used in one other Powerco zone substation. The 11kV switchboards at Tatua and Thames zone substations are similar, so when Powerco retires the Thames switchboard this will ensure there are enough spares to be able to defer the renewal of the Tatua switchboard. Two of the existing 66kV transformer circuit breakers at Thames require replacement. They are minimum oil type and are 42 years old.

Options

1. Seismically reinforce the existing switchroom and replace the existing 11kV switchgear. Replace the 66kV outdoor circuit breakers.
2. Build a new switchroom and install new 11kV switchgear in the new switchroom. Replace the 66kV outdoor circuit breakers.

Preferred option

The preferred option is to reinforce the existing switchroom and replace the existing 11kV switchgear (option 1), as this will optimise risk reduction vs capital expenditure. Separately replace the two outdoor 66kV circuit breakers.

A8.2.2.5 WHITIANGA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHITIANGA SEISMIC STRENGTHENING	ARR	$200	2024
WHITIANGA REFURBISH 11kV SWITCHBOARD	ARR	$596	2024-2025

Fleet issue

The Whitianga 11kV switchroom has a seismic strength of 65% NBS, below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Whitianga substation does not meet modern arc flash standards and is oil quenched. There is insufficient room to add new panels to the 11kV switchboard. The protection is of a first-generation electronic technology and has type issues. The replacement of this switchgear is not ranked highly in the circuit breaker condition-based risk management (CBRM) model.

Options

1. Seismically reinforce the existing switchroom to 67% of NBS and refurbish the existing 11kV switchgear.
2. Build a new switchroom and install new 11kV switchgear in the new switchroom.

Preferred option

The preferred solution is option 1, to reinforce the existing switchroom and refurbish the existing 11kV switchgear, as this will optimise risk reduction vs capital expenditure.

A8.2.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.2.3.1 KEREPEHI NEW 11KV FEEDER

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KEREPEHI NEW FEEDER	GRO	$1,800	2022-2024

Network issue

Ngatea feeder (KPE6) has an ICP count well in excess of the targeted maximum for its respective security level. The feeder is highly loaded and has insufficient capacity for growth – a new subdivision in Ngatea, of ~100 lots, has been approved by Hauraki District Council, and Muggeridge canal pumps on Kaihere Rd. Furthermore, the feeder has low voltage issues at the Hopai West Rd and struggles to provide backfeed capacity to adjacent 11kV feeders.

Options

1. Install DG or battery energy storage.
2. Install new 11kV feeder.

Preferred option

The preferred solution is option 2, to install a new feeder to cater for future load growth and split the existing KPE1 & KPE6 11kV feeders, which will improve the reliability of the feeders.

A DG solution is being considered at Kerepehi substation, with the ability to island and peak lop. However, this option is not economical for a feeder solution as it does not offer the flexibility of reconfiguring the existing network.

A8.2.3.2 COROMANDEL SUBSTATION ALTERNATIVE SUPPLY

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
COROMANDEL DISTRIBUTED GENERATION	GRO	$3,000	2025-2027

Network issue

Coromandel substation is supplied via a single 66kV circuit and an outage on this circuit results in the loss of supply to Coromandel substation. The 11kV backfeed from Thames is limited. In recent years, there have been a number of subtransmission outages resulting in loss of supply at Coromandel substation. Some of these outages have been for longer than 30 minutes.

Options

1. Second 66kV circuit to the Coromandel substation.
2. Install distributed generation (DG).

Preferred option

The preferred solution is to install a DG system that will offer backup, peak lopping, and be future proofed to provide grid scale microgrid capabilities until normal 66kV supply is restored to the substation. We intend to apply learnings from the DG/BESS (Battery Energy Storage System) project in Whangamata here, as it shares similar characteristics with Coromandel. This solution is currently being rolled out as part of Project CORE to test whether it is feasible.

Option 1, to build a second circuit to Coromandel, is unlikely to be economical.

A8.2.3.3 MATATOKI NEW 11KV FEEDER

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATATOKI NEW FEEDER	GRO	$1,360	2021-2023

Network issue

Matatoki feeder (MAT1), which mainly feeds the Kopu area, is highly loaded and has insufficient spare capacity to cater for growth. It also struggles to provide backup to adjacent 11kV feeders; Kerepehi (KPE3) and Thames (THS2).

Options

1. Install DG or BESS.
2. Install new 11kV feeder.

Preferred option

The preferred solution is option 2, to install a new feeder to split existing MAT1 feeder to cater for future load growth and improve reliability for KPE3 & THS2 feeders. This will also help backup during an outage to Matatoki substation by improving transfer capacity from Kerepehi to Matatoki.

A8.2.3.4 THAMES NEW 11KV FEEDER

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
THAMES NEW FEEDER	GRO	$3,430	2025-2027

Network issue

The existing 11kV feeders to Rolleston St and Thames Coast (THS1 & THS4) have ICP counts well in excess of the targeted maximum for their respective security levels. The feeders supply the northern area of Thames, are highly loaded, and backfeed capability is constrained. The existing cable between Tararu and Ngarimu Bay, ≈4km in length, is 1970s vintage cable with suspect cross-linked poly ethylene (XLPE) quality.

Options

1. Install DG or BESS.
2. Install new 11kV feeder.

Preferred option

The preferred solution is option 2, to install a new 11kV feeder to split THS1 and THS4 feeders. This option will improve backfeed capabilities to the adjacent 11kV network feeders in Thames and Coromandel. This option also takes into consideration condition-based replacement of the existing feeder vintage cable with suspect XLPE quality.

A8.2.3.5 COLVILLE-TUATEAWA 11KV LINK

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
COR1-COR7 11kV LINK	GRO	$1,770	2025-2027

Network issue

There is approximately 22km and 14km of 11kV overhead line on the Colville (COR1) and Kapanga Rd (COR7) feeders respectively. Neither of these feeders has backup during fault situations on the overhead (OH) line and any future planned renewal work would require substantial generation to reduce SAIDI impact.

Options

1. New 11kV overhead/cable link between Colville and Kapanga Rd feeder.
2. Install 2.5MVA generation. 1.25MVA unit for each feeder.

Preferred option

Currently, the preferred option is to construct a new 11kV overhead/cable link approximately 4.4km in length between Colville and Kapanga Rd feeders. This will create a backup link between these two feeders during fault and routine maintenance. The generation option is not preferred as it will involve locating smaller scale generation units at dispersed locations, which may potentially cause consenting difficulties and risks.

A8.3 WAIKINO

A8.3.1 SUBTRANSMISSION NETWORK PROJECTS

A8.3.1.1 WAIHI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33kV INDOOR SWITCHBOARD AT WAIHI SUBSTATION	GRO	$4,314	2021-2023

Network issue

The Waihi Beach supply is via a spur teed off one of the Waikino GXP-Waihi 33kV overhead circuits. Supply for Waihi Beach is lost if a fault anywhere on the overhead Waikino-Waihi Beach-Waihi 33kV circuit occurs. Conversely, a fault on the 33kV spur line to Waihi Beach will result in Waihi substation running on N (single redundancy) security.

Furthermore, the loss of the Waihi Beach spur may cause the parallel Waikino-Waihi 33kV circuit to overload at high loads, resulting in the need to shed Waihi Gold Mine load at Waihi to resolve the overloading.

Options

1. Extend 33kV outdoor bus to accommodate new bay for the Waihi Beach circuit. Install new 33kV cable from Waihi to the Waihi Beach tee-off to create dedicated Waihi-Waihi Beach circuit. Install a recloser (normally open) at the tee to allow remote reconfiguration of the network in the event of a cable fault or cable maintenance. This option requires an extension to the site.
2. Install a new 33kV indoor switchboard in a separate switchroom located next to the existing 11kV switchroom. Remove existing outdoor 33kV buswork. Install a new 33kV cable from Waihi to the Waihi Beach tee-off to create a dedicated Waihi-Waihi Beach circuit. Install a recloser (normally open) at the tee to allow remote reconfiguration of the network in the event of a cable fault or cable maintenance.

Preferred option

The preferred solution is to build a new 33kV indoor switchroom at Waihi (option 2). This will consolidate all existing outdoor switchgear into a modern indoor equivalent, which will free up space on the existing site and enhance safety. To give Waihi Beach a dedicated supply, a new 33kV cable will be laid from the new switchboard to the existing tee-off to create a new Waihi-Waihi Beach 33kV circuit. This option is the lowest cost option and has considerable safety and operational benefits compared to the option of extending the outdoor bus work.

Powerco has already acquired the adjacent land near Waihi substation for the 33kV indoor switchroom and the detail design for the 33kV indoor switchroom is under way, which will also allow for a future 33kV capacitor bank to address voltage issues. Refer to below network issue.

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33kV CAPACITOR AT WAIHI SUBSTATION	GRO	$1,170	2026-2027

Network issue

An outage on either of the Waikino-Waihi circuits can cause low voltage levels at Waihi, Whangamata and Waihi Beach during high load periods. The post-contingent voltage step change is excessive. This voltage constraint means Powerco cannot meet voltage regulation and voltage quality requirements.

Options

1. Install an outdoor 33kV shunt capacitor bank at Waihi substation.
2. Install dynamic reactive support (STATCOM) at Waihi substation.
3. Install 11kV capacitors across the distribution network.

Preferred option

The preferred solution is option 1, which is to install a 12MVAR switched multi-staged capacitor bank at Waihi 33kV bus to provide voltage support in the area.

Option 2, to install a STATCOM will be much more expensive, although it will offer faster response compared to the capacitors.

Option 3, to install more 11kV capacitors across our distribution network, will not be as economical compared to option 1. It also introduces a higher risk of network overloads particularly in areas where the fault level is weak. There will also be increased risk of amplifying harmonic distortions across the network because of resonance.

A8.3.2 ZONE SUBSTATION PROJECTS

A8.3.2.1 WAIHI BEACH SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WAIHI BEACH REPLACE 11kV SWITCHBOARD & SWITCHROOM	ARR	$1,960	2021-2023
WAIHI BEACH SECOND TRANSFORMER	GRO	$2,400	2021-2023
DISTRIBUTED GENERATION	GRO	$1,800	2023-2025

Network issue

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.

Waihi Beach substation is supplied via a single subtransmission circuit and an outage on this circuit does not meet our security class supply standards. One of the key 11kV backfeed supplies to Waihi Beach substation is underbuilt on the subtransmission circuit. This results in a high risk of failure that causes an outage to both circuits.

Options

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.
4. New 33kV circuit from Waihi substation to Waihi Beach substation.
5. Standby DG at Waihi Beach substation.

Preferred options

The proposed solution is to upgrade the Waihi Beach substation, resolving both network and fleet issues. Option 3 is to install an additional transformer, currently at Lake Rd substation, which is a match for the existing transformer and will increase the substation installed capacity. Conversion of outdoor equipment to indoor will free up space to accommodate future project option 5, to install backup DG. The DG would be remotely operable and will support load during an outage. It is not economic for an additional second 33kV circuit because of the small load at risk.

Fleet issue

The Waihi Beach 11kV switchroom has a seismic strength of 55% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Waihi Beach substation does not meet modern arc flash standards, has oil quenched circuit breakers and electromechanical relays. The existing switchroom will have to be extended to enable additional 11kV feeders, incomers and bus section breakers to allow for the second transformer. The 33kV outdoor buswork does not meet modern ground clearance standards.

Options

1. Seismically reinforce the existing switchroom, refurbish the existing 11kV switchgear, demolish the toilet and extend the switchroom. Replace the existing 33kV outdoor circuit breaker, increase the 33kV bus ground clearance, extend the bus and install an additional 33kV bus section breaker and two 33kV transformer breakers
2. Build a new combined 33kV and 11kV switchroom, install new 11kV and 33kV switchgear in the switchroom.

Preferred option

The preferred option is to construct a new combined 33kV and 11kV switchroom with new indoor 33kV and 11kV switchgear and associated equipment (option 2). This will align with the network preferred option and will free up space in the switchyard for future diesel generation and allow for additional 11kV feeders, incomer circuit breakers, diesel generation connection circuit breakers and bus section circuit breakers.

A8.3.2.2 WHANGAMATA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHANGAMATA SEISMIC STRENGTHENING, REFURBISH 11kV SWITCHBOARD	ARR	$732	2023-2025

Fleet issue

The Whangamata 11kV switchroom has a seismic strength of 15% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Whangamata substation does not meet modern arc flash standards, and has a mixture of vacuum and oil circuit breakers. It has modern protection relays.

Options

1. Seismically reinforce the existing switchroom to 67% NBS and refurbish the existing 11kV switchgear, including arc flash protection.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 1, to seismically reinforce the switchroom and refurbish the 11kV switchgear, as this will optimise risk reduction vs capital expenditure.

A8.3.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.3.3.1 WHANGAMATA-TAIRUA 11KV LINK

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WGM3-TAI3 11kV LINK	GRO	$1,860	2021-2024

Network issue

There is a single 33kV circuit (N-security) supply to Whangamata. Any outage on this circuit results in an immediate loss of supply to Whangamata substation and, therefore, loss of supply to the Opoutere feeder (WGM3).

Planned maintenance outages on 11kV network. There is approximately 32km of 11kV overhead line in Opoutere feeder with 642 ICPs and approximately 54km of 11kV overhead line in Hikuai feeder (TAI3) with 274 ICPs. Both these feeders have no backup during fault situations and any future planned renewal work would require substantial generation to reduce SAIDI impact.

Options

1. New 11kV overhead/cable link between Opoutere and Hikuai feeder.
2. Install 2MVA generation. 1MVA unit for each feeder.

Preferred option

The preferred option is to construct a new 11kV overhead/cable link approximately 4km in length between Opoutere and Hikuai feeder (option 1). This will create a backup link between these two feeders, which means during an outage to Whangamata subtransmission circuit, supply to Opoutere feeder will be maintained from Hikuai feeder and BESS32 will supply Whangamata Hetherington feeder. This link would reduce SAIDI impact for the planned overhead line renewal projects.

The generation option is not preferred as it will involve locating smaller scale generation units at dispersed locations, which may potentially cause consenting difficulties and risks.

32 Powerco 2019 AMP – Whangamata backup supply project BESS (Battery Energy Storage System).

A8.4 TAURANGA

A8.4.1 SUBTRANSMISSION NETWORK PROJECTS

A8.4.1.1 OMOKOROA CAPACITY REINFORCEMENT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OMOKOROA 33kV REINFORCEMENT	GRO	$10,036	2021-2023

Network issue

The region to the north-west of Tauranga is supplied by a 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 makes up two predominantly overhead circuits, approximately 12km long, that run north-west to Aongatete. Two tee-offs from these circuits supply Omokoroa. The peak load on these lines is approximately 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 thermal overload constraint.

The four substations supply a mix of both urban and rural land. The rural areas include small-holdings, market gardens, lifestyle blocks and kiwifruit orchards, which are expected to experience significant growth. In recent years, there has been rapid development of residential subdivisions, particularly in Omokoroa and Katikati.

The following constraints/issues exist:

3. The combined peak demand of all four substations is projected to exceed the N-1 thermal ratings of the uprated 33kV overhead lines between Greerton and Omokoroa, again breaching our security standards.
4. During outages of one of the Greerton-Omokoroa circuits, the 33kV voltages at Katikati and Kauri Pt substations are low, resulting in the 33/11kV zone transformer tap-changers exceeding their tap range during periods of high load.
5. 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 prone to sympathy tripping because of mutual coupling.

Options

Both non-network and network options have been considered to manage or resolve the existing constraints. Generation options are conceptually feasible but can only address the security issues if implemented at a large scale and use non-renewable energy sources. Solar photovoltaic (PV) generation, if combined with energy storage, could also address the N-1 capacity limitations, but would be unlikely to keep pace with the high growth anticipated.

Neither generation nor demand side responses, already a component of our network strategies, would provide the capacity necessary. As such, the following shortlisted options all contemplate major infrastructure upgrade. This included a review of our regional development path, and the consideration of transmission and GXP options.

The following network solutions were shortlisted:

1. Construction of a third Greerton to Omokoroa 33kV overhead line.
2. Construction of a new Greerton to Omokoroa 33kV underground cable circuit.
3. Upgrade of the existing Greerton to Omokoroa 33kV overhead line circuits.
4. Construction of a new 110kV overhead line spur from 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 third circuit using underground cable, is preferred because:

- Acquiring and consenting a new overhead line route (option 1) via either public road (including state highway) or private land (intensive horticulture or lifestyle) would be very challenging.
- Further upgrade of the existing lines (option 3) would require substantially larger conductor, invoking considerable design, property and consenting costs.
- The concept of extending the footprint of the 110kV grid (option 4) was examined in the wider context of possible links right through to 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.

Board approval has been granted and work is expected to start for option 2 in early 2021. Early indications suggest that the project will be completed as scheduled during the first quarter of 2023. The potential risk will be mitigated in the interim by a routine project that will address the post contingency voltage collapse, which could occur at Aongatete, Katikati and Kauri Point substations. This will be achieved through installation of two sets of 5MVA capacitor banks installed at Aongatete 33kV bus. One set will be permanently connected and the other will be switched, in the event of loss of supply.

A8.4.1.2 TAURANGA GXP CAPACITY UPGRADE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAURANGA-KAITIMAKO THIRD 110kV CIRCUIT	GRO	$26,000	2022-2032

Network issue

Tauranga GXP supplies 11 zone substations, with an area of supply covering the greater Tauranga region up to Kauri Point, north-west of the city. Several significant development projects planned within the Tauranga area of supply would add additional load to the subtransmission network.

- Urban intensification planned for Te Papa Peninsula – the district council will encourage mixed-use residential and multi-storey buildings.
- Tauriko Business Park has seen significant growth in the past, with more commercial/industrial developments planned for the next few years.
- Tauriko West Housing development would add 3,000-6,000 new residential sections within the planning period.
- Omokoroa has experienced significant growth recently. There would be approximately 2,500 new residential sections added within the planning period. Shopping districts, commercial and industrial zones are also planned for the area.
- The suburb of Ohauiti will have 1,600 new residential sections added within the planning period.

The increase in demand will exceed the firm capacity of the two existing 110/33kV transformers and subtransmission circuits currently supplying Tauranga GXP. Pyes Pa substation can be transferred to Kaitimako but this will only temporarily defer the constraint.

In addition to the forecasted growth exceeding the firm capacity at Tauranga GXP, fault levels at Transpower's Tauranga GXP 11kV bus are too high, despite series reactors being installed at the bus to lower the fault level. This poses a potential health and safety risk to the public, and could also generate stress on equipment because of the high fault duty. Reduction of earth fault level can be achieved by replacing the two existing small impedance 110/11kV transformers with 33/11kV units. However, this means additional load is transferred to the two existing 110/33kV transformers.

Options

1. Construct a new 33/11kV substation near Maleme St supplied from Kaitimako GXP, and transfer Tauranga 11kV GXP load to the new substation.
2. Construct a new 110/33kV substation at Greerton switching station.
3. Upgrade the 110/11kV transformers at Tauranga GXP.
4. Re-conductor existing 110kV dual circuits from Kaitimako to Tauranga GXP.
5. Install a third 110/33kV transformer. Install an additional third 110kV circuit from Kaitimako GXP to Transpower's Tauranga 33kV GXP. Install new 33/11kV transformers at Tauranga GXP and decommission the 110/11kV transformers.

Preferred option

The preferred long-term solution being explored is option 5. A feasibility study is currently under way to determine physical constructability, potential underground cable routes, equipment layout and preliminary project estimates. This option provides the necessary capacity to reliably cater for Tauranga's growth during the planning period, while also reducing the high earth fault level at Tauranga 11kV substation. Short to medium term options to mitigate the load increases suggest use of a special protection scheme to shed load or a variable line rating approach.

The above-mentioned options are typically within the purview of Transpower to explore and progress. Transpower has no long-term plans to improve the 110kV circuit or transformer capacity at Tauranga GXP. Tauranga GXP is supplied off a spur from Kaitimako and does not meet Transpower criteria for investment. Transpower has indicated that should any upgrades be necessary within the planning period, it would ultimately be a customer funded initiative.

A8.4.2 ZONE SUBSTATION PROJECTS

A8.4.2.1 AONGATETE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
AONGATETE REPLACE 11kV SWITCHBOARD AND OUTDOOR 33kV SWITCHYARD	ARR	$5,842	2024-2025

Fleet issue

The Aongatete 11kV switchroom has a seismic strength of 15% NBS, which is below the 67% NBS value required for seismic compliance. The existing 11kV switchboard does not meet modern arc flash standards and has oil circuit breakers with electromechanical relays.

The 33kV outdoor switchyard has oil circuit breakers that are due for replacement. Arranging 33kV outages for switch, bus and insulator maintenance is problematic.

Options

1. Seismically reinforce the existing switchroom and refurbish the existing 11kV switchgear, including arc flash protection. Upgrade and extend the existing outdoor 33kV bus, including new 33kV circuit breakers.
2. Build a combined 11kV and 33kV switchroom and install indoor arc flash compliant 11kV and 33kV switchgear. Dismantle the existing 33kV outdoor switchyard to make more space available for additional 33kV circuits, capacitor banks and transformer bank upgrades.

Preferred option

The preferred solution is option 2, to build a combined 11kV and 33kV switchroom with new 11kV and 33kV switchgear. This will align with Network Development priorities as additional 33kV and 11kV circuits are required to meet projected demand growth and security of supply criteria for Aongatete, Katikati and Kauri Point zone substations.

A8.4.2.2 MATUA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATUA SECOND TRANSFORMER MATUA	GRO	$2,400	2026-2028
SWITCHROOM SEISMIC REINFORCEMENT, 11kVSWITCHBOARD REFURBISHMENT	ARR	$1,220	2025-2026

Network issue

Matua zone substation provides supply to the residential suburb of Matua. There are five existing 11kV feeders emanating from the substation serving 4,525 ICPs. Matua substation is classified as AA in terms of network security criteria because of the nature and magnitude of the supplied load. Matua zone substation is normally supplied by one 12.5/17MVA 33/11kV transformer with a 5MVA unit on hot standby. The 5MVA unit is unable to completely support the Matua load at high load periods should a problem occur on the 12.5/17MVA transformer or the subtransmission line. The 5MVA transformer is scheduled to be refurbished and kept in store in 2021, making room for the future 2nd transformer. Existing 11kV backfeed capacity is sufficient to fully support the existing load, and it also involves multiple switching movements on the 11kV network to restore supply. With forecasted load growth, 11kV restoration will cause constraints at Otumoetai and Hamilton St substations. It is probable that demand on Otumoetai and Hamilton St substations will reach a level (16.5 and 15.5MVA respectively) that may cause constraints by backfeeding Matua's full load by 2026.

Options

1. Upgrade the 5MVA transformer to 12.5/17MVA capacity.
2. Increase 11kV inter-tie capacity.

Preferred option

The preferred solution is option 1, which is to replace the 5MVA transformer with a new 12.5/17MVA unit to match the existing unit. There is a 33kV-capable circuit that is energised at 11kV, supplied from Otumoetai substation, which provides the primary backup to Matua. When the new transformer is installed, this backup feeder will be re-energised at 33kV, and the 33kV configuration at Matua will change to become transformer feeders supplied from Otumoetai.

Fleet issue

The Matua 11kV switchroom has a seismic strength of 50% NBS. The existing 11kV switchboard at Matua substation does not meet modern arc flash standards, has a mixture of vacuum and oil circuit breakers, and has electromechanical protection relays.

The 5MVA transformer (currently on hot-standby) is the only transformer on the eastern network that is unbunded. Because of observed leaks and the cost involved to remove, repair and construct a bund suitable for the larger transformer that would be installed, it is uneconomic to return the transformer to service. It will, however, be refurbished and kept at Brown Rd substation for emergency use. This will address the environmental and operational risk presented by leaving the transformer without a bund.

Options

1. Seismically reinforce the existing switchroom and refurbish the existing 11kV switchgear, including arc flash protection.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 1, to reinforce the existing switchroom and refurbish the existing 11kV switchgear, as this option will maximise risk reduction vs capital expenditure.

A8.4.2.3 BETHLEHEM SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BETHLEHEM SECOND TRANSFORMER	GRO	$1,589	2023-2025

Network issue

Bethlehem zone substation provides supply to the residential suburb of Bethlehem. There are six existing 11kV feeders emanating from the substation, serving 3,620 ICPs. Bethlehem substation is classified as AA+ in terms of network security criteria because of the nature and magnitude of the supplied load. Bethlehem zone substation is supplied by one 16/24MVA 33/11kV transformer, with provision having been made for a second transformer. An outage of this transformer or subtransmission line causes loss of 33kV supply. Existing 11kV backfeed capacity is insufficient to support the entire load and involves extensive switching on the 11kV network to restore supply.

Options

1. Install a second transformer at Bethlehem substation.
2. Increase 11kV inter-tie capacity.

Preferred option

The preferred solution is option 1, to install a second 16/24 MVA 33/11kV transformer at Bethlehem substation, which will provide backup to the existing unit. This is the most effective method to ensure that the load is restored within the time period corresponding to the substation's security class, while also catering for future growth in Bethlehem.

A8.4.2.4 WELCOME BAY SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WELCOME BAY 11kV SWITCHBOARD REFURBISHMENT	ARR	$852	2025-2026
WELCOME BAY 33kV REINFORCEMENT	GRO	$5,390	2028-2032

Network issue

Welcome Bay zone substation is supplied from Kaitimako GXP via two 33kV overhead circuits. One of these circuits has a teed connection that supplies Atuaroa zone substation. This circuit is only used during a contingent event of a loss of supply at Atuaroa. Based on growth forecasts for the area, by about 2028, an outage on either of these 33kV circuits will cause the parallel circuit to operate above its rated capacity. At present, the existing 11kV backfeed has enough capacity to support the load during an outage of one Welcome Bay supply transformer or an outage of one of the 33kV circuits. However, this will be difficult further in the planning horizon with backfeed capacity eroded because of load growth.

Options

1. Increase 11kV backfeed capacity from adjacent substations.
2. Upgrade the existing subtransmission capacity supplying Welcome Bay substation.
3. Construct a new third 33kV circuit from Kaitimako GXP and improve security at Welcome Bay substation by installing a 33kV solid bus.

Preferred option

Currently, the preferred solution is option 3, to construct a third circuit from Kaitimako GXP to Welcome Bay substation. To accommodate the third circuit as well as improve security for Welcome Bay, a 33kV solid bus will be implemented at Welcome Bay substation. The third Kaitimako GXP-Welcome Bay circuit will resolve the N-1 capacity issue going beyond the planning horizon.

Option 1, to increase 11kV backfeed capacity from adjacent substations, will be costly, ineffective and uneconomical in the long run, so is not preferred.

Option 2, to upgrade the existing subtransmission capacity of the Kaitimako GXP-Welcome Bay circuits, is a viable option but will not facilitate a secure supply for the future second substation in Welcome Bay. Therefore, it is not preferred.

In the long term, we propose to install a new 33kV switchboard at Welcome Bay and to construct a new zone substation in the area to the east of the current substation. This will cater for ongoing residential development and reduce overall customer numbers per feeder. The existing tee connection off the 33kV circuit to Atuaroa will be removed and a 33kV circuit extended to Welcome Bay substation to enable a dedicated circuit to supply the proposed second substation in the Welcome Bay area out of the existing Welcome Bay substation.

Fleet issue

The Welcome Bay 11kV switchroom has a seismic strength of 82% NBS, and is not an earthquake risk. The existing 11kV switchboard at Welcome Bay substation does not meet modern arc flash standards, has a mixture of vacuum and oil circuit breakers, and has electromechanical protection relays.

Options

6. Supply the area from a new zone substation if the present Welcome Bay zone substation landowners are unable to extend the current lease or sell the land to Powerco.
7. Refurbish the existing 11kV switchgear, including installing new arc flash protection.
8. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 2, to refurbish the existing 11kV switchgear, as this will maximise risk reduction vs capital expenditure. This option may not allow for future additional 11kV feeder circuit breakers to be added to the switchboard without extending the switchroom. Powerco does not own the land on which the Welcome Bay zone substation is located. Any expenditure at Welcome Bay zone substation will require land ownership to be confirmed before commencing construction works at the site.

A8.4.2.5 OMOKOROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OMOKOROA SUBSTATION UPGRADE	GRO	$2,684	2026-2028

Network issue

As part of the Northern ring reinforcement, additional capacity in the form of a third circuit will be commissioned between Greerton and Omokoroa. Currently, it is not possible to terminate the proposed circuit at the substation because of coinciding works with the New Zealand Transport Agency (the Takitimu North Link road project), which may require the relocation of the entire substation. There would not be enough space in the current outdoor 33kV circuit breaker arrangement to cater for the full configuration of eight 33kV circuit breakers and bus section.

Options

1. Install the switchboard and lay the cables to the substation.
2. Await finalisation of the Takitimu North Link route and confirmation of the substation final position before completing the cabling and switchgear work.

Preferred option

Option 2 is preferred because of the cost saving and practicality. This option will result in increased capacity to the Omokoroa area. More reliability and greater flexibility can be achieved once the existing tee-offs are removed and the proposed third circuit is accommodated in a new 33kV switchroom. Allowance will also be made to link the proposed Pahoia substation to Omokoroa substation. This may be possible due to the Takitimu North Link road passing the existing substation and ending at the proposed new one.

