



Asset Management Plan 2021

1 April 2021 - 31 March 2031



COUNTIESPOWER



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PLAN SUMMARY

Introduction to 2021 Asset Management Plan

Counties Power welcomes the unique challenge of delivering smarter energy solutions for the rapid and ever expanding south Auckland and Waikato populations. Meeting the demands of Auckland as the largest city, provides us with impetus and commitment to find affordable, efficient, sustainable and innovative solutions. We see this as our responsibility and have a passionate and dedicated team committed to delivering service safely to not simply the growth of the city but to all communities on our network. We are dedicated to continue to provide quality service to our existing customers across our rural and urban network.

To do this, we invest wisely in our core network, and also in future technology that will service our community's needs and give our customers a smarter, more intuitive and sustainable network. Working with our customers, we're diversifying into emerging technologies, ensuring our network and our community is at the forefront of enhanced energy solutions.

We're leading the charge in developing cutting-edge solutions in distributed generation, batteries and EV technology to ensure we can power our region now and for future generations. We care about our community, our customers and our people, and safeguarding and growing our community's investment. We're powering our city, our homes, our farms and businesses, our community, our region and our economy now and into the future.

We're proudly a 100 percent customer-owned company which provides a strong catalyst for us to take leadership in being efficient, profitable, socially responsible and providing strong environmental stewardship.

Counties Power's objective is to operate as a successful electricity distribution and service business, ensuring that the necessary strategies are implemented to maintain an environment of zero harm for our staff, customers and the communities in which we operate, to provide a reliable service that meets customer needs and to achieve sustainable and superior shareholder value.

Our Vision Statement is "Shaping a Smarter Energy Future" which recognises the changing needs and wishes of our customers as technological and societal changes occur, including distributed generation, batteries, electric vehicles, as well as changing working and home arrangements.

The safety of our staff, our contractors and the communities in which we operate is our top priority. We are committed to continually providing services at or above the level commensurate with our customers' price expectations while fully discharging our responsibilities for quality, safety and environmental responsibility in all elements of our business.

We will continue to invest prudently in developing our assets, focus upon excellence in our core business, deliver on our targets and foster a philosophy of continuous improvement.

This 2021 Asset Management Plan (AMP) is a key document for the development and operation of the network and sets out our Asset Management practices that guide how we manage our assets over their lifecycle in an efficient, effective and sustainable manner. The target is to provide the best level of service sought by our customers commensurate with their willingness to pay. This document focuses our decision-making processes to deliver that outcome and covers new initiatives to help provide better decision making across our activities.

Counties Power traces its origins back over 90 years providing distribution to an area that was predominantly rural in nature with a few urban concentrations. Over recent years, the character of the area and network has gradually changed with significant urban growth including domestic, industrial and commercial development. However, the rural area is substantial and includes remote areas with difficult access, some of which is subject to extreme environmental conditions.

Urbanisation is planned to continue with Auckland Council identifying substantial housing growth in several locations in our area. New industrial developments are targeted in the Auckland Council area at Drury and by the Waikato District Council in the Pokeno areas.

Demand on our network continues to grow in the Pukekohe, Drury, Karaka, Glenbrook and Pokeno areas. This will continue to require investment in zone substations, network capacity upgrades and reliability improvements. As such, our key focus remains on cost-effectively increasing the reliability of our network while meeting the demand for new connections resulting from both housing and industrial/commercial developments.

As better information becomes available from developers and councils regarding residential and industrial developments in our region, we continually review the forward programme and re-schedule projects to reflect the latest growth forecasts and revise our forward capital expenditure.

We have examined the available data and investigated developers' plans in the light of the impact of the COVID-19 Auckland alert level restriction and assessed the likely impact of ongoing restrictions. Our view of the longer-term impact on our network is that while there could be some short term slowing of some developments, the longer-term drivers remain substantially unchanged and thus the expected investments will still be required. Overall, the impact of the alert level restrictions on revenue has been neutral with increased domestic revenue slightly exceeding the reduction in industrial/commercial revenue, thus our financial position remains sound.

We have reviewed the detailed area load growth studies undertaken recently across our supply area with the overall result being revised timing of projects and programmes when compared to previous AMP's.

We have also undertaken a further detailed review of the performance of the network using trend analysis of fault incidents. This review included studying the results of performance improvement projects carried out over the last three years on our network which have shown favourable results year on year. However, our performance remains unfavourable to target and we are introducing further initiatives to improve customer service and reduce unplanned outages. These initiatives include further network automation, reducing ICP numbers per feeder, targeted approaches to vegetation issues - particularly those resulting from flying debris from out of zone trees¹, and seeking to reduce third party interference (e.g. vehicles vs. poles).

We have completed a LiDAR² study of our network which has helped identify issues with overhead lines including potential tree interference (in and out of zone) and potential ground clearance issues. Work is in progress to improve our analysis of the data and to prioritise the issues.

This AMP indicates that our capital investment across the planning period will increase by \$18m on the 2020 AMP planning period reflecting additional expenditure on non-network items.

The establishment of the new 110/22kV substation at Pokeno required to meet the substantial industrial developments that have taken place was completed in the current year. At the time of preparation of this AMP feeders from the new substation were being installed and load transferred to it.

The previously expected significant industrial growth south of Drury has not yet occurred. The result of this is that the planned substation in the Drury South area (Quarry Road) remains deferred. However, the major project to build a new substation (Barber Road) near Bombay is on target, which will allow us to de-commission two end of life 33/11kV substations (Ramarama and Mangatawhiri) and for the existing end of life Transpower 33kV assets at Bombay GXP to be retired as well.

Housing development continues with substantial growth in several areas. There is significant development in the Pukekohe North area (Paerata Rise) and we plan to establish a new 110/22kV substation in this area, supplied from a 110kV switching station connected into the Opaheke 110kV circuits. The Barber Road and Pukekohe North works are expected to enable the deferment of the proposed Drury South area substation for some years, although if a major new customer load is required, or the uptake and usage of the newly created industrial zoned areas around the future substation site occurs, the timing will vary.

Forecast operating expenditure across the planning period is \$201m, which is an increase of \$17m from the 2020 AMP forecast. This is reflective of the growing asset base on the network and of the targeted works identified from the analysis and the LiDAR project noted above.

The base costing data has been revised to reflect the actual costs identified from recent substantial projects, but excluding the specific additional costs for operations under COVID-19 alert level conditions that were incurred in the current year. The pressure on all infrastructure has resulted in an overall shortage of specialist contractors (e.g. horizontal drilling) and an associated rise in their charges.

Overall, we believe that the programme of works identified in this AMP will ensure we meet the growth in demand from developments and improve the quality of service that the network provides our customers with minimal impact on costs and prices.

¹ Vegetation management as related to distribution networks are governed by the Electricity (Hazards from Trees) Regulations 2003. Out of zone trees are those that are not covered by these regulations.

² Light Detection and Ranging - a method for measuring distances by illuminating the target with laser light and measuring the reflection with a sensor.

Period covered by the 2021 AMP

This AMP covers the period from 1 April 2021 to 31 March 2031 (planning period).

Approval date

This AMP was reviewed and approved by the Counties Power Limited Board of Directors on 24 March 2021.

Purpose of this document

The purpose of the AMP is to inform and communicate to our stakeholders our approach to asset management of our network and the planned projects and programmes to maintain and enhance its capacity and overall performance. This plan reflects our latest demand forecast which is aligned with the ongoing substantial levels of growth in the area and to accelerate ageing asset renewal and replacement to meet our stakeholder requirements in accordance with our asset management strategy and objectives.

Intended audience

The intended audience for this AMP is our stakeholders. This includes our customers, our community, our shareholders, the Commerce Commission and the Electricity Authority, our staff and contractors, and other interested parties.





SERVICING OVER

44,000

HOMES, FARMS & BUSINESSES

1 INTRODUCTION

This chapter introduces our 2021 Asset Management Plan (AMP) and covers:

- **Purpose:** provides the reasons for producing this AMP, the period it covers, the date it was approved by our Board of Directors (Board), and the assets it covers;
- **Key Themes and Initiatives:** a summary of the key themes, analysis, approaches and initiatives that have been described in this AMP; and
- **Document Structure:** an outline of this AMP and how it is structured.

1.1 Purpose

The purpose and objective of our asset management practices and this AMP is to assist us in managing our assets over their lifecycle in an efficient, effective and sustainable manner in order to provide the type and level of services that our customers want and for which they are willing to pay. This AMP is a vital planning document as it focuses our decisions and activities so that our assets provide enduring value to our customers, our stakeholders and ourselves. It illustrates how our asset management objectives are aligned to our corporate objectives, vision and values.

We apply a disciplined and consistent approach to the management of our assets, so that we can attain our corporate vision of being a progressive and successful community owned electricity network business with the aim of delivering safe, reliable, and cost-effective network services to our customers. Our asset management approach converts our corporate objectives of operating a safe network, meeting customer needs and maximising shareholder returns into technical and financial decisions, plans and activities. This AMP links with our other documented plans that are a part of our business planning process. These documents are our Statement of Corporate Intent, our Strategic Plan, and our annual budget.

1.2 Period Covered

This AMP covers the period from 1 April 2021 through to 31 March 2031 (AMP period). As with any long-term planning document, there is greater certainty and greater detail available for works planned for the immediate future, generally up to five years out. Longer term projects are more indicative of our expectations based on known trends and projections which impact on the network.

1.3 Approval Date

This AMP was approved by our Board of Directors on 24 March 2021.

1.4 Scope

This AMP covers all network equipment and non-network solutions involved in the provision of network services to customers who are connected to our network.





Figure 1-1 Asset Management Plan – Structure of Document

1.5 Document Structure

Chapter 2 – Overview of Counties Power – this Chapter provides a brief background of Counties Power, our organisation, our operating environment, outlines who our stakeholders and customers are, and an overview of our network.

Chapter 3 – Service Levels – this Chapter provides an overview of the service levels we expect to provide to our stakeholders and which inform our asset management decision making.

Chapter 4 – Approach to Asset Management – this Chapter provides an overview of how we go about asset management at Counties Power and describes our framework and process for making investment decisions, including our approach to risk management.

Chapter 5 – Network Reliability – this Chapter presents an analysis at a detailed level of the various trends impacting on network performance to help identify the areas where new initiatives are required to maintain or improve the service levels as seen by our customers.

Chapter 6 – Innovation and New Technology – this Chapter provides information on the approaches we take to seek continual improvement in our performance, where we look to be innovative with developing analysis tools as well as considering the wider impact of technology advancement on both the role and the componentry of our network.

Chapter 7 – Renewal and Maintenance – this Chapter provides a more detailed overview of our assets by category, and includes our plans on how we inspect, maintain and replace them.

Chapter 8 – Network Development – this Chapter provides details on how we forecast our network demand, the capacity of our network to manage that demand and the constraints identified and includes our plans on how we are going to develop the network to address future growth.

Chapter 9 – Non-Network Investment – this Chapter provides details on the investments we will make in non-network equipment such as land and buildings, IT equipment, tools, vehicles and machinery.

Chapter 10 – Expenditure Summaries – this Chapter summarises all the operational and capital expenditure identified in Chapter 7, 8, and 9 for the 10-year period covered by this plan.

Chapter 11 – Evaluation of Performance – this Chapter assesses performance against previous plans as part of our continual improvement in asset management and overall business performance.

Appendix A to E – provides a glossary of terms, a summary of performance against previous plans, the information disclosure schedules, and director certification.

1.6 Plan Assumptions

Assumptions relating to individual aspects of the plan are considered in their respective Chapter's.

The overall assumptions relating to the plan are:

- Counties Power is an ongoing business;
- No significant legislative changes affecting the industry structure or operating environment;
- No significant changes to Transpower operating policies;
- No step changes in customer expectations or willingness to pay; and
- No significant legislative change to efficiency incentives, distributed generation or EV uptake.

2 OVERVIEW OF COUNTIES POWER

2.1 Our Company

Counties Power owns, manages and operates an electricity distribution network in South Auckland, North Waikato and Hauraki district areas with a system length of 3,418km covering an area of approximately 2250km². The Auckland Council area covers 830km² (37%) of the Counties Power network, the Waikato District covers 1340km² (60%), and the Hauraki District covers the remaining 80km² (3%). We receive power from the national grid at the Bombay and Glenbrook Grid Exit Points (GXP) and then transport it to our customers via nine zone substations and our extensive network of lines, cables, transformers and other equipment.

2.1.1 Ownership and Governance

Counties Power is 100% customer owned. All shares are held by the Trustees of the Counties Power Consumer Trust (Trust) on behalf of all local power customers. The Trust has a total of five Trustees, of which two are required to be elected every two years. Counties Power is managed for the benefit of its customers and their communities. The Trust oversees the performance of Counties Power through the appointment of a Board of Directors (Board). The Board and Management of Counties Power consult the Trust on our strategic direction, business plans, and asset management measures and targets. Information about the Trust can be obtained from www.countiespowertrust.co.nz.

Objective

Our objective is to operate Counties Power as a successful electricity distribution and service business, ensuring that the necessary strategies are implemented to maintain an environment of zero harm for our staff, customers and the communities in which we operate, to provide a reliable service that meets customer needs and to achieve sustainable and superior shareholder value.

To achieve this objective, we will embrace the concepts of quality, safety and environmental responsibility in all elements of our business. The safety of our staff, our contractors and the communities in which we operate is our top priority.

We are committed to continually providing services at or above the level commensurate with our customers' price expectations.

We will continue to invest prudently in developing our assets, focus upon excellence in our core business, deliver on our targets and foster a philosophy of continuous improvement.

Vision

Counties Power's vision statement is:

Shaping a Smarter Energy Future

Our overall company strategy is shown in the following diagram (Figure 2-1) which defines our vision, goals, strategic priorities, our foundation and values:

The evolution of our strategy

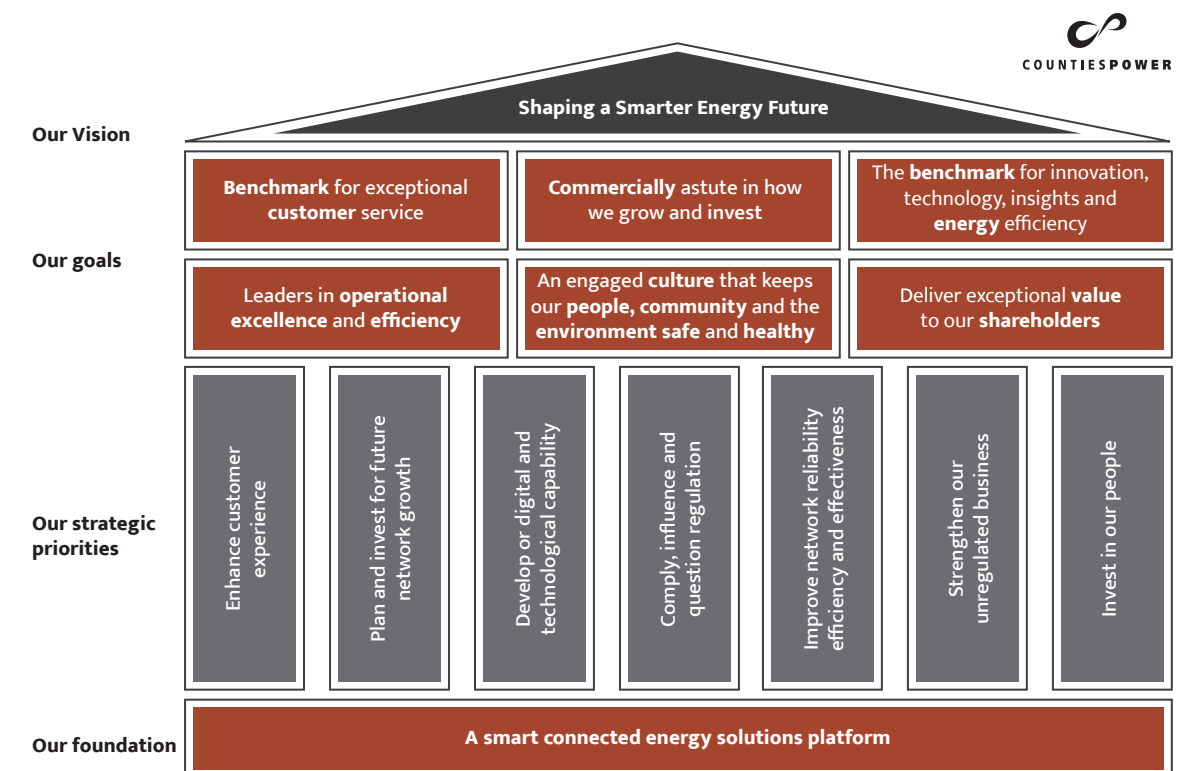


Figure 2-1 Overall Counties Power Strategy

Informing Asset Management Practices

We use our vision, goals and strategic priorities to guide our business and asset management practices by helping set priorities across our activities. Safety of our staff and the public is our top priority. Our company vision helps develop our service levels when considering the expectations of customers and flows through to identifying performance improvement opportunities as measurements record the actual levels achieved.

2.1.2 Corporate and Organisation Structure

The Counties Power Board is responsible for the overall governance of the business, including approval of the company strategy, business plans and annual budgets. The Directors are appointed by the Counties Power Consumer Trust. The Board reports to the Trust on a quarterly basis.

The Chief Executive is responsible for leading the business, implementing the company strategy and is accountable for business performance.

The Leadership Team reports to the Chief Executive and is responsible for specific areas of the business operation as shown in the diagram (Figure 2-2) below.

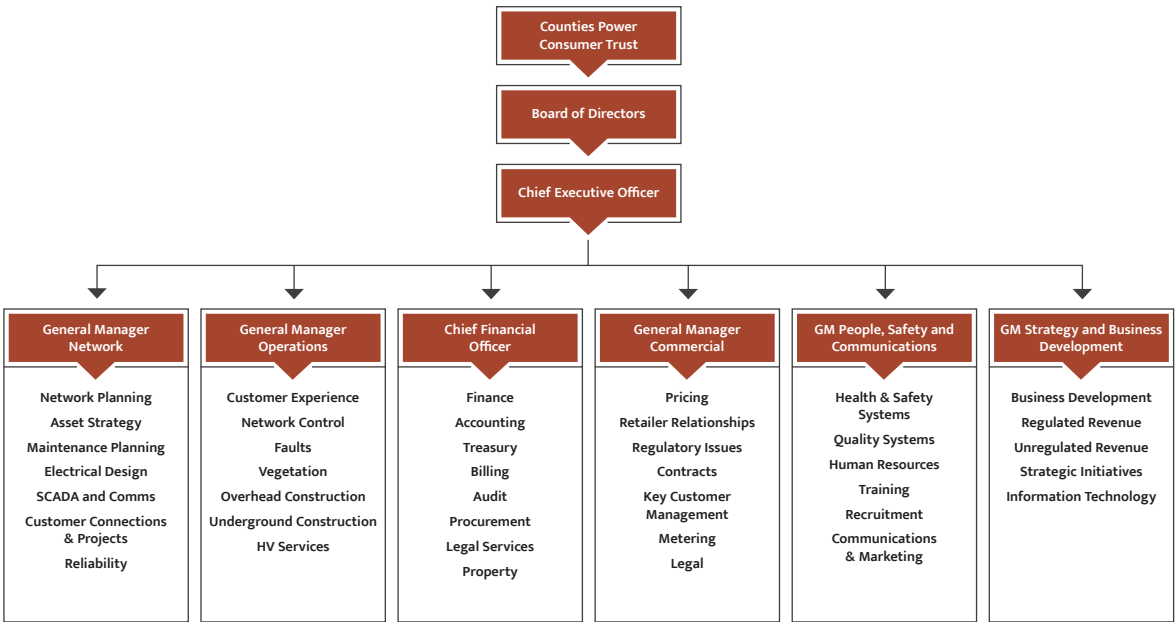


Figure 2-2 Overview of company Governance and Management

The General Manager Network is accountable for the asset management function in the business, including developing network planning and asset strategies, compiling and delivering annual plans for operational expenditure and capital investment, as well as facilitating customer connections to the network and ensuring the ongoing operation of the network meets safety and reliability expectations.