A8.4.2.6 PAHOIA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAHOIA ZONE SUBSTATION	GRO	$6,406	2023-2028

Network issue

Omokoroa substation (OMO) provides supply to the residential suburb of Omokoroa. There are six existing 11kV feeders emanating from the substation, serving 3,705 ICPs. Omokoroa is classified as AA in terms of network security criteria because of the nature and magnitude of the supplied load. Omokoroa zone substation is normally supplied by two 10/12.5MVA 33/11kV transformers and is almost at the firm capacity of the substation. The suburb is experiencing significant residential development, with 2,500 new homes expected to be constructed during the next five years. In addition, there is a new town centre planned for the area, along with two new schools, commercial and industrial areas. The existing Omokoroa substation will become capacity constrained by the proposed new developments. As a result, existing 11kV feeders will encounter capacity and low voltage issues, which worsen during backfeeds. There is also a significant existing industrial load (Apata cool store) supplied by the substation.

Options

1. Staged construction of new 11kV feeders from Omokoroa substation to the area to support growth.
2. Build a new substation in the Pahoia vicinity supplied off one of the Omokoroa-Aongatete 33kV circuits.

Preferred option

Option 2 is preferred, primarily to offload the existing substation and reinforce the 11kV network surrounding the developing load centre. Option 1 is not preferred, as 11kV infrastructure development will likely be more expensive and will not provide the same capacity boost of the substation-based options. Timing of the project is customer load-driven, and we will continue to assess the situation in order to ensure a cost effective solution is achieved that reflects our customers' requirements.

A8.4.2.7 BELK RD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BELK RD SUBSTATION	GRO	$14,605	2022-2027

Network issue

The suburbs of Pyes Pa and Tauriko are supplied from Pyes Pa and Tauranga 11kV substations. Because of the existing load and distance from Tauranga 11kV substation, very little additional capacity can be utilised to support growth in Pyes Pa. The area is primarily urban residential subdivisions, mixed with commercial and industrial developments. Pyes Pa substation is relatively new and has available capacity. Load uptake in the Pyes Pa/Tauriko industrial park is increasing rapidly because of the strong economy in the region. District council plans show potential for 3,000-6,000 new residential developments in the vicinity of Belk Rd, Keenan Rd and Tauriko West. The additional load would bring Pyes Pa to its firm load within the planning period. Tauranga City Council has confirmed its decision to intensify development in the Tauriko area as opposed to Welcome Bay, because of the existing infrastructure being capable of supporting growth. Significant investment in roads, and land settlements are required at other locations.

There are several industrial and commercial developments in the vicinity of the Belk Rd area. A major customer-initiated works (CIW) project is scheduled to be completed in January 2022. A large wallboard factory is being constructed in the Tauriko Business Estate with a connected capacity of 9.5MVA. The existing Pyes Pa substation can reliably supply the wallboard factory. However, as the residential development is completed, demand will exceed the firm load of Pyes Pa substation, breaching Powerco's network security criteria.

Options

1. Install larger power transformers at Pyes Pa substation.
2. Install two new 33kV circuits from Tauranga 33kV substation and commission a new zone substation within the vicinity of the proposed load centre.
3. Install one new 33kV circuit from Tauranga 33kV substation to Pyes Pa. Consolidate the two existing 33kV circuits with a solid bus, to supply Pyes Pa and Belk Rd substations.
4. Install new 33kV circuits from Kaitimako 33kV substation and commission a new zone substation within the proposed load centre.

Preferred option

Option 2 is the preferred solution. The potential for rapid growth within the planning period necessitates the need for a second substation to reinforce Pyes Pa substation. Significant industrial and residential growth is forecast for the area, with the possibility to expand further into the upper Belk Rd area outside of the planning period. One 16/24MVA transformer would be installed at Belk Rd to support the rapidly developing area. As the region develops, a second transformer can be installed to maintain network security.

Option 1 would require significant investment towards new 11kV feeders and would not be as beneficial. Option 3 would require either significant alterations to the existing Pyes Pa substation or an entirely new site and building to accommodate a 33kV switching station, in addition to the construction of Belk Rd substation. Option 4 is a much longer cable route, driving the project cost up and posing more difficulty in attempting to install new circuits along a state highway.

A8.4.2.8 OROPI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OROPI SUBSTATION	GRO	$9,471	2024-2027

Network issue

The suburb of Oropi, south of Tauranga, and its surrounds are supplied from long 11kV feeders out of Welcome Bay substation. The area has historically been predominantly used for rural lifestyle, mixed with horticulture farming. In recent years, strong growth in Tauranga has seen the development of new residential subdivisions in the region. Consequently, this is putting pressure on the existing 11kV infrastructure to maintain security of supply and support the growing demand.

A recent study commissioned by Tauranga City Council has deferred the additional residential development plans for Welcome Bay suburb because of the extensive infrastructure investment required. However, approximately 1,600 proposed homes will proceed in the upper Ohauiti area. The 11kV network in the vicinity of the proposed development is supplied from Tauranga GXP 11kV substation and Welcome Bay substation. Both these substations are almost at firm capacity and the distance to the proposed development will make backfeeding difficult. The ICP numbers on the existing 11kV feeders at Welcome Bay have exceeded our security standard target levels, bringing associated unacceptable reliability risks. Network automation schemes have been installed to try to mitigate the SAIDI issue, but backfeed capacity remains limited because of voltage constraints. Constraints at Welcome Bay will occur as more stages of the residential sections develop.

Options

1. Staged construction of new 11kV feeders to the area to support growth.
2. Build a new substation at Oropi to supply the growing load in the area, and offload demand from Welcome Bay and Tauranga GXP 11kV substations.

Preferred option

Option 2, to build a new substation at Oropi, is the preferred solution as it will not only increase supply capacity in the region, but will also improve reliability issues by shortening the 11kV feeder circuits (reducing ICPs per feeder), maintaining the network security criteria for residential loads, and increase backfeed capacity. The new substation will be supplied via 33kV subtransmission cables either direct from Kaitimako GXP or connected to the Tauranga GXP-Kaitimako GXP 33kV circuits. Once commissioned, the new substation will offload demand from Welcome Bay substation.

Option 1 is not preferred as 11kV infrastructure development will likely be more expensive and cannot provide the same benefits as option 2.

A8.5 MOUNT MAUNGANUI

A8.5.1 ZONE SUBSTATION PROJECTS

A8.5.1.1 ATUAROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ATUAROA SECOND TRANSFORMER	GRO	$1,320	2025
ATUAROA BUS SECURITY UPGRADE	GRO	$2,970	2023-2025

Network issue

At the Atuaroa zone substation, there is a single 12.5/17MVA supply transformer. An outage of the transformer at high load times makes it difficult to backfeed because of limited capacity from adjacent substations. Further load growth will worsen the situation and result in voltage constraints across the 11kV network. The relevant local council has indicated industrial growth in the Te Puke west area and a new industrial zone change at Washer Rd. Local cool stores are expecting major expansion, and new residential subdivisions are also located near the substation. All this load growth puts a significant burden on the single transformer. The existing 33kV subtransmission circuit supplying Atuaroa terminates directly to the transformer. Atuaroa does not have a 33kV bus. This limits options to improve subtransmission security of supply to the substation. This means that Atuaroa substation does not meet Powerco’s security of supply standards.

Options

1. Build new 33kV switchboard at Atuaroa substation and install a second 12.5/17MVA transformer.
2. Increase 11kV backfeed capacity into Atuaroa.
3. Install standby diesel generators within the substation site.

Preferred option

Currently, the preferred solution is option 1, which involves the construction of a new 33kV indoor switchboard and installing a second 33/11kV 12.5/17MVA transformer to parallel the existing transformer at Atuaroa zone substation. The new 33kV switchboard will facilitate the connection of a future 33kV circuit from Te Puke (refer to Atuaroa subtransmission reinforcement project). Option 2, to increase 11kV backfeed capacity from the adjacent substations (Papamoa, Te Puke and Welcome Bay), is not preferred as it is expected to be more expensive compared to option 1. Option 3, to install and run diesel generators on site in the event of an outage to supplement the existing 11kV backfeed, is feasible but not preferred as the substation site is next to a residential zone, causing air pollution and noise. The existing substation site is also space-constrained to make this option impractical.

A8.5.1.2 TE PUKE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TE PUKE BUS SECURITY UPGRADE	GRO	$2,920	2023-2025

Network issue

The Te Puke substation is supplied via two 33kV radial circuits from Te Matai GXP. It has a switched alternative supply from the Te Matai GXP-Atuaroa 33kV circuit. An outage of a Te Matai GXP-Te Puke 33kV circuit also results in an outage of a supply transformer at Te Puke substation, because of the 33kV bus normally operating as a split bus arrangement. The Te Puke region has and will continue to see large growth in the industrial and residential sector. Using our latest forecast from 2026 onwards, an outage of a Te Matai GXP-Te Puke 33kV circuit will cause the parallel circuit to overload. Existing 11kV backfeed capacity is insufficient to support the load. This means that the substation does not meet Powerco's security of supply standards.

Options

1. Construct a third Te Matai GXP-Te Puke 33kV circuit.
2. Implement a secure 33kV bus at Te Puke substation complete with bus zone protection.
3. Increase 11kV backfeed capacity to Te Puke substation.

Preferred option

The cost effective solution is option 2, which is to improve security at Te Puke substation by having a solid 33kV bus. Additional line circuit breakers are required, including a new bus coupler, communications systems upgrade and a fast bus differential protection scheme. The existing Te Matai GXP-Atuaroa 33kV circuit will be terminated to this solid bus, creating three 33kV circuits between Te Matai GXP and Te Puke substation. This project will then facilitate the connection of the proposed Atuaroa second 33kV circuit (refer to Atuaroa subtransmission reinforcement project). Option 1, to construct a third Te Matai GXP-Te Puke 33kV circuit, would be uneconomical and expensive to construct because of difficult terrain and suitable line route. Option 3, to further increase 11kV backfeed capacity, would involve substantial 11kV infrastructure investment and is unlikely to be economical.

A8.5.1.3 PONGAKAWA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PONGAKAWA 11kV SWITCHGEAR RENEWAL	ARR	$2,704	2022-2024
PONGAKAWA SECURITY OF SUPPLY GROWTH	GRO	$5,600	2023-2025

Network issue

The Pongakawa substation is supplied from a single 33kV overhead line from Paengaroa substation. The area supplied by Pongakawa substation is predominantly rural, and the 11kV network is characterised by very long spurs. An outage of either the Paengaroa-Pongakawa 33kV circuit or the Te Matai GXP-Paengaroa 33kV circuit results in a complete loss of supply to Pongakawa. As a result, Pongakawa does not meet Powerco's security of supply standards.

Options

1. Enhance the existing 11kV network from Paengaroa substation to increase 11kV inter-tie capacity to Pongakawa.
2. Install 5MVA of diesel generation at Pongakawa substation.
3. Construct a second 33kV circuit from Pongakawa to Paengaroa substation.

Preferred option

Currently, the preferred solution is option 2, to install 5MVA of diesel generation at Pongakawa substation. This option provides full backup support in a fault scenario. The generation will reduce the long switching time to backfeed Pongakawa in an outage, further reducing outage time.

Option 3 involves constructing a second 33kV circuit from Pongakawa to Paengaroa substation. The major problem with this option is that it is heavily dependent on the timing of the Rangiuru business park, which will provide N-1 security to Paengaroa. The need for this solution is likely to fall before the park is constructed. Without the business park, the line between Te Matai and Paengaroa will still be at risk, effectively keeping both Paengaroa and Pongakawa substations on N-security. This option is not preferred because of the uncertainties and timeline of the Rangiuru business park.

Option 1 initial estimates indicate at least three new 11kV feeders together with voltage regulators would be required to lift 11kV inter-tie capacity and ensure good voltage quality to customers at the remote ends of the network during the backfeed.

High level analysis indicates that the costs associated with this option are likely to make it uneconomical.

Fleet issue

The Pongakawa 11kV switchroom has a seismic strength of 15% NBS, and is an earthquake risk. The existing 11kV switchboard at Pongakawa substation does not meet modern arc flash standards, has oil circuit breakers, and has first generation electronic protection relays that have type issues.

Options

1. Refurbish the existing 11kV switchgear, including installing new arc flash protection.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom.

Preferred option

The preferred solution is option 2, to build a new switch groom and install 11kV arc flash compliant switchgear in the switchroom. This option will allow for additional 11kV feeder circuit breakers to be added to the switchboard, including switchgear for future diesel generation, which will be needed to meet network security of supply standards. Powerco does not own the additional land that will be required to build the switchroom.

A8.5.1.4 PAENGAROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAENGAROA SECOND TRANSFORMER AND BUS EXTENSION	GRO	$1,960	2024-2027

Network issue

Paengaroa substation has only one 12.5/17MVA transformer. The load has started to increase as larger industrial businesses expand into the area. The main cause of load is the horticulture sector, with kiwifruit demand increasing. Local council has also indicated plans for a large future residential development in north Paengaroa near the new business park. The security rating of the substation is AA. If an outage is to occur on the existing transformer, a complete backfeed would need to restore power within 60 minutes. As load continues to increase, the security rating of this substation will evolve to AA+, implying that power would have to be restored within 15 seconds to meet the security class restoration targets.

Options

1. Install a second transformer at Paengaroa.
2. Increase automated 11kV backfeed capacity to Paengaroa.
3. Install generation on-site.

Preferred option

The preferred solution is option 1. A second transformer will provide quick resupply to the 11kV board in a transformer fault scenario. With the increase in recent horticulture demand in the region, a second transformer provides the capacity needed for this growth. Expanding the 33kV bus to fit this transformer will give fast bus protection. This, coupled with the new 33kV capable cable from Paengaroa up Youngs Rd, will offer the substation full N-1 security in the future.

Option 2 increases automated 11kV backfeed capacity to Paengaroa and resolves the restoration of supply constraint. However, it does not provide enough capacity for growth because of 11kV feeder constraints.

Option 3 involves installing diesel generation at Paengaroa to improve response time in a fault scenario. The indicated future increase in load on Paengaroa substation will bring the existing transformer over its installed capacity. For this reason, generation will not be viable as it will need to be run during system normal operation in order to keep supply going. This option is not economical when accounting for these factors compared with the costs of the others.

A8.5.1.5 RANGIURU BUSINESS PARK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW RANGIURU SUBSTATION	GRO	$10,370	2024-2028

Network issue

A proposed 148ha industrial park located at Rangiuru is in council district plans, and is promoted by the Western Bay of Plenty District Council's development arm. Powerco is already conducting preliminary assessments for a new customer connection in the area. Buoyed by strong growth in the local economy, confidence in the development is high. The business park is part of the COVID-19 recovery plan – a shovel-ready project – and has been allocated funding to get civil works under way during the next two years. This also includes connection onto the Tauranga Eastern Link highway, which would help growth take off in the area, barring economic downturn. This project is now seen to be in the medium-term horizon, as load can be initially supported by the existing 11kV and the new Youngs Rd feeder. Although the area is supplied via 11kV feeders from Te Puke substation, future load growth in the area will place significant pressure on the 11kV network to support the expected load increase at the business park.

Options

1. Build new 11kV feeders from Te Puke substation and Paengaroa substation.
2. Construct two new 33kV circuits from Te Matai GXP to a new Rangiuru Business Park zone substation.
3. Construct a new Rangiuru Business Park zone substation via an in-and-out arrangement from one of the Te Matai-Wairakei 33kV circuits.

Preferred option

Currently, the preferred solution is option 3, which involves the construction of a new zone substation at Rangiuru Business Park with its 33kV supply taken from one of the two nearby Te Matai GXP-Wairakei 33kV circuits. Two new 33kV underground circuits cut into the Te Matai-Wairakei 33kV circuit will supply the new substation through an in-and-out arrangement. Currently under construction, there is a 33kV-capable underground cable being installed from Paengaroa to the tee intersection of Maketu Rd and Te Tumu Rd. The cable is initially going to be operated at 11kV until Rangiuru Business Park substation is commissioned. When the new zone substation is commissioned, the cable will be converted to 33kV operation and terminated into the substation, thereby creating a 33kV closed ring arrangement between Te Matai GXP, Wairakei, Rangiuru Business Park and Paengaroa zone substations. The ring will offer N-1 security to both the new zone substation and Paengaroa on the subtransmission network.

Option 2, to build two new 33kV circuits from Te Matai GXP to the new Rangiuru Business Park zone substation, is not preferred as it is expected to be costlier compared with option 3.

Option 1, to build new 11kV feeders, will only provide limited short-term capacity and will not sustain the expected growth in the region going into the future.

The local council has indicated future residential growth in the upper Paengaroa area as well as the business park. Timing of the project is customer driven. Because of COVID-19, the momentum of this project has been sped up as it has been marked as shovel-ready. We will continue to monitor the situation closely.

A8.5.1.6 WAIRAKEI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WAIRAKEI SECOND TRANSFORMER	GRO	$1,308	2021-2022

Network issue

The Wairakei substation has one 16/24MVA transformer. The load within the area continues to increase with new subdivisions, apartments and shopping centres. New feeders have been installed from Wairakei to accommodate growth. The AA security rating for this substation is likely to increase as development in the area expands. Because of this, a faster restoration of supply time will be needed for Wairakei substation.

Options

1. Install a second new 16/24MVA transformer at Wairakei.
2. Increase automated 11kV backfeed capacity to Wairakei.
3. Install standby diesel generators within the substation site.

Preferred option

Option 1, to install a second transformer, is preferred as it is the most economic solution and improves security of supply for the area. A second transformer will allow for uninterrupted supply to customers as a result of a bus section or single transformer fault. Increasing the supply capacity will promote future load growth within the area.

Option 2, increasing automated backfeed into the area, will require at least two new 11kV feeders from Papamoa to cater for existing load. This is a short-term solution and will not provide the value needed to resolve the issue.

Option 3 will provide a means to restore supply during an outage of Wairakei substation, however the generation needed to restore supply during a fault is significant. The economic cost of generation is very large when comparing with option 1.

A8.5.1.7 TRITON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRITON SUBSTATION RENEWAL AND TRANSFORMER UPGRADE	ARR	$6,308	2022-2023

Network issue

The Port of Tauranga has signalled that the development of the eastern port will occur once expansion of the western side is complete. This will likely increase the load significantly beyond the capabilities of the two substation power transformers. To reduce the stress on Triton substation and the existing 11kV network, a third transformer and dedicated feeders will need to be installed to cater for this increase. The timing and contribution of an installation of a third transformer and dedicated feeders to the port will be customer driven.

Fleet issue

The Triton 11kV switchroom has a seismic strength of 30% NBS, and is an earthquake risk. The existing 11kV switchboard at Triton substation does not meet modern arc flash standards, has oil circuit breakers, and electromechanical relays. The existing switchroom has insufficient space for additional 11kV feeder panels to be added to the switchboard. The Triton zone substation supplies the Port of Tauranga, which is the largest port in New Zealand by cargo volume and container throughput.

The site has had numerous issues in recent years, including:

- The existing transformers are N-1 constrained and can supply a maximum of 16MVA in summer before overheating. The present maximum demand is 20MVA.
- The requirement for intensive washing of 33kV outdoor equipment, as Triton is in an industrial and marine environment.

Options

1. Refurbish the existing 11kV switchgear, including installing new arc flash protection. Install two new 24MVA rated power transformers.
2. Build a new switchroom and install 11kV arc flash compliant switchgear in the switchroom. Install two new 24MVA rated power transformers.

Preferred option

The preferred solution is option 2, to build a new switchroom, install 11kV arc flash compliant switchgear in the switchroom and replace the existing transformers with two new 24MVA rated power transformers. The transformers will be supplied by 33kV transformer feeders in the short term, which will ensure that no additional land has to be purchased, and will eliminate maintenance outages on the existing 33kV outdoor bus and incomer circuits.

A8.5.2 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.5.2.1 PAENGAROA-YOUNGS RD

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAENGAROA NEW FEEDER	GRO	$1,909	2021

Network issue

In recent years, the load growth around Youngs Rd has increased, primarily driven by strong horticulture growth and coolstore expansion. Furthermore, the recent approval by the government to develop shovel-ready infrastructure projects as part of the COVID-19 recovery stimulus has accelerated the Rangiuru Business Park development, which will result in increased load on the existing 11kV network. The existing supply in the area is supplied via two 11kV feeders – Kaituna and Rangiuru. Kaituna feeder supplies a large coolstore site as well as the surrounding orchards and farmland. This feeder also has a large expected load increase in 2021. Rangiuru feeder supplies a large industrial customer alongside surrounding orchards and farmland. The Rangiuru Business Park will be developed in the area between Youngs Rd and the Tauranga Eastern Link. To support the strong kiwifruit and horticultural economy generated by the region, the business park is likely to promote the development of more coolstores in the area to further stimulate the export economy.

Options

1. Build new 11kV feeders from Te Puke and Paengaroa substation to support the growth.
2. Construct a new 11kV feeder from Paengaroa using a 33kV-capable cable for future use by a zone substation within the area.

Preferred option

The preferred solution is option 2, which involves installing a 33kV-capable cable operating at 11kV to supply the initial load growth. The 33kV capability provides flexibility to allow for growing load to be supplied in the meantime and reliability in the area to be improved, while maintaining an option to be utilised as a subtransmission circuit at the appropriate time in the future. If load increases further in the area, this cable can be energised at 33kV following completion of the Paengaroa 33kV switchboard project to supply the proposed zone substation at Rangiuru Business Park. As the Rangiuru Business Park and its surrounding land continue to be developed, the 33kV subtransmission will link back to one of the Te Matai-Wairakei cables to form a closed 33kV ring between Wairakei, the proposed Rangiuru Business Park substation, Paengaroa and Te Matai. This ring has multiple benefits of prompting growth in all three substation locations and increasing security of supply to Paengaroa.

Option 1 requires significant 11kV cabling from both Te Puke and Paengaroa in order to keep up with initial growth. This option will require an 11kV bus extension and switchroom expansion at Te Puke to allocate the space for new 11kV feeders. Because of these reasons option 1 does not stack up when compared with option 2.

A8.5.2.2 PONGAKAWA NEW FEEDER

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW FEEDER OFFLOAD ROTOEHU	GRO	$1,487	2024

Network issue

Rotoehu feeder is in Pongakawa at the edge of the Mt Maunganui region. Rotoehu consists of 80 kilometres of overhead lines and suffers from significant voltage drop when backfed from Paengaroa substation. Rotoehu feeder is also listed as the second worst performing feeder within the Mt Maunganui region. Furthermore, Otamarakau feeder, which runs adjacent to Rotehu, is also listed as one of the worst performers in the Mt Maunganui region.

Options

1. Build a new 11kV feeder from Pongakawa substation to split Rotoehu.
2. Install a new voltage regulator in a suitable position.

Preferred option

The preferred solution is option 1, to build a new 11kV feeder, as it will greatly improve the reliability. This option involves splitting Rotoehu by running a new feeder over 4km out of Pongakawa substation. By splitting Rotoehu into two feeders, the reliability issue on this feeder will be reduced during system normal operation. This option will also be used to remove ICPs off Otamarakau and offload them to the new feeder. Overall, a new feeder will greatly improve reliability to the area.

Option 2 will be less costly, however it is not preferable as it will only resolve the voltage issue and not improve the reliability within the area.

A8.5.2.3 PAENGAROA-ROYDEN DOWNS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PAENGAROA NEW FEEDER	GRO	$1,857	2024

Network issue

A large industrial customer connected to Paengaroa substation has indicated to Powerco its expansion plans on the Royden Downs Rd feeder. The increase in load is expected to overload the existing feeder in system normal operation in 2023. Royden Downs Rd feeder is one of the two backfeed links to Pongakawa substation. This increase in load will cause voltage to drop below acceptable levels when using this link, which reduces the backfeed transfer capacity into Pongakawa. This issue makes it increasingly difficult to shut down Pongakawa substation for maintenance without a significant outage to the surrounding area. The Pongakawa generation project will work alongside this project to reduce the transfer capacity needed from Royden Downs Rd in a full Pongakawa substation shutdown. The main driver is the load increase that consumes spare capacity to supply other residential customers along Royden Downs Rd. The expected coolstore load forecast drives the need to do costly conductor upgrades on the existing 11kV feeder. The increasing load also places supply transformer capacity pressure at Paengaroa, which is a large driver for the Paengaroa second transformer project. This project will be customer driven.

Options

1. Build a new 11kV feeder from Paengaroa substation.
2. Re-conductor the existing feeder and install a new voltage regulator in a suitable position.
3. Install local generation at the customer site to provide voltage support and peak lopping during high load periods.

Preferred option

The preferred solution is option 1, to build a new 11kV feeder from Paengaroa substation to the customer. The new feeder will be capable of supplying the customer's indicated maximum demand. By moving the customer's supply off Royden Downs Rd feeder, the backfeed to Pongakawa returns to the status quo. It is more cost effective to build a new feeder dedicated to the customer, with customer contribution to support its expansion plans.

Option 2, re-conductoring the existing feeder, will not be enough to supply the increase in load that has been indicated and backfeed Pongakawa in a fault scenario. Because of this, option 2 is not economic and will require more investment to keep up with future growth when compared with option 1.

Option 3 involves installing diesel generation at the customer's site. This will provide voltage support and peak lopping when the maximum demand of the feeder is breached. Option 3 will only be feasible if the load does not consistently breach the thermal current limit of the existing feeder. If the thermal current limit is exceeded, the generation would need to be run more often to support the coolstore's expansion plans. The load indicated by the customer for 2023 will exceed the conductor thermal current limit of the existing feeder. Therefore, the generation would need to be running during system normal operations, which is more expensive than the original intentions of peak lopping and backfeed support. For this reason, diesel generation has been discounted as an option.

A8.5.2.4 PAPAMOA-REID ROAD

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BRUCE ROAD EXTENSION	GRO	$936	2023

Network issue

Papamoa's Reid Road feeder has very poor reliability, with the highest number of faults in 2019 compared with the rest of the Mt Maunganui region. Local council has indicated large residential growth along the existing Reid Road feeder. The indicated load increase and existing poor reliability of the feeder have flagged this area as a high priority for SAIDI mitigation. The adjacent substation, Te Maunga, has a feeder called Bruce Road, which can take on more load.

Options

1. Build a new 11kV feeder from Papamoa substation to offload Reid Road feeder.
2. Extended Te Maunga substation's Bruce Road feeder to offload Reid Road feeder.

Preferred option

The preferred solution is option 2, to extend Bruce Road feeder along Welcome Bay Road to connect to Reid Road feeder. This will offload some of Reid Road load to the Bruce Road feeder. This option utilises an existing feeder, which has the ability to take more load. This will balance the load between the two feeders, increasing the reliability to the entire area.

Option 1, to build a new 11kV feeder from Papamoa substation to offload Reid Road feeder, would require significantly more cabling down heavy traffic roads and a new circuit breaker at the substation, when compared with option 2.

A8.6 WAIKATO

A8.6.1 SUBTRANSMISSION NETWORK PROJECTS

A8.6.1.1 ARAPUNI-PUTARURU

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PUTARURU GXP	GRO	$25,400	2019-2022

Network issue

Six zone substations with a combined demand of 52.1MW 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 customers, including Fonterra (Waharoa), Fonterra (Tirau), Open Country Cheese (Waharoa), Buttermilk (Putaruru), Icepak (Waharoa) and Kiwi Lumber (Putaruru). During the past decade, the Hinuera GXP has experienced steady growth. A significant portion of the load relates to the dairy industry, which means that the electrical demand peaks in spring/summer. Sustained outages, as have occurred too often in the past, have substantial economic impacts on our customers.

A number of constraints, therefore, apply to this and associated projects:

1. The single 110kV overhead line to Hinuera provides only N-security.
2. The peak demand on the Hinuera GXP is 52.1MW, which exceeds the N-1 capacity of the existing transformers.
3. The load to the north of Hinuera (Waharoa, Walton and Browne St substations), has limited backfeed from Piako, and this does not meet our security criteria.
4. Putaruru substation is supplied via a ≈10km, single circuit, 33kV line.
5. There is limited 11kV backup from the adjacent Tirau substation, which falls well short of that required by our security standard.
6. Maintenance on the 110kV line has been restricted because of constraints on outage windows.
7. Customer feedback in regard to the outages has been understandably strong. The South Waikato District Council has expressed concern over the security of supply to Putaruru and Tirau on a number of occasions.

Options

With only N-security provided by the single 110kV line to Hinuera, alternative transmission circuits or GXPs are the obvious options, and earlier analysis concluded that a new Putaruru GXP was the preferred solution. Constructing a new Putaruru GXP remains our strategic objective, but insurmountable property issues and grid reconfiguration have prompted reviews of available options. These reviews have modified the scope of the Putaruru GXP proposal, both in terms of grid interconnection, and in terms of considering high capacity underground circuits to obviate property issues. The only non-network option that could address the scale of the security issue at Hinuera would be a centralised thermal generation unit. Because of its unique commercial and operating characteristics, this option is not included in the shortlist below, but we will continue to investigate its viability and see if any commercial possibilities become evident.