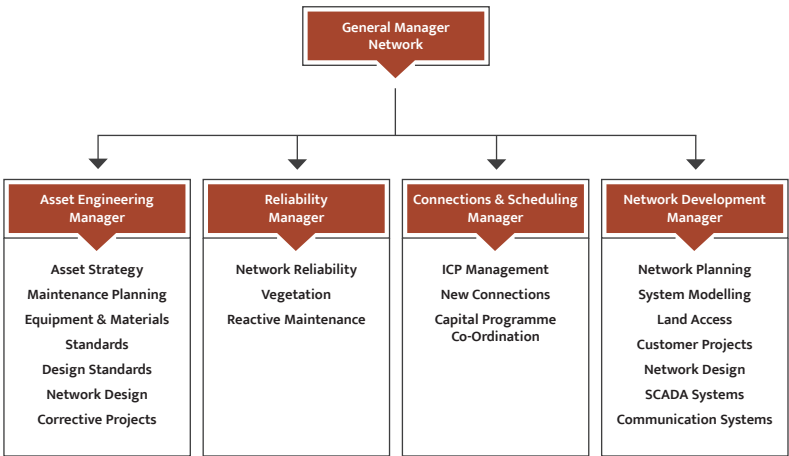


Figure 2-3 Overview of Asset Management Team

The General Manager Operations is accountable for the safe and cost-effective field delivery of annual plans and work programmes, including routine and corrective maintenance, asset replacement, construction of new network, network operations, fault dispatch and response, customer services, and vegetation management.

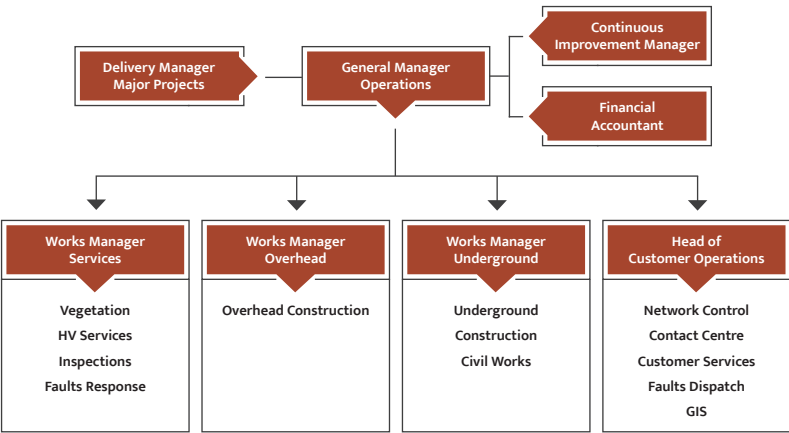


Figure 2-4 Overview of Operations Team

2.1.3 Asset Management Governance

Board Governance

Management report to the Counties Power Board on all relevant asset management governance requirements. These include but are not limited to; safety and environmental issues and initiatives, regular reliability reporting and analysis, operational issues, risk analysis and customer experience metrics.

Expenditure Approvals

Through this Asset Management Plan the Board of Directors is informed of the expected levels of expenditure required over the next ten years, but no expenditure is directly approved through the AMP process, rather annual budgets are prepared for their consideration.

The Board of Directors approves the annual budgets for operational and capital expenditure and delegates authority to the Chief Executive to approve the expenditure within a delegated authority framework, which is reviewed annually. Each major initiative or project is then subject to a robust business case and options analysis process before being recommended by the sponsoring executive for investment. The Chief Executive delegates authority to management to approve expenditure in line with the requirements of the position and responsibilities.

All network capital projects over \$200,000 have a business case approval process including a Capital Projects Governance Committee comprising members of the Leadership Team. Major Capital projects with a value in excess of \$1.0m are put to the Board for overall approval. All major projects over \$5.0m are reported to the Board on a monthly basis and are subject to a post implementation review to ensure objectives and targets have been achieved.

Any project variations which incur a cost increase or material time delay are managed within the approved delegated authority level and reported to the Board as appropriate.

Asset Management Capability

In order to deliver this plan, Counties Power has to ensure that appropriate skills and capability are available within the business.

Counties Power undertakes the majority of routine asset management activities in-house. As shown in the organisation structure diagrams earlier in this Chapter, the Network and Operations teams develop and deliver this plan, with the support of the wider company management team.

Some activities are outsourced to meet peak capacity requirements, or where it is not efficient to have specialist skills within the team. Examples of specialist services sourced externally include land and resource planning, specialist engineering and advisory consultants, and some field services such as specialist equipment repairers and protection technicians. A robust contractor assessment and approval framework provides assurance of safety, technical and capability competency before work commences and forms part of the ongoing contractor performance assessment framework.

Alongside maintaining worker competency, the training and development of staff is critical to the success of the business and identifying areas where new skills requirements or development pathways exist. Each year we recruit local school-leavers and others within the community to become apprentices in our skill areas, typically they form around 10% of our workforce.

Through the development of a rolling 10-year plan, Counties Power is able to identify the upcoming work types and volume, and assess the requirements for resources, capability and capacity.

2.2 Operating Environment

2.2.1 Network Overview

The Counties Power network was traditionally a provincial 'town and country' network distributing electricity across a broad geography in the southern Auckland and the northern Waikato region. However, the ongoing increase in the subdivision of land for housing together with the development of substantial industrial centres at Drury and Pokeno are seeing substantial growth of the urban area such that the longer term will see us as primarily an urban network but with a substantial rural sector.

Today, 70% of the Counties Power network is a rural overhead network by length; however the urban networks supplying Pukekohe, Waiuku, Tuakau, Pokeno, Drury and parts of Papakura comprise a split of overhead and underground assets. While the substantial majority of our network is rural the Installation Control Point (ICP) split is 32% Rural and 68% Urban, indicating the higher length of network, and costs associated with providing rural supplies. Generally, the eastern part of the network is newer, higher in ICP density and subject to high levels of growth in the areas adjacent to motorway and state highway corridors. The western part of the network is older, more remote and lower density. It has previously been subject to limited growth; however, the establishment of Special Housing Areas and other subdivisions is creating pockets of high growth requiring reinforcement, especially where they are some distance from existing substations.

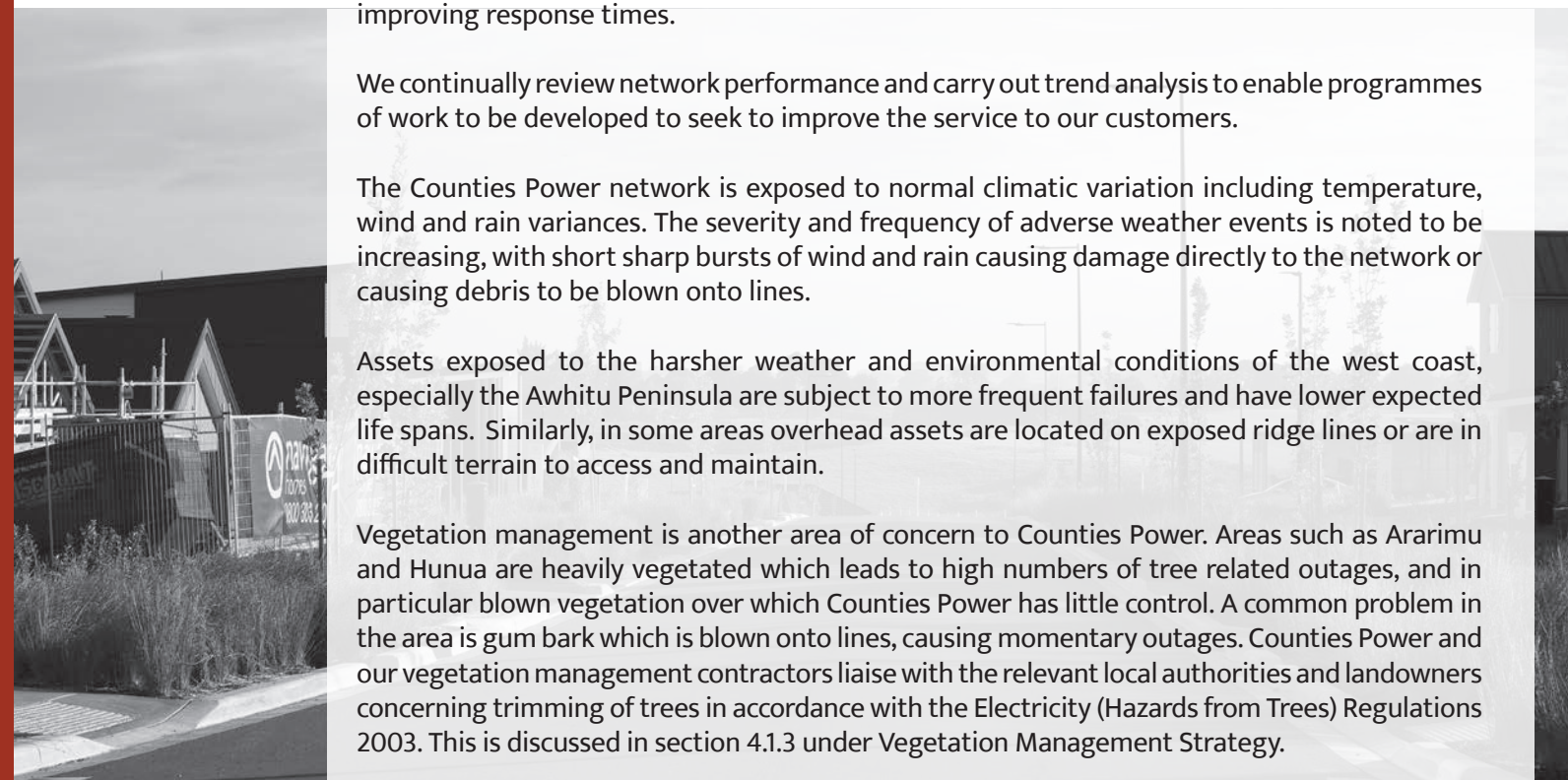
Network performance is consistent with other lines companies having an extensive rural network topology, largely owing to long restoration times associated with the remote Manukau Heads, Port Waikato and Kaiaua supply areas. Increasing levels of network automation are improving response times.

We continually review network performance and carry out trend analysis to enable programmes of work to be developed to seek to improve the service to our customers.

The Counties Power network is exposed to normal climatic variation including temperature, wind and rain variances. The severity and frequency of adverse weather events is noted to be increasing, with short sharp bursts of wind and rain causing damage directly to the network or causing debris to be blown onto lines.

Assets exposed to the harsher weather and environmental conditions of the west coast, especially the Awhitu Peninsula are subject to more frequent failures and have lower expected life spans. Similarly, in some areas overhead assets are located on exposed ridge lines or are in difficult terrain to access and maintain.

Vegetation management is another area of concern to Counties Power. Areas such as Ararimu and Hunua are heavily vegetated which leads to high numbers of tree related outages, and in particular blown vegetation over which Counties Power has little control. A common problem in the area is gum bark which is blown onto lines, causing momentary outages. Counties Power and our vegetation management contractors liaise with the relevant local authorities and landowners concerning trimming of trees in accordance with the Electricity (Hazards from Trees) Regulations 2003. This is discussed in section 4.1.3 under Vegetation Management Strategy.



We are planning in this current year to further increase our trimming of trees that have grown “in zone” to minimise the risk of outages from such interference. Our recent Light Detection and Ranging, a pulsed laser measurement technology (LiDAR) exercise has identified further attention is required and an increased budgetary provision has been included for next year (for an additional crew). Chapters 6 and 7 provides further details on this topic.

2.2.2 Territorial Authorities

The Counties Power network operates in an area split between three different territorial authorities; Auckland Council (37% of the Counties Power area), Waikato District Council (60%) and the balance in the Hauraki District Council area. Each territorial authority produces its own planning documents with rules which give effect to the Resource Management Act 1991, to promote the sustainable management of natural and physical resources.

2.2.3 Auckland Unitary Plan

Within the area of Counties Power that is administered by Auckland Council, the Auckland Plan 2050 will guide the long term spatial development of the wider Auckland area over the next 30 years. Its aims and objectives are supported by a number of documents including the Future Urban Land Supply Strategy 2017 (FULSS) and the Auckland Unitary Plan Operative in Part (AUP(OP)). The FULSS provides a long term, proactive approach to the delivery and timing of development ready land, providing clarity and certainty upon which to base infrastructure planning and investment decisions. The FULSS has been updated to reflect changes brought about by the Special Housing Areas, the AUP(OP) and new demand for development. The AUP(OP) came into effect in 2016 and replaced the former Regional Policy Statements and 12 District and Regional Plans. While there are still a number of outstanding appeals to the plan, (some of which are based in the Counties Power area), which means that it is still currently notified as Operative in Part, for practical purposes Counties Power follows the requirements of the AUP(OP) in the design, construction and maintenance of its network. While these requirements have the potential to add cost and complexity to maintenance and future development of the network, our experience to date has been that these circumstances occur only rarely.

2.2.4 Waikato District Plan

In the southern part of the Counties Power area the rules of the Waikato Regional Plan determine how we undertake work which might impact on the use, development or protection of natural resources; while the district plan rules are provided by the Proposed Waikato District Plan. Change 1 of the Proposed Waikato District Plan, which was publicly notified in July 2018, combines the Franklin and Waikato sections into a single plan for the Waikato district. The Proposed Waikato District Plan will provide guidance and set the rules that will shape growth and development in the southern part of the Counties Power area for the next 10 years. In March 2020 the council adopted the recommendations made by the Hearings Panel, as the council's decisions on the proposed plan change. There are currently 24 appeals lodged with the Environment Court of New Zealand over the proposed changes and due to the impact of COVID-19, delays have been granted for the submission of appeals.

We note the intention to concentrate development in existing developed areas such as Tuakau and Pokeno.

2.2.5 Hauraki District Plan

In the Hauraki District Council area, the requirements for Counties Power's operation, maintenance and development of the network are still based upon the Franklin District Plan. There are currently no proposals to review the Hauraki or Franklin section to create a single plan with district wide rules; however Plan Change 1 has been completed so that there are fewer restrictions on development within some areas of the District. These changes do not, however, impact significantly on Counties Power activities.

2.2.6 Growth – Present and Future

The Counties Power network is one of the fastest growing electricity networks in New Zealand with connection growth in the order of 2 to 3% per annum. This is largely driven by the growth of Auckland and our location within the ‘golden triangle’ of growth between Tauranga, Hamilton and Auckland.

The geographical data from the 2018 census provided by Statistics New Zealand³ show an overall increase in population across our area of supply as being between 10.1% and 15% since the previous census in 2013. However, several areas, including Patumahoe, Karaka, Pukekohe North and Pokeno are noted as having population growth of greater than 30%, with Tuakau, Pukekohe Central and Waiuku Central all identified as having growth of between 20.1% and 30%.

The census figures confirm our previous growth predictions and all indications are that the growth trend for population change will continue.

Population growth trends within the Counties Power area are monitored in terms of building consent applications and new connections. Applications have generally remained at a high level in spite of COVID-19 alert levels impacting the ability for us to process design requests and carry out physical works.

The largest contributor to demand growth in the medium term continues to be industrial and residential developments around Tuakau, Pokeno, and the approved Special Housing Areas at Paerata Rise, the proposed Drury South Business Park, and the Drury and Hingaia areas.

It has long been recognised that the growing population in Auckland is placing increased demands on land for housing, employment and associated infrastructure in the Auckland and neighbouring regions. To promote efficient urban development, while at the same time protecting natural and physical resources, the AUP(OP) has identified land which is potentially suitable for urban development and has defined its limit by means of the Rural Urban Boundary (RUB). The RUB, which gives effect to the AUP(OP)'s Regional Policy Statement regarding urban growth and form, contains sufficient appropriately zoned land within its boundary to accommodate a minimum of seven years of projected growth at any one time in terms of residential, commercial and industrial demand, as well as corresponding requirements for social facilities. Development of land beyond the RUB such as that proposed at Clarks Beach and Glenbrook Beach can only be achieved through a formal plan change process, thereby providing utility operators the opportunity to comment on the ability to supply the new development and identify any required upgrade. Maps outlining the RUB impact are provided in Chapter 8 Network Development.

A similar change notification process also applies for land zones “Future” within the urban boundary.

³ <http://statsnz.maps.arcgis.com/apps/MapSeries/index.html?appid=363cada2473a451d9f92ba0a4edc423a>

The supply and delivery of development ready land for housing and industrial growth is an important planning issue for Auckland. Figure 2-5 shows the anticipated dwelling capacity in future urban areas from the Greenfield Areas identified in the Auckland Plan Development Strategy, the future urban zoned land identified within the RUB area in the AUP(OP), and both the large future urban areas and the Rural Settlement future urban areas identified in the Auckland Future Urban Land Supply Strategy 2017 (FULSS)⁴. The sequencing and timing of these developments is proposed in the FULSS and provides a basis on which to calculate the scale and location of likely increases in demand on the network. It is noted, however, that there may be some slippage in the delivery of development ready land and further debate on the loss of productive market garden land may revise plans. While the timing of these developments is still uncertain, this provides information on the order of magnitude for anticipated dwelling capacity in our network development planning.

Anticipated dwelling capacity for future urban areas 2017 – 2042			
Location of new greenfield areas	Auckland Plan growth projections (2015)	Auckland Unitary Plan AUP(OP)	Auckland Future Urban Land Supply Strategy (2017)
South (Hingaia, Opaheke, Drury, Karaka, Paerata, Pukekohe) FULSS area (Clarks Beach, Glenbrook Beach, Kingseat, Patumahoe, Karaka North)	55,000	33,000 – 42,000	42,900

Figure 2-5 Anticipated dwelling capacity for future urban areas – projected numbers of dwellings

2.2.7 Special Housing Areas

The Special Housing Areas (SHAs) which were initiated to help maintain a ready supply of housing land during the preparation and development of the Auckland Unitary plan have been progressively disestablished since the Unitary Plan became operative (in part) in September 2016. These also feature in the FULSS and play a significant role in the first five years of sequencing and are part of the transition to longer term proactive planning. Construction has already commenced on many of these sites within the Counties Power area including sites at Belmont, Pukekohe, Hingaia, McLarin Road, Glenbrook, Clarks Beach, Paerata Rise, Bremner Road and Drury. While the final SHA was disestablished in May 2017, private plan changes such as the Bremner Road extension will mean that development sites will continue to be brought forward.

2.2.8 Regulation

Counties Power, as an electricity distribution business, is subject to regulation by the Commerce Commission, under Part 4 of the Commerce Act 1986. Due to the ownership structure, it is exempt from the Default Price-Quality Regime, as the customers are the beneficial owners through the Counties Power Customer Trust; however it is still required to comply with the Information Disclosure Requirements, of which this AMP is one requirement.

The business is also regulated by the Electricity Authority and is subject to compliance with the Electricity Industry Participation Code, both as a distributor and also as a metering equipment provider.

⁴ The primary purpose of FULSS is to identify the sequencing and timing of the future urban zoned land identified in the AUP(OP) and how it should be brought forward for development over the next 30 years based on zoning and infrastructure constraints. The FULSS includes development within rural urban areas of Clarks Beach, Glenbrook Beach, Kingseat, Patumahoe and Karaka North in addition to future urban zones areas within the RUB at Hingaia, Opaheke, Drury, Karaka, Paerata and Pukekohe.

Regulatory changes imposed by the Electricity Authority on other industry participants, such as Transpower, can have a consequential effect on the business, such as the method for determining transmission pricing.

In addition to economic and industry regulation, Counties Power has a range of legislative requirements to meet including Electricity Act 1992, the Electricity (Safety) Regulations 2010, the Health and Safety at Work Act 2015, the Electricity (Hazards from Trees) Regulations 2003, amongst others.

2.3 Customer Value and Cost Reflective Pricing

Counties Power’s capital and operating expenditure is continuing to grow as its network expands at a time when peak demand is growing twice as fast as sales volume and where average usage per customer is decreasing. The combination of Counties Power’s current volume based pricing, and the above factors means that distribution revenue per customer is also decreasing.

As with any electricity lines company, however, most of the company’s costs of providing distribution network access are fixed and are associated with building and maintaining infrastructure that can meet peak demand; the variable cost component is driven by the customer’s winter peak demand requiring additional distribution capacity and associated transmission charges. Customer volume is increasing at a lower rate than the customer peak demand is increasing, this creates a mismatch between revenue received and costs incurred. Counties Power’s current lines charges to its customers are not directly cost-reflective. Counties Power are currently consulting with retailers in order to establish a roadmap that will introduce pricing that is more cost reflective but have minimal impact to the customers on our network.

Counties Power believes that cost-reflective pricing is imperative to the long-term efficient management of the network. Without the correct price signals, customers may make inefficient investment decisions in emerging technologies, or they may utilise new technologies in an inefficient manner. Customer feedback on network pricing indicated that flexibility, transparency and simplicity in pricing is vital to elicit the required demand response. In response, Counties Power introduced a standardised pricing structure from April 2019. This standardised pricing structure, which is closely aligned with the Electricity Network Association’s pricing guidelines, aims to ensure that Counties Power’s pricing is user friendly for customers and retailers. In addition to the introduction of a standardised pricing structure, Counties Power introduced a peak/off-peak time-of-use (TOU) pricing structure across all mass market ICPs effective April 2019. This TOU pricing structure will continue to be refined.

Going forward, Counties Power will seek to rebalance future revenue from variable to fixed charges, with a view to increasing fixed prices and reducing the variable prices. An increase in mass market fixed daily prices will not only reduce household budget stress from seasonal variation in monthly bills, it will allow Counties Power to significantly decrease the variable off-peak and controlled rates. Counties Power anticipates that having a peak/off-peak rate, while reducing variable charges, will encourage electricity consumption (e.g. electricity over gas for space and water heating) and electric vehicle charging.

2.4 Stakeholders

Our stakeholders are the people or organisations that can affect, be affected by, or perceive themselves to be affected by our decisions or activities. Stakeholder requirements are important to us and we place considerable focus on identifying and meeting stakeholder expectations. Our stakeholders are described in Figure 2-6 below, along with their requirements, how those requirements are identified and how they are incorporated into our asset management practices.

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Customers	Safety;	Meetings;	Public safety initiatives;
	Reliable supply of electricity; at an acceptable quality and price;	Customer focus groups;	Service level targets; Investment in network;
		Annual surveys;	Price/Quality trade off;
	Effective communication particularly during emergencies and faults;	Special surveys for projects; and	Customer engagement process;
	Care of the environment; and	Feedback.	Network development projects for subdivisions and network extensions; and
	Lifelines preparedness.		Asset Fleet Management.



Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Public, Community, Iwi and Landowners	Safety;	Meetings;	Public safety initiatives;
	Lifelines preparedness;	Feedback; and	Network Development Planning;
	Care of the environment;	Consultations.	Service level targets; and
	Mana Whenua values and engagement;		Emergency preparedness planning.
	Protection of property and amenity values;		
	Reconciling land development opportunities with infrastructure routes; and		
	Effective communication regarding access and maintenance.		

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Local Authorities	Alignment with district and regional planning requirements; and	Meetings; and	Network Development Planning to ensure planned growth can be accommodated within the identified zones; and
	Accommodation of population and industrial growth arising from land use changes.	Consultations on appropriate infrastructure development and regional and district plans.	Emergency preparedness planning.
Electricity Retailers	Fair contractual arrangements;	Industry forums, conferences and seminars;	Service level targets; and
	Transparent, clear billing; suitable tariff structures; and	Regular consultation;	Network Development Planning.
Regulators and Governmental Agencies	Effective delivery of business to business services.	Electricity Industry Participation Code; and	
		Use of System Agreements.	
Regulators and Governmental Agencies	Statutory and Regulatory Compliance; and	Legislation and Regulations;	Network Development Planning; and
	Ensure customers receive a reliable supply of electricity at an acceptable quality and price.	Consultations; and	Service level targets.
Regulators and Governmental Agencies		Industry forums, conferences and seminars.	

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Transpower (as Grid and System Operator)	Security of supply;	Operational standards and procedures; and	Network Development Planning.
	New grid investment and planning provisions;	Regular meetings.	
Transpower (as Grid and System Operator)	Effective and timely communication;		
	Legislative and Regulatory compliance; and		
Transpower (as Grid and System Operator)	Sustainable earnings from connected and interconnected assets.		
Board of Directors	Governance;	KPIs; and	Risk Management integrated into all business processes; and
	Risk Management;	Regular Board Meetings and Directives.	Monthly reporting.
Board of Directors	Business direction and sustainability; and		
	Performance of Chief Executive and Leadership team.		
Staff	Safe and enjoyable work environment;	Employee surveys; and	Forward planning of work;
	Job satisfaction;	Regular employee briefings and communications.	Safety Initiatives and reporting;
Staff	Work/life balance;		Integration of Risk Management into all processes; and
	Development opportunities;		Training.
Staff	Fair remuneration; and		
	Effective support.		

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Contractors	Safety;	Contractual arrangements; and	Forward planning of work;
	Commercial treatment and access;	Regular meetings.	Safety initiatives and reporting; and
	Assurance of work continuity;		Integration of Risk Management into all processes.
	Visibility of forward workload requirements; and		
	Risk management.		
Suppliers	Fair, transparent, unbiased selection;	Contractual arrangements; and	Forward planning of work; and
	Forecast requirements to optimise supply chain;	Regular meetings.	Network Standards.
	Commercial sustainability; and		
	Risk management.		
Counties Power Customer Trust	Fair and reasonable rate of return on equity;	Trustee Meetings; and	Network Development Planning;
	Incentives to invest and innovate;	KPIs.	Organisation and governance structures; and
	Good governance; Risk management;		Integration of Risk Management
	Business sustainability;		Half-yearly and annual reporting.
	Good reputation with the community; and		
	Good asset management.		

Figure 2-6 Stakeholders and their requirements



2.4.1 Balancing Stakeholder Requirements

As we have a wide range of stakeholders it is important that conflicting stakeholder requirements are managed appropriately and consistently. Safety is a company-wide priority that takes precedence in resolving any conflicting requirements. Balancing differing requirements are managed in the following order:

- Safety and hazard mitigation;
- Regulatory and legal requirements;
- Contractual requirements;
- Customer price/quality; and
- Investment requirements.

2.5 Our Customers

Our customers are our owners. While we own a predominantly rural network, the majority of customers are in urban areas. However, our network services are one of the fastest growing areas in New Zealand. Consequently, the number of active ICPs has increased significantly over recent years and this growth is expected to continue over the planning period covered by this AMP.

2.5.1 Customer Profiles

As at November 2020, there were 44,728 ICPs connected to the Counties Power network with a maximum demand of approximately 129MW and annual delivered energy of 618GWh in the year ending 31 March 2020. In the most recent winter peaks in 2020, peak demand increased to 132.8MW. This number is increasing daily with new residential, commercial and industrial customers being connected. This is changing the customer mix from a predominantly rural, small town and rural commercial base (e.g. quarries, mines, food production) to an urban residential and industrial mix.

A breakdown of the ICP type is shown in the Figure 2-7 below:

	ICP's	Delivered GWh
Direct supply	9	100
Time of use	171	117
Commercial	7172	120.6
Domestic	37376	280.9
Total	44728	618.5

Figure 2-7 Breakdown of ICP Type

2.5.2 Major Customers

Counties Power has four large direct supply customers: Watercare Services Limited, New Zealand Steel Limited, Yashili New Zealand Dairy Company Limited and Synlait Milk Ltd. The four large direct supply customers comprise 16% of Counties Power's total electricity volume and this percentage is expected to continue to increase as Watercare expands their Waikato pumping operation and both Yashili and Synlait grow their production volumes and look to minimise their use of carbon-based fuels. Counties Power works closely with these companies to meet their electricity requirements and to understand their future expansion plans.

Power demand from Counties Power's other major customers has grown in recent years and has been driven by local economic and population growth. This growth has seen the mix of major customers change in recent years and this is likely to continue in the future as small companies expand and new companies are attracted to the region.

Counties Power's top customers are in the following industry sectors:

- Steel production;
- Dairy processing;
- Waste product and material handling;
- Food and produce processing and packing; and
- Timber and construction material processing.

Counties Power's top 11 customers account for 19% of Counties Power's total electricity volume.

Other customers with significant or strategically-important loads on our network include:

- Council infrastructure such as pumping stations, streetlights, and community facilities;
- Emergency and essential service providers; and
- Large industrial or commercial users in addition to those noted above.

We consider the needs of all our major customers when undertaking asset management activities:

1. **Safety** – we make sure the assets we own which supply them are safe and well maintained, particularly lines and transformers located on their sites.
2. **Reliability** – our network should provide the required level of performance in line with the terms under which the customer has connected.
3. **Value for Money** – that the price they pay for using our electricity network is competitive.
4. **Security of Supply** – our network should provide sufficient security of supply to enable maintenance and faults to be managed with acceptable levels of disruption to customers.
5. **Planning** – we make sure to consider their operations when planning network activities such as switching and outages.
6. **Communication** – we communicate openly with our major customers to understand their business and what's important to them, as well as providing feedback on events that may have impacted upon their operations.

2.5.3 Distributed Generation

Counties Power has 29 embedded generators greater than 10kW and 914 embedded generators under 10kW. Nine larger embedded generators (100kW or greater) consist of the following:

- Four hydro schemes operated by Watercare at their Hunua reservoirs. These comprise a 300kW generator at the Wairoa dam, a 300kW generator at the Mangatawhiri site, a 700kW generator at the Mangatangi dam, and a 300kW generator at Cosseys dam;
- A 7MW landfill generation plant at Hampton Downs landfill operated by EnviroWaste. This plant comprises seven 1MW containerised landfill generators;
- A 5MW plant in Papakura operated by an electricity retailer (consisting of a 3.5MW gas generator and a 1.5MW diesel generator);
- A 2MW windfarm in Waiuku operated by an electricity retailer; and
- Two 100kW photo voltaic installations operated by Watercare.

The remaining systems that are greater than 10kW are generally located on industrial or commercial sites. These are all are all photovoltaic installations.

The remaining 914 embedded generators under 10kW are nearly all small residential and business photo voltaic installations. The total number of photo voltaic installations has grown steadily over the last two years but with a greater growth in the number of larger (10kW to 100kW) systems.

2.5.4 Energy Delivered and Demand

Counties Power's total delivered electricity in the year to 31 March 2020 was 618GWh and peak demand was 129MW. The network load profile is winter peaking, with residential loads showing typical morning and evening peaks, and commercial loads generally having a constant daytime load.

Delivered energy has been growing at 2.2% per annum on average over the last five years and peak demand has grown at an average of 2.3% per annum over the same period. The graph below (Figure 2-8) shows the growth split over Counties Power's main customer groups and the peak demand increase.

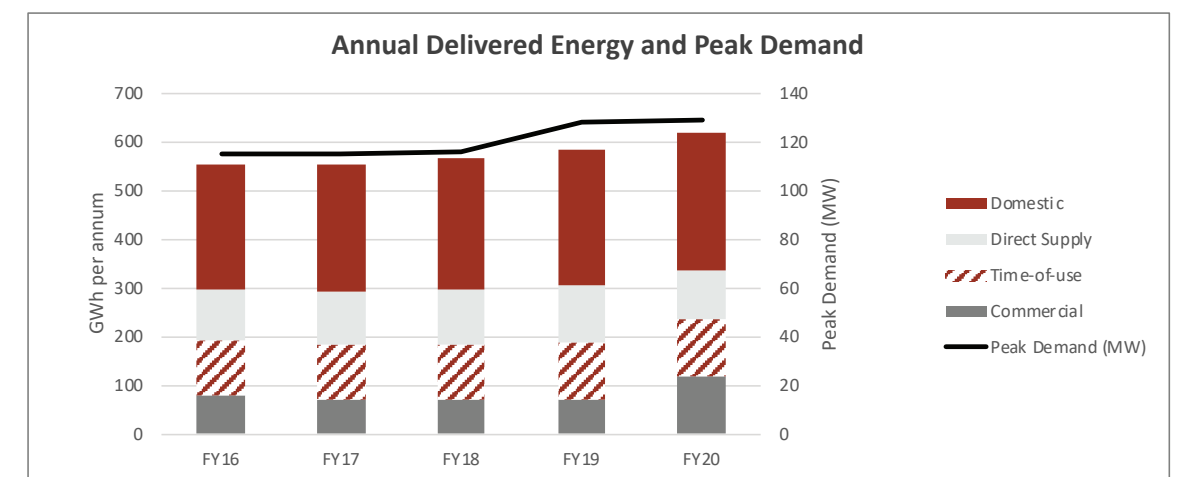


Figure 2-8 Energy volumes and network demand 2016 to 2020

2.6 Our Network

Counties Power has two points of supply from Transpower’s National Grid via Grid Exit Points (GXP) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33kV while Bombay GXP supplies the eastern substations at 110kV and 33kV. The number of active installations and the installed distribution capacity controlled by each GXP is shown in Figure 2-9. 73% of ICPs are supplied from the Bombay GXP at 110kV and 33kV, and the remaining 27% from Glenbrook GXP. Other details are included in the following sections.

GXP	Zone Substation	No. of Distribution Substations	Distribution Capacity (kVA)	Active ICPs				
				Total	Residential	Commercial	Industrial	% of Total ICPs
Bombay 110kV	Pukekohe	649	84,205	13329	11194	2066	69	30%
Bombay 110kV	Opaheke	484	68,890	8630	7683	906	41	19%
Bombay 110kV	Tuakau	726	50,968	6537	5314	1193	30	14%
Bombay 33kV	Mangatawhiri	413	21,860	2229	1672	545	12	5%
Bombay 33kV	Ramarama	352	19,700	2263	1780	477	6	5%
Glenbrook 33kV	Karaka	465	27,585	3840	3181	654	5	9%
Glenbrook 33kV	Maioro	112	19,275	536	361	171	4	1%
Glenbrook 33kV	Waiuku	645	43,310	7364	6202	1147	15	17%

Figure 2-9 Overview of Network Substations and Customer Information

Note: Pokeno Substation (Bombay 110kV) has just been commissioned but did not have customers connected at time of writing.



Figure 2-10 below illustrates the geographical area covered by the network, along with Figure 2-11 which shows the 110kV and 33kV subtransmission network, and the zone substations. More detailed maps showing the distribution network coverage areas are included in Appendix D – Network Diagrams.

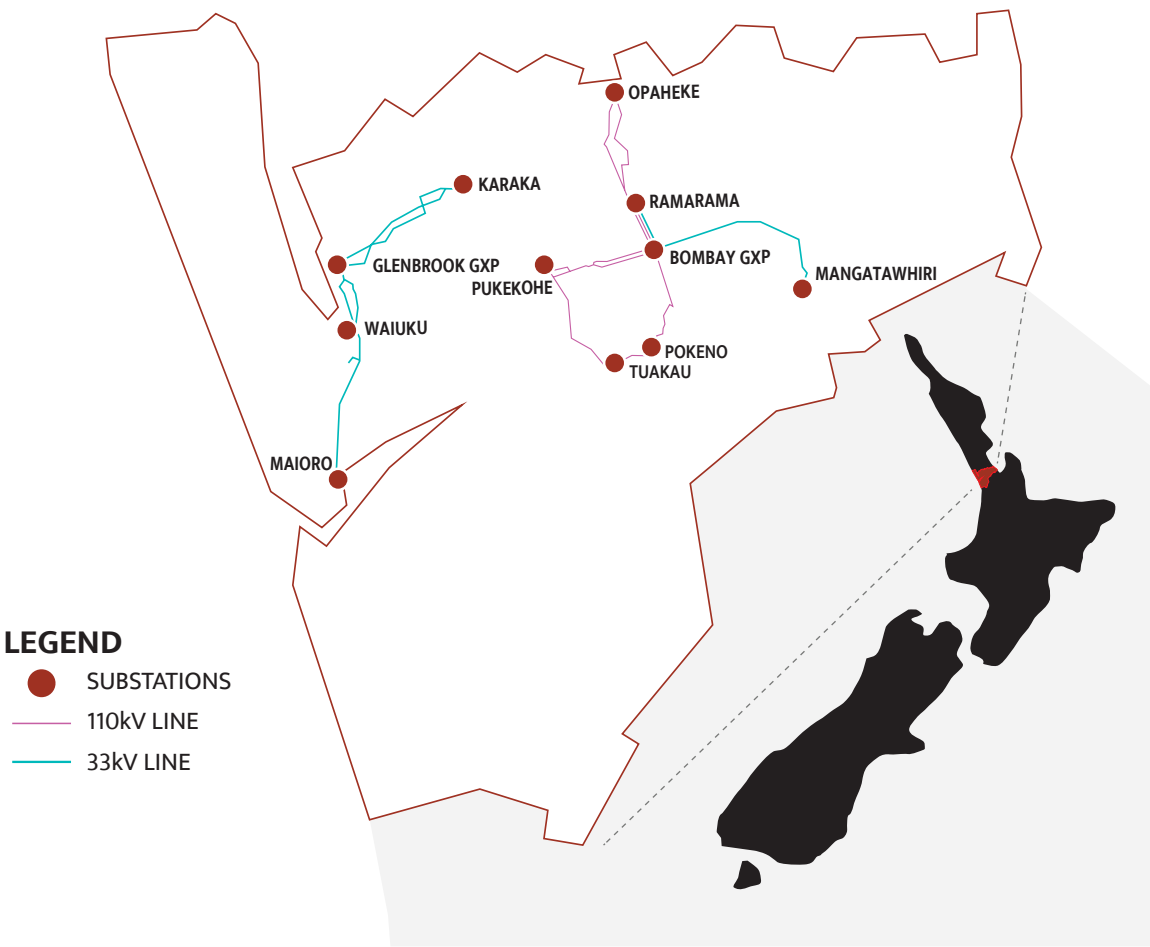


Figure 2-10 Geographic overview of the Counties Power Network Area

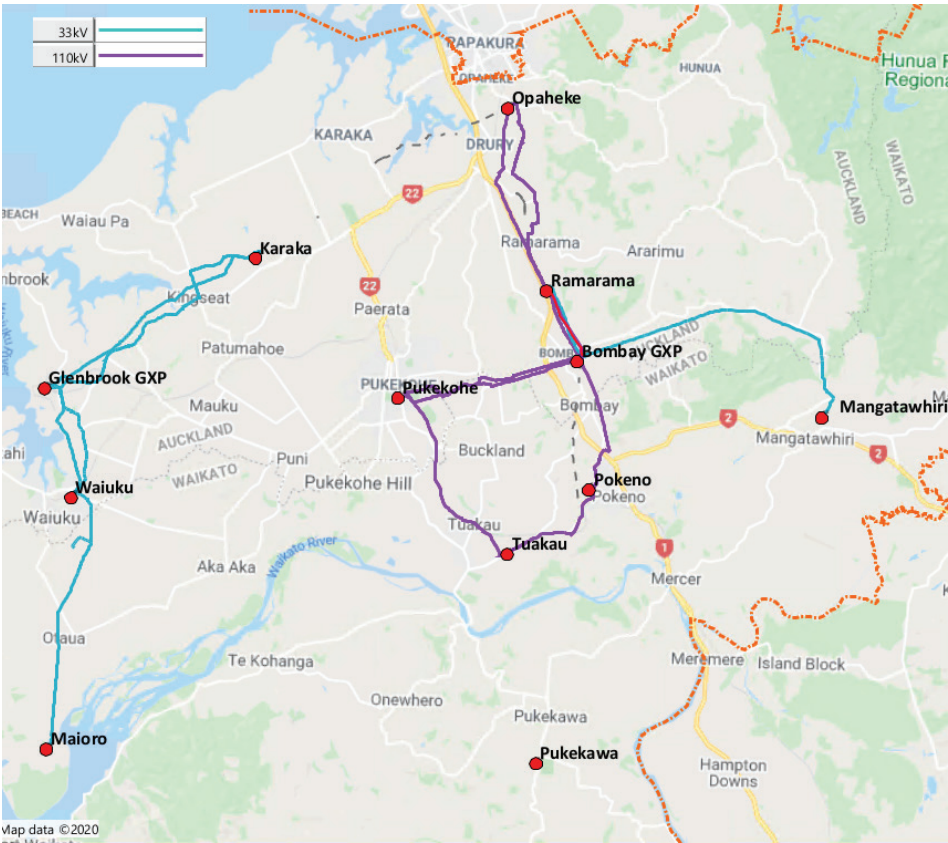


Figure 2-11 Overview of Counties Power Subtransmission Network

2.6.1 The Subtransmission Network

Our subtransmission network consists of a network of 110kV and 33kV subtransmission lines from Bombay and Glenbrook GXP. The architecture of the network is typically radial subtransmission circuits connecting to 33kV buses or configured as transformer-feeders where no bus is installed. Our 110kV supply to Pukekohe, Tuakau and the new substation at Pokeno is operated as a ring with three circuits supplying the three zone substations.