The following grid/network options were shortlisted:

1. Construct a new Putaruru GXP, connected to an existing Arapuni-Kinleith 110kV line.
2. Construct a new Putaruru GXP, connected to the Arapuni power station at 110kV.
3. Construct a new 110kV circuit from Arapuni power station to Hinuera GXP.
4. Construct a second 110kV circuit from Karapiro power station to the Hinuera GXP.
5. Construct a new GXP at Arapuni power station, and supply Putaruru via dual 33kV circuits.

Preferred option

Option 2 is preferred and involves constructing a new 110kV circuit from Arapuni power station to a new GXP located at Putaruru.

This outcome was confirmed through a collaborative study involving both Powerco and Transpower. This review of options was driven by unexpected changes to the grid configuration, which substantially reduced the benefits of the previously preferred option 1, by introducing constraints on the available offtake capacity from the Arapuni-Kinleith 110kV lines.

Option 2 is now preferred because, in conjunction with upgrades to the 33kV network at Hinuera, Kereone-Walton, Putaruru-Tirau and the recently commissioned underground 33kV link between Browne St and Tower Rd zone substations, it provides appropriate security to all customers currently supplied from the N-security Hinuera GXP. This option also has the lowest estimated cost and is less likely than other options to incur delays or cost escalation because of property or consenting difficulties. Option 2 resolves the limitations on grid offtake capacity imposed by option 1, and also adopts established grid and network architectures, protection and operating standards, including the ability to parallel both GXPs.

The estimated cost of option 4 is high, and it also exposes risks of delay or cost escalation by virtue of challenging property and consenting issues. It would also be necessary to upgrade the Karapiro 110kV bus.

Options 3 and 5 had similar order of cost to the preferred option 2. Option 3 exposes considerable risk around securing property rights and consents for a long overhead line. Option 5 has very similar cost/benefit outcomes to option 2, but does require voltage management under some contingencies, and has lower limits on the capacity when feeding right through to Hinuera from the new Arapuni GXP.

A8.6.1.2 KEREONE TEE-WALTON SUB

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KEREONE-WALTON 33kV SUBTRANSMISSION ENHANCEMENT	GRO	$7,650	2019-2023

Network issue

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 ~53.2MVA of demand.

The option to build a new Putaruru GXP resolves the constraints, in as much as they affect the substations south of Hinuera (Putaruru, Tirau and Lake Rd substations). However, the capacity of the 33kV network is not sufficient to secure the substations north of Hinuera (Browne St and Tower Rd in Matamata and Waharoa). Backfeed to Waharoa and Browne St from Piako GXP is limited by a low capacity 33kV line between Kereone 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. Waharoa alone has seen rapid expansion, and growth is forecast to continue. This does not include an anticipated growth on an existing upgrade to accommodate expansion for Open Country Dairy Ltd.

Because of the speed of growth at Waharoa, it has been necessary to temporarily split the substation bus and feed half the load from each direction. This means different parts of the load are supplied from different GXPs and subtransmission networks, which is operationally undesirable and further degrades reliability.

Walton substation has ageing 33kV and 11kV assets. The existing switchroom housing the old 11kV switchboard is seismically unsafe and due to the age of the building, there is suspect of asbestos board present which complicates modification of the existing building.

Planned renewals of the assets on Walton site will be coordinated with this project (see the separate Walton zone substation project).

During the line survey along Piako-Kereone 33KV line, it was identified that there is a significant amount of ageing overhead infrastructure that does not meet present-day safety standards. The many straight through joints along the route are prone to failure.

Options

Non-network options were considered, but only larger scale non-renewable generation could provide the required no-break security/availability to the industrial load base and flat demand profile. A Cogen arrangement would be the most likely scenario where this might be viable, but no synergistic commercial opportunities to implement a Cogen solution have yet been identified.

The following network solutions have, therefore, been considered:

1. Re-conductor the Kereone-Walton 33kV line and thermal 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 re-conductor Piako-Kereone 33kV line.
4. Re-conductor Piako-Kereone 33KV line, install a new Kereone-Walton 33kV cable, upgrade the assets at Walton site and transfer Walton load permanently to Waihou GXP.

Preferred option

Option 4 is our preferred solution. This makes use of the existing low capacity line to carry Walton load, switching it onto Waihou GXP. The new high capacity cable then feeds Waharoa from Piako GXP. This circuit has enough capacity to backfeed Browne St in Matamata, when supply from Hinuera is unavailable. This also allows us to remove the split at Waharoa bus so that all load is sourced from one GXP. The segment of the overhead circuit between Piako and Kereone will be upgraded and re-conductored through planned renewal in two stages, over FY2022 and FY2023, to improve the reliability of the overhead line section and increase its capacity.

Alternative options 1 and 2 require costly upgrade work to the existing Kereone-Walton line, and still impose severe capacity limitations on backfeed when factoring for future growth. Option 3 provides no greater capacity increase than option 4, but also requires uprating of the existing line between Piako and Kereone. Option 3 is constrained by the capacity of the Piako-Kereone section to support the combined Walton, Waharoa and Browne St loads during backfeed. Option 4 circumvents this problem by a reconfiguration, switching Walton substation onto Waihou GXP, which reduces the overload risk on the Piako-Kereone section.

A8.6.1.3 PUTARURU-TIRAU

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PUTARURU-TIRAU UNDERGROUND CIRCUIT	GRO	$6,700	2019-2023

Network issue

In 2016, Powerco installed a new 33kV underground cable from the Hinuera GXP to the Tirau substation to address an overload on the existing overhead line between the two substations. After the proposed Putaruru GXP is commissioned, insufficient subtransmission capacity remains between Putaruru and Tirau, which restricts the capability to backfeed up to Tower Rd from the new GXP. Voltage constraints will also appear when Tower Rd is backfed from Putaruru GXP.

Options

Both non-network and network options have been considered to manage or remove the existing constraint(s).

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

Currently, the preferred solution is option 2, which involves the installation of a 13km, 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. The dual circuit offers ease of maintenance of the supply circuits to Tirau and Putaruru, and still provides enhanced security to the loads at both substations.

A8.6.1.4 PIAKO GXP-MORRINSVILLE SUB

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MORRINSVILLE SECOND CIRCUIT	GRO	$2,829	2020-2023

Network issue

The Morrinsville substation is fed by a single 33kV circuit from the Piako GXP and only provides N-security. Because of the rapid development of residential subdivisions in the northern side of Morrinsville, as well as the industrial growth on the western side, demand is expected to increase. Ultimately, these issues will add pressure to the existing 11kV infrastructure and subtransmission supply security. Therefore, 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

1. Second 33kV circuit from Piako to Morrinsville. A second circuit (mostly underground cable via road reserve) 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.

Preferred option

The proposed solution is option 1, to construct a second 33kV circuit from Piako GXP to Morrinsville substation. This is both cost effective and provides adequate security at Morrinsville. This is the first stage of an overall bigger scale project to support future growth in this area. This provides deferral options for major Capex investment to upgrade the transformers, switchboards and switchroom.

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 to be too expensive because of the long distance between them. Increased 11kV capacity is viable, but it is operationally more complex for a minimal saving in cost. Backup generation could conceivably be deployed under contingencies, but no opportunities have been identified.

A8.6.2 ZONE SUBSTATION PROJECTS

A8.6.2.1 FARMER RD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WOOD RD SUBSTATION AND SUBTRANSMISSION NETWORK ENHANCEMENT	GRO	$10,300	2022-2023
FARMER RD SEISMIC STRENGTHENING	ARR	$200	2027

Network issue

The dual 5/6.25MVA, 33/11kV transformers at Farmer Rd substation supply the surrounding area and Waitoa Industrial Estate Limited (WIEL). The maximum demand is approaching the transformer firm capacity. Further increase in demand through industrial expansion will breach the security rating of the substation. Customer-driven industrial load increase is forecast to grow rapidly over the short term, triggered by expansion plans at WIEL. The substation and subtransmission network will be overloaded under a system normal situation. Backup supply options are limited, further constraining the ability to support the load increase.

Options

1. Install two identical 12.5/17MVA, 33/11kV transformers at Farmer Rd substation, an additional 33kV underground circuit from Piako GXP to Tatua site, and network reconfiguration.
2. Build a dedicated substation for WIEL along with subtransmission network reinforcement.

Preferred option

The preferred solution for Powerco and the customer is option 2, to construct a dedicated substation to meet the customer demand along with subtransmission network reinforcement. In the interim, a 33kV-rated cable will be installed from Farmer Rd substation to the customer site operating at 11kV to supply the first stage development. Ultimately, this cable will be converted to operate at 33kV to supply the proposed Wood Rd substation once it is established. This option allows the existing load supplied from Farmer Rd to be offloaded to the new substation and transfer the Farmer Rd substation to be supplied from Waihou GXP once the future load increase comes online at WIEL.

Fleet issue

The existing switchroom building is at 35% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom to 67% NBS.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard.

Preferred option

The lowest cost preferred solution is option 2, to seismically strengthen the existing switchroom. Option 3 is not preferred as it will be higher cost than option 2.

A8.6.2.2 HINUERA

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HINUERA OUTDOOR INDOOR (ODID) CONVERSION	GRO	$2,780	2021-2022
HINUERA/LAKE RD 11kV INDOOR SWITCHGEAR	ARR	$676	2021-2022

Network issue

The Hinuera GXP supplies the area around Matamata, Tirau and Putaruru. The network comprises of the following circuits:

1. Hinuera-Lake Rd-Browne St supplies Browne St, half of Waharoa substations.
2. Hinuera-Lake Rd-Tower Rd supplies Lake Rd, and Tower Rd substations.
3. Tower Rd and Browne St underground link.
4. Hinuera-Tirau supplies Tirau and Putaruru substations.

Constraints in the area include:

Single circuit breaker supplying both circuits to Tirau substation (one cable and one overhead line), and that the existing protection system is designed to operate with Hinuera GXP as a source.

To enable close ring operation between Hinuera, Tower Rd and Browne St substations, a high-speed protection system is required. A subtransmission underground link was commissioned recently between Browne St and Tower Rd substations along with fibre. To complete the communications link between the three substations, an underslung fibre on the existing 33kV overhead line between Hinuera and Tower Rd was originally proposed for installation at the same time as the line thermal upgrade. But because of consenting challenges, the underslung fibre was not feasible. A radio communication link is selected as the alternative option to enable the fast protection scheme between Hinuera and Tower Rd.

The outdoor bus at Lake Rd substation contains equipment currently under operational constraint because of safety concerns, and the switchyard earthing does not meet current step and touch potential requirements. The existing indoor 11KV switchgear does not meet modern arc flash standards and is contained in a building that does not meet current standards for operator safety.

Following the commissioning of the Putaruru GXP, and with the scenario of an outage of Hinuera GXP, the Hinuera area subtransmission network, including Tirau, Lake Rd and Tower Rd substations, will have slower tripping times because of the lower fault levels when Putaruru becomes a fault source. Because of these constraints, the required security levels at Lake Rd, Tower Rd, Tirau and Putaruru substations are not met.

Options

1. Extend the existing outdoor 33kV bus at Transpower's site.
2. Construct an indoor switchroom at Hinuera GXP that accommodates a 33/11kV switchboard, capable of fast bus protection to facilitate the connection of the new Hinuera-Tirau underground cable and other circuits.

Preferred option

The preferred solution is option 2. Powerco's original scope was to partially convert the 33kV outdoor yard to indoor to facilitate the connection of the recently installed Hinuera-Tirau 33kV circuit and the additional circuit to Lake Rd. It is also a pre-requisite for the Putaruru GXP project. This approach was based on the original assumption that Transpower had no plans to renew the outdoor 33kV assets within the planning period.

Transpower has since advised that it has scheduled replacement of the outdoor 33kV assets in 2022. Powerco intends to install a second transformer at Lake Rd. Also, the existing transformer at Lake Rd requires its bunding to meet present day standards. The existing 11kV switchboard does not meet arc flash requirements to conform to modern day standards. The existing switchroom at Lake Rd requires seismic strengthening.

As a result, it will be more cost effective for Powerco to carry out the full outdoor-to-indoor conversion and build a new switchroom that will accommodate all the subtransmission circuits that Hinuera GXP supplies and Lake Rd 11KV switchboard.

Fleet issue

The existing 11kV switchboard at Lake Rd substation does not meet modern arc flash standards and has oil quenched circuit breakers. The existing 11kV switchroom seismic capacity is 20% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Refurbish the existing Lake Rd substation 11kV switchboard, including arc flash protection, arc flash doors and end panels. The Lake Rd switchroom will also have to be seismically strengthened as it is 20% NBS.
2. Construct a new 11kV switchroom on the Lake Rd/Hinuera site. The existing Lake Rd substation is adjacent to the new Lake Rd/Hinuera substation site. The new switchroom will be 100% NBS. Install new 11kV switchgear that meets arc flash standards. The installation of the new 11kV switchgear can be combined with the new 33kV switchroom and 33kV switchboard project at Lake Rd/Hinuera.

Preferred option

The preferred solution is option 2, so that the 11kV and 33kV switchroom can be let as a single contract at the new Lake Rd/Hinuera zone substation site.

A8.6.2.3 LAKE RD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
LAKE RD SECOND TRANSFORMER	GRO	$540	2021-2022

Network issue

Lake Rd substation has a single 33/11kV transformer. Substations that could provide backfeed are quite remote, and existing 11kV capacity is not sufficient to meet our security standards and growth forecast.

Options

1. Install a second transformer. It is Powerco's intention to install two refurbished 5MVA transformers at the site. The 2x5MVA transformers still meet the A1 security class of this substation with support from 11kV backfeeds. This also facilitates easier maintenance work. The current transformer will be refurbished and installed at Waihi Beach substation.
2. Increased 11kV backfeed. This is more complex operationally and is expected to be higher cost in light of the large distance to the nearest substations.

Preferred option

The proposed solution is option 1, to install a second transformer. Implementation of this project will be co-ordinated with Hinuera ODID conversion as it is more cost effective.

Fleet issue

See the Hinuera/Lake Rd section for comment on the Lake Rd fleet issues.

A8.6.2.4 MORRINSVILLE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MORRINSVILLE SUBSTATION TRANSFORMER, SWITCHBOARD AND SWITCHROOM UPGRADE	GRO	$10,888	2023-2029

Network issue

Morrinsville substation supplies the township, commercial, residential and surrounding rural area. Major industrial customers include Greenlea Meats processing plant and Fonterra. Fonterra consumes 2.7MVA of the substation's present demand. The Morrinsville area has experienced rapid residential and industrial growth. The growth is expected to continue, and the firm capacity of the transformers has already been exceeded.

Although some backfeed from Piako and Tahuna is available, this is insufficient to meet the growing demand.

Fleet issue

The existing substation is space constrained and will not accommodate larger power transformers. The 11kV switchboard does not have a bus section and the switchboard cannot be extended within the footprint of the existing switchroom.

Options

1. Upgrade substation transformers to 16/24MVA with new 33/11kV indoor switchroom and switchboards on a new site.
2. Increase 11kV inter-tie capacity. This would need at least one high capacity bus tie circuit and substation upgrades.

Preferred option

The preferred solution is option 1, to construct a new switchroom for the new 33kV and 11kV switchboards and install higher rated transformers on a new site. With the new substation, bus section will be installed. This allows the two 33kV circuits from Piako GXP to supply each side of the bus and offer the ease of maintenance work. It is more economical to construct new 11kV feeders out of this new substation than from Piako substation. The intention is to reconfigure the 11kV network to pick up the load that is presently supplied by Piako substation. This will free up some capacity at Piako.

Option 2, to install additional 11kV inter-tie capacity, is limited as backfeed capability of existing donor feeders will continue to deteriorate because of load growth, which effectively means that new feeders will need to be constructed out of Piako and possibly Tahuna zone substations. This is unlikely to be economic because of the great distance and challenges, from a construction perspective.

A8.6.2.5 TATUA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TATUA SUBSTATION TRANSFORMER UPGRADE	ARR	$700	2025-2026

Network issue

The whole Tatua industrial site is supplied via a single bank transformer from Tatua substation. The supply security required by the industry is customer specific. This is a balance between our nominal security standards and the major customer requirements. The backfeed from the neighbouring 11kV feeder is limited and this is not desirable.

With planned expansion of the wastewater treatment plant at Tatua, it is anticipated that the demand will be close to 7.5MVA.The major customer at Tatua has signalled its intention to further expand its wastewater treatment plant during the next few years. Along with the recently planned industrial growth at Farmer Rd, the subtransmission circuit supplying Tatua and Farmer Rd will exceed its capacity. The subtransmission circuit will require upgrade, and the Tatua site will require expansion to improve its security.

Fleet issue

The existing transformer is rated at 7.5MVA, has a maximum demand (MD) of 4.8MVA, and is ranked No 17 in the power transformer condition-based risk management **(CBRM) model.**

Options

1. Replace the existing transformer with a 5/7.5MVA transformer.
2. Replace the existing transformer with a 7.5/10MVA transformer.

Preferred option

The planned date for replacement of the Tatua transformer is at the end of the planning horizon. The decision on the capacity of the replacement transformer will be taken in FY2025 and will depend on any interim demand growth at the adjacent Tatua Co-operative Dairy Company.

A8.6.2.6 TAHUNA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAHUNA SEISMIC STRENGTHENING	ARR	$200	2026

Network issue

Tahuna substation is supplied via a long single subtransmission circuit and 11kV backup is limited. A second subtransmission circuit is likely to be expensive because of the distance involved. Council growth plans proposed for Tahuna in the long term may trigger the need to invest in infrastructure upgrade.

Fleet issue

The Tahuna 11kV switchroom has a seismic strength of 15% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard has previously been upgraded to include arc flash protection.

Options

1. Seismically reinforce the existing switchroom.
2. Build a new switchroom and move the existing 11kV switchgear to the new switchroom or install new 11kV switchgear in the new switchroom.

Preferred option

The preferred solution is option 1, to reinforce the existing switchroom as this will be lower cost than building a new switchroom.

A8.6.2.7 TIRAU SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TIRAU SECOND TRANSFORMER	GRO	$3,275	2021-2022
TIRAU 11kV INDOOR SWITCHGEAR	ARR	$660	2025-2026

Network issue

A single 7.5MVA, 33/11kV transformer supplies Tirau and a large dairy factory. New production facilities will be installed in FY2022 and this will exceed the firm capacity of the substation.

At present, an outage of this transformer causes loss of supply to all customers supplied by the Tirau substation. Existing 11kV backfeed capacity is insufficient to support the Tirau load. This means that the substation does not meet Powerco's security of supply standards.

Options

1. Install a second transformer at Tirau substation and expansion of 33kV and 11kV switchboards.
2. Install a second transformer at Tirau substation and upgrade the existing transformer to a higher capacity unit.
3. Increase 11kV inter-tie capacity.

Preferred option

In line with the dairy factory expansion time frame and the consumption requirement, the option is to install a second 12.5/17MVA, 33/11kV transformer at Tirau substation and extend 33kV and 11kV switchboards as an interim option until an upgrade of the 11kV switchboard, through planned renewal programme in FY25-26.

Later in the planning horizon, upgrade the existing 7.5MVA transformer to a matching 12.5/17MVA transformer to mitigate operational issues associated with transformer overloading, operating them in parallel and provide an ease of transformer maintenance.

Fleet issue

The existing 11kV switchboard at Tirau substation does not meet modern arc flash standards, has oil quenched circuit breakers, and electromechanical relays. The existing 11kV switchroom seismic capacity is 80% NBS and is therefore seismically compliant.

Options

1. Refurbish the existing Tirau substation 11kV switchboard, including adding arc flash protection, arc flash doors and end panels.
2. Construct a new 11kV switchroom at Tirau and install new 11kV switchgear that meets arc flash standards.

Preferred option

The preferred solution is option 1 as this will maximise arc flash risk reduction vs capital expenditure. The existing 11kV switchroom is seismically compliant so does not require seismic reinforcement or the construction of a new switchroom.

A8.6.2.8 WAHAROA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WAHAROA – 33kV OUTDOOR TO INDOOR (ODID) CONVERSION	GRO	$3,815	2030-2033
WAHAROA T1 POWER TRANSFORMER REPLACEMENT	ARR	$1,249	2025-2026

Network issue

In the latter part of the planning period, following the establishment of the 33kV closed ring circuit (Browne St-Tower Rd and Hinuera), the loss of the Hinuera-Browne St circuit will overload the Hinuera-Tower Rd circuit during high load periods. Similarly, the loss of the Hinuera-Tower Rd circuit will overload the Hinuera-Browne St circuit. To overcome the overloading of the circuit is to offload the Waharoa industrial load to Piako GXP. Presently, the two supply transformers are fed from two overhead strung bus via 33kV outdoor breaker from two GXPs and separated by a recloser. This presents operational complexity when paralleling GXPs between Hinuera and Piako. The equipment is exposed to weather andthe strung bus requires a larger outage area in order to carry out scheduled maintenance.

Options

1. Convert the existing 33kV overhead strung bus to 33kV indoor gear and supply the whole Waharoa load from Piako GXP.
2. Expand existing outdoor yard to accommodate 33kV outdoor assets.

Preferred option

Because of the space constraints on site, the preferred solution is option 1, to convert the 33kV overhead strung bus to 33kV indoor gear and transfer the industrial load to Piako GXP following the replacement of the smaller transformer to match the 12.5/17MVA unit. There is no space available on site to construct a proper outdoor 33kV bus that will meet modern standards.

Fleet issue

Transformer T1 at Waharoa is approaching firm capacity. Its capacity is 7.5/9.4MVA with a present maximum demand of 8MVA.

Options

1. Increased 11kV backfeed. Improve transfer capacity by connecting additional 11kV feeders and/or re-conductoring existing 11kV feeders. Improving 11kV transfer capacity can be complex operationally and, potentially, has a high cost.
2. Replace the existing T1 transformer. Install a new 12.5/17MVA 33/11kV power transformer to replace T1. This would match the existing T2 power transformer and give full N-1 security of supply, based on installed transformer capacity, and would allow transformer maintenance to be carried out on either bank when required.

Preferred option

The preferred solution is option 2, to replace T1 with a new 12.5/17MVA 33/11kV power transformer. This project is not programmed to take place until 2025-2026. In the interim the condition and loading of T1 will be monitored in case the timing of the project can be moved.

A8.6.2.9 WALTON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WALTON 11kV and 33kV INDOOR SWITCHGEAR	ARR	$1,415	2021-2023

Network issue

As most of the subtransmission network in the Waikato region is supplied via overhead lines, the architecture is mainly radially interconnected with fewer substations that have two dedicated circuits. The majority of them rely on switched 33kV backfeeds from different GXPs. Backfeeding Waharoa and Browne St from Piako GXP is limited by a low capacity 33kV line between Kereone and Walton substation. Parallel operation is often quite challenging without modern equipment. To ease the operational complexity, an indoor switchboard will be implemented through a renewal programme.

With the establishment of the Kereone-Walton subtransmission enhancement project, Walton load will be permanently transferred to Waihou GXP and the entire Waharoa load will be fed from Piako GXP.

Fleet issue

The existing 11kV switchboard at Walton substation does not meet modern arc flash standards and has oil quenched circuit breakers. The 33kV circuit breakers are bulk oil and carry higher maintenance and operation costs. The 33kV switchyard does not meet our current requirements for earthing, having a grass yard. The existing 11kV switchroom seismic capacity is 34% NBS, and the building contains asbestos.

Options

1. Do nothing.
2. Refurbish the existing Walton 11kV switchboard, including arc flash protection, arc flash doors and end panels. Seismic strengthen the current 11kV switchroom. Rebuild the existing 33kV outdoor switchyard to modern standards including new switchgear.
3. Construct a combined 33kV and 11kV switchroom at the Walton site. The new switchroom will be 100% NBS. Install new 11kV and 33kV arc flash compliant switchgear. The installation of the new 11kV switchgear can be combined with the new 33kV Walton switchroom and 33kV switchboard project, which includes additional 33kV circuit breakers.

Preferred option

Do nothing is not tenable given the numerous asset risks on site. Option 3 is preferred as this best accommodates the new 33kV cable that is being installed through the Kereone-Walton 33kV subtransmission enhancement project, as well as improving constructability, which also allows the construction work to be let as a single contract at the Walton zone substation site. Detailed design for this option is under way.

A8.6.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.6.3.1 PIAKO SUBSTATION NEW FEEDER

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PIAKO SUBSTATION-TE MIRO 11kV FEEDER	GRO	$1,712	2021-2022

Network issue

The Piako substation supplies the rural area surrounding Morrinsville, some of the outlying suburban areas of Morrinsville, and one major industrial load. The Piako zone substation contains two supply transformers with seven 11kV feeders. The Kereone 11kV feeder is 114km in length with three other rural 11kV feeders more than 40km in length. During peak periods, the loads at the end of the feeders can experience low voltages. These feeders experience voltages outside the regulatory requirements with which Powerco must comply.

Moreover, the Kereone area is experiencing steady growth, so the voltage performance of these feeders will deteriorate over time.

Options

1. Upgrade the existing 11kV overhead conductor.
2. Provide voltage support.
3. New feeder with network re-configuration.

Preferred option

The proposed solution is option 3, to split the existing Kereone feeder into two feeders – one of the new feeders will be created to serve the area to the south including Te Miro, and the other feeder will essentially be the remaining section of the existing Kereone feeder, which will serve the Kereone area only. This reduces the feeder length, and load, thereby improving the voltage and performance.

This solution will also provide sufficient capacity for future growth in this area.

Alternative solutions, such as voltage support and upgrading the conductor, are not favoured as they will only provide limited improvements in capacity and short-term benefits, and will not improve reliability because of the long feeder lengths.

A8.6.3.2 MAUNGATAUTARI AREA

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MAUNGATAUTARI AREA REINFORCEMENT	GRO	$3,876	2024-2026

Network issue

Maungatautari and Karapiro are areas on the edge of Powerco’s network.

Supply to the area is from Tirau substation. The ability to provide a secure supply to the area is hampered by distance and terrain. A total of 746 ICPs are supplied by Cambridge Rd feeder, and 11kV backfeed capacity from Lake Rd substation is minimal because of the great distance.

Historically, the time taken to restore supply in this area is longer after an outage. Because of the terrain involved, accessing the site for fault-finding and repair is more difficult.

Options

1. Install a new feeder from Lake Rd, network enhancement, create an underground link, along with the implementation of automation devices.
2. Install new 33/11kV substation with new 33kV circuit.
3. Install distributed generation (DG) equipment for islanded operation.

Preferred option

The preferred solution is option 1, to install a new feeder out of Lake Rd to balance the load on Totmans Rd feeder. This will also address the existing voltage constraint on this feeder during high load times. Along with the underground link on Cambridge Rd feeder and loop automation scheme, this strategy also serves to improve the voltage at the fringes of Cambridge feeder and support the load in the Maungatautari region during an outage.

It is challenging to find a suitable site in an area comprising lifestyle blocks and farmland to construct a new substation (option 2). The cost of installing a 33kV circuit and the substation is significantly higher than option 1.

Finding a suitable site on a lifestyle block to install DG equipment (option 3) requires lengthy landowner negotiation. This option does not offer benefits to the network supplied by Lake Rd substation.

A8.7 KINLEITH

A8.7.1 SUBTRANSMISSION NETWORK PROJECTS

Baird Rd and Maraetai Rd are supplied via 33kV subtransmission circuits, which consist of overhead line and cable sections. The overhead subtransmission lines have been thermally upgraded. A Baird Rd 33kV incomer cable upgrade was completed in 2020. The remaining cable sections (Maraetai Rd 33kV incomer cables and cables from Kinleith GXP to overhead lines for both substations) will be upgraded as part of routine growth projects.

A8.7.2 ZONE SUBSTATION PROJECTS

Below summarises the project planned for the Kinleith area.

A8.7.2.1 BAIRD RD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BAIRD RD 11kV SWITCHBOARD REPLACEMENT AND SEISMIC UPGRADE	ARR	$852,000	2023-2024

Network issue

Baird Rd 11kV cable terminations exiting the 11kV switchboard are undersized and need to be reconductored.

Fleet issue

The existing 11kV switchboard at Baird Rd substation does not meet modern arc flash standards and has electromechanical relays. The 11 kV switchroom seismic strength is 62% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Seismically reinforce the existing switchroom and upgrade the 11kV switchboard in the existing switchroom.
2. Install a new 11kV switchboard in new switchroom.

Preferred option

The preferred solution is option 1, to seismically reinforce the existing switchroom and upgrade the 11kV switchboard in situ.

A8.8 TARANAKI

A8.8.1 SUBTRANSMISSION NETWORK PROJECTS

A8.8.1.1 HUIRANGI GXP-MCKEE TEE 33KV LINE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HUIRANGI To McKEE TEE SECOND 33kV LINE	GRO	$1,340K	2021-23

Network issue

During peak demand periods, if the Waitara West line is unavailable, the single 33kV Waitara East circuit from Huirangi GXP has insufficient capacity to supply all four substations – Waitara East, Waitara West, McKee and Inglewood. The tee configuration of the Waitara East/McKee 33kV lines also causes protection issues and limits generation injection levels.

Options

1. Construct a second circuit from Huirangi to McKee/Waitara Tee. This allows the tee to be removed and provides a dedicated circuit for each of the McKee circuit and the Waitara East circuit. The new circuit will have enough capacity to resolve the existing constraints for contingencies on the Waitara West circuit.
2. Upgrade the existing 33kV circuit. This can resolve the capacity issue, but not the protection and network architecture issues presented by the tee configuration.
3. Secure generation availability. This option does not resolve the protection and configuration issues.

Preferred option

The preferred solution is option 1, to 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 secured standard network configuration that resolves all existing operational and protection issues.

A8.8.1.2 CARRINGTON GXP-OAKURA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OAKURA SECOND 33kV LINE AND SECOND TRANSFORMER	GRO	5,950K	2025-28

Network issue

The Oakura substation supplies Oakura township, Okato township, which is 12km south, and surrounding rural customers – mainly dairy and farming.

Oakura's 2020 demand was 3.4MVA (1,830 ICPs), and expected demand in 2030 is 3.9MVA. Present security class is AA, which requires restoration of supply within 45 minutes.

The substation contains one 7.5/10MVA 33/11kV transformer fed by one 14km long 33kV line (mostly overhead).

The 11kV backup supply from neighbouring Moturoa substation will be inadequate for Oakura's forecast demand from 2027. A large subdivision of 300 lots, next to Oakura substation, could be developed in the next five to 10 years.

Options

1. Install 5MVA of standby generation at Oakura.
2. Construct a second 33kV line from Carrington St GXP. Install a new 33kV circuit breaker at Carrington St GXP and Oakura, with a second 33/11kV transformer into Oakura.

Preferred option

The preferred solution is option 2, to construct a second 33kV line (16km) from Carrington St GXP along with a second transformer at Oakura, as this option would be easy to implement and would provide more secured supply to Oakura substation.

Option 1 is not favoured, as it would be expensive to implement and maintain.

A8.8.1.3 STRATFORD GXP-CLOTON RD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CLOTON RD SUBSTATION SECOND DEDICATED 33kV LINE	GRO	1,840K	2026-28

Network issue

Cloton Rd substation supplies Stratford town and surrounding urban and rural customers. Its 2020 demand was 10MVA. Present security class is AA+, which requires restoration of supply within 15 minutes.

Cloton Rd's 33kV supply is from Stratford GXP through two overhead lines – one is dedicated (4.14km long) and the other is shared (3.9km of 5km) with one Eltham substation 33kV line.

When there is an outage on the Eltham 33kV line, this shared portion (capacity 16.5MVA) reaches capacity at present demand of Cloton Rd and Eltham substations, 10MVA and 10.5 MVA respectively.

Options

1. Re-tension the shared part 33kV line (3.87km) to operate at 70°C (23.4MVA).
2. Separate the shared part by installing 4km of new 800mm^2 AL 33kV cable from Stratford GXP and a new 33kV circuit breaker at the GXP.

Preferred option

The preferred solution is option 2, as this would be less expensive and would achieve adequate capacity for both substations' future load growth.

Option 1 is not favoured, as the re-tensioning work would be expensive and difficult because of the under-built 11kV and low voltage lines. In addition, during re-tensioning both substations' security of supply would be compromised and could have high impact on SAIDI because of the loss of 33kV supply to both substations.

A8.8.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Taranaki area.

A8.8.2.1 CARDIFF SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
4700T POWER TRANSFORMER REPLACEMENT	ARR	$1,522	2021-22

Fleet issue

Cardiff is single transformer zone substation. The power transformer is a 1962 GEC unit with a Ferranti tap-changer and will be 69 years old at the end of the planning period. The transformer is in average condition but, in the event of a fault, parts are not freely available. Cardiff has a good 11kV backfeed.

Options

1. Do nothing.
2. Replace the existing transformer with a new transformer.
3. Replace the existing transformer with a refurbished transformer unit.

Preferred option

We are currently proceeding with option 2. Doing nothing is not tenable for continued supply.

A8.8.2.2 CITY SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$1,043	2021-22

Fleet issue

City has two Tyree power transformers with Ferranti DS2 tap-changers. The transformers were manufactured in 1978 and will be 52 years old at the end of the planning period. The transformers are ranked 77 and 78 in the power transformer CBRM model.

The existing 11kV switchboard at City substation does not meet modern arc flash standards, has a mixture of vacuum and oil circuit breakers, and has electromechanical relays.

Options

1. Refurbish the existing City 11kV switchboard including arc flash protection, arc flash doors and end panels.
2. Install a new 11kV switchboard in the existing City switchroom. This will involve changes to the switchroom floor cutouts, cable terminations and switchgear mounting arrangements.

Preferred option

The preferred solution is option 1, to refurbish the existing City 11kV switchboard. Option 2 is not preferred as it will be higher cost than option 1 as it will involve changes to the switchroom floor cutouts, cable terminations and switchgear mounting arrangements.

A8.8.2.3 DOUGLAS SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$235	2030

Fleet issue

The existing switchroom building is 60% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom to 67% NBS.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard.

Preferred option

The preferred solution is option 2, to seismically strengthen the existing switchroom, as it is the least cost option. Option 3 is not preferred as it will be higher cost.

A8.8.2.4 LIVINGSTONE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33kV OUTDOOR SWITCHYARD REBUILD	ARR	$1,043	2021-22
T1 AND T2 POWER TRANSFORMER REPLACEMENT	ARR	$1,522	2023-24

Fleet issue

The two transformers were purchased in 1964, are reaching end of life, and have significant rust issues (rust-treated and re-painted in 2016). We have had mechanism issues with the older CIII Reinhaussen tap-changers.

The 33kV switchyard is at end of life. Given its proximity to the coast, the 33kV concrete structures are spalling heavily and in poor condition. There are ‘do not operate’ notices (DNOs) on several of the 33kV circuit breakers and switches, complicating network switching.

Options

1. Do nothing.
2. Rebuild as a 33kV indoor switchboard/switchroom, replace power transformers.
3. Rebuild as 33kV like-for-like, defer replacement of power transformers.

Preferred option

We are currently proceeding with option 3. Doing nothing is not a tenable option as continuing to operate with DNOs in place puts greater load at risk. Rebuilding the outdoor 33kV switchyard on a like-for-like basis will be the lifecycle least-cost option, as this is a rural location. We believe we can defer transformer replacement as repairs were carried out in 2016. The timing of transformer replacement will be reviewed once the 33kV switchyard has been refurbished.

A8.8.2.5 MOTUKAWA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV ODID	ARR	$1,349	2027-28
3x33kV CIRCUIT BREAKER REPLACEMENT	ARR	$2,150	2025-26

Fleet issue

The Motukawa outdoor 11kV bus work is suffering from corrosion and is space constrained, complicating maintenance and repair outage requirements.

Options

1. Do nothing.
2. Replace the outdoor 11kV switchyard, 11kV circuit breakers and 33kV circuit breakers on a like-for-like basis.
3. Replace the outdoor 11kV switchyard with an 11kV switchroom and indoor 11kV switchboard (ODID). Replace the 33kV outdoor circuit breakers on a like-for-like basis.

Preferred option

We are proceeding on the basis of option 3, noting that this renewal project is not scheduled until later in the planning period.

A8.8.2.6 WAITARA EAST SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV ENTIRE SWITCHBOARD REPLACEMENT	ARR	$724	2026-27

Fleet issue

The 11kV switchboard at Waitara East does not meet modern arc flash standards. The switchboard is ASEA (ABB) type HPA12 with SF_6 circuit breakers and is not arc flash rated. This type of switchboard is classified as obsolete by ABB and is only supported as detailed by the ABB lifecycle management policy. ASEA (ABB) type HPA12 switchgear is installed at two other Powerco zone substations, Waitara West in Taranaki, and Waitoa in the Thames Valley.

Options

1. Continue to monitor the condition and performance of the 11kV switchgear at Waitara East and renew the switchgear as recommended by the ABB lifecycle management policy.
2. Install a new, fully arc flash rated and arc flash protected 11kV switchboard in the existing Waitara East switchroom. This will involve, inter alia, changes to the switchroom floor cutouts, cable terminations and switchgear mounting arrangements.

Preferred option

The preferred solution is option 2, to install a new, fully arc flash rated 11kV switchboard in the existing Waitara East switchroom. While this is likely to be the more expensive option it has the benefit of a) allowing the decommissioned switchgear to be used as spares for Waitara West and Waitoa zone substations and b) reducing the number of orphan types of switchgear on the Powerco network.

A8.8.2.7 ELTHAM SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ELTHAM TRANSFORMERS UPGRADE	GRO	$4,400	2020-22
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2029

Network issue

The Eltham substation supplies Eltham town, the surrounding rural areas, and two significant industrial loads. The substation contains two 7.5/10MVA transformers. The demand has exceeded the secure capacity of the transformers (ie the capacity that can be supplied by one transformer plus available 11kV backfeed).

The shortage of firm capacity would restrict new customer connections to the Eltham network. Should this inhibit further development of the area, it would not be acceptable or justifiable to the community.

The 11kV backup supply availability from neighbouring substations is only 1MVA, with poor voltage quality. In the past two years, there have been about 20 incidents when the substation has operated with one transformer only. One of the incidents continued for two days. Should these incidents have coincided with peak demand periods, we would have had to shed load.

Options

1. Continue to operate Eltham with its present two transformers. This is not tenable. As the Eltham load has already exceeded single transformer capacity and given it supplies important industrial customers, it doesn't meet Powerco's security standard requirement, which requires full backup within 15 seconds of a component failure.
2. Upgrade Eltham's two transformers to 12.5/17MVA units. This resolves the capacity issue for future load growth and provides required security of supply to the customers of Eltham.
3. Construct additional 11kV feeders from neighbouring substations. This is not practical. As the neighbouring substations Kaponga, Cloton and Cardiff are also approaching firm capacity. It would need two new feeders (10km and 7km long), two voltage regulators and two 11kV circuit breakers.
4. Generation or energy storage. This is not economical, as costs for a generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs. Resource consenting for noise issues and site suitability of earthing systems to expected fault levels could be difficult to resolve.

Preferred option

The preferred solution is option 2, to upgrade the Eltham substation transformers along with new foundation, neutral earthing resistors (NERs), earthing, 33kV bus-coupler ABS structure, 110V DC supply, and stock and security fencing. This is the least cost, long-term economically sustainable solution to meet the security of supply requirement (AA+) and future load growth of industrial and agricultural customers.

A8.8.2.8 INGLEWOOD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
INGLEWOOD SUBSTATION TRANSFORMERS UPGRADE	GRO	2,100K	2024-26

Network issue

The Inglewood substation supplies power to Inglewood town and the surrounding rural areas. The substation contains two 5MVA transformers. Its security class is AA, which requires restoration of supply within 45 minutes.

Inglewood's 2027 forecast demand of 6MVA would exceed the secure capacity of the present transformers (ie the capacity that can be supplied by one transformer plus available backfeed).

Being close to New Plymouth city, Inglewood township load is growing quickly through the development of a new subdivision. In the past year, there have been three customer-initiated works (CIW) applications totalling 600kVA of transformers.

At times Inglewood supports neighbouring single transformer substation Motukawa, which has a demand of 1MVA.

Options

1. Upgrade Inglewood's two transformers to two 7.5/10MVA units. This will secure the load at Inglewood and provide adequate capacity for anticipated future load.
2. Construct additional 11kV feeders. This is not practical, as neighbouring Cloton Rd is also approaching firm capacity. Furthermore, it would need one dedicated 11kV feeder (23km long) along with one voltage regulator.
3. Generation or energy storage. This is not economical as costs for a generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs. Resource consenting for generator noise issues and the site suitability of earthing systems to expected fault levels could be difficult to resolve.

Preferred option

The preferred solution is option 1, as this is the least cost, long-term economically sustainable solution to meet the security of supply requirement (AA) and future load growth.

A8.8.2.9 KAPONGA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
4708T AND 4709T POWER TRANSFORMER REPLACEMENT	ARR	1,818K	2025-26

Fleet issue

Kaponga has two OEL power transformers. The transformers were manufactured in 1967 and will be 63 years old at the end of the planning period. The transformers are ranked 84 and 86 in the power transformer CBRM model.

Options

1. Refurbish the existing Kaponga power transformers, depending on workshop evaluated condition.
2. Purchase and install new power transformers.

Preferred option

The preferred solution is option 2, as modern transformers have lower power losses and come equipped with low maintenance vacutap or similar on load tap-changers. Vacutap tap-changers have a maintenance interval of 300,000 switching operations or between 30 and 50 years. Older tap-changers have a 3-5 year maintenance interval.

A8.8.2.10 KAPUNI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
3x33kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$1,818	2025-26
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2025
11kV ENTIRE SWITCHBOARD REPLACEMENT	ARR	$959	2025-26
T1 and T2 POWER TRANSFORMER REPLACEMENT	ARR	$1,522	2026-27

Fleet issue

The 33kV outdoor Takaoka 30KO circuit breakers were manufactured in 1981, are oil quenched and have type issue. The existing switchroom building is at 40% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard was manufactured by GEC and contains BVRP1 circuit breakers. The 11kV switchboard is not arc flash rated or arc flash protected and is the only example of this type of switchgear on the Powerco network.

Kapuni has two Tyree power transformers with tap-changers supplied by Associated Tapchangers. The transformers were manufactured in 1968 and will be 62 years old at the end of the planning period. The transformers are ranked 9 and 10 in the power transformer CBRM model.

Options

1. Do nothing.
2. Replace the outdoor 33kV Oil CBs with new 33kV circuit breakers on a like-for-like basis. Seismically strengthen the existing switchroom and install a new arc flash rated 11kV switchboard with arc flash protection. Review the ongoing demand at Kapuni and, if appropriate, replace the two power transformers with new 10MVA units.
3. Replace the outdoor 33kV OCBs with new 33kV circuit breakers on a like-for-like basis. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard. Review the ongoing demand at Kapuni and, if appropriate, replace the two power transformers with new 10MVA units.

Preferred option

The least cost, preferred solution is option 2. Option 3 is not preferred as it will be higher cost than option 2. A detailed conceptual design exercise examining and costing all options will be carried out to confirm option 2 as optimal.

A8.8.2.11 EGMONT VILLAGE NEW SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW EGMONT VILLAGE SUBSTATION	GRO	6,500K	2025-28

Network issue

The Mangorei 11kV voltage regulating station supplies three feeders (1,218 ICPs) at 11kV. The 11kV supply is from Brooklands substation by a dedicated feeder, Brooklands-5, which consists of 1.7km underground cable and 3km of overhead line. This feeder is rated for 33kV operation.

The underground section of Brooklands-5 feeder is forecast to reach capacity by 2030. Mangorei's voltage regulator (manufactured in 1982) is forecast to approach capacity.

Furthermore, the Mangorei regulating station is not at the centre of the demand, so voltage quality of two feeders is approaching the acceptable limit (95%).

Options

1. Upgrade feeder cable (1.73km) and replace voltage regulator with a new 7.5MVA unit.
2. Offload Mangorei by constructing a second 11kV feeder (4.73km) from a circuit breaker at Brooklands substation and a new voltage regulator at Mangorei.

3. Extend Mangorei's line by another 6km to Egmont Village and construct a new 10MVA capacity substation there.

Preferred option

The preferred solution is option 3, as it brings the substation closer to the centre of the load. The 33kV line could be extended (about 7km) to join with Inglewood substation 33kV line, which would then provide N-1 supply.

Options 1 and 2 are not favoured as they are not long-term sustainable solutions and do not resolve voltage quality.

A8.8.2.12 MIDHIRST NEW SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW MIDHIRST SUBSTATION	GRO	10,000K	2023-26

Network issue

Midhirst township and its large rural network (51km long) on its northern side is supplied through an 11kV voltage regulating station at Midhirst, located on land owned by Powerco. There are 328 ICPs supplied by this network and its 2019 demand was 1MVA.

An 11kV feeder from Cloton Rd substation supplies Midhirst regulating station. This feeder (7.1km) supplies another 607 ICPs enroute to Midhirst and has a demand of 130 amps (2.5MVA), including Midhirst network demand.

Voltage quality at the Midhurst regulator is just 1% above the threshold (95%). Being close to Stratford town, Midhirst network load is expected to grow. Last year, there were two CIW applications, to connect new 100kVA and 200kVA transformers.

A small industrial customer, Ample Group Ltd, has informed that its load will increase from 0.8MVA to 5MVA by 2025, with 0.7MVA additional load in December 2021.

The North feeder that supplies Ample and the Midhirst network, cannot supply this load increase.

At times, North feeder also supports half of Ratapiko feeder, Motukawa (a single transformer substation) and half of Mountain Rd feeder, Inglewood substation.

Options

1. Construct two dedicated 11kV feeders (each 4.8km) from Cloton Rd substation, along with two 11kV feeder circuit breakers, and upgrade Cloton Rd substation's two 10/13MVA transformers to 16/24MVA.
2. Install an indoor 33kV switching station (5-panel) on the 33kV line that supplies Cardiff and Kaponga and, from there, extend two 33kV lines (each 4.6km) to Midhirst Powerco land and construct a 33/11kV substation (capacity 2x7.5/10MVA).

Preferred option

The preferred solution is option 2, to construct a new 33/11kV substation at Midhirst, as this would provide a long-term solution for this area and would offload Cloton Rd substation by 1.5MVA, which would defer the Cloton Rd substation transformers upgrade (see below) for some years.

Option 1 is not favoured as it is not a long-term sustainable solution, and the cost difference from option 2 is not large.

A8.8.2.13 CLOTON RD SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CLOTON RD SUBSTATION TRANSFORMERS UPGRADE	GRO	3,100K	2026-28

Network issue

The Cloton Rd substation supplies power to Stratford CBD, the Cheal gas production station, and the surrounding urban and rural areas. The substation contains two 10/13MVA transformers. Its security class is AA+, which requires restoration of supply within 15 seconds in N-1 configuration.

Cloton Rd 2020 demand of 10.5MVA is close to its firm capacity of 13MVA. At times, Cloton Rd supports Motukawa, a single transformer substation, which has a demand of 1MVA.

In 2020, there were four CIW applications for the connection of four transformers, totalling 700kVA capacity.

Furthermore, Ample Group Ltd's initial additional load of 0.7MVA in December 2021 is to be supplied from Cloton Rd until new Midhirst substation construction is completed, which is expected to be in 2026.

The 11kV backup supply availability from neighbouring substations is only 2MVA, with poor voltage quality.

Options

1. Continue to operate Cloton Rd with its present two transformers. This would need review against probabilistic security standard. The load is expected to exceed single transformer capacity because of a large number of CIW applications.
2. Upgrade Cloton Rd's two transformers to 12.5/17MVA units. This resolves the capacity issue for future load growth and provides required security of supply to customers.
3. Construct additional 11kV feeders from neighbouring substations. This is not practical as it would need one 11kV feeder (15km long) from Inglewood substation and another feeder from Eltham substation (8km long) along with two voltage regulators and two 11kV circuit breakers.

4. Generation or energy storage. This is not economical, as costs for a generation solution would be similar to a transformer upgrade solution and have higher operational and maintenance costs. Resource consenting for noise issues and site suitability of earthing systems to expected fault levels could be difficult to resolve.

Preferred option

The preferred solution is option 2, to upgrade the Cloton Rd substation transformers along with new pad and bunding, as this is the least cost, long-term sustainable solution to meet the security of supply requirement (AA+) and future load growth in Stratford town and its surrounding rural area – an important industrial and agricultural area.

A8.8.2.14 WHALERS GATE NEW SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHALERS GATE NEW SUBSTATION	GRO	7,910K	2025-28

Network issue

The Moturoa substation supplies several important loads – Port Taranaki, Taranaki Base Hospital, Omata tank farm and the Moturoa commercial area within the west part of New Plymouth. There are about 8,900 customers supplied by this substation.

Moturoa's forecast 2030 demand is 22.2MVA, and Taranaki Base Hospital is increasing its demand load in December 2023 by 2.4MVA. At such demand, Moturoa would exceed its single transformer capacity of 24MVA.

Any new subdivisions and developments in certain areas of New Plymouth, such as Whalers Gate, would add additional load to Moturoa.

Options

1. Construct additional 11kV feeders from neighbouring substations. This is not practical as the neighbouring substations, City and Brooklands, would then approach their firm capacity. Furthermore, it would need the installation of cable for three new feeders (each about 4km long), which would be difficult to implement, as the route would be through the city area.
2. Establish a new zone substation at Whalers Gate. This resolves the capacity issue for Moturoa substation and provides enough spare capacity for future load growth in this area.

Preferred option

The preferred solution is option 2, to establish a new zone substation of 24MVA capacity at Whalers Gate. Land would need to be sought. Moturoa's two 33kV cables, installed last year, have a capacity of 40MVA, which would be adequate to supply both Moturoa and this new substation for at least 20 years of forecast demand growth.

Option 1 is not favoured as it would inhibit future load growth in the area.

A8.8.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.8.3.1 INGLEWOOD TOWN AND SURROUNDING RURAL AREAS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
INGLEWOOD 6.6kV TO 11kV CONVERSION	GRO	$5,200K	2019-22

Network issue

The Inglewood substation supplies power to Inglewood town and the surrounding rural areas at 6.6kV. The substation contains two 33/11-6.6kV supply transformers. Only two substations in Powerco's Western network – Inglewood and Motukawa – operate at 6.6kV.

Disadvantages with operating a 6.6kV network include:

- Voltage drop at the ends of the feeders becomes excessive as the load increases, resulting in poor quality supply to customers.
- The network is isolated from neighbouring zone substations, which all operate at 11kV. This limits the backfeed capacity available to Inglewood substation during a contingent event.
- The 6.6kV voltage is a non-standard Powerco distribution voltage.
- Because of these issues, the Inglewood substation does not meet our required security and performance quality levels.

Options

The nature of this project is unique in contemplating a strategic decision to upgrade a small section of 6.6kV distribution to standard 11kV voltage. Typical development options that consider new circuits, substations or network architecture are not appropriate in this context, and neither are non-network options.

The following network solutions have been considered:

1. Continue to operate the Inglewood network at 6.6kV by upgrading conductors to meet voltage and capacity demands. Over time, all the 115km of feeders would need to be replaced.
2. Install 6.6/11kV step-up transformers midway on the feeders, converting the ends of the feeders to 11kV and progressively moving the step-up transformers back towards the start of the feeder, eventually carrying out a full conversion to 11kV.
3. Replace the remaining 6.6kV/400V transformers with dual wound transformers and then converting all feeders to 11kV within a 2-3 year timeframe.

Preferred option

The preferred solution is option 3, which involves replacing all of the remaining 6.6kV/0.4kV distribution transformers in the Inglewood area with dual winding transformers (11-6.6kV/0.415kV) over a 2-3 year timespan.

Options 1 and 2 are not favoured because of the higher capital cost needed for the required upgrades.

A8.8.3.2 TARANAKI BASE HOSPITAL ADDITIONAL 2.2MVA LOAD

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HOSPITAL 4KM 11kV CABLES AND 3 RING MAIN UNITS	GRO	$3,400K	2021-24

Network issue

Taranaki Base Hospital has confirmed that its load is increasing from 1.27MVA to 3.5MVA in December 2023 to decarbonise its heating system and to supply additional load for new buildings.

Normal supply 11kV feeder Whiteley St (Moturoa substation) and backup supply (through auto changeover) feeder Brooklands-14, cannot supply this additional load in their present state. Whiteley St feeder demand would reach capacity and Brooklands-14 feeder would exceed capacity by 2MVA.

Whiteley St supplies 605 ICPs and Brooklands-14 supplies 1,224 ICPs, while supporting several neighbouring feeders.

Options

1. Reconfigure Brooklands-9 feeder to shift its load to Brooklands-8 feeder and install 2.5km of new cable to provide normal supply to the hospital. Similarly, reconfigure Whiteley St feeder by installing two ring main units (RMUs), and install 1.5km of new cable for backup supply to the hospital.
2. Implement Whalers Gate zone substation project, as mentioned above ($7.9m), and from there install two 300mm2 AL 11kV cables (each about 1.5km) to supply the hospital.

Preferred option

The preferred solution is option 1, as it uses the remaining firm capacity of Moturoa (6MVA) and Brooklands (9MVA) substations. Furthermore, it offers the hospital normal and alternative supply options from two substations.

Option 2 is not favoured, as it is an expensive option and it is not the right time to finalise the optimal location for Whalers Gate substation.

A8.8.3.3 BELL BLOCK, PARAITE RD FEEDER

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PARAITE RD FEEDER BACKUP SUPPLY	GRO	$1,680K	2023-25

Network issue

Bell Block substation Paraite Rd feeder supplies two large industrial customers, Tegel Foods (1.8MVA) and McKechnie Aluminium Solutions (2.8MVA), plus another 92 ICPs. Its 2020 demand was 4.9MVA, which cannot be supported by any other feeders.

This makes maintenance access difficult on the 11kV line (1.2km) near the substation or at the feeder breaker. Tegel Foods and McKechnie would need t o reduce their loads by at least half, and this is not likely.

The Bell Block substation supplies industrial loads, is conveniently sited for access to the highway, port and rail, and further industrial load growth is likely. Bell Block's 2020 demand was 16.4MVA and its firm capacity is 24MVA. In 2020 there were seven CIW applications for the connection of 1.2MVA of capacity.

Neighbouring Katere substation experiences much less CIW activity and its 2020 demand was 14.3MVA.

Options

1. Construct a new feeder (3km) from Bell Block substation.
2. Construct a new feeder (2.8km) from Katere substation.

Preferred option

The preferred solution is option 2, as it creates the option to backfeed Paraite Rd feeder. In the future, if required, Bell Block can be offloaded onto Katere substation.

A8.8.3.4 MOTUKAWA RURAL AREAS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MOTUKAWA 6.6kV TO 11kV CONVERSION	GRO	$2,690K	2024-26

Network issue

The Motukawa zone substation supplies power to Tarata and Ratapiko townships along with surrounding rural areas at 6.6kV. The substation contains one 5MVA 33/11-6.6kV transformer.

- Disadvantages with operating a 6.6kV network include:
- A 6.6 kV network has substantially lower power carrying capacity than 11 kV systems and also contributes to more severe voltage drop issues. Ratapiko and Tarata feeders experience voltage at just 1% above the acceptable level.

- The neighbouring Inglewood and Midhirst 6.6kV network is being converted into 11kV during the customised price-quality path (CPP1) period. Motukawa would then be the only remaining 6.6kV substation.
- The 6.6kV voltage is a non-standard Powerco distribution voltage.

Options

1. Continue to operate the Motukawa network at 6.6kV by installing two voltage regulators on two feeders and upgrading about 15km of backbone line to meet voltage quality.
2. Install 6.6/11kV step-up transformers midway on the feeders, converting the ends of the feeders to 11kV and progressively moving the step-up transformers back towards the start of the feeder, eventually carrying out a full conversion to 11kV.
3. Replace the remaining (about 130 out of 163) 6.6/0.415kV transformers with dual wound (11-6.6/0.415kV) transformers and then convert all feeders to 11kV within 2-3 years.

Preferred option

The preferred solution is option 3, which involves replacing all of the remaining 6.6kV/0.4kV distribution transformers in the Motukawa network with dual winding transformers (11-6.6kV/0.415kV) over a 2-3 year period.

Option 1 is not favoured because of the long length of feeder upgrades required and consequent high cost.

Option 2 is not favoured because of the higher capital cost of installation of 6.6kV/11kV step-up transformers on each feeder and, after 11kV conversion, there would not be any other places to reuse these step-up transformers.

A8.9 EGMONT

A8.9.1 SUBTRANSMISSION NETWORK PROJECTS

A8.9.1.1 MANAIA SUBTRANSMISSION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MANAIA TEE REMOVAL	GRO	8,400K	2021-23

Network issue

The Manaia substation supplies Manaia township and surrounding rural areas. One industrial customer, Yarrows The Bakers, takes a significant part (1.7MVA) of its load (6.3MVA).

Manaia is supplied by a short section of single overhead 33kV line (3.3km long) teed to a ring network that runs from Hawera GXP to Manaia tee (13km), Manaia tee to Kapuni substation (6.9km), and Kapuni substation to Hawera GXP (16.4km).

Because of this configuration, Manaia side 33kV network (23.2km) operates without any intermediate protection. A fault on this long line causes an outage of Manaia substation. There are 1,586 ICPs supplied by this substation.

Manaia is also at risk of an outage on its single transformer (10/12.5MVA).

Present 11kV backup supply is inadequate. Only half of its load can be transferred to other substations, through the installation of a mobile voltage regulator. For a planned outage, Yarrows needs to significantly reduce its load.