- The Pukekohe Substation is supplied via two 110kV lines from Bombay, with a 110kV bus;
- The Opaheke Substation is supplied via two 110kV lines from Bombay configured as transformer-feeders; and
- The Tuakau and the new Pokeno Substations are supplied on a ring circuit via two 110kV lines – one from Bombay and one from Pukekohe.

The remaining five zone substations are supplied via the 33kV subtransmission network with distribution supply operating at 11kV, with some feeders stepped up to 22kV using auto transformers.

The subtransmission system schematics, capacity and demand information is provided in Chapter 8 Network Development. A summary of the loading and other characteristics of the subtransmission system and zone substations are illustrated in Figure 2-12.

GXP (Grid Exit Point)	Zone Substation	Number of GXP circuits	Circuit Description	Installed Capacity (MVA)	N-1 Capacity (MVA)	Load 2020 [2019] (MVA)	No. of Customers (Oct-20)	Average Forecast Growth Trend (%)
Bombay 110kV	Pukekohe	2	Single 110kV pole line	2 x 30/60	60	42.0 [39]	13,329	3.1
Bombay 110kV	Opaheke	2	Single 110kV tower line & pole lines	2 x 20/40	40	27.3 [21]	8,630	8.1
Bombay 110kV	Tuakau	2	Single 110kV pole line	2 x 20/40	40	22.5 [21]	6,573	0
Bombay 110kV	Pokeno	2	Single 110kV pole line	2 x 30/40	40	Note 1	Note 1	5
Bombay 33kV	Ramarama	2	Single 33kV tower & pole lines	1 x 5 + 5/6.25	5	6.6 [6]	2,263	Note 2
Bombay 33kV	Mangatawhiri	1	Single 33kV pole line	1 x 7.5/9.4	--	7.4 [7.0]	2,229	Note 2
Glenbrook 33kV	Waiuku	2	Single 33kV pole line	2 x 10/20	15	16.1 [16.0]	7,364	2.6
Glenbrook 33kV	Karaka	2	Single 33kV pole line	2 x 10/20	20	11.5 [10]	3,840	5.6
Glenbrook 33kV (via Waiuku)	Maoro	1	Single 33kV pole line	2 x 7.5/9.4	--	9.2 [9]	536	0

Figure 2-12 Summary of Subtransmission and Zone Substations Characteristics

Note: 1 Pokeno Substation has been lived in but load transfer was not completed prior to the winter peak.
Note: 2 Ramarama and Mangatawhiri are planned to be replaced by Barber Road – growth trend 1%

2.6.2 The Distribution and LV Network

Our zone substations supply a total of 63 distribution feeders (operating at 22kV or 11kV) via approximately 4188 (including private) substations. The distribution substations connect over 44,728 customers to the Counties Power network.

Distribution substations transform the 22kV or 11kV distribution voltage to 400V/230V reticulation voltage and typically include - distribution transformers, high voltage fuses or circuit breakers and low voltage fuses.

A total of 46 22kV/11kV transformers, the earliest of which were installed in 1994, are also in use on the network to provide interconnection between circuits operating at each voltage.

Of the total distribution network circuit length (both HV and LV), 67% consists of overhead lines and 33% is underground cable. On the low voltage network, approximately 46% is overhead while on the high voltage network, 86% is overhead (see Figure 2-13). Further details about the distribution network, including quantities and age profiles are included in Chapter 7 Renewal and Maintenance. In addition to our distribution network, there are overhead lines owned by private land owners which connect to our network, and in places third party poles, such as those owned by Chorus, are used to support overhead lines.

Secondary assets include ripple injection systems, protection, Supervisory Control and Data Acquisition (SCADA) and telecommunication systems.

	Voltage	Length (km)
Underground	22kV	162
	11kV	77
	LV	859
Overhead	22kV	572
	11kV	888
	LV	720

Figure 2-13 Composition of Distribution Network (as at Sep-20)

If we undertake voltage conversion projects, we increase the system length of 22kV network, and decrease the length of 11kV network. All new network extensions are constructed for 22kV operation however they may only be energised at 11kV.

Generally, distribution overhead lines and underground cables feed ground-mounted or pole-mounted transformers via fused switchgear such as dropout fuses (DDOs) and ring main units. These distribution transformers step the voltage down to a low voltage level of 400V or 230V to supply our customers through our low voltage network.



3 SERVICE LEVELS

3.1 Stakeholder and Customer Engagement

Counties Power is building on its strong existing connections to its customers and local community. Being Trust owned provides an advantage as we have a long-standing community connection through our customer ownership Trustees and our staff, most of whom live locally. Initiatives over the last couple of years have been the appointment of a dedicated Customer Relationship Manager to enhance our existing approach to community support, dedicated education and information sharing particularly around safety but also raising awareness on energy. This allows us to get greater feedback and engagement which is complemented by our customer analytics and leadership focus concentrated on our customers. The Electricity Pricing Review (EPR) provided sound oversight of the issues contributing to energy hardship and lack of smaller customer voices being heard and we take our responsibility to our customers seriously as we seek to enhance the customer voice.

Customer Outage App

Counties Power has developed an industry leading customer outage app that won the 2019 Deloitte Network Initiative of the Year Energy Award. This app provides Counties Power’s customers with near real time visibility of network faults and planned outages (planned outages are shown three days forward). The app also enables customers to report faults directly to Counties Power and allow customers the option to be notified of faults that will impact their premises. We see this a strong step in the direction of giving customers greater and easily accessible information.

3.2 Stakeholder Engagement

3.2.1 Customer Surveys

Counties Power has engaged an external specialist survey company to carry out comprehensive targeted customer surveys on an annual basis, and to conduct post-service feedback surveys every month. The annual surveys include questions directly relating to network performance and provide useful information for planning. The monthly post-service surveys measure the level of satisfaction directly with customers who have contacted Counties Power for any reason at all, thus there is only limited useful direct information from these surveys on network performance.

The annual customer surveys measure and monitor both residential and commercial customers experience and rating of the power supply service they receive. The last customer survey was conducted in November 2020, by an external research company. The respondents surveyed were across four customer groups, defined by rural or urban location and residential or commercial customers.

	Residential	Commercial	Total
Rural	108	108	216
Urban	108	109	217
Total	216	217	433

Figure 3-1 Distribution of Customers Surveyed

The 2020 survey evaluated current satisfaction levels in addition to identifying the key factors that influence overall satisfaction. The key factor analysis is a Customer Value Management model (CVM) which has been developed to understand how the various service elements influence the overall satisfaction with Counties Power and its power supply grouping factors under the four categories. Reliability of supply is grouped under “Overall Service Delivery” which represents 21% of the final customer rating. The overall model is shown in Figure 3.2.

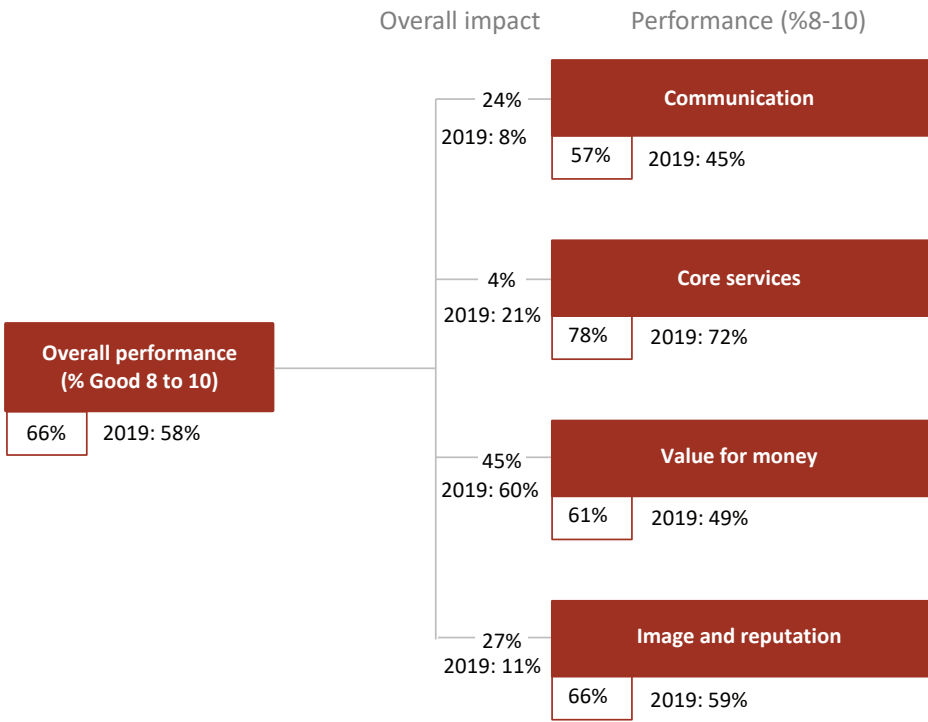


Figure 3-2 Customer Value Model

The above diagram shows the four areas questioned and their individual scores. The overall impact is applied to these scores to calculate the Overall Performance figure. The previous survey (2019) figures are provided for comparison.

Overall Reliability of Supply was rated at 78% satisfaction (i.e. rated 8 or higher on a 1 to 10 scale), reflecting that in general most customers are satisfied with the reliability of their power supply. This is an improvement on the 2019 survey result which had a satisfaction rating of 72%.

The level of satisfaction varies with customer type and their location as shown in Figure 3.3 below.

Residential Urban	Residential Rural	Commercial Urban	Commercial Rural
84%	74%	80%	72%

Figure 3-3 Customer satisfaction with reliability of supply by type

The largest single influence on overall customer satisfaction was “Value for money”; this has two drivers, “line charges being good value” and “satisfaction with the level of discount received”. As lines charges are only identified separately to a few large customers it is difficult to separate whether the survey response is a reflection of customers’ views of their total power bill or of the actual lines charges.

Understanding of the value delivered through line charges is of importance to our customers and is an area of opportunity for Counties Power. There is a high recognition of Counties Power as their local lines company (76% unprompted); however it appears that customers do not fully understand the components of their overall electricity bill and the difference between lines and energy charges. It is intended that future surveys will include questions to try to establish what knowledge responders have on the make-up of the total power account and thus what the knowledge is of the actual level of lines charges.

Of those surveyed over seven out of ten customers (70%) would prefer to maintain current levels of service. Rural customers and Urban Commercial customers, are more willing to pay an increased line charge for increased reliability, however the majority of those willing to pay more identified a willingness to pay an increase of less than \$10 per month. The expected level of improvement for this has not yet been established.

The study identified the overall perceptions of customers by type as shown in Figure 3-4 below.

	Residential Urban Customers	Residential Rural Customers	Commercial Urban Customers	Commercial Rural Customers
What is most important to these customers	Lines charges being good value, the annual discount, embracing technology, communication about what Counties Power is doing.	Lines charges being good value, the annual discount, caring about the community, provision of exceptional service and solutions.	Lines charges being good value, the annual discount, embracing technology, caring about customers.	Lines charges being good value, the annual discount, communication being sufficient.
Opportunities for improvement	Demonstrating the value of lines charges and the discount received.	Demonstrating the value of lines charges.	Demonstrating the value of lines charges.	Demonstrating the value of lines charges.

Figure 3-4 Results of 2020 survey identifying what is of most importance to customers and opportunities for improvement.

3.3 Service Level: Workplace Safety

Counties Power is committed to conducting business in a way which enables everyone to be healthy, safe and well every day.

It is through the application of the principles, provisions, definitions and intent of the Health and Safety at Work Act 2015 that Counties Power will demonstrate strong and visible health, safety and wellbeing leadership by recognising, managing and minimising health and safety risks in all areas of the business.

The focus for Counties Power’s health, safety and wellbeing programme are:

- Risk - We know, understand and reduce our risks by:**
 - Knowing our critical risks, aiming to eliminate, or where not possible, minimise these critical risks with effective controls;
 - Setting health and safety standards and receiving adherence; and
 - Partnering with organisations who mirror our commitment to health and safety.
- Relationships – We work together to look after ourselves and our work mates by:**
 - Recognising that we all have a role to play in keeping everyone safe, every day;
 - Expecting everyone to ‘speak up’ on health, safety and wellbeing; and
 - Celebrating the positive health, safety and wellbeing contributions.

- Resource - We have the right tools and skills to succeed by:**
 - Providing the tools and resources so our people can perform at their best;
 - Ensuring, through training, our people have the competencies needed to work safely; and
 - Promoting health, safety and wellbeing across the business

Counties Power continues to be an active member of the Business Leaders’ Health and Safety Forum, the Electricity Supply Industry (ESI) Health and Safety Forum, Electricity Engineers’ Association (EEA) and the Electricity Networks Association (ENA). It is a regular contributor to industry working groups on matters concerning staff and public safety and safety by design.

3.3.1 Safety Objectives

To achieve our health and safety vision, and our corporate mission and values we have placed health and safety as the highest priority over all our business objectives. Our most important priority is to conduct ourselves in a manner that protects our staff, contractors, visitors to our site and members of the public who interact with our assets. We acknowledge our responsibilities for maintaining high health and safety standards in the workplace and will provide resources, effective systems and sufficient capacity within our business to fulfil this commitment.

3.3.2 Safety Initiatives

In order to achieve these objectives, we continue with the following initiatives:

- Bowtie methodology for evaluating each critical risk and the associated controls to ensure robust measures are identified and implemented;
- Staff have electronic access to record, report, log and investigate incidents, safety observations, vehicle inspections and site audits;
- A reward and recognition scheme for those who make considered contributions to safety;
- Continuous promotion of worker engagement through an active Health and Safety Committee;
- Continued engagement and communication flow with the workforce through a departmental representation at the Health and Safety Committee;
- Subjecting each high potential incident to a detailed Incident Cause Analysis Methodology (ICAM) investigation by ICAM trained managers;
- Review of Job Safety and Environmental Analysis (JSEA) to ensure relevancy and identification of gaps;
- An elevated level of Field audits through external auditor MITA;
- Introduction of E-road to all company vehicles; and
- Annual safety culture survey with departmental workshops to identify improvements.

3.3.3 Safety Measures and Targets

We have grouped our safety performance targets into two categories; namely lagging and leading indicators. These are:

- Leading Rate Measures. This includes safety audits (internal and external), safety observations and asset surveys.

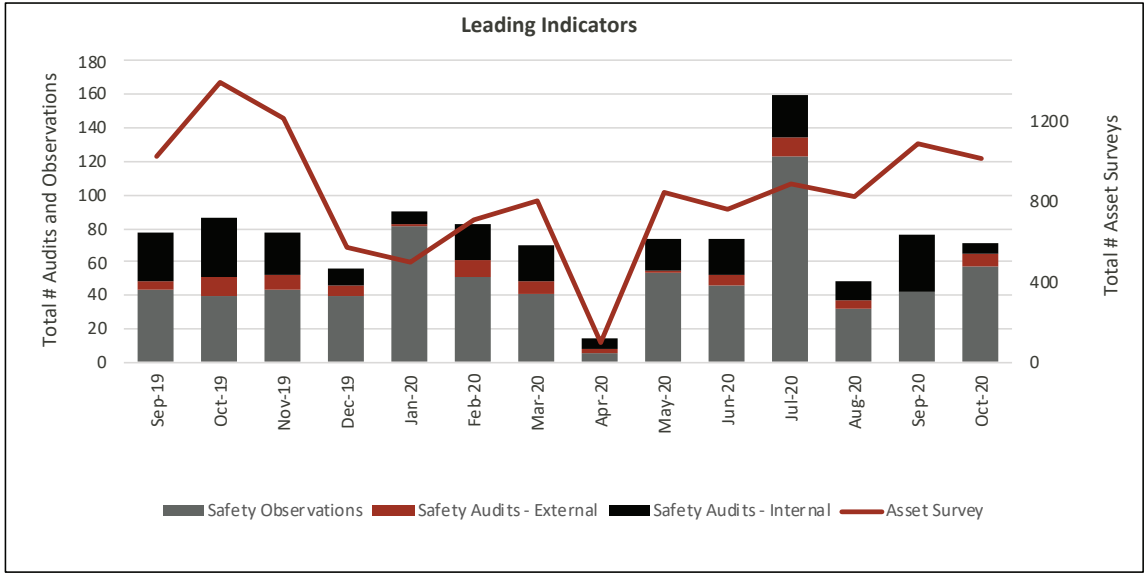


Figure 3-5 Leading Indicators - Safety

- **Lagging Injury Rate Measures.** Under this category we measure Total Recordable Injury Frequency Rate (TRIFR) which includes all lost time, restricted work and medically treated injuries using a calculation based on 1 million hours. We also measure Lost Time Injury Frequency (LTIFR) and Lost Time Injury Severity (LTISR) which encompasses total number of lost time injuries and total lost days. Our company wide target for each measure is to reduce to zero.