Options

1. Second 33kV line (4.2km) from a new indoor 33kV board at the Manaia tee location and a second transformer at Manaia substation.
2. Increase 11kV backfeed. While reducing the risk of extended outage, this cannot meet the security class requirements because of the switched backfeed. This option would construct 15km of 11kV line and two voltage regulators.
3. Generation or energy storage. This is not economical, as costs for a generation solution would be similar to option 1 and have higher operational and maintenance costs. Resource consenting for generator noise and the site earthing system to expected fault levels could be difficult to resolve.

Preferred option

The preferred solution is option 1, as it would meet Manaia's security of supply requirement, AA+, and it would provide an option for future third 33kV line (from Hawera GXP, see below) termination at the Manaia tee new 33kV board.

Option 2 is not favoured as the investment would fail with load growth and does not achieve Manaia's security of supply requirement.

A8.9.1.2 MANAIA-KAPUNI 33KV RING

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KAPUNI AND MANAIA SUBSTATIONS THIRD 33kV LINE	GRO	3,200K	2024-28

Network issue

Kapuni and Manaia substations take 33kV supply from a ring network, which runs from Hawera GXP to Kapuni (16.4km long), Kapuni to Manaia tee (6.9km) and Manaia tee to Hawera (13km). The Manaia tee-off is a single 3.5km long 33kV line. The Manaia tee removal project will construct a second 33kV line from this tee-off point.

The security class of Kapuni is AA+. Manaia will achieve its required security class of AA+ through the Manaia tee removal project.

The 33kV ring has a capacity of 15MVA in N-1 situation. Forecast 2030 loads for Kapuni and Manaia substations are 7.2MVA and 7.8MVA respectively. In addition, Manaia 33kV bus voltage would drop to 89% in N-1 situation and Manaia transformer tap position would be just one tap above its limit.

Options

1. Re-tension the 33kV ring network (32.9km) to operate at 70°C (capacity 22.7MVA). Replace Manaia's transformer with a larger voltage regulation range transformer.
2. Construct a new 33kV line (approximately 14km) from Hawera GXP to Manaia tee, with an indoor 33kV board near Manaia tee location.

Preferred option

The preferred solution is option 2, as it is the least cost, and economically sustainable long-term solution. If the previous project is implemented, this option of a 33kV board near Manaia tee would not be required.

A8.9.1.3 HAWERA-CAMBRIA 33KV OIL CABLE REPLACEMENT

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CAMBRIA WHITE/BLACK 33kV CABLE REPLACEMENT	ARR	3,200K	2024-28

Fleet issue

The 2x3km circuits running from Cambria substation were installed in 1968, and are expected to be 63 years of age at the end of the period.

While these are still in good condition, these circuits are costly to maintain – requiring regular inspections of oil levels and, because of the small amount of oil cable remaining in our network, it is becoming increasingly difficult to access specialist service providers who can repair or service these.

Options

1. Do nothing.
2. Replace 2x33kV circuits with new cross-linked poly ethylene (XLPE) cables.
3. Replace 2x33kV with new overhead circuits.

Preferred option

Option 2 is our preferred option. It is the lowest risk option of supply to Cambria substation, as this circuit runs along Tawhiti Rd and keeps to our existing use rights.

Option 1 is not a preferred option. Given the age of the cables and their criticality to Cambria substation, a do nothing strategy introduces increasing amount cost of repairs and risk of loss of supply to Cambria substation.

Option 3, while the least cost option, does not appear to have any feasible routes away from the current location, given the encroachment into the residential area of Hawera township, which increases the risk of supply loss.

A8.9.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Egmont area.

A8.9.2.1 CAMBRIA ZONE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$235	2028

Fleet issue

The existing switchroom building is at 25% NBS, which is below the 67% NBS value required for seismic compliance.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom to 67% NBS.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom. Option 3 is not preferred as it will be higher cost.

A8.9.2.2 HAWERA GXP 33KV SWITCHGEAR

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HAWERA GXP 33kV ODID	GRO	5,400K	2021-24

Network issue

Hawera is a Transpower 110/33kV GXP, located just outside Hawera township. It supplies five Powerco substations – Cambria, Manaia, Kapuni, Livingstone and Mokoia via eight outgoing 33kV feeders.

Transpower has identified that its outdoor 33kV switchgear is in poor condition and approaching the end of its life. Its preference is to replace this switchgear via an indoor conversion project.

Options

1. Powerco builds the indoor conversion through the installation of a new indoor 33kV board, on land provided by Transpower, and assumes asset ownership.
2. Transpower builds the indoor conversion and maintains asset ownership.

Preferred option

The preferred solution is option 1. Powerco has identified from a similar project at Te Matai, that its construction cost is lower. Furthermore, the ownership of a 33kV board provides Powerco more control and visibility at GXP level and removes the dependency on Transpower for the 33kV operation and maintenance.

A8.9.2.3 NGARIKI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
33kV REBUILD	ARR	$2,150	2025-26

Fleet issue

Ngariki 33kV has a very tight 33kV outdoor structure. Any fault or maintenance work requires a complete 33kV bus outage. There have been multiple 33kV circuit breaker failures during the past few years. We have retained older decommissioned 33kV circuit breakers for spare parts to enable reactive repairs, but this is, at best, a short to medium term solution.

Options

1. Do nothing.
2. Rebuild outdoor 33kV structure with modern clearances and new 33kV outdoor circuit breakers.
3. 33kV ODID conversion.

Preferred option

Our preferred solution is option 2, given the ample room available on-site to expand. This is determined as the least cost lifecycle option to address the clearance and circuit breaker reliability issues at this rural substation.

We don't believe a do nothing option is tenable, as we have already experienced multiple failures and current 33kV circuit breakers are in poor condition. We have limited spares remaining and this does not resolve the difficultly of obtaining outages to carry out repairs on the 33kV structure.

A8.9.2.4 OPUNAKE GXP 33KV SWITCHGEAR

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OPUNAKE GXP 33kV ODID	GRO	4,400K	2021-24

Network issue

Opunake is a Transpower 110/33kV GXP, located just outside Opunake township. It supplies three substations – Pungarehu, Ngariki and Tasman via three outgoing 33kV feeders.

Transpower has indicated that its outdoor 33kV switchgear is in poor condition and approaching the end of its life. Its preference is to replace this switchgear via an indoor conversion project.

Options

1. Powerco builds the indoor conversion through the installation of a new indoor 33kV board, on land provided by Transpower, and assumes asset ownership.
2. Transpower builds the indoor conversion and maintains ownership.

Preferred option

The preferred solution is option 1. Powerco has identified from a similar project at Te Matai, that its construction cost is lower. Furthermore, the ownership of a 33kV board provides Powerco more control and visibility at GXP level and removes the dependency on Transpower for the 33kV operation and maintenance.

A8.9.2.5 TASMAN SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TASMAN SUBSTATION TRANSFORMERS UPGRADE	GRO	2,200K	2025-27
11kV SWITCHBOARD ARC FLASH RETROFIT	ORS	$916	2025-26

Network issue

The Tasman substation supplies Opunake township, the surrounding rural areas and Maui gas production station (1.2MVA load). The substation contains two 5MVA transformers. The demand has exceeded single transformer capacity by 2MVA.

The present shortage of firm capacity would constrain new customer connections. Should this inhibit further development of the area, it would not be acceptable.

The 11kV backup supply availability from neighbouring substations is only 2MVA, mostly from Ngariki, with poor voltage quality. However, Ngariki is a single transformer substation and, at its 2030 forecast demand of 4.1MVA, would run out of capacity to support Tasman.

Because of the nature and size of the load Tasman supplies, it needs to maintain AA+ security of supply, which requires restoration of supply in 15 seconds, in N-1 situation.

Furthermore, Tasman's transformers will be 52 years old in 2028. Usual life length of a transformer is 60 years.

Options

1. Continue to operate Tasman with its present two transformers. This is not tenable as the Tasman load has already exceeded single transformer capacity and, given it supplies an important industrial customer, it doesn't meet Powerco's security standard requirement, which requires full backup within 15 seconds of a component failure.
2. Upgrade Tasman's two transformers to 7.5/10MVA units. This resolves the capacity issue for future load growth and provides required security of supply to the customers of Tasman substation.
3. Construct additional 11kV feeders from neighbouring substations. This is not practical as the neighbouring Ngariki substation is approaching its capacity. Manaia substation is 22km away.
4. Generation or energy storage. This is not economical as costs for a generation solution would be similar to a transformer upgrade solution and may have higher operational and maintenance costs.

Preferred option

The preferred solution is option 2, as it is the least cost, long term economically sustainable solution to meet the security of supply requirement (AA+) and future load growth in Opunake township and its surrounding rural areas. An arc flash retrofit would be achieved on the 11kV switchboard in the year prior.

A8.9.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

In Egmont area there are no significant distribution projects arising from load growth.

A8.10 WHANGANUI

A8.10.1 SUBTRANSMISSION NETWORK PROJECTS

A8.10.1.1 WHANGANUI GXP-HATRICKS WHARF

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHANGANUI GXP BUS L TO HATRICKS WHARF	GRO	$1,610	2023-2025

Network issue

Powerco has a project under way to install a second high capacity (30MVA+) line from Whanganui GXP Bus K. Upon completion of this project, the subtransmission export capacity of Whanganui GXP Bus K and L will be mismatched in totality. This presents a constraint under a half Bus K outage scenario.

In winter, there is a capacity constraint between Whanganui GXP and Hatricks Wharf sub (12MVA), when parallel supply is compromised.

Options

1. Run a new high capacity cable from Whanganui Bus L to Hatricks Wharf. This route is through urban developed land east of the river and there is already a conductor route through.
2. Do nothing. This option prolongs the risk of a contingent capacity constraint, when parallel supply is compromised.

Preferred option

The preferred solution is option 1, to upgrade conductor capacity to above 23MVA, lessening the Brunswick GXP outage scenario constraint. The various conductor types would be upgraded to a uniform size by design.

A8.10.1.2 HATRICKS WHARF-PEAT ST

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
HATRICKS WHARF TO PEAT ST	GRO	$1,200	2024-2026

Network issue

Hatricks Wharf is centrally located on the subtransmission ring between Brunswick and Whanganui GXP stations. This centrality requires Hatricks to provide bi-directional high capacity supply to Peat St.

When supply to Roberts Ave, Castlecliff or Peat St is compromised, supply between Hatricks Wharf and Peat St becomes over-loaded at later year demand forecast levels, on both 630mm2 cable and conductor portion.

Options

1. Upgrade subtransmission circuits through Beach Rd and Castlecliff to Peat St. Geographically, this option is too lengthy to make economic sense, even though these lines do also reach near capacity under certain switching configurations of the ring.
2. Link Taupo Quay to Peat St to bring high capacity from the Whanganui Bus K cable project that is under way. Upgrade of the existing line and cable is more cost effective than this option.

Preferred option

The preferred solution is option 1, to upgrade cable and conductor capacity to minimum 32MVA, providing sufficient contingent capacity to the steadily growing Peat St sub demand.

An interim year commitment to dual transformers at Brunswick GXP would not impact this project, since a commensurate demand reverse supply from Peat St to Hatricks Wharf is also required during a Whanganui GXP constraint.

A8.10.1.3 PEAT ST-CASTLECLIFF

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PEAT ST TO CASTLECLIFF	GRO	$2,400	2024-2026

Network issue

Taupo Quay subtransmission forms part of the Peat St, Beach Rd, Castlecliff and Hatricks Wharf ring. At year 2029, forecast demand outage modelling of a malfunction of the Taupo to Beach conductor, shows the alternative Peat St to Castlecliff ring loading 99% of the cable (300mm2 AL) and conductor (Cockroach).

The simple ring structure of the subtransmission ring does not allow direct supply of Beach Rd from Hatricks Wharf, so there is an inherent reliance of Castlecliff and Beach Rd substations on this circuit out of Peat St.

Options

1. Run a direct cable from Hatricks Wharf to Beach Rd.
2. The upgrade of the existing circuit is preferred for lowest cost.
3. A new line direct from Brunswick, past Peat St to join the ring near Beach Rd. While this breaks up the inherent ring limitations, it covers close to 15km and would be cost prohibitive for this singular constraint remediation.

Preferred option

The preferred solution is option 2, to upgrade existing cable and conductor to minimum 24MVA, allowing supply of Castlecliff and Beach Rd subs at forecast demand levels.

A8.10.1.4 BRUNSWICK GXP-ROBERTS AVE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BRUNSWICK GXP TO ROBERTS AVE CONDUCTOR	GRO	$1,154	2024-2025

Network issue

Supply to Peat St from Brunswick GXP is constrained upon an outage of the 5.49km 30MVA direct path conductor.

There is a 2019 project delivering a new large capacity cable between Roberts Ave and Peat St substations.

Once the Roberts Ave to Peat St new cable project is completed, there will be an alternative path for supply to Peat St. However, the capacity of the conductor upstream of Roberts Ave is only 22MVA.

The lower-capacity portion of this alternative path lessens future security of Peat St and dependent substations.

Options

1. Run a third circuit from Brunswick GXP to Peat St to provide the full security requirement. This would require more time for an ODID at Brunswick and a second transformer for subtransmission N-1.
2. Upgrade the conductor portion of Brunswick GXP to Roberts Ave.

Preferred option

The preferred solution is option 2, a conductor capacity upgrade for the 3.6km conductor between Brunswick GXP and Roberts Ave sub, ensuring adequate contingent supply through Roberts Ave.

This would ensure a high-capacity alternative supply path between Brunswick GXP and Peat St, and dependent subs beyond.

A8.10.1.5 ROBERTS AVE-PEAT ST

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ROBERTS AVE TO PEAT ST 33kV CIRCUIT	GRO	$3,800	2022-2023

Network issue

Peat St is the most critical substation in Whanganui but is supplied by a single circuit, meaning security is dependent on backfeed from Whanganui GXP substations. Such cross GXP backfeed arrangements also require break-before-make changeover, which is inappropriate for a substation serving the city's CBD.

When existing circuits from Whanganui GXP are unavailable, there is insufficient capacity through Peat St to secure all dependent substations.

Kai Iwi is sub-fed from Peat St.

Under normal configuration, the loading of the subtransmission conductor between Peat St and Castlecliff is above 80% thermal capacity.

Under a contingent configuration, the Peat St to Hatricks Wharf cable and Taupo Quay to Beach Rd conductor are loaded above acceptable level.

Options

1. A new 33kV circuit between Roberts Ave and Peat St.
2. A second transformer into Brunswick. This provides security, but not capacity.
3. Upgrade of the existing circuits into Whanganui from Whanganui GXP. This option attracts SAIDI, encounters much urban underbuilt lines, and is limited by river crossing tower structures.

Preferred option

The preferred solution is option 1, the construction of a new 33kV circuit between Roberts Ave and Peat St substations. The project will provide a partial alternative supply to Peat St.

A subsequent AMP21 project will upgrade the existing 33kV circuit between Brunswick GXP and Roberts Ave substation. These projects will create a secure supply to Peat St and Roberts Ave substations.

The project is subject to considerations under the Te Awa Tupua Act related to the Whanganui River and adjacent lands and streams.

A8.10.1.6 WHANGANUI GXP-TAUPO QUAY

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHANGANUI GXP TO TAUPO QUAY SECOND CIRCUIT	GRO	$3,750	2022-2023

Network issue

Taupo Quay and Hatricks Wharf are each fed by single 33kV circuits, but the substations are in parallel 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 backfeed Taupo Quay through Brunswick, Peat St, Castlecliff and Beach Rd. Additional security at Taupo Quay in the form of another circuit would mean such backfeed configurations would rarely 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 Whanganui GXP. Significantly greater capacity is required, especially on the Taupo Quay circuit, to enable secure supply under such contingencies.

Options

1. A new cable from Whanganui GXP to Taupo Quay.
2. A second transformer into Brunswick. This provides security, but not capacity.
3. Uprate of the existing circuits into Whanganui from Whanganui GXP. This option attracts SAIDI, encounters much urban underbuilt lines, and is limited by river crossing tower structures.

Preferred option

The preferred solution is option 1, to install an additional 33kV circuit from Whanganui GXP into Taupo Quay. This would operate in parallel with the existing circuit and improve security to Taupo Quay and the dependent substation of Beach Rd and contingent dependent Castlecliff. Peat St and Hatricks Wharf would benefit from the additional transfer capacity when Brunswick is offline. The solution begins to mitigate the risks of a single 220/33kV transformer at Brunswick GXP.

A8.10.1.7 PEAT ST-TAUPO QUAY

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PEAT ST TO TAUPO QUAY NEW 33kV LINE	GRO	$6,000	2022-2023

Network issue

Brunswick GXP is a critical supply point for the Whanganui subtransmission ring, but is limited in both security and capacity when compared with Whanganui GXP capability.

A recent initiative is progressing towards securing a second transformer for Brunswick GXP, and Transpower intends to replace the existing single phase bank transformer post 2025. A second transformer, even on a single bus connection, will provide valuable security to zone substations west of the river.

The capacity limitation is because of only having a single subtransmission feeder from Brunswick GXP into Peat St. This project seeks to double the available 36MVA capacity, reducing reliance primarily on the Castlecliff through Hatricks Wharf subtransmission circuits and, secondarily, on the Whanganui/Marton 110kV circuit.

Options

1. Expand the Whanganui GXP (Transpower) transformer capacities.
2. Bring new circuits out from Whanganui GXP (see Taupo Quay second 33kV project).
3. Establish a new substation off the 110kV, near Roberts Ave.
4. Instal a new circuit from Peat St to Taupo Quay.

Preferred option

The preferred solution is option 4. This second subtransmission line project aligns with present day thinking that capacity upgrades to Transpower's 110kV circuits are uncertain, and Whanganui ring reliance upon Brunswick GXP for future enabling capacity and security is advised.

A8.10.1.8 WHANGANUI GXP-WHANGANUI EAST

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHANGANUI EAST SECOND LINE	GRO	$2,020	2025-2027

Network issue

The Whanganui East substation supplies urban and rural loads to 5.2MVA. It aims to have a security class of AA. The substation is supplied by one single 33kV circuit from Whanganui GXP (N-security) and contains one very large 12.5/17MVA supply transformer.

There is potential for loss of supply at the substation for a transformer or subtransmission fault. There is also limited backfeed capability from the distribution network, approximately 3.4 MVA not served during an outage.

Options

1. Genset provision for the 3.4MVA not served during an outage. The lowest cost option would provide just a pad for temporary installs. The highest cost option is a permanently located genset package at either the sub or mid feeder tie.
2. A second supply line project.
3. Alternatives, such as increased backfeed would likely cost the same as the above proposed solution as there is no adequate transfer capacity, even with substantial distribution upgrade. BLB4 and ROB4 do not have the capacity to backfeed neighbouring feeders without a significant upgrade.

Preferred option

The preferred solution is option 2. A second subtransmission line from Whanganui GXP to Whanganui East substation.

A8.10.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Whanganui area.

A8.10.2.1 KAI IWI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$247	2023
11kV SWITCHBOARD ARC FLASH RETROFITS	ARR	$533	2022-23
W27 POWER TRANSFORMER REPLACEMENT	ARR	$1,416	2022-23

Fleet issue

The Kai Iwi switchroom building is at 20% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard is not arc flash/arc blast rated or arc flash protected, and includes oil circuit breakers (OCBs).

Kai Iwi has one Bonar Long 4.8MVA power transformer with a Fuller F3 OLTC. The transformer was manufactured in 1965 and will be 65 years old at the end of the planning period. The transformer is ranked 32 in the power transformer CBRM model. Kai Iwi has N transformer security with limited 11kV backfeed, so it is difficult to arrange an outage to carry out transformer maintenance.

Options

1. Do nothing.
2. Seismically strengthen the switchroom and refurbish the existing 11kV switchboard with vacuum circuit breakers, arc flash protection and arc flash doors/end panels. Replace the existing power transformer with a new low maintenance transformer. Upgrade the site for connection of the mobile transformer before installing the new transformer.
3. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard. Replace the existing power transformer with a new low maintenance transformer. Upgrade the site for connection of the mobile transformer before installing the new transformer.

Preferred option

The least cost, preferred solution is option 2. Option 3 is not preferred as it will be higher cost. Kai Iwi is likely to continue as a single transformer zone substation, it will therefore be best to replace the existing power transformer with a new low maintenance transformer, rather than an older refurbished transformer.

A8.10.2.2 TAUPO QUAY SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAUPO QUAY TRANSFORMER UPGRADE	GRO/ARR	$1,460	2023-2025
NEW 11kV SWITCHROOM AND SWITCHBOARD	ARR	$1,400	2021-22

Network issue

The existing transformer at Taupo Quay is 10/12.5MVA rated. The maximum demand at Taupo Quay is 5.4MVA, therefore it does not have the capacity to fully backfeed Hatricks Wharf load (13.5MVA) during an outage via 11kV bus tie if Hatricks Wharf was to lose supply from Whanganui GXP.

Fleet issue

W30 is a 1973 Power Construction transformer, with an older-style Fuller tap-changer. While the condition is reasonable for its age, given the number of leaks and Taupo Quay being an N-security substation, this is showing up as a high risk transformer site in our CBRM modelling. This is ranked 17 out of 117 substations in terms of risk.

The 11kV switchroom is <33% NBS, and the existing 11kV board does not meet arc flash requirements. We have a project under way to rebuild the11kV switchroom and 11kV switchboard.

Options

1. Do nothing. Probabilistic standards might preference this option.

2. Upgrade the transformer at Taupo Quay to 16/24MVA to support the full load at Taupo Quay and Hatricks Wharf during planned and forced outages.

Preferred option

The preferred solution is option 2, to upgrade the existing transformer to provide adequate contingent capacity to supply the Taupo Quay demand, future growth, plus Hatricks Wharf demand.

Presently, there is room for only one transformer at Taupo Quay substation. The site easement doesn't allow for installation of a second transformer, hence the need to upgrade the existing unit.

A8.10.2.3 CASTLECLIFF SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CASTLECLIFF TRANSFORMERS	GRO	$2,280	2023-2025
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$788	2024-25
11/33kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2024

Network issue

Castlecliff substation modelling, at present year forecast demand, shows an outage of one transformer will load the single transformer to firm capacity. There exists a local community preference to maintain a rating near to AA+ security class.

Options

1. Do nothing. Demand growth is healthy around the Peat St supply zone, although probabilistic standards might preference this option.
2. Upgrade both transformers with second-hand units. Two transformers from Kelvin Grove substation might become available if that upgrade is successful.

Preferred option

The preferred solution is option 2, to upgrade one or both transformers to provide firm capacity well above 10MVA, factoring for future growth. The present time suggestion would be for 1x17MVA transformer, although the exact rating would be decided during the feasibility design phase.

There might exist an opportunity to re-use 2x15MVA transformers from the Kelvin Grove upgrade, condition assessment pending, which introduces cost control.

Fleet issue

Castlecliff substation has mismatched transformers, which is an operational constraint. One of the power transformer units has experienced mech box failures. We have also had a number of issues with the 33kV switchboard, which is housed in an extension to the original 11kV switchroom. The extension was constructed in 2004 and is not weather tight. This has further exacerbated the 33kV switchboard issues.

The Castlecliff switchroom building is at 65% NBS, which is marginally below the 67% NBS required for seismic compliance. The 11kV switchboard is not arc flash/arc blast rated or arc flash protected, and includes OCBs. The 11kV switchboard does have more modern electronic protection relays, however these relays do not offer arc flash protection elements.

Options

1. Do nothing.
2. Seismically strengthen the 33/11kV switchroom and refurbish the existing 11kV switchboard with vacuum circuit breakers, arc flash protection and arc flash doors/end panels. Replace the existing power transformers.
3. Construct a new 11kV switchroom and install a new arc flash rated 11kV switchboard. Replace the existing power transformers.

Preferred option

The preferred solution is option 2, to seismically strengthen the 33kV/11kV switchroom, arc flash retrofit the existing 11kV switchboard and replace the power transformers with new power transformers. The options proposed above will be examined in more detail at the conceptual design stage.

A8.10.2.4 ROBERTS AVE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
ROBERTS AVE UPGRADE AND SECOND TRANSFORMER	GRO/ARR	$2,070	2025-2027

Network issue

The Roberts Ave substation is situated in Aramoho, supplying the Aramoho industrial area and surrounding residential and rural areas.

The substation is supplied by one single 33kV circuit from the Brunswick GXP (N-security) and contains one supply transformer.

The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. There is also limited backfeed capability from the distribution network.

The fleet plan is to replace the existing transformer in 2024, which is an opportunity to uprate the unit and enable future customer demand growth.

Options

1. Install a second transformer.
2. Upgrade distribution backfeed capacity. Increased 11kV backfeed would be costly as there is not easily achievable transfer capacity that far upriver.
3. Do nothing.

Preferred option

The preferred solution is option 1, to design and land consent for an upgrade to a second transformer. A new probabilistic planning standard would likely defer actual installation until customer demand was closer to single transformer capacity.

Automation of backfeed switching points is being pursued under the routine planning budget. This will reduce the outage durations of any events that occur under a single transformer configuration.

A8.11 RANGITIKEI

A8.11.1 SUBTRANSMISSION NETWORK PROJECTS

A8.11.1.1 MARTON GXP-ARAHINA

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$211	2022
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$788	2023-24
ARAHINA SECOND SUBTRANSMISSION AND TRANSFORMER	GRO/ARR	$2,000	2025-2027

Network issue

The Arahina substation supplies urban and rural loads. It has a security class of A1 but AA is intended. The substation is supplied by one single 33kV circuit from Marton GXP (N-security) and contains one supply transformer. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer or subtransmission fault.

A fault on Arahina subtransmission supply will result in an outage on Rata substation as well. There is also limited backfeed capability from the distribution network. Arahina has 8.2MVA load, therefore, the neighbouring zone substations do not have the capacity to backfeed.

Options

1. Increased backfeed would be costly as there is no adequate transfer capacity, even with substantial distribution upgrade.
2. Second line and transformer.

Preferred option

The preferred option 2 is to install a second subtransmission supply and transformer at the substation.

Fleet issue

The 11kV switchroom is 35% NBS, which is below the 67% NBS required for seismic compliance. The 11kV switchboard consists of older Reyrolle OCBs without arc flash and arc blast protection. The power transformer CBRM risk ranking is 29 out of 115 sites. The single power transformer was manufactured in 1971 and has a Ferranti tap-changer. The transformer has a number of minor oil seeps and degraded paint, but is fully bunded. The fleet renewal drivers are weak, and so any refurbishment or renewal may be delayed until FY31/32 or as determined by development drivers.

Options

The options for renewal will be reviewed in more detail closer to the future FY31/32 implementation date.

Preferred option

The preferred option at this stage will be seismic strengthening of the existing switchroom and to retrofit the existing 11kV switchboard with vacuum circuit breakers and arc flash protection. The least cost, preferred option will be reviewed in more detail before the future implementation date.

A8.11.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Rangitikei area.

A8.11.2.1 LAKE ALICE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW LAKE ALICE SUBSTATION	GRO	$3,790	2025-2026

Network issue

Bulls and Pukepapa subs supply both residential and commercial customers, via Parewanui and Lake Alice feeders respectively. Demand is approaching voltage support limits on these feeders, but there are still customer load increase requests being submitted for approval. Significant backbone conductor upgrades would have an impact on SAIDI targets and would likely not provide the step change required.

Discussions have been ongoing for some time with local large irrigators, regarding the prospect of transferring their generator loads onto the main network. Successful conversion would mean a MW scale step change of demand on both feeders.

Some subtransmission extension preparatory work has already been completed along the Lake Alice feeder, in the form of overbuilt line, although has not been extended back to a sub yet.

Options

1. 22kV upgrade.
2. Genset solution located close to seasonal irrigators. The geographical spread of new conversion sites, and their prolonged operation profile during summer, escalates the cost of this option.
3. New substation close to new irrigator needs.

Preferred option

The preferred option 3 is for a new substation at the end of Lake Alice feeder to supply potential irrigation conversions from gensets. The project is being designed, but procurement and construction phases would only proceed when an MOU is established between parties.

A8.11.2.2 PUKEPAPA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
PUKEPAPA SECOND TRANSFORMER	GRO	$1,200	2026-2027
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2025
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$660	2026-27

Network issue

The Pukepapa substation is adjacent to Transpower's Marton GXP and supplies Marton's surrounding 5.5MVA rural residential and irrigation loads. It is the main distribution backup supply for the Arahina substation and, to a lesser extent, to the Bulls substation. Its security level is A1, although demand is forecast to approach 6MW after 2030.

The substation contains a single supply transformer and has N-1 subtransmission switching capability. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from the distribution network.

Options

1. Increased 11kV backfeed would be costly as there is no adequate transfer capacity.
2. Genset solution at site.
3. Second transformer.

Preferred option

The preferred solution is option 3, would install a second transformer at the substation. Probabilistic planning standards may defer the timeline or adopt an alternative option in the interim.

Fleet issue

The 11kV switchroom has been assessed as having a seismic capacity rating of 15% NBS. The 11kV switchboard consists of older Reyrolle OCBs without arc flash and arc blast protection. Pukepapa has two transformers – the 33/11kV transformer was manufactured in 1967 and the 11/22kV transformer was manufactured in 1988 by Tyree Power Construction Ltd.

Options

1. Do nothing.
2. Seismically reinforce the existing 11kV switchroom and upgrade the existing RPS switchboard with arc flash protection.
3. Build a new seismically compliant 11kV switchroom and install new arc flash rated switchgear in the new switchroom.

Preferred option

The preferred solution is option 2. Seismically reinforce the existing 11kV switchroom and upgrade the existing RPS switchboard with arc flash protection will be the least cost, preferred option.

A8.11.2.3 TAIHAPE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TAIHAPE INSTALL NEW SWITCHBOARD	GRO	$1,375	2025
TAIHAPE SECOND TRANSFORMER	GRO	$1,370	2026-2028
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$320	2024-25
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2023

Network issue

The Taihape substation supplies Taihape township's urban and rural load. There are several essential services within the 4.4MVA Taihape township, including private and public hospitals, police and the fire department.

The substation contains a single supply 8.5MVA transformer and has N-1 subtransmission switching capability. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation for a transformer fault. There is also limited backfeed capability from the distribution network because of the long distances and rural terrain.

Taihape substation has two 33kV incomers, which give the sub good security to expand the number of feeders and support any offloading plans of neighbouring substations.

Mangaweka feeder needs offloading through distribution ties and relocating switches. Voltage becomes marginal under normal configuration at end-of-line, and customer demand growth is difficult to supply. Overhead ties will be completed in stages in later years, along with switch moves, under the routine planning budget.

What is required is additional 33kV and 11kV circuit breakers and a tidy up of the unusual 11kV extended distribution bus arrangement.

Options

1. Increased 11kV backfeed is estimated to be costly in comparison to the other options, as there is no adequate transfer capacity.
2. Do nothing. With Mangaweka feeder requiring improvement, this option moves the need onto nearby substations, which would still need expansion works to support additional feeders for distribution of load purposes.
3. Install new 33kV and 11kV switchgear. The 33kV would be expanded, for future enabling of 33kV interconnects to new or uprated substations. The 11kV board would be simplified in arrangement but expanded in functional circuit breakers, to supply offloading feeds to Mangaweka and surrounding feeders.

Preferred option

The preferred option 3 is expansion works on the 33kV switch yard and a new expanded 11kV board. A solution project would install a second transformer at the substation. This will support the switchroom upgrade project also planned.

Fleet issue

The 11kV switchroom has been assessed as having a seismic capacity rating of 13% NBS. The 11kV switchboard consists of older Reyrolle circuit breakers without arc flash and arc blast protection.

Options

1. Do nothing.
2. Seismically reinforce the existing 11kV switchroom and upgrade the existing RPS switchboard with arc flash protection.
3. Build a new seismically compliant 11kV switchroom and install new arc flash rated switchgear in the new switchroom.

Preferred option

Preferred option 2 is seismically reinforce the existing 11kV switchroom and upgrade the existing RPS switchboard with arc flash protection will be the least cost, preferred option.

A8.11.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.11.3.1 WAIOURU SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
POWER TRANSFORMER REPLACEMENT	ARR	$814	2025-26
BACKFEED UPGRADE	GRO	$1,500	2026-28

Network issue

The Waiouru substation is situated just south of Waiouru. It supplies the Waiouru Military Camp and the surrounding rural areas. The substation is supplied by one single 33kV circuit from Mataroa GXP (N-security) and contains one supply transformer.

The demand has exceeded the class capacity, sustaining about 2.9MVA, and there is potential for loss of supply at the substation for a transformer or subtransmission fault. Because of these constraints, the Waiouru substation does not meet our required security level.

Options

1. Installation of a second subtransmission supply and transformer for the substation would be costly.
2. 11kV upgrade.

Preferred option

The preferred solution is option 2, increases 11kV distribution backfeed capability. Because of the long lengths and high impedances of the conductors, upgrades to 22kV could be a good option due to cost effectiveness, determined during design phase.

Fleet issue

Waiouru T1 is a 1963 Bonar Long transformer, which will be 68 years old at the end of the period, and is showing signs of leaking.

Options

1. Do nothing.
2. Refurbish existing T1R.
3. Replace transformer.

Preferred option

Given the age of the transformer, and limited supply redundancy, option 1 is not feasible. Option 2 is not preferred because of the age of the transformer and type of tap-changer, which are orphans. Our preferred solution is option 3, the replacement of the existing transformer with a new unit.

A8.12 MANAWATU

A8.12.1 SUBTRANSMISSION NETWORK PROJECTS

A8.12.1.1 LINTON GXP-NEW FERGUSON SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
PALMERSTON NORTH CBD	GRO	$25,000	2016-2023

Network issues

The Palmerston North CBD is supplied by three substations – Pascal St, Main St and Keith St.

- The Pascal St substation is connected to Linton GXP via two 33kV circuits. A third 33kV circuit runs between the Main St substation and the Pascal St substation. This circuit can provide limited backup to the Pascal St substation.
- The Keith St substation is connected to the Bunnythorpe GXP via two 33kV circuits. A third 33kV connects the Keith St substation to the Bunnythorpe GXP via the Kelvin Grove substation.
- The Main St substation is connected to the Keith St substation via two 33kV circuits.

This interconnected 33kV subtransmission supplying the three CBD substations is now experiencing constraints. The existing network does not have sufficient capacity to meet security requirements for the three substations. The network configuration means that all three substations are vulnerable to supply loss on a 33kV circuit supplying the respective substation.

Both Main St and Pascal St substations have already reached their capacity limit. Further expansions at these substation is not practical because of space limitations.

Because of these constraints, all three substations do not meet our required security level.

Options

1. Construct a new substation at Ferguson, install two new 33kV circuits from the Linton GXP to Ferguson substation, and two new 33kV circuits from Linton GXP to the Main St substation.
2. Construct a new substation at Ferguson, install a new 33kV circuit between the Linton GXP and the Ferguson substation, install new 33kV circuit between Linton GXP and the Main St substation, install a new 33kV circuit between Main St and Ferguson and divert the second Linton GXP to Pascal St 33kV circuit to connect to Ferguson substation.
3. Construct a new substation at Ferguson, install two new 33kV circuits between the Linton GXP and the Ferguson substation. Install two new 33kV circuits between Main St and Ferguson and install a new 33kV circuit between Pascal St and Ferguson.

Preferred option

The preferred solution is option 3, which involves constructing a new substation at Ferguson, installing two new 33kV circuits between the Linton GXP and the Ferguson substation, installing two new 33kV circuits between Main St and Ferguson, and installing a new 33kV circuit between the Pascal St and Ferguson substations.

This option will deliver the highest reliability benefits to the Palmerston North CBD. It will alleviate all the existing subtransmission constraints and, with the construction of a new substation at Ferguson, relieve the capacity issues at Main St and Pascal St substations. With this option, all three existing CBD substations will meet our required security levels.

Another benefit of this option is that it will transfer load from the Bunnythorpe GXP to the Linton GXP. The Bunnythorpe GXP has recently exceeded its capacity and does not meet our required security level. Because of its size and complexity, any upgrades at Bunnythorpe will be challenging and costly. The Linton GXP is operating well below capacity, so the increased use of Linton GXP to supply the Palmerston North CBD will reduce the loading on the Bunnythorpe substation and provide benefits in terms of diversity of supply into the Palmerston North CBD.

Note that the new Ferguson substation with single transformer has been completed together with the 11kV network interconnection. Also, some 33kV cables have been installed.

A8.12.1.2 SANSON-BULLS

PROJECT	DRIVER	COST ($000)	TIMING (FY)
SANSON-BULLS 33kV LINE	GRO	$11,500	2019-2023

Network issue

The subtransmission network supplying Feilding, Sanson and Bulls townships, including RNZAF Ohakea air base, does not meet Powerco's security of supply standards. There are capacity constraints on the existing circuits and a lack of alternative supply feeds during contingencies. Sanson substation is loaded beyond firm capacity, as is Transpower's Bunnythorpe GXP. The latter supplies this region, including most of Palmerston North.

In addition, the New Zealand Defence Force (NZDF) has embarked on significant upgrades to the airbase at Ohakea and has requested increased capacity beyond what can be supplied from our existing network. Advice from the Ministry of Defence is that the capital works will eventually increase airbase demand to 8MVA.

Options

The N-security resulting from the single Feilding-Sanson 33kV line, means alternative 33kV circuits are the most effective solutions. Similarly, non-network options could not address the intrinsic need for secure subtransmission.

The following shortlisted options were considered:

1. Construct a new 33kV line from Feilding substation to Sanson substation and install an 11kV remote switching device at Bulls substation and voltage regulators to provide voltage support.
2. Thermally upgrade the Bunnythorpe to Feilding 33kV lines, construct a new 33/11kV substation at Ohakea, construct a new 33kV line from Bulls substation to the new Ohakea substation, and install an automatic load transfer facility at Sanson substation.

Preferred option

The preferred solution is option 2, which involves thermally upgrading the Bunnythorpe to Feilding 33kV lines, constructing a new 33/11kV substation at Ohakea, constructing a new 33kV line from Bulls substation to the new Ohakea substation, and installing an automatic load transfer facility at Sanson substation.

In option 2, the Sanson substation will be normally supplied from Bulls via the new 33kV Bull-Ohakea-Sanson line. For a contingent event on the Bull-Ohakea-Sanson line, the automatic load transfer facility will ensure the Sanson zone substation will be switched over to be supplied from Feilding substation. The installation of the automated changeover switch (load transfer facility), will shift some load from the Bunnythorpe GXP to the Marton GXP, therefore relieving the congested Bunnythorpe GXP to Feilding 33kV circuits.

A8.12.1.3 LINTON GXP-TURITEA SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
TURITEA SUBSTATION NEW 33kV LINE	GRO	$2,000	2023-2025

Network issue

The Turitea substation supplies Massey University, Linton Military Camp, New Zealand Pharmaceuticals, and residential and rural load to the south-east of Palmerston North. Its single 33kV supply limits its security level to AA but AAA is intended. The substation has switched N-1 subtransmission switching capability from Bunnythorpe and Linton GXPs. The demand has exceeded the class capacity, and there is potential for loss of supply at the substation during a subtransmission fault.

Turitea substation 11kV backup supply is limited because it is located on the other side of Manawatu river and there is only three 11kV inter-tie to the feeders of other substations.

Because of these constraints, the Turitea substation does not meet our required security level.

Options

1. Construct a new 33kV line from Linton GXP to Turitea substation.
2. Increase the 11kV backfeed capability to Turitea substation.

Preferred option

The preferred solution is option 1, which involves constructing a new 33kV line from Linton GXP to Turitea substation. This will improve the security level of this substation.

Alternatives, such as increased backfeed, would be costly as there is no adequate transfer capacity.

A8.12.1.4 FEILDING-SANSON 33KV LINE

PROJECT	DRIVER	COST ($000)	TIMING (FY)
FEILDING-SANSON LINE UPGRADE	GRO	$1,400	2023-2025

Network issue

The Feilding-Sanson 33kV line supplies the Sanson zone substation through a single 33kV circuit (14.7km) with a section of Quail conductor, which has a thermal capacity of 9.5MVA (166A). The Sanson substation supplies 3,005 ICPs, including the RNZAF Base Ohakea, which will have a load increase of 3MVA. There is a project (IR14201) to upgrade a section of the Feilding-Sanson 33kV line to improve its thermal capacity to support the load increased at Ohakea. Upon completion of this project the new thermal limit of this line is 12.7MVA (Dog).

However, this 33kV line will also serve as an alternative supply to Bulls substation (current MD 5.7MVA) when the Sanson-Bulls 33kV interlink project, coupled with a new substation to supply Ohakea, is completed. This will link Sanson and Bulls substations at 33kV, providing the required security of supply to Sanson and Bulls as well as Ohakea. Total load for these three substations is about 18.6MVA.

The addition of Bulls substation load will overload the Sanson 33kV supply, hence a new line upgrade will be needed.

Options

1. Do nothing.
2. Upgrade Feilding-Sanson 33kV line to increase its thermal capacity.

Preferred option

The preferred solution is option 2. This will provide the capacity to support the additional loads.

A8.12.1.5 BUNNYTHORPE GXP-FEILDING

PROJECT	DRIVER	COST ($000)	TIMING (FY)
FEI EAST AND WEST THERMAL UPGRADE	GRO	$5,900	2023-2025
FEILDING NEW (THIRD) 33kV LINE	GRO	$8,500	2024-2026

Network issue

Feilding substation takes its 33kV supply from Bunnythorpe GXP by two lines, one is 8.6km (FEI East) and the other is 9.1km (FEI West). Each 33kV line has a conservative rating of 415A (23.7MVA, Butterfly). Feilding's 33kV bus supplies Sanson substation by one 14.5km line and Kimbolton substation by another 26.5km line. Also, Feilding will supply Bulls and Ohakea substations for the upcoming Sanson-Bulls 33kV interlink and future second Feilding zone substation.

The total demand of Feilding, Sanson, Bulls, Ohakea, Kimbolton and Feilding 2 substations on the Bunnythorpe-Feilding circuits will exceed their N-1 capacity.

Options

1. Do nothing.
2. Upgrade existing Feilding 33kV circuits.
3. Install a new 33kV line from Bunnythorpe GXP-Feilding substation.

Preferred option

The preferred solutions are options 2 and 3.

These will provide adequate capacity for the future demand with appropriate security.

A8.12.1.6 BUNNYTHORPE GXP-NORTH EAST INDUSTRIAL SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW 33kV LINE BPE-NEI	GRO	$3,500	2024-2026

Network issue

A 33kV supply will be needed for the proposed new zone substation in the North Industrial Area to accommodate the load growth on the north-east side of Palmerston North.

Options

1. Use the existing BPE-KST 33kV line to supply the new zone substation.
2. Install a new 33kV line from Bunnythorpe GXP to the new North East Industrial zone substation.

Preferred Option

The preferred solution is option 2. This will increase the security of supply to the new zone substation.

Option 1 could be used initially to supply the new substation and as an alternative after the completion of the new 33kV line.

A8.12.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Manawatu area.

A8.12.2.1 SANSON-BULLS SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
SANSON-BULLS RIPPLE INJECTION PLANT	REL	$956	2021-2022

Network issue

Powerco has initiated a project to transfer the 33kV supply to Sanson substation from Bunnythorpe GXP to Marton GXP. Details of this project are covered in IR13371. Sanson zone substation is supplied from Bunnythorpe GXP, which has a load control system operating on 317 and 750Hz. The Marton GXP has a load control system operating on 383Hz.

Transferring Sanson substation across from Bunnythorpe GXP to the Marton GXP will result in the loss of control of any load control receivers (both 317 and 750Hz) on the Sanson network. The converse also applies when, as part of mitigating a system contingent event, the supply to Bulls substation, which is on the Marton GXP, is transferred across to the Bunnythorpe GXP – control of the 383Hz receivers will be lost. The normal configuration of injection plant signalling frequency and coupling cell allows for two-frequency operation, as currently at Bunnythorpe, but the need to provide both 750 and 317Hz signalling for the Sanson network from Marton injection plant is problematic.

Options

1. Do nothing.
2. Install two 11kV injection plants to provide control for two-frequency operations (317Hz and 383Hz) that will allow the transfer of Sanson and Bulls substations to different GXPs without loss of control to any load control receivers.

Preferred option

The preferred solution is option 2.

A8.12.2.2 KELVIN GROVE SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
KELVIN GROVE TRANSFORMER UPGRADE	GRO	$3,045	2021-2022
NEW 33kV/11kV SWITCHROOM AND SWITCHBOARDS	ARR	$5,167	2025-27
11kV SWITCHBOARD REPLACEMENT	ARR	$1,108	2025-26

Network issue

The Kelvin Grove substation supplies the commercial, industrial, and residential loads in Palmerston North city, and the rural load to the north of Palmerston North city. The substation contains two transformers. The demand has exceeded the transformers' capacity, and there is potential for loss of supply at the substation for a transformer fault.

There is also limited backfeed capability from the 11kV distribution network. Because of these constraints, the Kelvin Grove substation does not meet our required security level.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
2. Increase the 11kV backfeed capability to Kelvin Grove. This option assumes that the backfeeding capability from the neighbouring substation can be increased to cover the forecast demand.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. It will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeeding capacity, is not favoured because of the complexity of upgrading the mix of conductors on some of the lines. In addition, the switching required on the 11kV network can take a considerable amount of time for a substation outage.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term reliability of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs.

Fleet issue

The existing outdoor 33kV swithyard uses Schneider dogbox 33kV circuit breakers, which have type issues related to internal moisture buildup. The existing indoor 11kV switchboard is an orphan, being the only board of its type on our network, is no longer supported, and is not arc flash rated. The 11kV switchgear building has a seismic capacity rating of 60% NBS.

Options

1. Do nothing.
2. Seismically reinforce the existing 11kV switchroom, install new 11kV switchgear, and replace the existing outdoor Schneider dogbox 33kV circuit breakers.
3. Build a new seismically compliant combined 11kV and 33kV switchroom and install a new 33kV indoor switchboard and a new 11kV switchboard.

Preferred option

The preferred solution is option 3, to better future proof this key site. Option 2 is not preferable because of safety and supply risk in complete switchboard replacement into the existing building.

A8.12.2.3 FEILDING SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW FEILDING ZONE SUBSTATION	GRO	$5,800	2025-2027
NEW COMBINED 33/11kV SWITCHROOM AND SWITCHBOARDS	ARR	$4,800	2022-23

Network issue

The Feilding substation supplies Feilding and the associated commercial, industrial, residential, and rural loads in the area. The substation contains two transformers nominally rated at 21MVA each. The load growth is high in areas covered by Feilding substation. The demand forecast for 2021/2025/2030 are 21.8/22.5/23.5MVA respectively, which will exceed the firm capacity of the transformers. Because of limitations in backfeed capability, the security of supply will not be adequate as load grows.

Options

1. Increased 11kV backfeed. The distance to Feilding from comparably sized secure substations precludes this option.
2. Install a third transformer. This would be a non-standard substation configuration, which we would prefer to avoid because of the additional protection complexity.

3. New zone substation. A new zone substation for Feilding is a viable long-term strategy. 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.

Preferred option

The preferred solution is option 3, to build another zone substation in Feilding. This is a more appropriate long-term strategy. The transformers at Feilding can be rerated to provide N-1 capacity giving sufficient time for the establishment of a second zone substation.

Our approach to the 33kV supply for a second Feilding zone substation is to build a new 33kV capable line from the existing Feilding substation.

Fleet issue

The existing overhead 33kV bus and structure arrangement is old and poses operational safety risks. Additionally, the existing switchroom building is at 65% NBS. The existing 11kV switchboard does not meet the Powerco requirement for arc flash mitigation and is a risk to operators.

The majority of the legacy 33kV and 11kV switchgear assets date back to 1965 and are at the end of life. The 33kV outdoor bulk oil circuit breakers and their associated instrument transformers are all original 1965 equipment – the oil current transformers have needed temporary repairs to stop leaks, and issues with one of the circuit breakers in 2011 required complete replacement as we no longer have parts to service these assets.

The existing 33kV outdoor switchyard has minimal room for future expansion and has 33kV clearance issues.

Options

1. Do nothing.
2. A full 33kV outdoor to indoor conversion (ODID) in a new combined 33kV/11kV switchroom. Installation of a new arc flash compliant 11kV switchboard.
3. Seismically strengthen the existing 11kV switchroom building. Carry out an arc flash upgrade on the existing 11kV switchboard combined with installing new 33kV outdoor circuit breakers.

Preferred options

Option 2 is the preferred solution and will include a full outdoor to indoor 33kV conversion (ODID) in a new combined 33kV/11kV switchroom, together with the installation of new arc flash compliant 11kV switchboard. Option 1 does not resolve the seismic and arc flash issues. Option 3 does not address the clearance issues in the 33kV outdoor switchyard.

A8.12.2.4 PARKVILLE SUBSTATION

PROJECT	DRIVER	COST ($000)	TIMING (FY)
NEW 7.5/10MVA TRANSFORMER	ARR	$521	2022

Fleet issue

Parkville 11kV was upgraded in 2018. In FY21, power transformer T1 experienced a low voltage (LV) winding failure because of lightning. We have installed our emergency spare transformer to restore the network to normal. The use of the emergency spare transformer at Parkville is a temporary arrangement until a permanent replacement has been ordered and commissioned at site.

Options

1. Do nothing, retaining the old spare transformer.
2. Purchase/install a new 7.5/10MVA transformer.

Preferred option

Option 2 is the preferred solution – purchasing a new 7.5/10MVA cabled unit to replace (and scrap) the emergency spare transformer.

The emergency spare is an older unit and is only intended for temporary reinstatement. It still requires a full refurbishment in order to provide sufficient confidence. Relying on the emergency spare unit is not ideal as this leaves an unacceptable level of risk remaining at this N-security site.

A8.12.2.5 NEW NORTH EAST INDUSTRIAL SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NORTH EAST INDUSTRIAL SUBSTATION	GRO	$5,300	2023-2026

Network issue

Kelvin Grove substation supplies several important loads, including the North East Industrial area.

The North East Industrial area has been planned as a transport and warehouse hub because of its strategic location in the national transport infrastructure.

There is major industrial load emerging within the industrial park and surrounding area. There are some commercial and small industrial customers, namely Leisureplex, Ezibuy, Allflex, Budget Plastics and Vesta.

Kelvin Grove substation forecast 2030 demand is about 19MVA and the transformers are scheduled to be upgraded in FY 2021-22 to 2x24MVA units. However, with the addition of the Woolworth hub (2MVA) plus the proposed Hiringa Energy refuelling station (1.4MW initially) and the proposed KiwiRail hub (2MW initially) in this area, Kelvin Grove would likely exceed the 24MVA capacity of its single transformer. Neighbouring Milson substation has 2x12.5/17MVA transformers and the demand forecast in 2030 is about 18MVA.

Options

1. Construct a new zone substation to accommodate the load growth on the north-east side of Palmerston North. A new 33kV circuit from Bunnythorpe GXP will be needed to supply this new substation.
2. Construct a new 11kV feeder from Kelvin Grove substation.
3. Upgrade existing 11kV feeders.

Preferred option

The preferred long-term solution is to establish a new zone substation, named North East Industrial to cater for the load growth in this area.

The other options are not enough to provide long-term security of supply in this area.

A8.12.2.6 NEW LINTON ARMY CAMP SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
LINTON ARMY CAMP SUBSTATION	GRO	$5,000	2023-2025

Network issue

The New Zealand Defence Force (NZDF) operates New Zealand's largest military barracks and associated facilities at Linton, near Palmerston North. Future planned upgrades to the military base include the decommissioning of coal fired boilers, which will increase the power demand. An additional 5MVA of load is forecast, in addition to the existing 1.7MVA supply to the military base.

Linton Army Camp is primary supplied at 11kV from CB6 (Linton Express feeder) at the Turitea substation. The backup supply is from Kairanga substation CB12 (Awapuni feeder).

There are thermal capacity (ampacity) and voltage drop restrictions on the existing overhead and cable 11kV feeders, which restrict the load that can be supplied from the existing distribution network.

The existing firm capacity of the zone substations and 11kV overhead lines supplying the military base can supply an additional 0.3MVA of load before network upgrades are required to facilitate the proposed load increase.

Options

1. Construct a new zone substation within or adjacent to the military base.
2. Construct a new 11kV feeder from Turitea substation.
3. Upgrade existing 11kV feeders.

Preferred option

The preferred solution is option 1, to establish a new 33/11 kV substation within or adjacent to the military base. The proximity of the proposed substation to the new load centres is such that 11kV voltage drop and conductor ampacity constraints to the upgraded NZDF 11kV network are minimised. The initial primary supply for this new substation will come from the existing 33kV line (Linton-Kairanga) near the Linton Army Camp.

The other options are not enough to provide long-term security of supply for the base.

A8.12.2.7 KAIRANGA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KAIRANGA TRANSFORMERS	GRO	$2,140	2025
33kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$660	2024-25
NEW 11kV SWITCHROOM AND SWITCHBOARD	ARR	$1,860	2024-25

Network issue

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 forecast for 2021/2025/2030 is 18/18.5/19.1MVA respectively, which has exceeded the transformer firm capacity.

High growth is expected on this substation because of both residential and agricultural developments.

Options

4. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
5. Increase the 11kV backfeed capability to Kairanga substation. This option assumes that the backfeeding capability from neighbouring substations can be increased to cover the forecast demand.
6. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeed capacity, is not favoured because of the complexity of upgrading the mix of conductors on some of the lines. In addition, the switching required on the 11kV network can take a considerable amount of time for a substation outage.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term reliability of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs.

Fleet issue

The Kairanga 11kV switchboard is an orphan (Merlin Gerin FLURAC FG1) and is one of the last two remaining FG1 type switchboards on the Powerco network. This switchgear is no longer supported, cannot be extended, and spare parts cannot be sourced. This switchboard does not have a bus section circuit breaker. Bus section facilities are achieved by a section of 11kV cable between two feeder class circuit breakers. In addition, the existing switchroom has an assessed seismic capacity of 15% NBS. The switchroom has a number of cracks and signs of water ingress. In addition, the current site is low lying, with an increased risk of flooding.

The Kairanga outdoor 33kV switchyard has Takaoka circuit breakers, which were refurbished in 2013. These will be 49 years old at the end of the planning period and will be past their expected service life.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom, replace the 11kV indoor switchboard with a new equivalent 11kV switchboard, and replace the 33kV outdoor circuit breakers on a like-for-like basis.
3. Construct a new 11kV switchroom, install a new 11kV switchboard and replace the 33kV outdoor circuit breakers on a like-for-like basis.
4. Construct a new combined 33kV/11kV switchroom and install new 33kV and 11kV indoor switchboards.

Preferred option

The preferred solution is option 4, to construct a new 11kV switchroom, install a new 11kV switchboard, and replace the 33kV outdoor circuit breakers on a like-for-like basis. Option 2 is not preferred, as upgrading the existing switchroom can not be carried out easily as it is in poor condition and has an assessed seismic capacity of 15% NBS. Option 3 is also not preferred as it will be higher cost than option 4.

A8.12.2.8 TURITEA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TURITEA TRANSFORMERS	GRO/ARR	$2,140	2024-2025
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2022
33kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$660	2024-25

Network issue

Turitea supplies Massey University, Linton Military Camp, New Zealand Pharmaceuticals and residential and rural load to the south-east of Palmerston North.

It has two 12.5/17MVA transformers, each of which have a continuous/4/2-hour rating of 15/19/21.9MVA. The transformers were manufactured in 1970 and the projected demands for 2020/2025/2030 are 16.6/17.6/18.7MVA. This will exceed the single transformer capacity.

A consultant was previously engaged by Massey to review the feasibility of electrifying its existing gas-fired heating systems. The consultant estimated an expected 10-15MW of additional demand if the heating system is changed to electricity from gas.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for future demand and improve the security level.
2. Increase the 11kV backfeed capability to Turitea substation. This option assumes that the backfeed capability from the neighbouring substation is sufficient to supply the projected Turitea increase in demand.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeeding capacity, is not favoured as the substation 11kV backup supply is limited because it is located on the other side of Manawatu river and there are only three 11kV inter-ties to the feeders of other substations.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term security of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution but have higher operational and maintenance costs.

Fleet issue

Turitea's matched pair of power transformers were originally installed at Feilding zone substation. These were manufactured in 1970 and have Ferranti tap-changers. They will be 61 years old at the end the planning period.

The 11kV switchroom building has an assessed seismic capacity of 15% NBS. The 11kV switchboard was renewed and upgraded in 2016, so it is arc flash compliant and does not contain any oil circuit breakers.

The three of the 33kV circuit breakers are older English OKW minimum oil circuit breakers reaching end of service life.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and replace older 33kV circuit breakers.
3. Construct a new seismically compliant 11kV switchroom, and install a new 11kV switchboard and replace older 33kV circuit breakers.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom and replace the outdoor circuit breakers like for like. Option 3 is not preferred as it will be higher cost with limited benefit, especially given the current 11kV switchboard was installed in 2016.

A8.12.2.9 MILSON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MILSON TRANSFORMERS	GRO	$2,140	2026-2027
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$535	2021-22
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2021-2022

Network issue

Milson supplies the industrial, commercial and residential load in western Palmerston North, including the airport and industrial park. It has two 12.5/17MVA transformers, each with a continuous/4/2-hour rating of 15/19.2/22.1MVA. The transformers were manufactured in 1980 and the forecast demands for 2020/2025/2030 are 16.8/17.3/17.8MVA, which is close to exceeding its single transformer capacity.

Also, there is an ongoing development along Airport Drive (CIW). The total area covered by the subdivision is about 30 hectares, but much of that is existing load. The land area available for new load is about 20 hectares. Based on transformer density for commercial/industrial land in Palmerston North, the new transformer capacity that might be installed in that development will be somewhere between 3.1MVA and 4.6MVA. This development will affect the demand on the Milson substation.

Options

1. Replace the existing transformers with two larger units to provide adequate capacity for the future demand and improve the security level.
2. Increase the 11kV backfeed capability to Milson substation. This option assumes that the backfeeding capability from the neighbouring substation can be increased to cover the forecast demand.
3. Generation or energy storage.