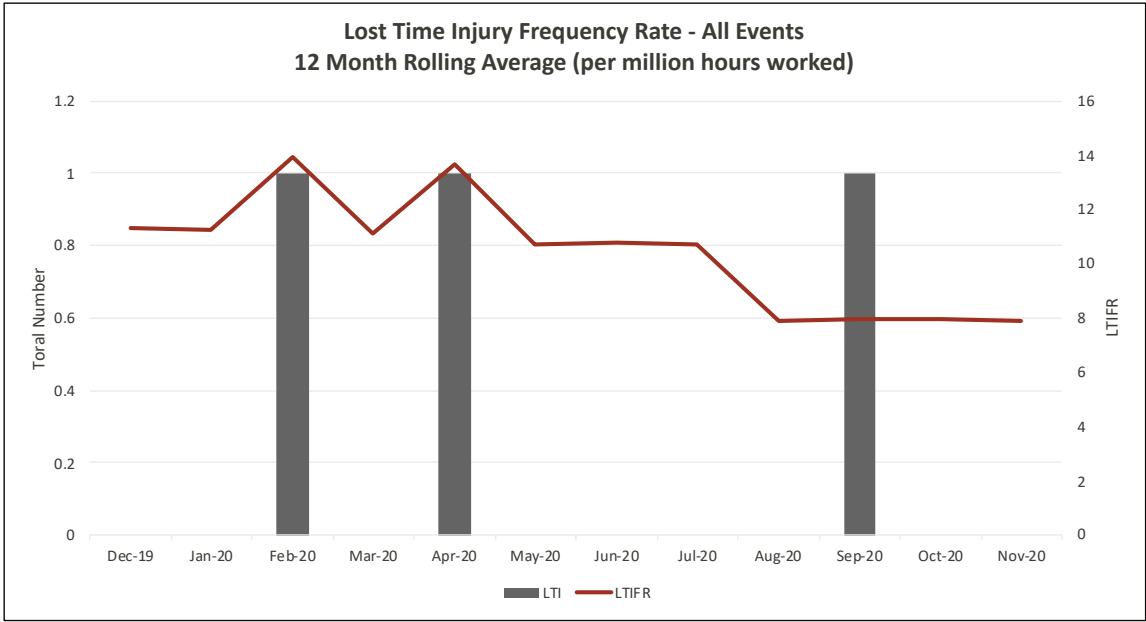


Figure 3-6 Lost Time Injury Frequency Rate

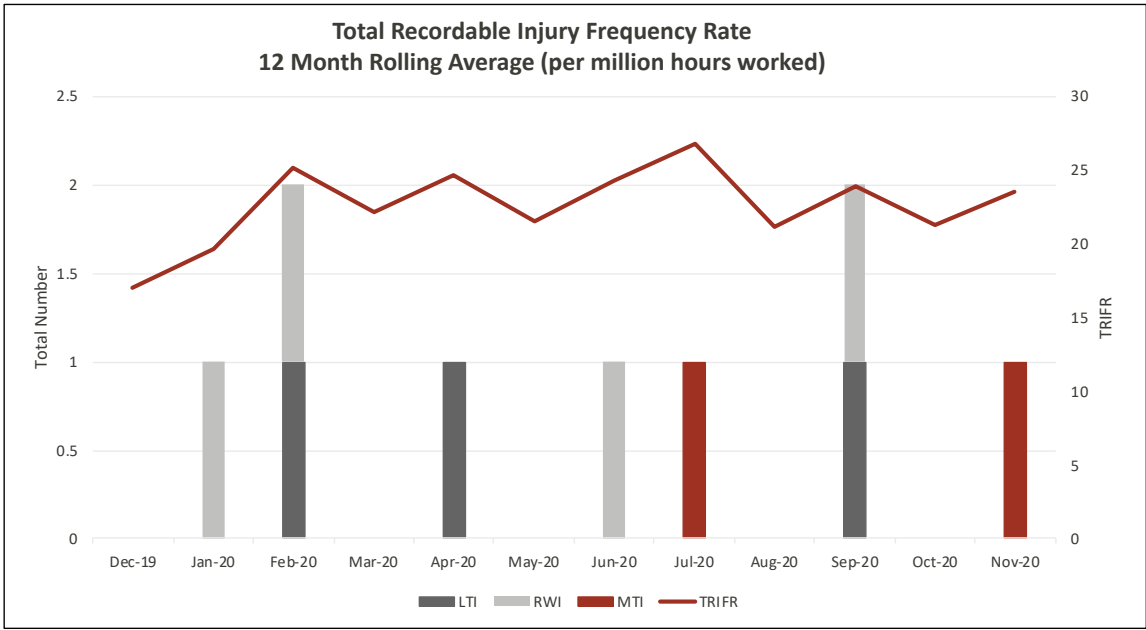


Figure 3-7 Total Recordable Injury Frequency Rate

Safety Culture and Leadership

Safety culture at Counties Power has continued to be strong over the past 12 months. Team Leader development training has been launched, not only with a focus on safety leadership but also with a focus on developing effective communication and leadership skills. The programme covers core skills in verbal communication, decision making, problem solving and conflict management which are designed for learners to work more effectively as a member of a team, building collaboration across teams and ensure projects are being performed successfully. This enables staff to further develop as effective people leaders.

3.4 Service Level: Environmental

3.4.1 Objectives

Counties Power acknowledges that we are obligated to provide environmental leadership within the community in which we live and work; recognising that environmental protection and sustainability are important issues facing our community now and in the future. With this in mind we're continually seeking to implement environmental best practice through all stages of a network asset life cycle; so that we minimise our environmental impact, while maintaining compliance with our legal obligations.

3.4.2 Targets

We have identified which network components pose the highest risk for environmental problems; these being insulating oil leakage and SF₆ gas leakage.

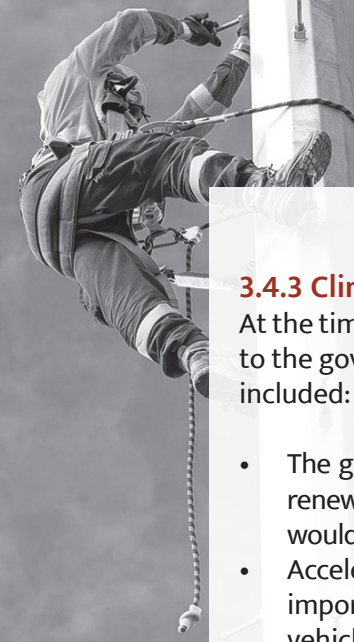
In the case of insulating oil, the primary concentration is in zone substation transformers and we have completed installation of oil separation systems and/or bunding at all zone substation sites to mitigate oil leakage.

The next largest individual volume of oil is in the 22/11kV interconnection transformers located on the network, generally on road reserves. We have improved the oil containment design for all new transformer installations with a capacity of over 1000L.

The individual volumes of oil in distribution transformers, both pole and berm mounted, is small and the risk of leakage is managed by close examination of the transformer tank and fittings during routine inspections.

SF₆ gas is used as an insulant in various types of distribution switches. Where possible, existing installations are monitored for leakage and individual action is taken as appropriate and we report against SF₆ usage as per our Environmental Protection Agency - Emissions Trading Scheme obligations. Investigations are in progress for other overhead switchgear solutions to minimise our SF₆ quantities.

Our overall target is to investigate 100% of all reported environmental events.



3.4.3 Climate Change Commission Draft Report

At the time of writing the AMP, the Climate Change Commission had released their draft advice to the government on recommendations to reduce greenhouse gas emissions. This advice has included:

- The government to develop a long-term national energy strategy, with the aim of increasing renewable energy from 40% to 60% of total energy use by 30 June 2023. Most of this increase would be from switching from gas and petroleum fuels to electricity; and
- Accelerate the EV uptake with the Government to consult on options. Then, phasing out imports of light internal combustion engines between 2030 and 2035, with 40% of light vehicles targeted to be electric by 2040.

These proposals will increase the demand on Counties Power's network. In this regard, Counties Power is ensuring that new subdivision developments will be able to support this increased load with the region's large new subdivisions having 22kV reticulation. This includes the large Drury and Paerata Rise developments as well as the Pokeno residential and industrial subdivisions.

3.5 Service Level: Public Safety

3.5.1 Objectives

Our objective is to ensure that no member of the public is harmed by our network assets, and that hazards introduced by our network assets are controlled so as to not pose a risk to the public.

3.5.2 Targets

Leading Indicators

Categories for leading public safety indicators include:

- Number of asset inspections and tests undertaken on:
 - High risk asset categories in the public domain – pillars, transformers, ring main units, poles, zone substations;
 - Safety critical assets – earthing, protection systems; and
 - Assets in special locations – those located around schools, public recreation spaces, commercial and shopping areas.
- Time to repair high risk defects on the network (percentage completed within required timeframes); and
- Number of external stakeholder engagement activities such as public safety notifications and school safety visits.

Lagging Indicators

In addition to leading indicators, we record lagging indicators including:

- Number of incidents reported with or without harm; and
- Number of damaged property incidents (customer premises and network property).

Actual Performance for FY19 to FY21 is shown in Figure 3.8 below.

Details	FY19	FY20	FY21 YTD
Property Damage to Network Assets	315	249	50
Reported Injuries from Network Assets	5	4	1

Figure 3-8 Public Safety Lagging Indicators

Along with introducing targets for leading indicators, we are also going to extend our reporting of lagging metrics, including:

- Number of assets found or reported to be insecure; and
- Number of lines down and unassisted pole failure incidents.

3.5.3 Initiatives – Public Safety

In order to provide the highest levels of public safety, we have the following initiatives in place:

- Ensuring assets are inspected, maintained and defects repaired in accordance with good industry practice;
- That equipment is designed, selected and installed in a way to promote public safety (safety by design);
- That earthing and protection systems are designed, tested and operate to clear faults quickly to protect members of the public from electric shock;
- Maintain compliance and certification to the requirements of NZS7901 for Public Safety Management Systems, including undertaking periodic external performance assessment;
- Public Safety awareness – undertaken print, web and social media awareness campaigns, as well as engaging with local primary and secondary schools and providing safety resources on our website www.countiespower.com; and
- Active engagement with Energy Safety in relation to unsafe activity around our network by third parties, or where people have come to harm from our assets, on their own premises.

3.6 Service Level: Reliability

3.6.1 Objectives

Our objective is to operate the network to provide a level of performance in line with the price customers are willing to pay, this includes:

- Minimising the number and duration of outages experienced by customers;
- Restoring power as quickly and safely as possible following an unplanned outage and providing communication to keep customers informed; and
- Providing customers with sufficient notice ahead of planned outages required for maintenance.

There are some customer groups on our network who demand higher levels of reliability, and are prepared to pay more for that benefit, and we accommodate their needs where practicable.

3.6.2 Targets

Customer Reliability Service Levels

We set reliability service levels for our customers in the Use of System Agreements we have with Retailers trading on our network. These outline the target times for restoration of supply following a fault on the network, as well as the timeframes for notifying the customer that we have to turn off their supply for planned works.

Description	Target
Restoring electricity supply after the Distributor becomes aware of the fault.	Rural – 6 hours Urban – 4 hours
Notice of pre-planned supply interruption	Not less than 5 days’ notice to the Retailer unless already agreed with by the Customer

Figure 3-9 Restoration Targets

This service level is presently monitored, although it is recognised to be at a level of granularity below what is desirable. It is only presently possible to report on the maximum duration of a particular event and we can therefore not distinguish the durations at a customer level. For example, an event that impacts 500 customers in total, of which 400 are impacted for 10 mins, 80 for 2 hours and the final 20 for 6 hours, would show in the reporting as simply being 6 hours (being the maximum duration), despite the fact 96% of the affected customers experienced a service significantly better than this. Discussions are ongoing regarding how our systems can be improved to better capture this information and report accurately on this service level. It is likely this will be included in the initiative relating to setting reliability standards by customer type (refer section 5.6.3).

Overall Network Performance

As an exempt Electricity Distribution Business (EDB), our network performance indices have not been required to be calculated in accordance with the Commerce Commission default price-quality path (DPP) methodology; however we have taken this into account when assessing our network performance as several of our peer group comparisons and our neighbours are non-exempt. Forward targets for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are shown in Figures 3-10 and 3-11 below.

With the introduction of the Health and Safety at Work Act in 2015, we implemented a risk based live work decision framework aligned to the Electricity Engineers’ Association’s guide to live work which resulted in an increased number of planned outages to complete our work safely. More recent experience gained under the new guide has resulted in some increase in live work; however there is a mixed level of adoption of these live work guidelines across the industry, thus making it difficult to accurately benchmark SAIDI and SAIFI performance against our peers.

Our performance targets have been set based upon recent network performance over the period 2017 to 2020, which, after consideration of the planned targeted improvement works, has been used to set internal targets for unplanned SAIDI (Section 5.3 provides further detail on this aspect). An internal target of 90 (180 non-normalised) minutes for planned SAIDI had been adopted. These are shown in Figure 3-10 below.

Network SAIDI	FY20	FY21	FY22	FY23	FY24
Planned	90	90	90	90	90
Unplanned	110	140	130	125	120
Total	200	230	220	215	210

Figure 3-10 Network SAIDI forward targets

Similarly, SAIFI targets have been set as shown in Figure 3.11 below.

Network SAIFI	FY20	FY21	FY22	FY23	FY24
Planned	0.4	0.3	0.29	0.28	0.27
Unplanned	2.4	2.7	2.61	2.52	2.43
Total	2.8	3.0	2.9	2.8	2.7

Figure 3-11 Network SAIFI forward targets

Internally we track planned SAIDI and SAIFI figures utilising the Commerce Commission’s Default Price Path (DPP2) methodology. This enables us to halve the SAIDI impact of planned outages. By adopting this position on planned SAIDI, and coupling this with restricted levels of live work, we are able to undertake more planned work when de-energised, an important safety improvement, as well as reducing the dependence upon generator support. Customer service expectations have been carefully managed, as has engagement with communities on the reasons behind this important safety improvement initiative and the resultant impact on outages. There are regular meetings with our major stakeholder, Counties Power Consumer Trust, for two way interchange of information on customer matters.

In recognition of these new targets being a step change, resulting in a reduction in service to customers, and reflecting our plan for continuous improvement, we have researched ways to improve the performance for future years and have set reducing targets accordingly. This also reflects that prior to the notable change in operating environment around 2016, a slight increasing trend in underlying SAIFI for the preceding years was noted, for which the network initiatives described in later Chapters are expected to address over the medium term. We have developed a specific programme to reduce the number and impact of unplanned outages by applying a targeted trend analysis approach. This is detailed in chapter 5 and the resulting improvement projects, which comprises maintenance driven projects and network development projects, are outlined in Chapters 7 and 8 respectively.

It is worth highlighting that it is not always possible to predict the exact benefits of every network investment project/initiative. As such, the link between service level targets and proposed investment is often based on a reasonable amount of best judgment using the strongest insights available at the time. In these cases, the network performance monitoring feedback loop is recognised as being even more important than normal, as the output results can then be used for validation (although even this method still relies on some assumptions around causation). This continuous improvement feedback loop is therefore used to validate or amend plans, investment levels or service levels. This may mean that our targets for SAIFI/SAIDI will reduce in future versions of this AMP providing the performance to cost trade-off remains aligned with the expectations of our stakeholders.

As at 30 September 2020, our unplanned SAIDI performance is slightly above target. This is based on spreading the annual total SAIDI minutes on a per month basis. The planned SAIDI figure is also currently above the target level. Our analysis indicates this reflects the extended time taken for work under COVID-19 control requirements.

Overall, the total SAIDI minutes are above target at this time.

Our SAIFI performance for unplanned outages matches the SAIDI situation, being slightly above target. For planned SAIFI the performance to date is just below target.

Overall, the total SAIFI figure matches the target at this time.

Our current predictions are that the total SAIDI minutes will be above target, reflecting ongoing pressure for new works, but that the total year SAIFI figure will be close to target.

The above predictions for end of year performance are substantially dependent on no further significant COVID-19 alert levels impacting works.

Our recent performance and forward targets are shown in Figures 3-12 and 3-13 below.

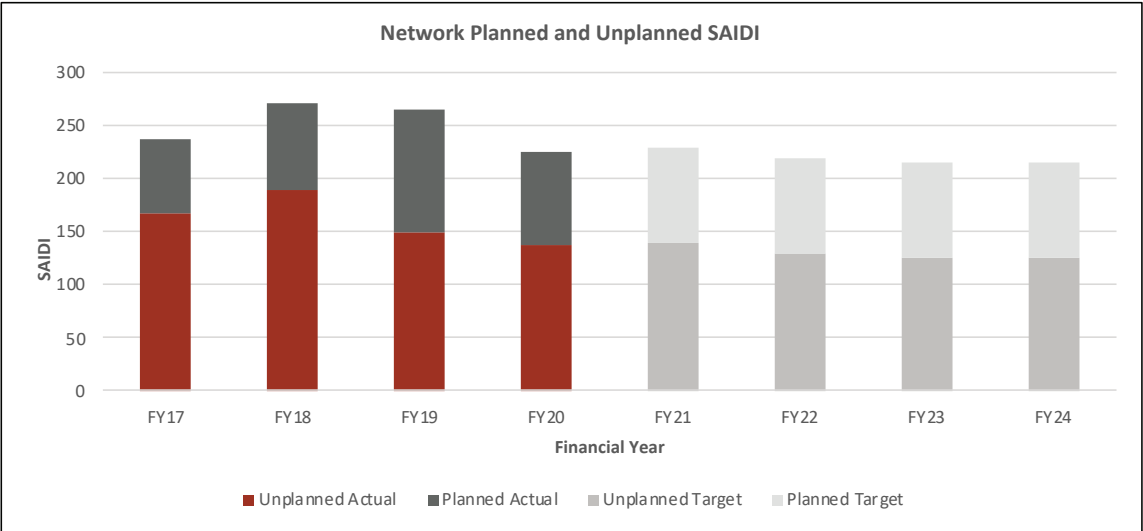


Figure 3-12 Historic Network SAIDI FY17 – FY24 utilising DPP normalisation

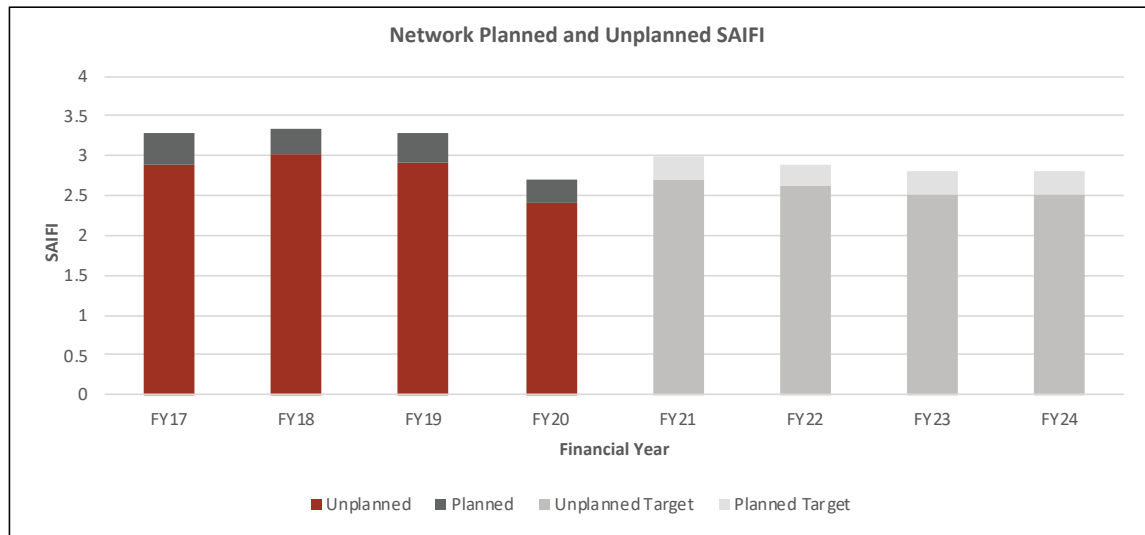


Figure 3-13 Historic Network SAIFI FY17 – FY24 utilising DPP normalisation

3.7 Service Level: Customer Service

3.7.1 Objectives

- Our customers are aware of who we are and what we do;
- Customer feedback is easy to give and it can be given across multiple channels;
- Customers know we will act on their feedback and requests, and they value the services we offer; and
- We aim to deliver our services (including the delivery of electricity) at the levels sought by our customers.

3.7.2 Initiatives

- Ensuring customer feedback is integrated into our asset management planning process and AMP as well as into our daily operations;
- Enhanced communication channels to customers for planned and unplanned power outages, including a real-time messaging service for unplanned outages and updated self-service web application;
- Process reviews and continuous improvement of our service offerings to make it more efficient and easier to serve our customers;
- Measuring the delivery of our services against time, accuracy and satisfaction parameters;
- Regular surveys of customers, seeking feedback on our service, our price and reliability;
- Achieve 100% compliance with Utilities Disputes (formerly the Electricity and Gas Complaints Commission - EGCC) scheme; and
- Seek and record customer contact information so notifications can be sent out in the event of an unplanned outage.

3.7.3 Targets

- Overall customer satisfaction with our services, price and reliability;
- Response times (acknowledgement) of letters and electronic communications from customers;
- Positive customer feedback on services we provide; and
- Complaint handling meets or exceeds Utilities Disputes (and our own) requirements.

Description	Target
Service request – such as providing a new supply for new reticulation; permitting a high load or processing a Distributed Generation approval	On the date agreed with the customer (or their Retailer) for that service
Voltage complaint	Advise outcome of investigations and nature and timing of intended remedial action (if required) within 10 business days after receipt of the complaint
Service response	Answer an average 80% of calls within 20 seconds (force majeure events excluded) and acknowledge or resolve customer-driven service requests via email by the next working day

Figure 3-14 Customer Service Targets

3.8 Service Level: Economic Efficiency

3.8.1 Objectives

- Effectively and efficiently manage the network to have a low cost to serve;
- Reduce losses on network; and
- Ensure high utilisation of assets (load factor) subject to economic analysis of cost of losses.