Preferred option

The preferred solution is option 1, which involves replacing the existing transformers with two larger units. This will provide adequate capacity for the future demand. This will also improve the security level, although to fully meet our required security level, enhancement to the subtransmission network will be needed.

Option 2, which involves increasing the capacity of the 11kV feeders to provide the required backfeeding capacity, is not favoured because of the complexity of upgrading the mix of conductors on some of the lines. In addition, the switching required on the 11kV network can take a considerable amount of time for a substation outage.

Option 3 is not preferred. There are no economically comparable options for local generation or battery storage that would achieve the long-term reliability of supply and provide for expected load growth at reasonable cost. Costs for an installed diesel generation solution would be similar to the transformer upgrade solution and have higher operational and maintenance costs.

Fleet issue

The existing switchroom building at 40% NBS is below the 67% NBS value required for seismic compliance. The 11kV switchboard does not meet Powerco requirements for arc flash mitigation, and poses a risk to operators.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and carry out an arc flash retrofit of the existing switchboard.
3. Construct a new seismically compliant 11kV switchroom, and install a new arc flash rated 11kV switchboard.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom. Option 3 is not preferred as it will be higher cost.

A8.12.3 SIGNIFICANT DISTRIBUTION NETWORK PROJECTS

A8.12.3.1 SANSON SUB-OROUA DOWNS

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
OROUA DOWNS EXPRESS FEEDER	GRO	$5,500	2023-2025

Network issue

The Oroua Downs feeder from Sanson sub is, in its current configuration, very long and serving about 1,331 ICPs. There are two voltage regulators on this feeder, VR-4183 and 10269. The 11kV network from Rongotea Rd to Himatangi Beach along SH1 has experienced significant load growth from irrigation. Farmer feedback suggests that at certain times of the day during irrigation periods the network along Himatangi Beach Rd is below acceptable voltage level.

Because of the length and demand of the feeder, growth is constrained in this area and additional customer load cannot be added without voltage levels decreasing below regulated limits. Customers have expressed frustration at the inability to connect new large loads in this area. A voltage dip recently occurred in Himatangi area when work was being done on the network that necessitated high voltage (HV) switching, causing issues for irrigators.

There is an initiative for creating a link from Electra's network to resolve the issue and improve the capacity of the feeder in this area. However, discussion is still continuing.

A new substation (Rongotea) in the area would resolve the issue but would come at a significant cost. The approach to the 33kV supply for the proposed Rongotea zone substation is to build a new 33kV capable line from Kairanga or Sanson substation and initially operate as an additional 11kV feeder.

Options

1. Construct a new 17km express underground HV feeder, splitting Oroua Downs feeder, as the first phase for the proposed long-term solution – to build a new zone substation.
2. Upgrade existing 11kV feeders.

Preferred option

The preferred solution is option 1.

A8.13 TARARUA

A8.13.1 SUBTRANSMISSION NETWORK PROJECTS

A8.13.1.1 MANGAMAIRE GXP-PONGAROA SUB

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
VOLTAGE REGULATOR ON PONGAROA 33kV FEEDER	GRO	$542	2023-32
PONGAROA 33kV UPGRADE LAMPREY TO COYOTE	GRO/ARR	$4,347	2023-32

Network issue

Pongaroa 33kV feeder comprises 41.4km of overhead line using Lamprey conductor in rough terrain. Lamprey is a light capacity smooth body aluminium conductor steel reinforced (ACSR). The high resistance of this conductor combined with the length of this feeder causes excessive voltage drop.

When supply from Eketahuna 33kV (Mangamaire GXP to Parkville substation) feeder is lost, Pongaroa 33kV feeder carries the entire load of the Mangamaire-Parkville-Alfredton-Pongaroa 33kV ring. During this contingency scenario, the bulk of the load is also at the end of the open 33kV ring. This causes 33kV bus voltages of 84.5% at Pongaroa substation, 79.7% at Alfredton substation, and 77.6% at Parkville substation, even at present demand levels.

Options

1. Do nothing.
2. Reconstruct the entire Pongaroa 33kV feeder, 41.4km of overhead line with Coyote conductor.
3. Install 33kV voltage regulator at the Pongaroa end of Pongaroa 33kV feeder.
4. Install 33kV voltage regulator at the Pongaroa end of Pongaroa 33kV feeder and upgrade failure prone parts of Pongaroa 33kV feeder.

Preferred option

The preferred solution is option 4.

A8.14 WAIRARAPA

A8.14.1 SUBTRANSMISSION NETWORK PROJECTS

A8.14.1.1 GREYTOWN GXP-NEW “THE KNOLL” SUBSTATION AT BIDWELLS-CUTTING

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
BIDWELLS 33kV FEEDER EXTENSION TO GREYTOWN GXP	GRO	$1,840	2025-28
NEW ZONE SUBSTATION IN BIDWELLS-CUTTING	GRO	$3,233	2025-28

Network issue

This project addresses multiple subtransmission security issues and zone transformer security issues.

Contingency modelling of the Greytown-Featherston-Martinborough 33kV ring (with its 33kV spur lines to Tuhitarata and Featherstone subs) shows insufficient N-1 capacity.

An outage on the Greytown-Martinborough 33kV feeder causes the Greytown-Featherston 33kV feeder to overload at 111% thermal loading, and causes 33kV bus voltages of 89.2%, 88.8% and 89.1% at Tuhitarata, Martinborough and Hau Nui zone substations respectively.

An outage on the Greytown-Featherston 33kV feeder causes the Greytown-Martinborough 33kV feeder to overload at 110% thermal loading, and 33kV bus voltage of 90% at Featherston zone substation.

Furthermore, Martinborough, Kempton, Tuhitarata and Hau Nui are all single transformer substations and, as such, require full or near full 11kV transfer capacity.

The relivening and extension of Bidwells’ 33kV feeder solves the subtransmission security issue by adding 16MVA capacity to the Greytown-Featherston-Martinborough 33kV ring and providing voltage support during contingency to all substations supplied by this ring.

The new substation at Bidwells-Cutting, which draws dual 33kV supply from the relivened and extended Bidwells 33kV feeder, will improve transfer capacity to N-security substations Kempton, Tuhitarata and Hau Nui. This will defer, for a number of years, distribution capacity upgrades and dual transformer upgrades at these substations. This new substation is to be named “The Knoll” to avoid confusion with the existing Bidwells 33kV switching station.

Options

1. Upgrade Greytown-Featherston and Greytown-Martinborough 33kV feeders. Upgrade Dairy Factory, Kumenga, Dyerville, Cologne St and Moroa 11kV feeders.
2. Upgrade Greytown-Featherston and Greytown-Martinborough 33kV feeders. Convert Martinborough, Kempton and Tuhitarata to dual transformer substations.
3. Reliven and extend existing Bidwells 33kV feeder and build new zone substation in Bidwells-Cutting.

Preferred option

Option 3 is preferred because of the better cost benefit.

In addition, not only does adding a third 33kV line to the Greytown-Featherston-Martinborough ring cost less, it also provides significantly more capacity in comparison to rebuilding the existing ring for higher capacity.

A new substation also increases distribution feeder reliability for the feeders involved in transfer capacity.

A8.14.1.2 MASTERTON GXP-CLAREVILLE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
RE-TENSION CLAREVILLE-1 33kV FEEDER	GRO	$352	2026-28
RE-TENSION CLAREVILLE-2 33kV FEEDER	GRO	$313	2026-28

Network issue

Clareville is an AA substation that supplies approximately 10MVA of load and 4,500 ICPs in Carterton township and surrounding areas. This substation is supplied by two 33kV feeders from Masterton GXP.

Clareville substation is expected to undergo significant growth because of load increases at industrial customers such as Premier Beehive, in the near future, and council plans for subdivisions. These include industrial and commercial lots in the southern areas of Carterton and more than 2,000 residential lots in the surrounding areas during the next 30 years.

Contingency analysis shows 96.6% loading on Clareville-1 33kV feeder and 95.9% loading on Clareville-2 33kV feeder.

Clareville substation transformer upgrades are due to commence in FY23.

Options

1. Rebuild Clareville-1 and Clareville-2 33kV feeders. These two feeders have recently had pole replacements carried out.
2. Re-tension Clareville-1 and Clareville-2 33kV feeders.
3. Strengthen automated 11kV backfeeds to Clareville substation. Clareville substation is surrounded by N-security substations, with the exception of Norfolk substation. However, the distribution feeder connection to Norfolk substation is weak, and even with a full overhead 11kV line upgrade of more than 14km, because of excessive length it fails to provide a significant part of Clareville substation's full load.

Preferred option

Option 2 is preferred. As Clareville-1 and Clareville-2 feeders have already had recent pole replacements, and the conductor is believed to be in reasonable condition, a full rebuild is unnecessary. In terms of 11kV backfeed, it is overall a more economical strategy to maintain sufficient N-1 capacity to Clareville substation and use this capacity to support the surrounding N-security substations, such as Kempton and Gladstone.

A8.14.1.3 MASTERTON GXP-NORFOLK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
CONVERT 800M OVERHEAD 33kV DUAL SUPPLY TO UNDERGROUND	GRO	$588	2024-26
RE-TENSION 1.1KM OF DUAL 33kV OVERHEAD LINE	GRO	$93	2024-26

Network issue

The Masterton-Norfolk 33kV feeder is part of the Masterton-Chapel-Norfolk 33kV ring that supplies Chapel and Norfolk zone substations.

Norfolk substation supplies about 6.5MVA of predominantly industrial load (300 ICPs) and is of AA+ security classification. Two of the largest customers supplied by this substation, JNL (4.2MVA) and Kiwi Lumber (1.8MVA) are planning load increases in the near future.

Chapel substation supplies about 15MVA of load (4,300 ICPs) and is classified as AAA. It supplies Masterton CBD and provides some 11kV backup to feeders from neighbouring substations. Notable customers are Masterton bus depot, major supermarkets in the area, and ChargeNet EV charger. As electric vehicle (EV) use in the region expands, this load is likely to grow rapidly.

Masterton-Chapel 33kV feeder is being upgraded, and upgrades to the 11kV and 33kV switchgear at Chapel substation, and upgrades to the distribution network off Chapel substation, are also planned.

Sufficient 33kV capacity and security on the Masterton-Chapel-Norfolk 33kV ring, in combination with these planned upgrades would:

1. Bring Chapel substation up to standard as per its security classification.
2. Enable increased utilisation of excess zone transformer capacity at Chapel substation for the purpose of increasing the security of neighbouring Akura and Te Ore Ore substations, through the 11kV network. This, therefore, defers investment on the Masterton-Akura-Te Ore Ore ring, which is also short of N-1 capacity.

However, contingency modelling shows Masterton-Norfolk 33kV feeder at 163% thermal loading.

Masterton-Norfolk 33kV feeder is a 1.91km long overhead line. It is built together side-by side with the first 1.91km of the Masterton-Akura 33kV feeder. These two feeders run up Cornwall Road from Masterton GXP, cross State Highway 2, and run up Norfolk Rd until they reach Norfolk substation.

On Norfolk Rd, there is 11kV and LV overhead built under the 33kV dual line in a non-standard configuration that makes servicing the 11kV line nearly impossible to be carried out safely without causing major outages. The 11kV feeder supplies Waingawa Industrial Park and, as such, would ideally be of high reliability.

Options

1. Re-tension or rebuild with higher capacity Jaguar conductor the Masterton-Norfolk 33kV feeder in present configuration. This option fails to resolve safety and reliability issues on Norfolk Rd.
2. Convert Norfolk Road part (800m) to underground and re-tension or rebuild with higher capacity Jaguar conductor the Cornwall Rd part (1.1km) of the 2x33kV feeder.
3. Convert the entire length (1.9km) along Norfolk Rd and Cornwall Rd of the 2x33kV feeders to underground.

Preferred option

Option 2 is preferred, as the Cornwall Rd part of the dual 33kV line is in good condition.

A8.14.1.4 CHAPEL SUBSTATION-NORFOLK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
REBUILD 2.2KM OF CHAPEL-NORFOLK 33kV OVERHEAD LINE	GRO	$510	2024-26

Network issue

The Chapel-Norfolk 33kV feeder is part of the Masterton-Chapel-Norfolk 33kV ring that supplies Chapel and Norfolk zone substations.

Norfolk substation supplies about 6.5MVA of predominantly industrial load (300 ICPs) and is of AA+ security classification. Two of the largest customers supplied by this substation, JNL (4.2MVA) and Kiwi Lumber (1.8MVA) are planning load increases in the near future.

Chapel substation supplies about 15MVA of load (4,300 ICPs) and is classified as AAA. It supplies Masterton CBD and provides some 11kV backup to feeders from neighbouring substations. Notable customers are Masterton bus depot, major supermarkets in the area, and ChargeNet EV charger. As EV use in the region expands, this load is likely to grow rapidly.

Masterton-Chapel 33kV feeder is being upgraded, and upgrades to the 11kV and 33kV switchgear at Chapel substation, and upgrades to the distribution network off Chapel substation, are also planned.

Sufficient 33kV capacity and security on the Masterton-Chapel-Norfolk 33kV ring, in combination with these planned upgrades would:

1. Bring Chapel substation up to standard as per its security classification.
2. Enable increased utilisation of excess zone transformer capacity at Chapel substation for the purpose of increasing the security of neighbouring Akura and Te Ore Ore substations, through the 11kV network. This, therefore, defers investment on the Masterton-Akura-Te Ore Ore ring, which is also short of N-1 capacity.

Chapel-Norfolk tie feeder is an overhead line just over 7km long. Contingency modelling shows 134% thermal loading.

Options

1. Re-tension existing Dingo conductor to 70°C.
2. Rebuild line with Jaguar conductor.
3. Add new feeder to the Masterton-Norfolk-Chapel 33kV circuit.

Preferred option

The preferred solution is option 2, as it optimally addresses the capacity issue on the ring, as well as the age and condition issue on the existing Chapel-Norfolk 33kV tie feeder.

A8.14.1.5 MASTERTON GXP-AKURA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
RE-TENSION 5KM 33kV OVERHEAD LINE	GRO	$210	2024-26

Network issue

The Masterton-Akura 33kV feeder is a 6.9km long overhead line and is part of the Masterton-Akura-Te Ore Ore 33kV ring that supplies Akura and Te Ore Ore zone substations. A 33kV spur off this ring also supplies Awatoitoi and Tinui zone substations.

Akura substation supplies about 13MVA of load (4,500 ICPs) and is classified as AAA. It supplies the area stretching from the northern part of Masterton City to the Mount Bruce area. The northern Masterton area is a mix of urban residential, commercial and industrial loads.

Notable industrial customers supplied by Akura substation are Breadcraft Ltd, Hansells Ltd and Webstar Ltd.

Te Ore Ore zone substation supplies about 7MVA of load and 3,200 ICPs, including Masterton Hospital. Te Ore Ore substation has AA+ security classification.

Contingency modelling shows 125% loading on Masterton-Akura feeder.

On its GXP end, 1.9km of this feeder is planned to be upgraded under the Masterton-Norfolk 33kV upgrade.

Options

1. Re-tension 5km on the Akura end of the Masterton-Akura 33kV feeder.
2. Utilise excess zone transformer capacity at Chapel substation to provide 11kV backup for Akura and Te Ore Ore substations, and therefore defer investment on Masterton-Akura 33kV feeder to FY24.

Preferred option

Option 2 is preferred.

A8.14.2 ZONE SUBSTATION PROJECTS

Below are summaries of the major Growth and Security projects planned for the Wairarapa area.

A8.14.2.1 GREYTOWN GXP

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
GREYTOWN 33kV SWITCHGEAR OUTDOOR TO INDOOR CONVERSION	GRO	$4,208	2022-2024

Network issue

Powerco neither owns nor operates any of the 33kV switchgear at Greytown substation. There are no remotely operable bus coupling devices on the Greytown GXP 33kV bus. This means that Greytown GXP 33kV bus is at N-security. Isolation or repair of a bus fault at Greytown GXP generally takes four hours or more, causing, on average, more than $900,000 in lost load per outage, as Powerco relies on Transpower work parties at Haywards GXP travelling to Greytown to carry out any isolations and fault work.

Greytown GXP hosts only 3x33kV feeder circuit breakers.

A new feeder, Greytown-Bidwells 33kV line is planned for supplementing the N-1 capacity of the Greytown-Featherston-Martinborough 33kV ring and for supplying a new zone substation at Bidwells-Cutting, which is intended to provide 11kV transfer capacity to N transformer security zone substations in south Wairarapa.

Another new feeder, Greytown-Kempton 33kV, is planned to supply Kempton zone substation. This is because council plans and rezoning make it very likely there will be substantial growth at Kempton substation during the next 20 years.

The 33kV switchyard site can only accommodate one more 33kV outdoor circuit breaker bay because of limited space.

Options

1. Do nothing.
2. Like-for-like replacement option. This option addresses risks caused by ageing switchgear and buswork. However, the 33kV bus remains at N-security without provision for the planned new circuits.
3. Outdoor expansion of 33kV switchyard at new site. This option isn't feasible because the location of the 33kV switchyard is contingent upon the location of the 110kV switchyard.
4. 33kV ties to other circuits. The problem of N-security on the Greytown GXP 33kV bus can be addressed by building tie lines to the 33kV network of other GXPs. However, the south Wairarapa area that Greytown GXP supplies is somewhat geographically isolated, with the Pacific to the south and east, and the Rimutaka and Tararua ranges to the west. The only other GXP to which this 33kV network could connect is Masterton GXP. This option requires $5m at a minimum (single overhead line and 33kV voltage regulator), along with significant Opex, reliability costs, and as much as $10m for an underground cable. It leaves the need for new 33kV feeders unresolved.
5. Construct indoor switchroom to accommodate 2x4-panel indoor 33kV switchboards, under Powerco ownership, to facilitate the connection of existing and planned circuits off Greytown GXP.

Preferred option

The preferred solution is option 5, as it provides the best cost-benefit, addressing all the network and fleet issues at minimum cost.

A8.14.2.2 AKURA SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER CAPACITY UPGRADE (12.5/17MVA)	ARR/GRO	$2,031	2023
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$980	2022-23

Network issue

Akura substation supplies about 13MVA of load (4,500 ICPs) and is classified as AAA. It supplies the area stretching from the northern part of Masterton City to the Mount Bruce area. The northern Masterton area is a mix of urban residential, commercial and industrial loads.

Notable industrial customers supplied by Akura substation are Breadcraft Ltd, Hansells Ltd and Webstar Ltd.

Already, Akura substation is 3MVA over N-1 transformer capacity.

The 11kV cables are under sized and have to be uprated from 95mm² Al to 300mm² or similar cross-sectional area to increase the feeder capacity.

Fleet issue

The Akura substation's transformers were manufactured in 1965 and are approaching the end of their design life. Other issues with the transformers exist because of a lack of oil bunds. This gives a high risk of oil runoff to the nearby creek – an issue raised by Powerco's Environment & Sustainability Manager that requires action.

The 11kV RPS, 12-panel indoor LMT switchboard was manufactured in 1966 and requires an arc flash upgrade. This upgrade will include replacing the existing oil circuit breakers with vacuum type circuit breakers.

Some of the RPS 11kV indoor LMT panels have compound filled switchgear terminations. There may be an opportunity to upgrade these terminations to heat shrink terminations with arc flash sensors.

Options

1. Do nothing.
2. Retain the existing transformers, upgrade the 11kV switchboard, and retain the existing 11kV feeder cables.
3. Replace the existing transformers, upgrade the 11kV switchboard, and retain the existing 11kV feeder cables.
4. Replace the existing transformers, upgrade the 11kV switchboard and the existing 11kV feeder cables.

Preferred option

Option 4 is preferred, however, because of the costs involved, the project is being further reviewed. This review will be delivered in the form of a Conceptual Design Report (CDR), which will analyse all available options in greater detail. The CDR is due to be returned by February 2021.

A8.14.2.3 CLAREVILLE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER CAPACITY UPGRADE (12.5/17MVA)	GRO/ARR	$2,460	2023-26

Network issue

Clareville is an AA classified substation that supplies approximately 10MVA of load and 4,500 ICPs in Carterton township and surrounding areas. This substation is supplied by two 33kV feeders from Masterton GXP.

Clareville substation is expected to undergo significant growth, with load increases at industrial customers such as Premier Beehive, in the near future, and council plans for subdivisions. These include industrial and commercial lots in the southern areas of Carterton and more than 2,000 residential lots in the surrounding areas during the next 30 years.

The zone transformers at Clareville substation are at almost full N-1 capacity, under normal configuration of its 11kV feeders.

Options

1. Swap existing zone transformers for refurbished transformers from another substation.
2. Upgrade to a 12.5/17MVA 1 x zone transformer with new unit, and defer investment on a second transformer.
3. Upgrade both zone transformers to 12.5/17MVA with new units.

Preferred option

The preferred solution is option 3 because of its lower losses and ongoing maintenance costs.

A8.14.2.4 KEMPTON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$200	2024
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$596	2024-25
BUNDING UPGRADE	ORS	$148	2025

Fleet issue

The existing switchroom building is at 55% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard does not meet Powerco's requirement for arc flash mitigation and poses a risk to operators. The 5MVA power transformer does not have an oil bund. In the event of an insulation oil leak or spill the oil may flow into nearby waterways.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and carry out an arc flash retrofit of the existing switchboard. Install a transformer bund.
3. Construct a new seismically compliant 11kV switchroom, and install a new arc flash rated 11kV switchboard. Install a transformer bund.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom, carry out a switchboard arc flash upgrade, and install a transformer bund. Option 3 is not preferred as it will be higher cost.

A8.14.2.5 TE ORE ORE SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
INSTALL SECOND TRANSFORMER (7.5/10 MVA)	GRO	$1,480	2023-26

Network issue

Te Ore Ore zone substation supplies about 7MVA of load and 3,200 ICPs, including Masterton Hospital. Te Ore Ore substation has an AA+ security classification.
Te Ore Ore zone substation is also the only substation that provides 11kV backup supply to Awatoitoi and Tinui substations, which are supplied by a 33kV spur of poor reliability, off the Masterton-Akura-Te Ore Ore 33kV ring.

Te Ore Ore substation at present has N transformer security.

Options

1. Do nothing.
2. Install a refurbished 7.5/10MVA transformer.
3. Install a new 7.5/10MVA transformer as a second transformer.

Preferred option

The preferred solution is option 3, to install a new 7.5/10MVA transformer. Option 2 will need to be considered on a case-by-case basis, but at this time we have no suitable candidates on the network.

A8.14.2.6 NORFOLK SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
TRANSFORMER CAPACITY UPGRADE (12.5/17 MVA)	GRO	$2,490	2025-28

Network issue

Norfolk substation supplies about 6.5MVA of predominantly industrial load (300 ICPs) and is of AA+ security classification. Two of the largest customers supplied by this substation, JNL (4.2MVA) and Kiwi Lumber (1.8MVA), are planning substantial load increases in the near future. Therefore, the existing 7.5/8.3MVA zone transformers may be insufficient before FY25.

Options

1. Offload all of Waingawa Rd feeder (excluding Kiwi Lumber) to Chapel St substation and defer transformer upgrade. This option is likely to reduce reliability because of the long overhead feeder length to Waingawa Industrial Park.
2. Swap the existing 7.5/8.3MVA zone transformers for refurbished 7.5/10MVA transformers.
3. Install new 12.5/17MVA transformers.

Preferred option

The preferred solution is option 3, to install new 12.5/17MVA transformers. Option 2, installing refurbished transformers, will need to be considered on a case-by-case basis, but at this time we have no suitable candidates on the network.

A8.14.2.7 FEATHERSTON SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
NEW 7.5/10MVA TRANSFORMER INSTALLATION	GRO	$766	2019-22
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$235	2023
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$788	2024-25

Network issue

Featherston zone substation supplies about 5MVA of load and just over 2,000 ICPs. Featherston substation has AA security classification and supplies Featherston township and the northern and western shores of Lake Wairarapa. Featherston substation is one of the two main 11kV backup supplies to Tuhitarata substation, which has N subtransmission security. Notable loads are Davis Sawmilling Ltd and ChargeNet EV charger. As EV use in the region expands, this load is likely to grow rapidly.

A second new 7.5/10MVA zone transformer is being installed at Featherston substation, after which Featherston substation will have N-1 transformer and limited N-1 subtransmission security.

Options

1. Do nothing.
2. Install a refurbished 7.5/10MVA transformer.
3. Install a new transformer as second transformer.

Preferred option

The preferred solution is option 3. Featherston substation has limited transfer capacity and provides much of the existing transfer capacity for nearby Tuhitarata, Martinborough and Kempton substations. Because of this criticality, option 3 is chosen. Option 2, to install refurbished transformers, will need to be considered on a case-by-case basis, but at this time we have no suitable candidates on the network.

Fleet issue

The existing switchroom building is at 25% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard does not meet Powerco's requirement for arc flash mitigation, and poses a risk to operators. The power transformer has rust issues and the winding tests show it is in poor condition.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and carry out an arc flash retrofit of the existing switchboard. Carry out a mid-life refurbishment of the existing power transformer once the second power transformer has been installed.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard. Carry out a mid-life refurbishment of the existing power transformer once the new second power transformer has been installed.

Preferred option

The least cost, preferred solution is option 2, to seismically strengthen the existing switchroom and carry out a switchboard arc flash upgrade. Option 3 is not preferred as it will be higher cost. The mid-life refurbishment of the existing power transformer unit will be reviewed once the second power transformer has been installed.

A8.14.2.8 MARTINBOROUGH SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
11kV SWITCHROOM SEISMIC STRENGTHENING	ORS	$235	2024
11kV SWITCHBOARD ARC FLASH RETROFIT	ARR	$660	2024-25
2x33kV CIRCUIT BREAKER REPLACEMENT	ARR	$405	2024-25

Network issue

Martinborough substation supplies about 4MVA of load and about 2,100 ICPs. Martinborough substation has AA security classification and supplies Martinborough township and surrounding areas, including the area along White Rock Rd, leading to Hau Nui substation. Martinborough zone substation is one of the two main 11kV backup supplies to Tuhitarata substation, which has N subtransmission security and N transformer security.

Options

1. Do nothing.
2. Replace the existing transformer with a new transformer.
3. Install a refurbished transformer from another substation as a second transformer.
4. Install a new transformer as a second transformer.

Preferred option

The preferred option is 4, to provide security and capacity.

Fleet issue

The existing switchroom building is at 45% NBS, which is below the 67% NBS value required for seismic compliance. The 11kV switchboard requires minor upgrades to meet arc flash mitigation standards. The 33kV outdoor Takaoka & AEI circuit breakers are oil quenched and past their expected service life, with no parts available.

Options

1. Do nothing.
2. Seismically strengthen the existing switchroom and carry out a minor arc flash retrofit of the existing switchboard. Install two new outdoor 33kV circuit breakers.
3. Construct a new seismically compliant 11kV switchroom and install a new arc flash rated 11kV switchboard. Install two new outdoor 33kV circuit breakers.

Preferred option

The least cost, preferred solution is option 2, seismically strengthen the existing switchroom and carry out a minor switchboard arc flash upgrade. Option3 is not preferred as it will be higher cost. The mid-life refurbishment of the existing power transformer unit will be reviewed once the second power transformer has been installed.

APPENDIX 9 FEEDER PERFORMACE

A9.1 APPENDIX OVERVIEW

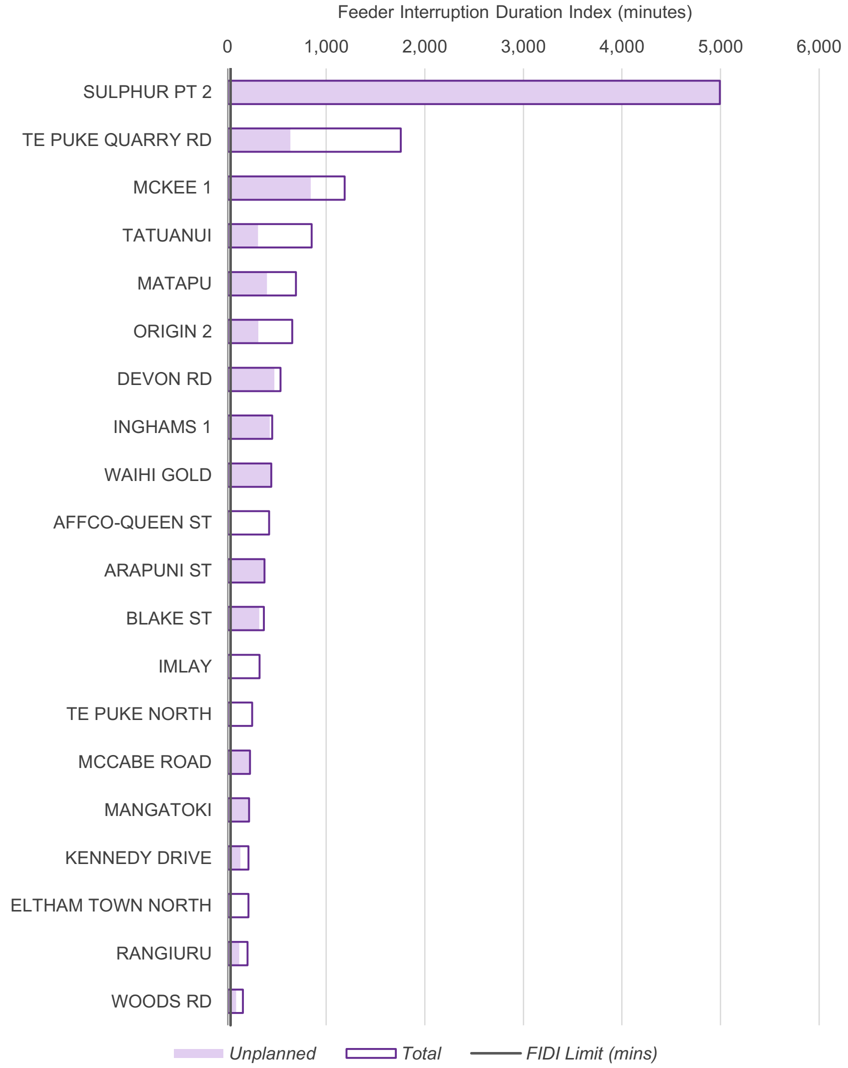
This appendix discusses the performance of our poorer performing feeders. For the worst few of these feeders we explain the reasons and any planned remedial works.