3.8.2 Initiatives

- Continuous improvement in the works delivery model and processes to reduce costs;
- Investigate new technology options for reduced ‘whole of life costs’;
- Actively manage capacity and asset utilisation; and
- Utilise distribution voltages to reduce technical losses where economical to do so.

3.8.3 Targets

Cost to Serve – Operating Expenditure

To deliver on our vision of having cost effective supply of electricity to our customers, it is important we have efficient operating costs. We measure operating cost per customer, and by system length. Our aim is to be at or below the industry average and to ensure that both the asset management and business operating decisions we make do not drive unnecessary cost into the business.

Our performance and targets are shown in Figure 3-15 below.

Our future target cost per ICP is trending up, which reflects an increase in expenditure on best practice operating systems and resources. The target cost per ICP will still be below the current industry average.

Operating Cost per ICP	FY18	FY19	FY20	FY21+ Target
	\$309	\$344	\$362	\$395

Operating Cost per km	FY18	FY19	FY20	FY21+ Target
	\$3,985	\$4,498	\$4,672	\$5,098

Figure 3-15 Operating Cost Targets

Network Losses

We aim to keep our losses at or below the industry average. Our traditional network was a predominantly rural network with moderate customer density and thus our electricity losses tended to be higher than average. However, losses have been kept close to the industry average through the gradual uprating of the primary distribution voltage to 22kV and the subtransmission voltage to 110kV. Using higher operating voltages together with the network architecture we have implemented have contributed to reducing technical losses. Our deployment of smart meters, and consequential installation audits has reduced non-technical ‘unaccounted for energy’ on the network over the past three years. However as the amount of energy lost due to technical losses on a typical distribution network is many times higher than that typically due to non-technical (such as those associated with metering), it is not unexpected that the loss reducing benefits of the smart metering programme isn’t clearly manifested in the overall loss factor result.

Our performance and targets are shown in Figure 3 - 16 below.

Loss ratio	FY18	FY19	FY20	FY21+ Target
	4.70%	4.60%	4.80%	4.70%

Figure 3-16 Loss Ratios

Network Utilisation

Network Utilisation is another important aspect of operating an economically efficient electricity network, and ensuring that our distribution network has been constructed in a way that meets customer demand, but does not have too much excess capacity built in. The Load Factor is an important measure of utilisation as it compares the installed transformer capacity to the demand at peak times.

Our performance and targets are shown in Figure 3-17 below.

Network Utilisation	FY18	FY19	FY20	FY21+ Target
	58%	54%	57%	54%

Figure 3-17 Utilisation

High levels of growth have been experienced from both industrial/commercial developments and new multi-stage subdivisions and thus significant works have been carried out which have created headroom of installed distribution capacity ahead of the uptake in demand. The changed economic situation is expected to slow the addition of the planned new loads; however in the longer term, based on land zoning and council planning, we expect this to change and our utilisation figures to increase.



4 APPROACH TO ASSET MANAGEMENT

4.1 Asset Management Framework

4.1.1 Framework Overview

Counties Power has adopted an approach to Asset Management that follows the principles of the ISO 55000 framework, specifically adopting the process of seeking continual improvement. Figure 4-1 below shows the high-level Asset Management framework for Counties Power.

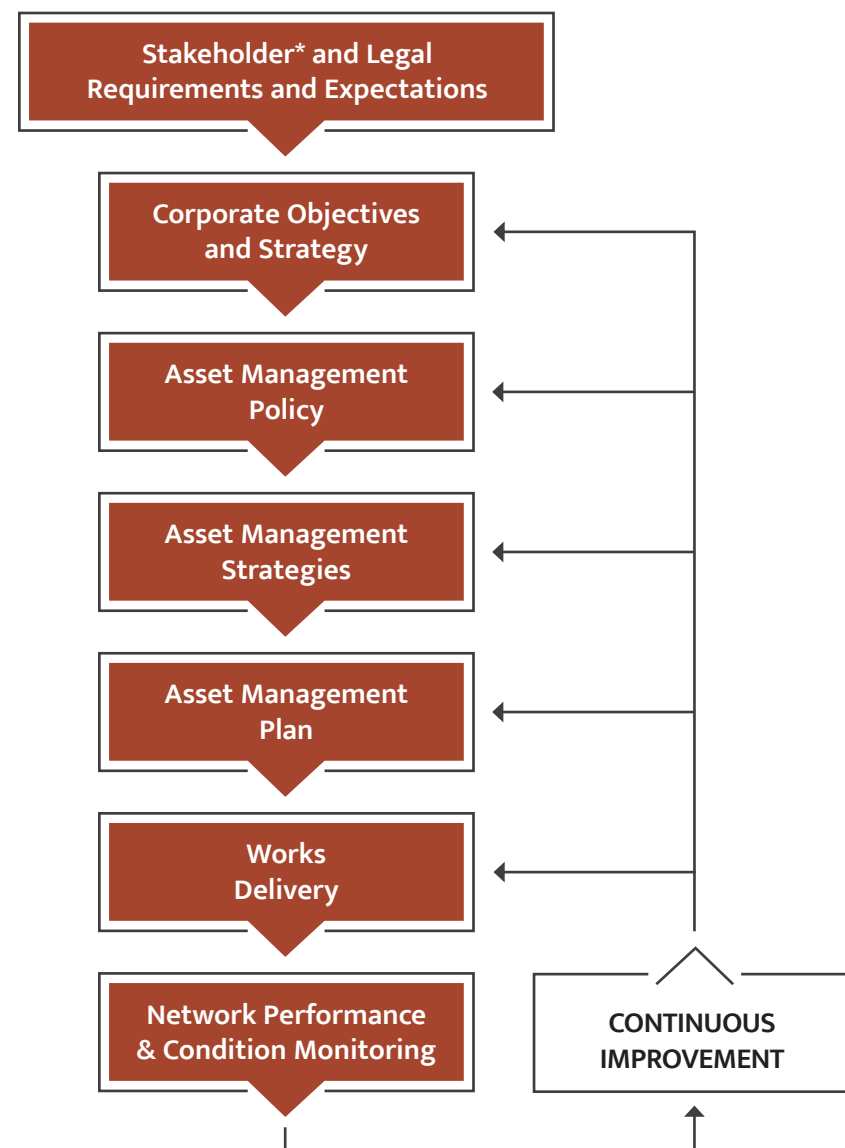


Figure 4-1 Asset Management Framework

* Refer to section 2.4 for details of our Stakeholders

4.1.2 Asset Management Policy Objective

Our Asset Management Policy links our Asset Management approach to our corporate objectives and details the Objectives, the Accountabilities and the Implementation considerations.

Our Corporate Vision Statement is:

Shaping a Smarter Energy Future

Figure 4-2 Corporate Vision Statement

Our Asset Management Policy Objective is:

To provide electrical connections to our customers, that meet their service and price expectations, by building and operating our network using safe, sustainable, reliable and cost-effective methods over the life of the assets.

Figure 4-3 Asset Management Policy Objective

4.1.3 Asset Management Strategies

We are in the process of developing formally documented asset management strategies to deliver the requirements of the Asset Management Policy; these cover maintenance, replacement, and network development.

We carry out detailed network performance trend analysis which provides input for each of these strategies; this is discussed in Chapter 5 of this plan. To improve our approach to asset management we are currently carrying out a Failure Mode, Effects & Criticality Analysis (FMECA) across all components of our network.

Each of these strategies informs this Asset Management Plan and results in proposed programmes of work – comprising operational expenditure and capital investment – which are detailed in Chapters 7, 8, and 9.

Maintenance Strategies

Maintenance comprises asset inspection, measurement, recording and assessment of condition, and undertaking required corrective or preventative action to minimise risk and/or maximise performance. In the course of normal business some assets fail in service, often influenced by external factors such as trees, motor vehicles, wildlife, or extreme weather. We have to repair or replace those assets reactively, however failure analysis is carried out to detect developing problems and develop preventative approaches where possible.

Maintenance is required to meet our objectives of providing a reliable service that our customers value. Our obligations under our Public Safety Management System, are to meet the requirements of the Electricity (Safety) Regulations 2010 and to ensure we meet good industry practice.

Our maintenance programme consists of three categories of maintenance activity.

- **Preventative Maintenance** – routine inspection, testing and servicing to ensure our assets are safe, free from defects and meet their service expectations. We also use the inspection process to undertake condition assessment to forecast when the asset will have to be refurbished or replaced. We include vegetation management as a form of preventative maintenance;
- **Corrective Maintenance** – scheduled repairs to assets following inspection or testing, to address known defects, based on the risk they present; and
- **Reactive Maintenance** – unplanned repairs or replacement of assets once a defect or failure has been identified, or where they present an immediate risk to safety or the network.

Preventative maintenance can also include an enhanced monitoring approach where an asset which has been identified as deteriorating, but is still serviceable will be subject to more frequent inspection/testing or more in-depth forms of testing. This normally applies to high value items and it ensures the maximum life is obtained from them before replacement, but minimises the likelihood of failure in service.

A key part of our maintenance strategies is to assess the benefits of major repair work against outright replacement or retirement of assets. Although the cost of replacement can be many orders of magnitude greater than a repair, we consider the ‘whole of life’ cost of the asset when contemplating repairs to assets nearing the end of their economic life. In addition, for more major works the value seen by our customers is assessed using Value of Lost Load (VoLL) analysis.

We undertake targeted maintenance in some areas where network performance is poor, or the consequence of failure is extreme, and categorise ‘Worst Performing Feeders’ to address reoccurring issues and improve network performance.

Vegetation Management Strategy

We undertake vegetation management to ensure safety around our network and that network performance meets expectations. Our vegetation management is undertaken in accordance with the Electricity (Hazards from Trees) Regulations 2003. The regulations are prescriptive and transactional, focusing on addressing any vegetation that is growing close to conductors, but at present do not support Counties Power to consider risk factors such as criticality of supply from the line, species of tree, or the effect of that tree on the line during storms and high winds. There is also no provision for trees further away from lines that either present a risk of falling through or shedding debris into lines, the combination of which represent about 65% of our known vegetation related faults, rising even higher during stormy weather conditions. These are industry recognised problems and it is understood that the Ministry of Business, Innovation and Employment (MBIE) is currently undertaking a full review of the regulations, on which progress updates are keenly anticipated.

The strategy for vegetation management is reliability focused, although there is a reasonable component supporting public safety where trees contacting lines have become a hazard. Prior to FY20 the programme was prioritised based on areas of high vegetation related outages, where trees encroaching power lines as per the regulations were identified and remedied. This approach, although effective, has since been recognised as being somewhat reactive, as outages would have to occur before priority was given to the section of network. The completion of the LiDAR survey in early 2020 and subsequent analytics (refer to Chapter 6) has now enabled a more proactive risk based approach where the likelihood is informed by sections of line with known vegetation from the LiDAR survey as well as recent fault history and the consequence is estimated from the known customer impact of an outage. This will be further enhanced in 2021 once the network criticality model is built (refer to Chapter 6).

A component of the proactive approach also ensures our 33kV and 110kV subtransmission circuits are targeted, as the criticality of these lines is much higher than that of distribution feeders.

From FY20 onwards, approximately 70% of our annual vegetation spend is targeted at the proactive programme, with the balance going on reactive (fault) events and other urgent escalations. The intent is to increase this share as much as possible, recognising that reactive works are less efficient and an effective proactive programme should see the number of unplanned events, and therefore reactive work, decrease with time.

Replacement Strategies

As we continue to be a rapidly growing network, a number of areas of the network have been constructed or rebuilt over the past 20 years which means some parts of our network are relatively new. Other parts of the network, particularly the older 11kV network in the southern and western areas, are approaching end of life in some locations and are beginning to experience increasing rates of failure, particularly at component level, as well as systematic issues with certain types of conductors. We have forecast that a higher level of renewal expenditure will be required over the planning period to address safety, condition and performance risks with this older equipment.

Major substation plant is of high value, has a significant consequence associated with failure, and can present a serious risk to safety, the network, and the environment if poorly managed. We have preventative and corrective maintenance programmes to ensure these assets perform as expected and to ensure we understand their condition to allow us to plan repair and replacement activities. We base replacement of major assets on a detailed condition assessment, as well as an assessment of the risk of failure. Options analysis is undertaken where investment is significant or in an area where major changes in demand forecast are being projected.

Many of our major substation assets are approaching the end of their economic service life just as capacity and security constraints are becoming binding. This allows the assets to be replaced at the optimal time to maximise their service life by moving towards condition based replacement and then being upgraded to meet new capacity requirements at the time it is required. More details of this can be found in Chapter 8 Network Development.

Distribution assets are generally in the public domain and can present a risk to public safety. We inspect these assets to identify defects and undertake condition assessment, analyse failure rates and causes to forecast when replacement will be required. Our objective is to replace these assets based on condition before they fail or present an unacceptable risk.

Some asset classes have a lower risk to safety and network performance and a low consequence of failure. These often are not able to be condition assessed and thus these can be managed with a run-to-failure strategy.

In some cases, where the asset is at end of life and is no longer required or has been superseded, it may be retired from service without replacement.

A detailed description of our replacement programmes is covered in Chapter 7 Renewal and Maintenance.

Development Strategies

As demand on our network grows, we have to ensure it is able to meet our customer's requirements for capacity, security and reliability.

We have developed security and planning criteria and assess the network against these for the reasonable growth forecast. This results in the identification of constraints and timeframes for investment. Our strategy is to ensure that the development options we select do not lead to over investment (too much), premature investment (too soon), or lead to a high risk of asset stranding. We also aim to get as much renewal benefit as possible when upgrading or replacing assets due to growth and avoid the early write-off of assets before the end of their economic service life.

Future projects include specific works to work towards improvement of our network performance as defined by SAIDI and SAIFI to reflect the customer and wider expectations of service delivery as identified in our network performance trends analysis.

Details of these network development plans are covered in Chapter 8 Network Development.

Integration of Strategies

While each of the above three strategies identify actions that are required on the network to ensure that all expenditure is optimised, proposals from each driver are examined against the other two drivers to check that the proposed works are integrated to ensure the maximum value is obtained from all expenditure.

A process is followed which compiles a detailed integrated Network Development Plan for all types of work which is reviewed to ensure works are fully integrated. For example, if a replacement strategy initiated project on a line has been identified, this is checked against development strategy projects to ensure that if reinforcement is planned for the near future in this vicinity the final project reflects all drivers and requirements.

At a detailed level the formal integration of project lists is carried out on an annual basis and any proposed change or additional work (e.g. triggered by an inspection) that arises during the year is reviewed at that time.

4.2 Investment Planning

Our network investment process consists of a sequence of decision-making steps, used to ensure we make the correct investment decisions and have adequately considered alternatives. A high-level overview of this process is shown below.

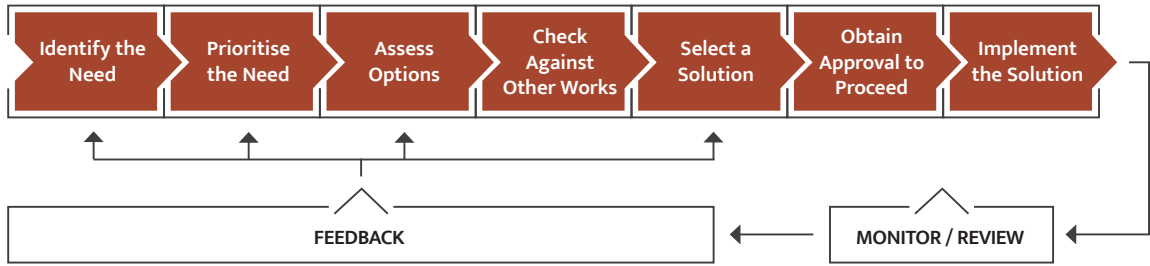


Figure 4-4 Decision process for network Investments

The key steps in our investment planning process for network initiated projects are:

- 1. Identification of the Need** – the need for investment arises from routine business cycle activities such as the network planning process which identifies constraints on the system and the maintenance process which includes asset condition surveys, network fault and performance data, including the network performance trend analysis. These processes produce outputs of a list of issues which may require investment.
- 2. Prioritisation of the Need** – once the need has been identified, it is prioritised by risk (including safety, security, reliability, environmental, and regulatory) and the timing of when the issue requires resolution.
- 3. Assess Options** – a long list of possible solutions is developed, with a high level order of cost and assessment of benefits. Benefits will include all aspects including those directly seen by our customers (such as improved SAIDI and SAIFI performance) as well as wider benefits from improved network resilience. From this a short list of preferred solutions is selected, based on the cost, the benefits they provide, and the alignment with our strategic goals.
- 4. Check Against Other Works** – As noted there are various drivers for investment (growth, maintenance, refurbishment, performance improvement), thus projects being considered from one driver are checked for overlap with other projects to optimise planned expenditure.
- 5. Select a Solution** – once the short list of options has been assessed, a preferred solution is selected based on delivering the greatest benefit, which is then scoped and priced to a detailed level to allow a full business case to be developed. For major projects an assessment of the “value” seen by customers will be undertaken using Value of Lost Load (VoLL) to assess this.
- 6. Approvals to Proceed** – the business case outlining the preferred solution is presented for the appropriate level of management approval.
- 7. Implementation of the Solution** – once approved, the solution enters the design and delivery phase, where the detailed design is created, the scope of works finalised, and it is handed to Field Operations to deliver the solution.
- 8. Review/Feedback** – after completion the project implementation and results are reviewed and feedback provided to inform and improve the steps in the process for future projects.

For customer initiated projects such as network extensions and subdivision reticulation, the investment decision making process is simplified and a solution is identified to meet the customer’s requirement for capacity, security and cost. The timing of these investments is to suit the customer and is not discretionary.

A summary of our processes for investment planning are shown in Figure 4-5 and Figure 4-6.

4.2.1 Investment Planning Process – Renewal and Replacement

Our process for renewal and replacement investment is shown in the diagram below. Key inputs to this process are Asset Condition Surveys, Known Type Issues, Performance Issues and Trend Analysis. These are all prioritised by the risk the asset presents, considering public and personnel safety, network security and reliability, regulatory requirements and environmental effects.