The analysis uses FIDI, which is the average number of minutes that a customer on a feeder experiences without supply. The analysis period is the 2020 calendar year.

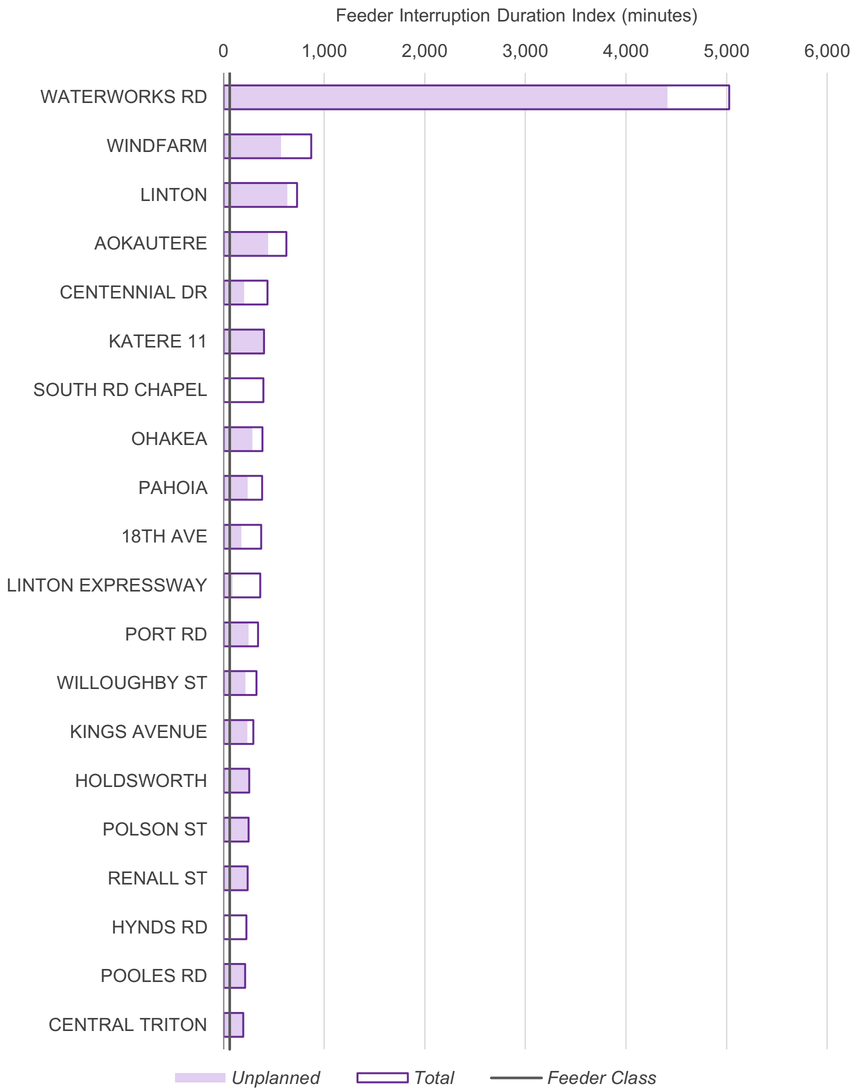
The analysis is broken down by feeder class[114]. Each distribution feeder is assigned a class that best encompasses the types of consumers connected to the feeder.

[114] 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.

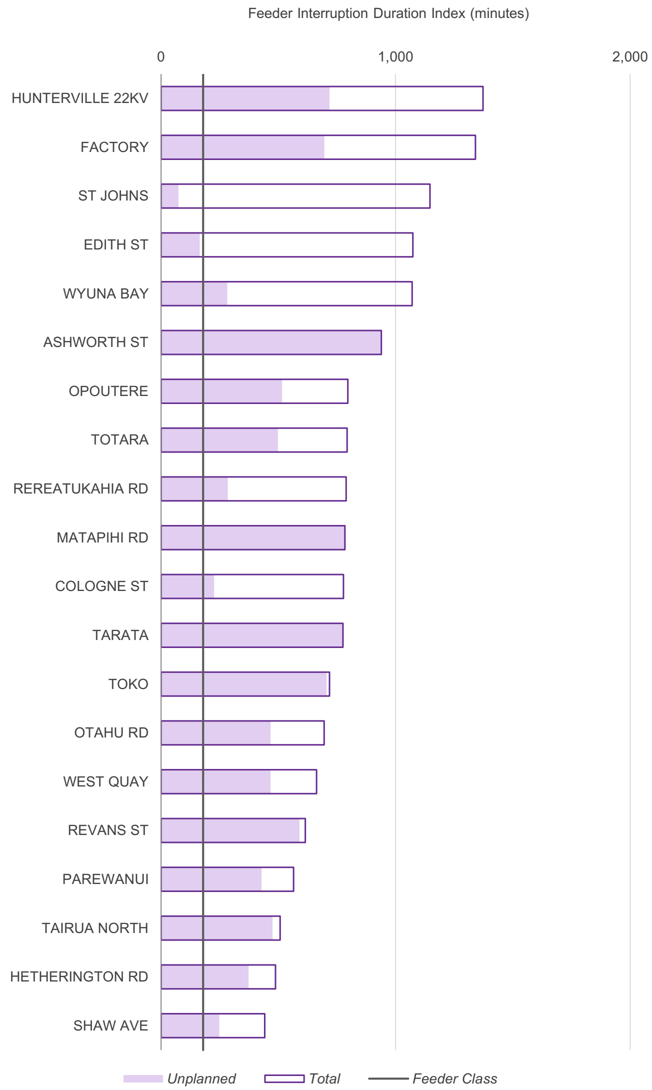
A9.2 FEEDER CLASS F1



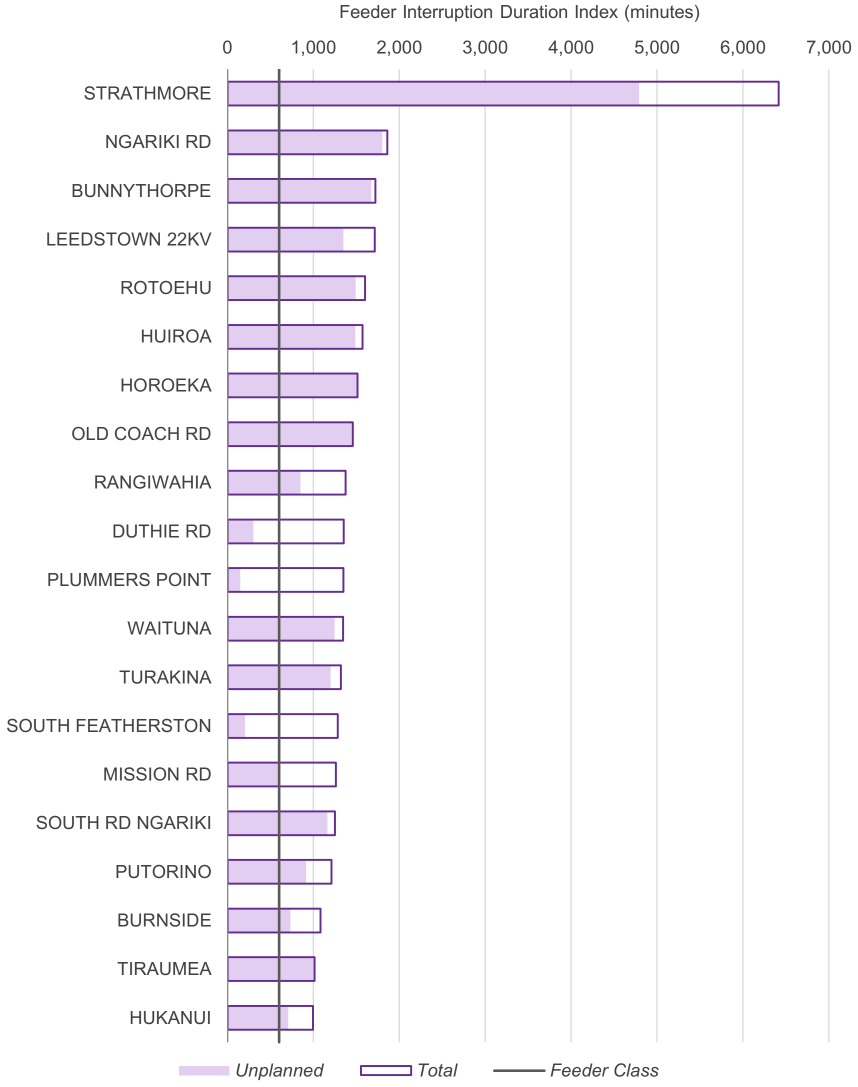
A9.3 FEEDER CLASS F2



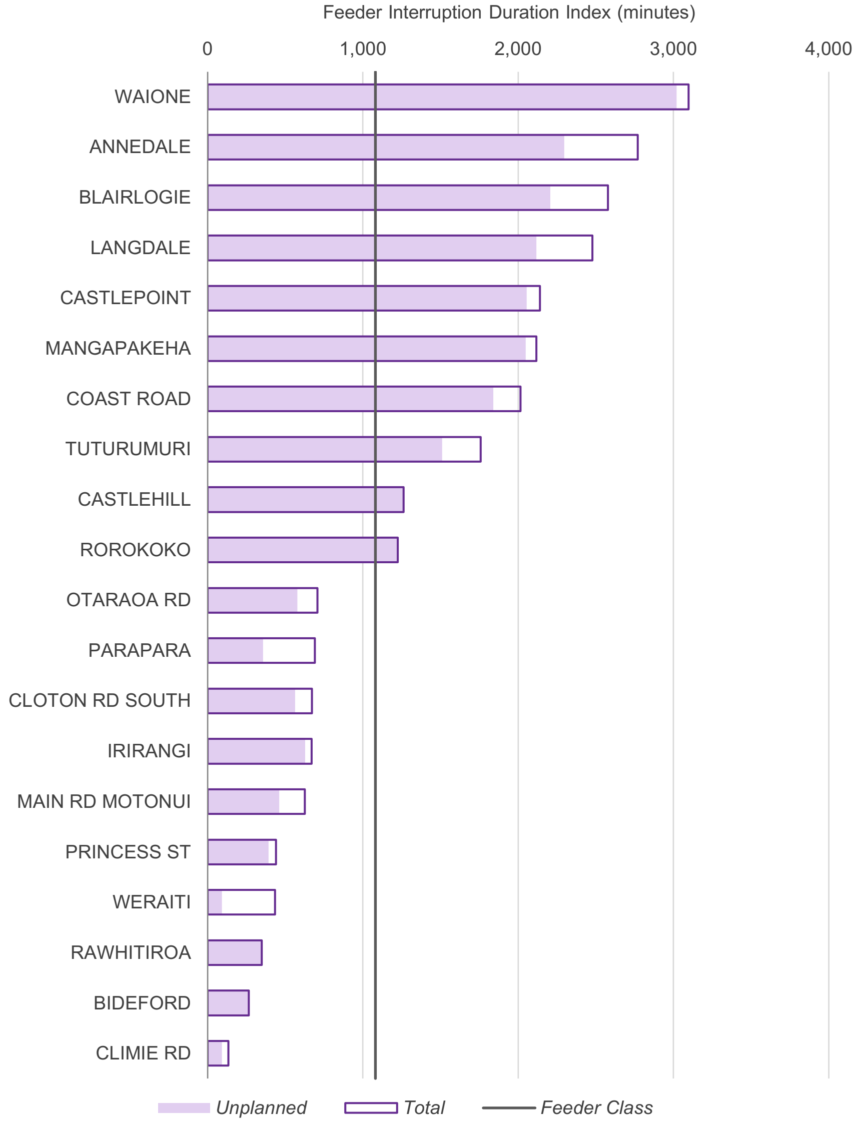
A9.4 FEEDER CLASS F3



A9.5 FEEDER CLASS F4



A9.6 FEEDER CLASS F5



APPENDIX 10 REGULATORY REQUIREMENTS LOOK-UP

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).

ATTACHMENT A: ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP CHAPTER WHERE ADDRESSED
Contents of the AMP	
3. The AMP must include the following:	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Chapter 1 is an Executive Summary and provides a brief overview and the key messages and themes in the AMP. Chapter 2.3 provides information on the structure of the AMP
3.2 Details of the background and objectives of the EDB's asset management and planning processes	The background to our asset management and planning process is provided in Chapters 3 to 6. This describes the context in which we operate. The objectives of our asset management and planning process are provided in Chapter 4.
3.3 A purpose statement which: 3.3.1 Makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes 3.3.2 States the corporate mission or vision as it relates to asset management 3.3.3 Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB 3.3.4 States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management 3.3.5 Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest	3.3.1: The purpose statement is in Chapter 2.2. 3.3.2: Our corporate vision, mission and values and their relationship with the AM process is discussed in Chapter 4.2. 3.3.3: Chapter 5 outlines how our core asset management strategies are derived from our corporate plans. The chapter also documents the core asset management strategies used to develop our plans 3.3.4: Chapter 9 outlines the process of how our business objectives filter down into our Capex and Opex plans. 3.3.5: Chapter 4 maps our corporate goals into our asset management objectives. These asset management objectives are broken into specific strategies in chapter 5. The asset management objectives are further broken down into specific targets in chapter 7.
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	Our AMP planning period is from 1 April 2021 to 31 March 2031, as described in Chapter 2.2.2.
3.5 The date that it was approved by the directors	The AMP was approved on 25 March 2020 (refer to Appendix 11).
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 Chapter 2.2.3. A more detailed description of each main stakeholder's interests, how these are identified and accommodated in the asset management plan is provided in Appendix 3.
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: Chapter 13.2.1 outlines the responsibility of our board 3.7.2: Chapter 13.2.2 outlines the responsibilities of our Executives. Chapter 13.5 outlines how we govern asset management activities. 3.7.3: Chapter 13.4 outlines how our field-works are outsourced. Chapter 13.3 describes the asset management team and service delivery functions within our organisation used to manage field works. Chapter 13.6.3 outlines the competency framework we use to manage the skills of outsourced contractors

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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 28.3.1 describes the key assumptions and uncertainties in the development of the AMP. 3.8.3: Refer to Chapters 3 and 6. 3.8.5: Chapter 28.3.2 describes how we developed the escalators we used to inflate our forecasts into nominal New Zealand dollars in schedules 11a and 11b (refer to Appendix 2).
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures.	This is discussed in Chapter 28.4.
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	Chapters 8-14 describe our Asset Management System – how we go about managing our assets. Chapter 9 explains how corporate vision is translated into Asset Management investment and operational decisions. Chapter 10 explains our approach to asset management decision-making. Lifecycle management is discussed in Chapter 11. Chapters 12 and 13 describe the organisational structures, responsibilities and accountabilities related to system performance, risk and cost control.
3.11 An overview of systems and information management data To support the AMMAT disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe: • The processes used to identify asset management data requirements that cover the whole of life cycle of the assets • The systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets • The systems and controls to ensure the quality and accuracy of asset management information • The extent to which these systems, processes and controls are integrated	Our information management systems are described in Chapter 14. The governance structure for ensuring data quality is described in Chapter 13.5.1. The governance structure for system modifications is described in Chapter 13.5.2. A description of the systems and controls to manage the quality and accuracy of asset management data is provided in Chapter 27.2.
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.	Asset data and system limitations and improvement initiatives are detailed in 27.2.2 and 27.2.3. Disclosure schedule 12a in Appendix 2 outlines our data completeness for each asset type
3.13 A description of the processes used within the EDB for: 3.13.1 Managing routine asset inspections and network maintenance 3.13.2 Planning and implementing network development projects 3.13.3 Measuring network performance.	3.13.1: Chapter 11.3.2 outlines how our maintenance and vegetation programme is developed. Routine maintenance regimes for each fleet are listed in chapter 18-25 3.13.2: Chapter 11.3.1 outlines how we develop our capital works programme. Chapter 11.4 outlines how we develop individual projects and Chapter 15 outlines our major network development projects for each area. 3.13.3: Our asset management and network performance measurements are listed in chapter 7

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3.14 An overview of asset management documentation, controls and review processes. To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should: (i) Identify the documentation that describes the key components of the asset management system and the links between the key components (ii) Describe the processes developed around documentation, control and review of key components of the asset management system (iii) Where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy (iv) Where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house (v) Audit or review procedures undertaken in respect of the asset management system	Chapters 8—14 describe Powerco's Asset Management System and the processes contributing to Powerco's Strategic Asset Management Plan. We are currently preparing for certification to ISO55001. The results of the most recent audit are contained in Chapter 4.8. There are no aspects of the AMS that are outsourced.
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	An overview of our key stakeholders and the key discussion with them is outlined in Chapters 2.2.3. Appendix 3 further outlines the interests for our stakeholders. We undertake regular staff engagement surveys, promote open-door access to senior managers, undertake regular team building activities, and are in the process of developing a Communications Plan.
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	Figures are reported in constant FY21 dollars. Refer to each chart axis throughout the AMP and Chapter 28.
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. The purposes of AMP disclosure referred to in clause 2.6.1(2) are that the AMP: (1) Must provide sufficient information for an interested person to assess whether (a) Assets are being managed for the long-term (b) The required level of performance is being delivered (c) Costs are efficient and performance efficiencies are being achieved (2) Must be capable of being understood by an interested person with a reasonable understanding of the management of infrastructure assets (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks	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 how we go about achieving appropriate levels of performance. (1) & (2): An overview of the AMP is provided in Chapter 2.3. Chapters 5 to 9 describe how we manage our assets. A glossary is provided in Appendix 1 to assist understanding; and (3): Risk is discussed in Chapter 12 and Appendix 6. High Impact Low Probability (HILP) events are specifically addressed in Chapter 12.6.5.
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 Chapter 2.4. 4.1.2: Large consumers are described in Appendix 4. 4.1.3: Load characteristics for our two network regions are described in Chapter 2, and for each of our planning areas throughout Chapter 15. Detailed demand forecasts are included in Appendix 7. 4.1.4: The load characteristics for each area are is provided in the figures and tables in Chapter 15. Total energy delivered is provided in Table 2.2 in Chapter 2.4.

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4.2 A description of the network configuration, including:- 4.2.1 Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point 4.2.2 A description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings 4.2.3 A description of the distribution system, including the extent to which it is underground 4.2.4 A brief description of the network's distribution substation arrangements 4.2.5 A description of the low voltage network including the extent to which it is underground 4.2.6 An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	4.2.1: Bulk supply points for each region are described in Chapter 15. Chapter 15.17 identifies the grid Exit Points (GXP) that we connect to on our network. The list of embedded (distributed) generators connected into Powerco networks is in Chapter 15.18. 4.2.2: The subtransmission system is described using text, maps and tables throughout Chapter 15. The information required on zone substation capacity is provided in Schedule 12b of Appendix 2. 4.2.3: The distribution system is described at a high level in Chapter 2, along with the extent to which it is underground. Chapters 15, and 18 to 24 describe the distribution system in more detail. 4.2.4: Chapter 15 outlines the demand and constraints for each of our Zone Substations. Chapter 21 outlines the plans for renewing our zone substations. Appendix 8 outlines the key options considered for managing the zone substation. Chapter 22 outlines our plans for managing our distribution transformers through their lifecycles. 4.2.5: The low voltage system is described at a high level in Chapter 2, along with the extent to which it is underground. Chapters 22 and 23 describe the low voltage system in more detail. 4.2.6: Refer Chapter 24. 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.	Chapter 15 and Appendix 8 outline our network development and significant renewal plans for each our regions.
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category: 4.4.1 Voltage levels 4.4.2 Description and quantity of assets 4.4.3 Age profiles 4.4.4 A discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	An asset summary is provided in Chapter 2.5. The Powerco Fleet management Strategy is described at a high level in Chapter 5.2. Individual fleet management plans, including renewal criteria, are provided in Chapters 18-25.
4.5 The asset categories discussed in subclause 4.4 above should include at least the following: 4.5.1 Sub transmission 4.5.2 Zone substations 4.5.3 Distribution and LV lines 4.5.4 Distribution and LV cables 4.5.5 Distribution substations and transformers 4.5.6 Distribution switchgear 4.5.7 Other system fixed assets 4.5.8 Other assets 4.5.9 Assets owned by the EDB but installed at bulk electricity supply points owned by others 4.5.10 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand 4.5.11 Other generation plant owned by the EDB.	4.5.1- 4.5.8: Refer to Chapters 18-24. 4.5.9: GXP meters installed at Transpower bulk supply points are discussed in Chapters 24.6 4.5.10: Chapter 21.3 includes a grey box callout that discusses our mobile substation. 4.5.11: Powerco owns: • Several 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 19.4.6. • A small diesel generator used to back up our central control room power supply. • A 2MW/2MWh Battery Energy Storage System and 2.5MVA diesel generator located at the Whangamata Zone Substation. This asset is described in a grey box callout in Chapter 21.5.

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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 describes the AMP performance objectives and why they are consistent with the business strategies and asset management objectives. This includes targets over the planning period (refer to figures).
6. Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next five disclosure years.	Chapter 7.3 discusses our unplanned SAIDI and SAIFI targets. Chapter 7.6 discusses our planned SAIDI and SAIFI targets.. Schedule 12d in Appendix 2 provides out forecast values for the next five years.
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: Chapter 7.3 provides customer-orientated indicators. The consumer types that we service are listed in Table 2.1. 7.2: Chapter 7 discusses our network targets, including a summary of the basis of our targets in each Asset Management objective area.
8. The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	This is discussed in Chapter 7.
9. Targets should be compared to historic values where available to provide context and scale to the reader.	The figures throughout Chapter 7 provide historical performance for new targets.
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	Expenditure forecasts reflect the investment we believe is needed to achieve the performance targets listed in Chapter 7
Network Development Planning	
11. AMPs must provide a detailed description of network development plans, including:	Network development planning is discussed in Chapter 15.
11.1 A description of the planning criteria and assumptions for network development	The criteria are discussed in Chapter 5.3.
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described	This is discussed in Chapter 5.3.
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs	The use of standard designs and standardised assets is discussed throughout Chapters 18 to 24. Materials and equipment standards are specifically covered in Chapter 11.2
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 18 to 24 which are disaggregated to individual asset categorises. The approach used for standard designs is in Chapter 11.2, including standardised assets to address obsolescence.
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.	Chapter 4 describes our aspirations and objectives associated with reliability and efficiency improvements, including appropriate success measures.
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network. The criteria described should relate to the EDB's philosophy in managing planning risks.	This is discussed in Chapter 15.
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.	Chapter 15 provides detail on how network development is prioritised, and Chapter 4 demonstrates how these align with corporate visions and goals.

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11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand: 11.8.1 Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates 11.8.2 Provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts 11.8.3 Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period 11.8.4 Discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives	11.8.1: The demand forecasting methodology is described in Chapter 5.3. 11.8.2-4: Forecasts at zone substation level, constraints and the impact of distributed generation are provided in Chapter 15 (refer to tables and figures for each region) and Appendix 7.
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	11.9.1,2: Appendix 8 discusses all network and non-network options considered for major projects. 11.9.3: Chapter 3 provides an overview of the forces shaping our network and the broad strategies that need to be employed to address them. Chapters 6 and 15.19-21 describe our current innovation program and strategies.
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include: 11.10.1 A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months 11.10.2 A summary description of the programmes and projects planned for the following four years (where known) 11.10.3 An overview of the material projects being considered for the remainder of the AMP planning period	Chapter 15 summarises our Area Plans and describes all significant network developments within the planning period. The timing for major projects in chapter 15 and appendix 8. Appendix 8 discusses all network and non-network options considered for major projects.
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	Chapter 9.3 describes how we treat distributed generation in our demand forecasts which informs network development plans. Our policies for connecting distributed generation are available on our website www.powerco.co.nz
11.12 A description of the EDB's policies on non-network solutions, including: 11.12.1 Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation 11.12.2 The potential for non-network solutions to address network problems or constraints	Refer to Chapter 6, Chapter 15 and Appendix 8
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 described in Chapter 9.2.
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 12.2.1 The approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done 12.2.2 Any systemic problems identified with any particular asset types and the proposed actions to address these problems 12.2.3 Budgets for maintenance activities broken down by asset category for the AMP planning period	Our maintenance strategy is discussed in Chapters 5.2.3 and 9. Each asset class fleet plan in Chapters 18 to 24 contains known issues and programmes of replacement, together with expenditure forecasts by asset category.

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12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 12.3.1 The processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets 12.3.2 A description of innovations made that have deferred asset replacement 12.3.3 A description of the projects currently underway or planned for the next 12 months 12.3.4 A summary of the projects planned for the following four years (where known) 12.3.5 An overview of other work being considered for the remainder of the AMP planning period	12.3.1: These are described in Chapter 5.2 12.3.2: Several examples are documented in Appendix 8. 12.3.3-5: Chapters 18 to 24 covers our renewal strategy which documents all asset replacement and renewal policies and programmes. Key Asset Replacement and Renewal (ARR) projects over the planning period are identified in Appendix 8
12.4 The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	The fleet categories and a Portfolio to Asset Fleet mapping are provided in Chapter 2. Our fleet management plans are grouped by the asset categories listed in 4.5 above. See Chapters 18 to 24.
Non-Network Development, Maintenance and Renewal	
13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including:	Chapter 14 describes our non-network assets. Chapter 27 associated maintenance plans, renewal plans, planned capital investments and expenditure forecasts.
13.1 A description of non-network assets	Chapter 14 provides a description of our non-network IS assets. Chapter 27.5 outlines our facilities.
13.2 Development, maintenance and renewal policies that cover them	Chapter 27 outlines our non-network renewal and development plans for our non-network assets.
13.3 A description of material capital expenditure projects (where known) planned for the next five years	Chapter 27 outlines our non-network expenditure.
13.4 A description of material maintenance and renewal projects (where known) planned for the next five years	Chapter 27 outlines our non-network renewal and development plans for our non-network assets, with expenditure forecasts in Chapter 28.
Risk management	
14. AMPs must provide details of risk policies, assessment, and mitigation, including:	Chapter 12 provides an overview of our risk management practice, including details of our policies and processes for assessment and mitigation.
14.1 Methods, details and conclusions of risk analysis	14.1: Methods are discussed in Chapter 12.6.
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, 14.3: Chapter 6.6 describes our proposed response to climate change risk. In Chapter 11.9 we discuss our critical spares management systems. HILP events are discussed in chapter 12.6.5
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 14.2.	
14.4 Details of emergency response and contingency plans.	14.4: In Chapter 11.6 we discuss our emergency preparedness systems and response to civil emergencies.
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	Chapter 7 contains objectives, targets, and the rationale for these targets. 15.1: Project and expenditures variances are described in Appendix 5. Additional material is provided throughout Chapters 18 to 24.

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15.2 An evaluation and comparison of actual service level performance against targeted performance: (1) In particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances	Chapter 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.	Chapter 7.6 outlines the progress of our asset management maturity. Schedule 13 in Appendix 2 outlines specific process improvement initiatives aimed at improving our asset management maturity
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.	Our network targets in chapter 7 align with our Asset Management objectives outlined in chapter 4. The initiative used to deliver our asset management objectives our described in chapter 5.
Capability to deliver	
16. AMPs must describe the processes used by the EDB to ensure that:	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved.	Chapters 4-7 describe how we ensure the AMP is realistic and objectives can be achieved.
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Chapter 13 describes the processes and organisational structure we use for implementing the AMP.

Directors Certificate

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pursuant to clause 2.9.1 of Section 2.9

We, JOHN LOUGHLIN and PAUL CALLOW being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Powerco Limited prepared for the purposes of clauses 2.6.1, 2.6.6, and 2.7.2 of the Electricity 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 with align with Powerco's corporate vision and strategy and are documented in retained records.

Director

JOHN LOUGHLIN

Date 26/03/21

Director

PAUL CALLOW

Date 26/03/21

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POWERCO