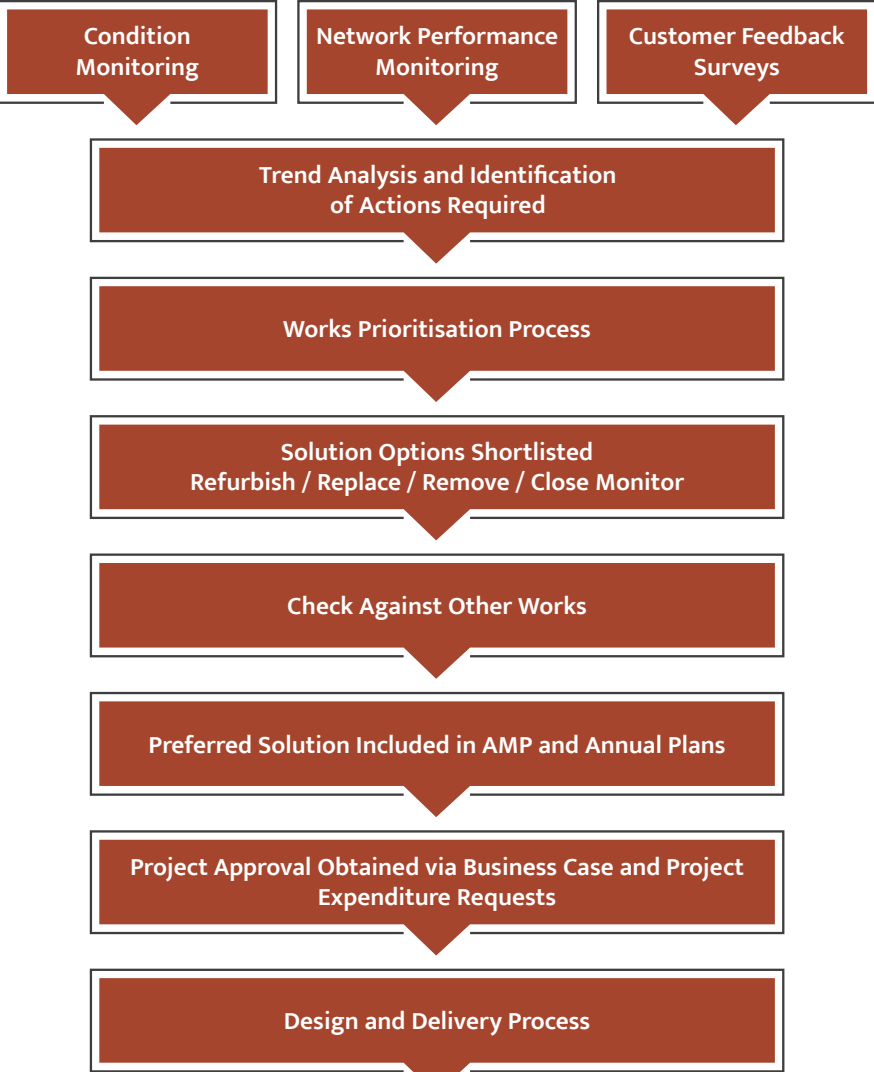


Figure 4-5 Renewal and Replacement Investment Process

4.2.2 Investment Planning Process – Network Development

Our process for network development investments is shown in the diagram below. Key inputs to this process are the load forecast, the network model and system capability, the security and planning criteria and customer notifications. When considered together, these identify constraints on the network which will drive investment. Full details of this process are provided in Chapter 8 Network Development.

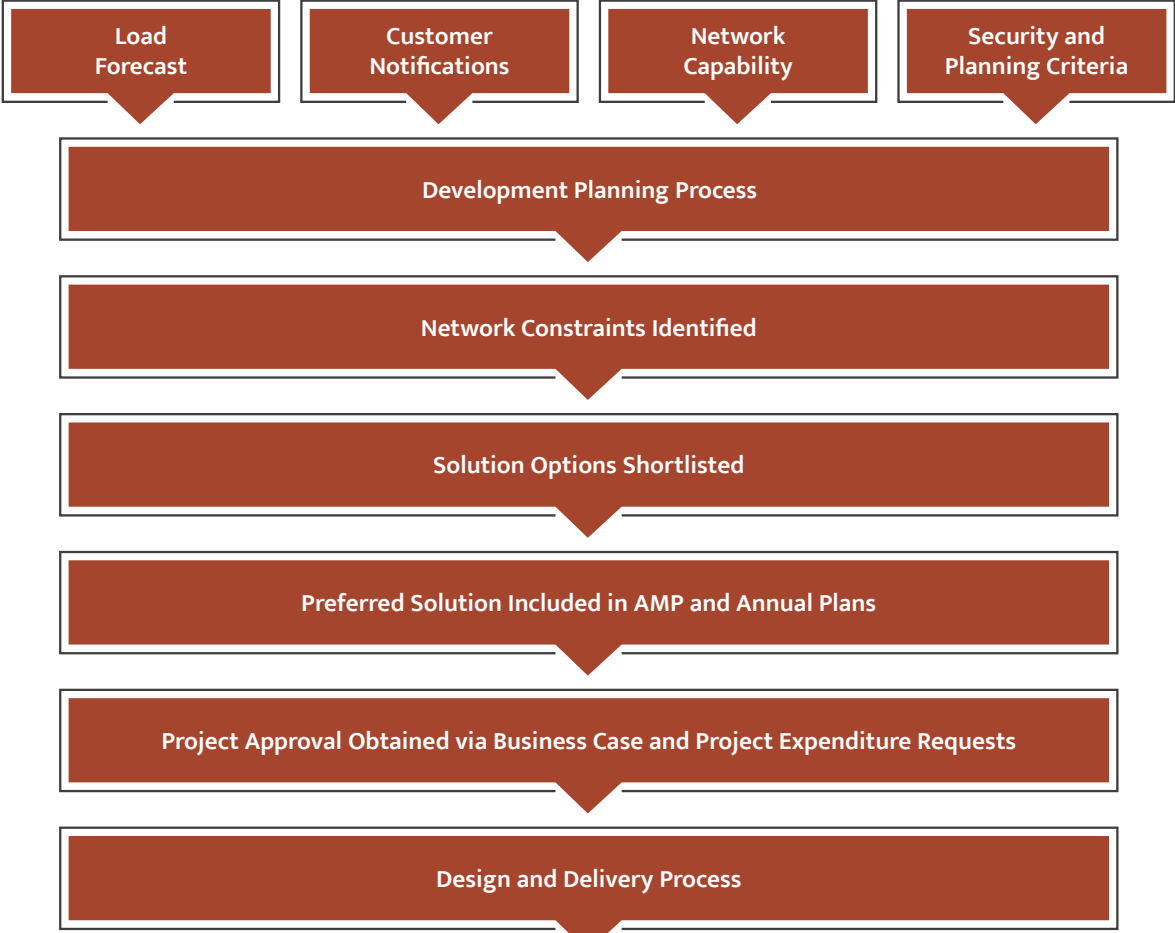


Figure 4-6 Network development investment process

4.2.3 Consideration of Network Alternatives

Network alternatives (sometimes referred to as non-network solutions) are considered in the options analysis to address a network constraint, particularly a capacity or voltage constraint.

We then consider if network alternatives are feasible such as demand side management, localised storage or generation, and other assets which can be installed to defer the need for investment by reducing the peak demand or supporting the voltage along a feeder. Where the investment need is driven by poor condition of assets presenting a safety risk, a network alternative is not normally suitable, and investment in replacement network components is required, however consideration is given to the size and configuration of these to determine if the network can be optimised in any way.

Further details around our assessment and selection of Network Alternatives are covered in Chapter 8 Network Development.

4.2.4 Energy Efficiency Considerations

As part of our network planning process, we make the following considerations for energy efficiency:

- Voltage and Loading – we select appropriate operating voltages and operate the network in a configuration that minimises electrical losses;
- Energy Efficient Equipment – we ensure that all new equipment, in particular transformers, comply with the required International Electrotechnical Commission (IEC) Standards and Australian Standards (AS) for energy efficiency, in particular the Minimum Energy Performance Standard;
- Design Options – for network reinforcement we review the impact on efficiency from a network losses viewpoint and this is considered in the preferred option selection process; and
- Metering – we ensure our metering equipment is calibrated and compliant with the Code to reduce the ‘unaccounted for’ energy lost on the system.

4.3 Asset Management Information and Systems

4.3.1 Asset Management Systems

There are a number of key systems used in the asset management process, as well as part of our wider business operation. The key systems are listed below with a brief description of the role they play. Some minor systems have not been detailed here.

Geographic Information System (GIS) – Smallworld Electric Office

We use GE Smallworld Electric Office to record all our geospatial information relating to network assets, including location, physical and electrical attributes. This platform is also used to record some maintenance attributes relating to the assets, and enables the business to:

- View geospatial data on the web without needing a full software licence;
- Have a common platform to view projects across the network for improved coordination; and
- Geospatial Analysis (GSA) tool to deliver analysis and reporting.

As part of the implementation of this upgrade, a significant amount of data cleansing and connectivity improvements were undertaken. GIS data quality improvements continue to be a focus area in the coming years.

IQGeo

The IQGeo Platform is a foundation product for transforming the ability for Counties Power to manage their complex and constantly evolving network assets, and provide mobile asset information to field users.

IQGeo’s enterprise geospatial software is proposed to be expanded at Counties Power through 2021 to streamline construction, inspection maintenance processes and improve field data capture, data quality, and dynamic as-built data pending feasibility studies.

Roames World

The Roames world platform displays the digital twin of the network, displaying the following data captured in January 2020:

- Pole characteristics;
- Conductor characteristics, including ground clearance; and
- Vegetation details, including volume and distance to conductor.

Further details around LiDAR capture and our use of this data can be found in Section 6.3.1.

Enterprise Asset Management System – Maximo (EAMS)

Maximo was introduced in 2020 as the enterprise asset management system and is under development to deliver the following functions:

- Provide asset information, condition insights and performance data;
- Plan, forecast and monitor planned preventative maintenance activities; and
- Plan and monitor corrective maintenance activities.

There are ongoing feasibility studies to establish whether the EAMS will be expanded to include capital and reactive works management.

Supervisory Control and Data Acquisition (SCADA) – iPower

Our GE iPower SCADA system is used for real time operations of the high voltage network and provides telemetry and remote control of substation and automated field equipment such as ring main units and overhead switchgear. It is used for network switching in planned and unplanned (fault) situations and provides a representation of the network and all the control points such as switches and ring main units. It has the capability to record event logs and measurement data for future analysis.

This system also contains the load management functionality we use to manage system peak demands and to operate our load control (ripple) plants.

Microsoft Dynamics NAV

We use Microsoft Dynamics NAV as an enterprise resource planning system and primary system of record, chiefly for financial management and accounting, purchasing, but also for customer service, project management activities such as quoting and estimating, and works management.

This system has been customised to provide a number of asset management functions including:

- Faults and outage recording and reporting;
- ICP management and billing;
- Asset survey records; and
- Vegetation management records.

Field Computing Tools

We have developed a range of in-house field tools based on the Google Android platform. These are used as part of our despatch process, as well as for recording job information in the field, and capturing the results of asset surveys. This system has linkages to GIS and Microsoft Dynamics NAV.

SharePoint Intranet Sites

The business has a SharePoint based electronic document management system (EDMS) which provides a number of functions to the business, primarily as an intranet containing a range of corporate information and providing a platform for two important asset management requirements:

- Public Safety Management System – for recording information on all PSMS activities and reported incidents; and
- Quality Management System – for managing all controlled documents such as policies and standards.

DigSILENT PowerFactory

PowerFactory is used as the main network planning tool for power flow analysis and network simulation. We use it for undertaking systems studies for large scale new connections, assessing network loads and identifying network constraints, and for assessing network performance and operational scenarios. We have a complete network model represented within PowerFactory.

AutoCAD

All of our design work is undertaken in AutoCAD including substation electrical designs, network projects and subdivision reticulation plans. We also create standard drawings in AutoCAD for common construction assemblies. Our network operational diagrams are also maintained in CAD format.

Smart Meters

Counties Power has developed several systems using the data available to it from smart meters. These systems and current developments are covered in Chapter 6.

INDI

Infrastructure and Network Data Interface (INDI) is a cloud based big data platform that utilises data from Google Maps and Counties Power's GIS network data. Further information is in Chapter 6.

4.3.2 Asset Management Information

To support our asset management processes, we use the following information, some of which is held electronically, and some is held in hard copy. Our expectation is that all asset management information obtained going forward will exist in electronic format in centralised repositories.

Examples of our asset management information include:

- Controlled Documents – as part of our Quality Management System (QMS), these include all Policies, Standards and Procedures;
- Standard Drawings – these detail how we build our network, and include standard underground and overhead assemblies used by field crews working on our assets;

- Network Diagrams – this information is contained in both AutoCAD drawings, as well as in the GIS system. These are used to plan and operate the network;
- Test and Inspection Records – outcomes of these activities are stored for future reference and for regulatory compliance;
- Fault Records – following planned and unplanned outages on the HV network (as indicated by SCADA events or customer calls), fault records are created in the NAV system indicating duration, cause and number of customers affected. These are used for calculating our SAIDI and SAIFI figures for regulatory reporting, as well as analysis of network performance trends; and
- Legacy Information – we have a range of information contained in hard copy format, particularly older test and inspection records, equipment manuals and technical documentation. Some information has been digitised, however much of it remains in hard copy and there is little benefit in digitising it.

Through our business process, we identify the information we require to make decisions relating to our network, and where necessary introduce new processes to capture this, and identify where systems need to be updated to accommodate this.

As new standards and processes are developed, these are processed through our QMS and socialised with relevant stakeholders through training sessions, toolbox meetings, team meetings and electronic communications.

We have identified opportunities for improvement on how we manage our geospatial data. With the implementation of the GIS system, we will utilise the electrical and quality checking tools available to verify data integrity. This initially focussed on urban areas, but continues across the network. In addition, our as-building and data capturing processes are being updated to reflect the requirements of the new system.

4.4 Works Delivery Processes

4.4.1 Key Works Processes

An outcome of the asset planning process is a range of work that comprises the annual work plan. Once the annual budgets are approved, individual projects and programmes of work gain approval by way of a business case. This section describes the key works processes in delivering the plan.

Network Projects

Network projects cover a range of work from system growth and capacity projects, through to asset replacement and renewal programmes.

Once a project has been included in the annual plan, and expenditure approval received from the appropriate authority holder, the work is initiated by either the Asset Engineering team (for renewal projects) or Network Development team (for growth/development projects) and a design and specification is created (or a basic work pack for minor jobs) by a Design Engineer within those teams. This work is agreed with the Field Operations team, a Works Manager is allocated, the work is scheduled through a mix of internal and prequalified external resources, and the project enters the construction phase.

Once construction is completed the work is audited and accepted by the responsible Design Engineer and the Network Control team, and the assets enter their operational phase.

Customer Projects

Customer projects include new connections to existing network, network extensions or new subdivision reticulation, or other customer initiated work such as street lighting connections, asset relocations or capacity upgrades.

Customer projects are initiated with requests coming through the Connections team, or directly to a Customer Projects Engineer in some cases (larger subdivisions). The customer requirements are identified, a concept and budget price is then presented to the customer. Following customer acceptance of the budget price, a detailed design is created and provided as a formal offer. When the customer accepts with payment, the work is passed to the Field Operations team following the same process as for a network project.

Preventative Maintenance Planning

Preventative maintenance is the programme of routine inspections, testing and servicing of network assets to ensure they are performing as expected with regard to public and personnel safety, network reliability, that they are free of defects, and to survey their condition to determine when end of life replacement is required.

The type of activity, and the frequency that it is undertaken, is determined by regulatory requirements, known historic performance, manufacturer's recommendations and good industry practice. We develop maintenance standards for each asset class and these are used to develop the overall Preventative Maintenance Plan.

The Network team develops the annual preventative maintenance plan in conjunction with Field Operations, who then deliver the programme over the course of the year.

Corrective Maintenance Planning Process

Corrective maintenance addresses network defects arising from preventative maintenance surveys, replacement of components following network faults where supply has been restored but further work is required, or to address other network requirements such as dismantling of old assets or refurbishment of equipment.

Corrective maintenance is prioritised based on the following criteria:

- Public and staff safety risk;
- Location of the affected equipment;
- Impact on network operations;
- Type and severity of defect; and
- Type and age of equipment.

The corrective maintenance programme is developed by the Network team in conjunction with the Field Operations team and the individual work packages are scoped up along with a description of the required work. During the course of the year the programme may be reprioritised to address higher risk defects on the network.

Reactive Maintenance Process

Our reactive maintenance process handles the situations where network assets have failed in service, or been damaged by external influences, causing an outage or presenting an immediate hazard.

Outages on the low voltage system typically result in a customer calling into our Customer Service team, or to our call centre, or are logged using our customer web application. A service order is created and dispatched to a duty fault crew who then attend to the issue.

Outages on the high voltage system are notified to a network controller through the SCADA system, where a substation circuit breaker or field device such as a recloser has operated. In this situation fault crews are dispatched to attend to the issue by the Network Control team, and undertake the necessary network switching and isolation to restore customers, and complete repairs to the network.

Immediate hazards can be identified by our staff or are reported by members of the public through our Customer Service team. Similar to the low voltage outage process, a fault crew is dispatched to attend to the issue.

To provide information to customers on outages, customers can access a map showing events on our website (<https://app.countiespower.com/>) or alternatively by downloading our smart phone app. This map provides details of outages and the expected restoration time. We use the INDI smart meter system to check that outages have been fully restored after an event by checking in real time that customers have had supply restored.

Vegetation Management Process

The vegetation management strategy is set by the Asset Management team and is described above in section 4.1.3.

We have a vegetation management team in our Field Operations team which oversees and delivers the vegetation management programme, including undertaking tree surveys, tree owner liaison and undertaking much of the field work. This team was expanded to include an additional crew in 2020. In some cases, external subcontractors are used.

Once a tree has been identified as presenting a hazard to the line, or is within the limit zones, a notice will be issued to the tree owner. First cuts are undertaken and paid for by Counties Power providing the required criteria are met, and second and subsequent cuts are the responsibility of the tree (land) owner or future owners. In some cases it is advantageous for either the network or the tree owner that the tree is removed and this can sometimes be facilitated by negotiation. For "out of zone" trees we advise the owner and work with them to try to eliminate identified high risk situations. Full information relating to trees near power lines is available on our website: www.countiespower.com/trees.

Public Safety Services Process

In addition to providing fault response and routine maintenance on the network, we provide a number of public safety services to ensure those working around our network do not come to harm or cause damage to our assets, including:

- **Close Approach Consents** – where third parties wish to operate machinery or undertake other activities within 4.0m of our network they need to be aware of the hazards and have our permission in writing in accordance with ECP34;
- **High Load Permits** – where transport operators wish to move oversized objects, typically houses, along routes which have overhead lines. In some cases, we provide an escort to assist them and reduce the likelihood of harm to people or damage to the network;
- **Plans and Markouts** – we provide plans of our network, and can undertake onsite locates or markouts to show where our buried services are; and
- **Safety Disconnections** – the disconnection of customer supplies to enable them to undertake work on their property without the hazard of live electricity.

Members of the public or contractors can request these services from Counties Power. These requests are initially handled by our Customer Service team, and the requests are fulfilled by the Network Control or Field Operations teams depending upon the nature of work required.

4.4.2 Field Delivery Capability

The majority of field work is managed and delivered internally by Counties Power through our Field Operations team.

We have internal capability to undertake fault response, routine network maintenance, construction of overhead and underground networks, substation electrical work, electrical inspections and meter installations, as well as vegetation management.

We outsource some types of work where we do not have the capability and/or the capacity, for example where:

- The tasks require a specialist skill which Counties Power staff do not have, and volume of work does not justify having those skills internally – for example some protection and communications work, fibre optic splicing, specialist substation work such as major plant refurbishment;
- To manage peak capacity requirements when our people are fully utilised – for example some civil and electrical construction work; and
- Where the work type is not core business to Counties Power – such as construction of substation buildings.

Using our forward work plans, we can forecast work volumes and balance work programmes to get the best utilisation of our people. Programmes such as preventative and corrective maintenance can be balanced with project work to manage peak capacity constraints and ensure high utilisation.

The COVID-19 alert levels have impacted on our ability to carry out normal (non-urgent) works programme since the first level 4 implementation in late March 2020. To minimise the delays to all types of our work we increased the engagement of external contractors from July. The August level 3 restrictions further delayed works and we are continuously assessing the impact on the physical works carried out until the end of the financial year as further restrictions may occur.

4.5 Risk Management Framework

Risk management and asset management are intricately linked. We recognise that risk management is an integral part of good management practice, corporate governance, and it is central to effective asset stewardship. We are committed to maintaining an environment that effectively minimises risk exposure to acceptable levels and ensures compliance with legislation as well as industry and organisational standards and codes. Our Risk Management Framework is aligned to the *ISO 31000:2009 Risk management – Principles and guidelines* standard and it ensures that all our risks are identified, understood and managed consistently across all levels of our business. We assess our risks in accordance with our set consequence and likelihood ratings. We monitor, treat, control and manage all of our known risks. Responsibilities for managing risk are clearly allocated. Our Risk Management Framework strengthens our asset management decision making and practices. We apply risk management in all our business activities, including policy development, business planning and change management. All business cases include a risk analysis as part of the overall factors considered when developing a solution.

Our risk management framework consists of the following components:

- Risk management policy;
- Risk management process;
- Risk management plans;
- Risk registers; and
- Risk reporting.



4.5.1 Risk Management Policy

We have a Risk Management Policy that establishes the context for our risk management activities and ensures that the risk management process is integrated with all organisational policies, processes, and practices to support efficiency and effective management. Our Risk Management Policy also outlines our risk management principles, and the roles and accountabilities for risk management.

Accountabilities and Responsibilities

The following figure presents the roles and responsibilities for risk management throughout the company:

Position	Roles and Responsibilities
Board of Directors	Corporate governance Independent review of risks and associated mitigations
Chief Executive	Risk management sponsor Representative to the Board of Directors Oversight of risk management process
Leadership Team (LT)	Ensure risk identified and managed to acceptable levels Risk management framework is in place and continuous Legislative and governance obligations are met Integration of risk management with policies, process and practices
Chief Financial Officer	Risk management administrator, in addition to LT responsibilities Schedule formal review sessions Ensure governance reporting obligations met
Managers and Team Leaders	Promote risk management culture Identify, manage and monitor risks in their groups Participate in risk planning, training and review sessions Assign and undertake responsibilities
Risk Owners	Support risk management within their area of responsibility Ongoing identification and assessment of risks, and responding appropriately relative to objectives Management of the relevant risk, within acceptable risk tolerance levels

Figure 4-7 Overview of Risk Management Accountabilities and Responsibilities

4.5.2 Risk Management Process

Our risk management process is designed to ensure that risk management decisions are based on a robust approach, assessments are conducted in a consistent manner and a common language is used and understood across our business. Our risk management process comprises the following steps:

Establish the Context

Many factors are considered including both internal and external parameters such as operating environment, stakeholders, internal structure and capabilities, and the risk appetite of the business.

Risk Identification

Our risks are identified through operational processes including Hazard Identification by staff in the field, team and project meetings, our Health and Safety management process, and our Public Safety Management System. Risk identification is also undertaken by members of the Leadership Team and senior staff as part of the audit and review process.

For identification purposes, we have grouped our risks into five types. These are:

- Financial: Risks with consequential impact on cash flow, balance sheet and financial liability;
- Safety: A risk event that adversely impacts on the health and safety of the public, staff or contractors of the company;
- Operational: Risks affecting the efficient operation of the company including service delivery, continuity and recovery of the company. This includes customer relations and reputation;
- Regulatory: Risk of the company failing to meet current or foreseeable legal obligations; and
- Environmental: Potential or actual negative environmental or ecological impacts, regardless of whether these are reversible or irreversible in nature.



Risk Analysis

We use both qualitative and quantitative methods during the risk analysis stage. All identified risks are analysed in terms of probability, frequency, and consequence criteria in the context of our business objectives. A numeric rating is applied against the criteria of probability, frequency, and consequence. Risk ratings are based on the result of the scoring of these criteria. The probability, frequency and consequence ratings are provided in Figures 4-8, 4-9 and 4-10 below.

Level	Rating	Probability of the event occurring	Description
10	Almost Certain	1 event in 1 to 2 years, > 50%	The event is almost certain to occur
7	Likely	1 event in 2 to 5 years, 50%	The event is likely to occur within 5 years
1	Possible	1 event in 5 to 10 years, 20%	The event could possibly occur in the next 5 – 10 years
0.5	Unlikely	1 event in 10 to 20 years, 10%	The event is unlikely to occur possibly within 10 – 20 years
0.2	Rare	1 event in 100 years, < 1%	The event may occur only in exceptional circumstances

Figure 4-8 Probability Rating



Level	Rating	Frequency of exposure to the risk of the event	Description
10	Daily/Continuous	> 1 exposure in 24 hours	Exposure expected within a day
6	Weekly/Frequent	> 1 exposure in 7 days	Exposure expected within a week
2	Monthly/Occasional	> 1 exposure per month	Exposure expected within a calendar month
1	Yearly/Seldom	> 1 exposure per annum	Exposure expected within a year
0.2	Rare	< 1 exposure per annum	Exposure expected to be less than once a year

Figure 4-9 Frequency Rating



Level	Description	Examples of Consequence
100	Catastrophic	Major unplanned service outage for over seven days; Very serious irreversible environmental impairment of ecosystem functions; One or more fatalities and or severe injury to staff, customers or public.
40	Major	Major unplanned service outage for up to seven days only; Very serious, long-term environmental impairment to ecosystem functions; Serious injuries and or disability to one or more staff, customers or public.
15	Moderate	Unplanned service outage for up to five days; Serious medium-term environmental effects; Serious injuries to staff, customers or public, requiring hospitalisation and or lost work days.
5	Minor	Unplanned service outage for up to three days unless it affects a key customer or occurs at a significant time (e.g. major sporting event or public holiday); Moderate short-term environmental effects, but not affecting ecosystem functions; Injury to a staff member, customer, or public requiring medical treatment.
1	Insignificant	Unplanned service outage for less than 24 hours unless it occurs at a significant time (e.g. major sporting event or public holiday); No measurable impact on biological or physical environment.

Figure 4-10 Consequence Rating

Risk Evaluation

All of our identified risks are evaluated against our probability, frequency, and consequence numeric ratings listed above, to ascertain the residual risk score. This assists us in our decision making to ascertain which risks need treatment and the priority for treatment implementation.

Risk Treatment

We treat a risk, depending on the numeric score it has been allocated in the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks, and these can include the following:

- Avoiding the risk by not commencing or continuing the activity;
- Accepting or increasing risk in order to pursue an opportunity;
- Removing the risk source;
- Changing the frequency or probability;
- Changing the consequences;
- Sharing the risk with another party or parties (e.g. contracts and insurance); and
- Retaining the risk by informed decision.

4.5.3 Risk Register

Information from the risk management process is recorded, reported and monitored using our risk register. The risk register assists us to monitor and review risks in alignment with our business objectives.

4.5.4 Risk Reporting and Monitoring

All of our risks are reviewed by our Leadership Team and are reported according to the residual risk score in Figure 4-11 below:

Residual Risk Score		Report to
> 400	Extreme	Board of Directors and Leadership Team
200 - 399	High	
70 - 199	Medium	Leadership Team and Operational Managers
20 - 69	Low	Operational Managers and Staff
< 20	Insignificant	

Figure 4-11 Risk Reporting Criteria

The Board of Directors receive detailed reviews of specific risks in monthly reports. They also receive a periodic report summarising the top risks that we face, and the treatment applied to those risks. The Leadership Team and other senior managers review our risk management position.

4.5.5 Project Risk Management Planning

In addition to corporate level risk management activities, a risk management plan is produced for each activity or project the business undertakes. Each project risk management plan specifies the risks relating to that project covering the approach to risk management including the risk treatments, any relevant task Job Safety Analysis (JSAs) and work standards that apply to the project.

The design and implementation of each project risk management plan is to consider our overall business objectives.

4.6 Public Safety Management System (PSMS)

Public safety is a critical component of our risk management framework. We adopt the requirements set out in NZS 7901:2008 Electricity and gas industries – Safety management systems for public safety to safeguard the public or their property from safety-related risks arising from the presence or operation of our network distribution assets.

In 2020, our certification continued after a review audit was conducted by Telarc against NZS 7901:2008. This follows recertification in 2015, 2018, and initial certification in 2012.

4.7 High Impact, Low Probability Events (HILP)

We are exposed to a number of potential HILP events, which could give rise to a major unplanned service outage for an extended period of time. HILP events are defined as having a widespread impact, but occurring rarely. However they are incredibly expensive to avoid, if this can be achieved at all. Accordingly, we have a responsibility to plan and manage for HILP events as best we economically and practically are able to. Within this context, our policy is to ensure the timely restoration of power supply, effective communication, a safe environment for staff, contractors and the wider community, and efficient provision of information tools for critical business activities should we be subject to a HILP event.

Our critical business activities relate primarily to safety and customer service, as well as security, reliability, and quality of supply. Events that could interrupt our critical business functions include natural disasters such as flood, tropical cyclones and windstorms, electrical storms, volcanic eruption, earthquake, airspace incident, asset failure, communications failure, Information System security breach or loss, and unplanned loss of supply from Transpower or generators.

Note: Lack of generation capacity (e.g. due to a “dry year”) leading to supply restrictions is not included in the definition of HILP events as it is able to be managed in advance of any impacts.

We have recently completed a detailed study into the potential total loss of either of our two Grid Exit Points (Transpower Bombay and Glenbrook). This confirmed that any action to mitigate for the total loss of a GXP effectively requires some form of duplication of the Transpower assets with very high associated costs. The Transpower assets are very secure at both locations and the level of investment required to improve this would not pass the grid investment test. In the longer term, when a new GXP is built at Drury, there will be a relatively low-cost option, using existing Counties Power 110kV lines, to provide interconnection between Bombay and Drury which would cover the total loss of either GXP; this will be considered further when the GXP is established.

Studies have also been undertaken into the subtransmission system of lines, cables breakers and transformers which has identified the requirement for 110/22kV and 33/11kV transformers that could be relocated in a HILP event should there be a total loss of transformers at a zone substation. With current system redevelopments, we will be in the position of having one transformer for each of the two types made readily available for relocation. For both cases the identified transformers will be in service at a zone substation but this substation could operate for an appropriate period without one transformer which would be relocated to the outage site.

Ongoing reviews are planned of the potential natural and other hazards for key network locations to ensure potential HILP events have been identified and contingency plans prepared.

4.8 Emergency Response and Contingency Plans

We place an emphasis on pre-event planning for HILP events. Our assets are designed to provide a certain level of resilience under a normal operating environment as defined in our security of supply and planning guidelines. Natural disasters and emergency situations subject our assets and operations to conditions beyond that for which they are designed to withstand, which may result in outages or other supply issues.

Criticality and Failure Mode analysis activities are underway to identify and evaluate critical spares and contingency requirements.

While our network is not primarily designed to withstand significant HILP events, as costs are prohibitive, we have response policies, procedures and contingency plans in place and critical emergency spares are held in stock to ensure that our power supply is restored in as minimum time as possible. Our contingency plans provide details concerning expected events and the necessary response. These include, for example, contingency operational plans for loss of SCADA and communications networks, and switching schedules associated with the loss of transformer banks and subtransmission lines.

When reviewing network development projects, the issue of resilience under abnormal conditions is considered as part of the selection process from the available options.

4.8.1 Lifeline Utility and Engineering Lifeline Groups

To help make New Zealand resilient to disasters, the Civil Defence and Emergency Management (CDEM) Act 2002 stipulates the responsibilities and roles of key organisations that provide an essential service within New Zealand. Our core business of electricity distribution is an essential service and under the CDEM Act we have been classified as a “Lifeline Utility.” As such, we must:

- Ensure that we are able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency;
- Have a plan for functioning during and after an emergency;
- Participate in CDEM strategic planning; and
- Provide technical advice on CDEM when required.

We are members of the Auckland Engineering Life Lines Group and the Waikato Engineering Lifelines Group. Lifeline groups are a voluntary group of organisations with representatives from territorial authorities, major utilities and the transportation sector. The emphasis of these groups is on pre-event planning rather than taking a post-event operational role. Collaborating with other Life Line members provides a much greater understanding of the general vulnerabilities and interdependencies that individual utility response plans need to consider. As well as further developing the preparedness of lifelines operators for major hazard events, one of the key areas of emphasis is to create and maintain awareness of the importance of lifelines to the community at large.

4.8.2 Civil Defence Plan

We have a Civil Defence Plan in place which details how we respond to a Civil Defence Emergency.

4.8.3 Information System Security Breaches or Losses

We place an emphasis on the security of information within all business systems. We have in place comprehensive data backup and recovery policies. Our operating systems and SCADA systems are particularly critical; therefore they require effective protection from external and malicious access. We participate in the New Zealand Control Systems Security Information Exchange. This organisation is designed to facilitate the exchange of information between its members, in a confidential and trusted environment, concerning threats, vulnerabilities and incidents of electronic attack on control system networks and environments.

4.9 Asset Management Maturity

4.9.1 AMMAT

The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment process required by the Commerce Commission as part of the information Disclosure Schedules, included in the appendices. It is a set of questions derived from the UK Standard PAS 55 (now superseded by ISO 55000) which requires distributors to rate their asset management capability through 31 questions.

The purpose of the AMMAT is for distributors to identify the level of maturity they have in asset management activities and opportunities for improvement and provide a structured method of benchmarking.

4.9.2 AMMAT Assessment

The completed Asset Management Maturity Assessment Tool is included as Schedule 13 of this AMP.

The results from this are shown in Figure 4-12 below. These have improved over the last two years, with several scores improving from 2 to 3, with the average now 2.7, increased from 2.3. These are scored out of 4.

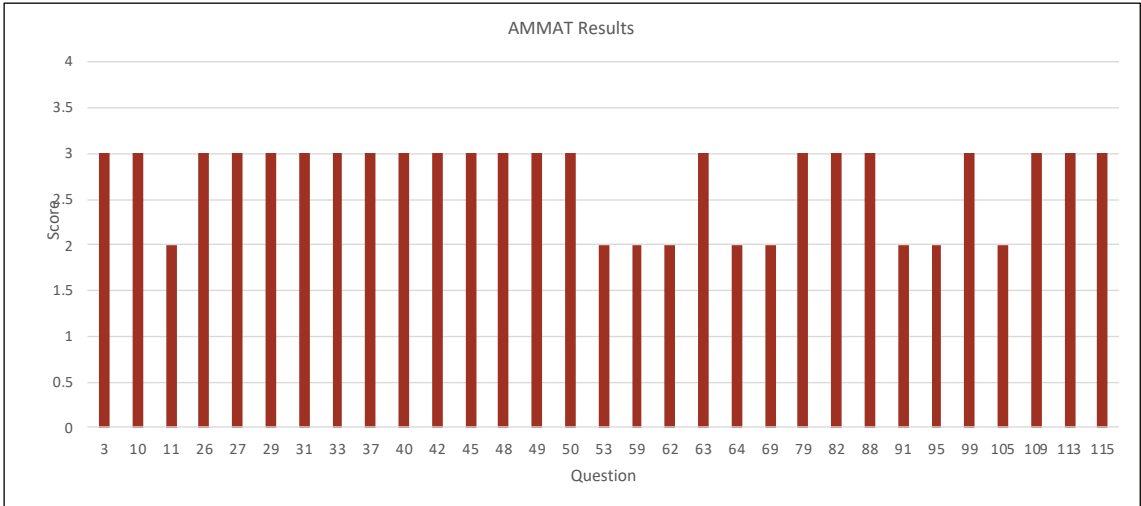


Figure 4-12 AMMAT Results

4.10 Improvement Initiatives/Continuous Improvement

The above AMMAT review together with our network performance analysis work identifies that there continues to be areas for improvement in asset management practices. Chapter 6 of this AMP outlines the major initiatives currently underway together with consideration of the impact of new technologies.

We are also currently in the process of completing a FMECA (Failure Mode Effects and Criticality Analysis) at a detailed level across all network components to help improve the lifetime management of our component fleets. This will help improve AMMAT scores in several categories.

We have also created a full-time role for a Continuous Improvement Manager to lead our improvement activities.



5 NETWORK RELIABILITY

5.1 Introduction

This chapter provides an overview of how network reliability is managed at Counties Power in order to meet the network reliability targets defined earlier in this plan as service levels (refer Chapter 3). This ongoing monitoring forms one of the main continuous improvement feedback loops within the Asset Management Framework (refer section 4.1.1), and is based on a number of metrics which are regularly monitored and used to trigger corrective actions or future improvement initiatives as required. This Chapter explains these metrics, summarises the key themes identified from the analysis and outlines any notable actions which have resulted.

5.2 Philosophy

Customer surveys (refer section 3.2) have consistently identified that, although improved service levels are desired, there is generally very limited support for increased line charges to support such improvements. It is therefore a primary focus of asset management to ensure all expenditure is targeted to achieve the best overall network performance, recognising that the asset is a long term one and thus a minimum whole of life approach to costs is usually the most appropriate. Network reliability and the direct effect it has on the experience of the connected network customers is treated as a core business priority, demonstrated by the appointment of a dedicated Reliability Manager in 2020.

As an exempt EDB, we are obliged to meet disclosure requirements although is not mandated to meet the quality standards of non-exempt EDBs. Nonetheless the regulatory regime is recognised as a widely consulted and agreed methodology in the industry and as a result we presently aim to closely align to the regulatory (DPP2 2015-2020) methodology as far as possible. Adjustments have however been made to how targets are set to account for the significant changes in operating environment between the 2005-2014 regulatory 10-year benchmark period and the present day, further details of which can be found in section 5.3. For FY20 the preceding three year period between FY17 and FY19 was used as the starting internal benchmark and it is intended to extend this over time to provide a more stable longer term benchmark period for comparison.

The DPP2 methodology is also followed to adjust (normalise) for major network events such as storms. Although the normalisation for major events limits the volatility of the metrics, keeping the focus on the underlying performance and helping to ensure reliability can still be managed for the year, it is fully recognised the customer still experiences the full (non-normalised) impact of the event. Internal analysis therefore considers both the normalised and full values. The normalised portion is seen as business-as-usual network reliability, whereas limiting the impact of major events is regarded as a resilience challenge.

We plan to update our processes to align with the updated DPP3 methodology - refer section 5.6.1

5.3 Change in Operating Environment

If the DPP2 methodology were strictly followed, the SAIFI/SAIDI targets would be set to match the average network performance between FY05 and FY14. However, we recognise a number of externally imposed changes have occurred which have significantly impacted on the performance that can be reasonably expected against these measures. The most notable changes being:

- Weather Trends: The reference period included a large period of relatively benign weather compared to recent trends;
- Live Working: Following the introduction of the Health and Safety at Work Act in 2015, the electricity industry responded with a review on the justification of live working. We implemented a risk based live work decision framework aligned to the Electricity Engineers' Association's guide to live work which resulted in a significant decrease in live working, allowable only in exceptional justifying circumstances. Aside from a significant increased number of planned outages to complete our work safely, this also impacted unplanned outage restorations as certain live working techniques previously used to assist were no longer justifiable;
- Reclosing After a Fault: 2016 also saw us implement a change to circuit breaker reclosing protocols following a fault trip event. This change set out to further decrease the risk to public safety, particularly where lines may have come down and may have previously been re-livened. Aligned to the Electricity Engineers' Association's guide to manual reclosing, a mandatory fifteen minute wait period was introduced for rural lines, and reclosing prevented entirely on urban lines until a full patrol of the line had been carried out. These protocols were updated further in November 2017 allowing faster restoration in some cases where network protection technology such as distribution automation or fault passage indicators provided positive confirmation of fault location; and
- Traffic Management: Recent years have seen significant developments around traffic management safety. These changes impact both the financial cost and duration of planned and unplanned events.

It can be seen the overall operating environment has changed to such an extent that attempting to extract useful trends using SAIDI, and to a lesser extent SAIFI, using data from before FY17 is unlikely to yield meaningful results. Data that simply logs events (e.g. faults per 100km) does remain more relevant as it is not impacted to the same extent by the above changes so the longer-term view is still largely valid.

Thus, for this trend analysis, we have taken the approach that performance from FY17 as being more indicative of the new typical network performance under the revised operating regime. As noted in Chapter 3 we have set targets to provide an improving service to our customers reflecting the new initiatives being adopted.

5.4 Reliability Metrics (For Unplanned SAIFI/SAIDI)

We recognise that unplanned SAIDI and SAIFI are a direct result of three input factors which are monitored as reliability metrics:

1. Number of events

Linked to failure/fault rates.

2. Number of customers impacted per event

Linked to the topology/design of the network, and where on the network the events occur.

3. Duration of outage

Linked to how quickly supply is restored.

It should be noted that SAIFI is a product of the first and second factor, with SAIDI being the product of SAIFI and the third factor.

The three contributing factors are monitored for each unplanned event category and compared to internal targets derived from the FY17-19 benchmark period as explained in section 5.2. These targets are designed to manage each category so each contributes appropriately to meet our overall network reliability objectives set out in Chapter 3.

The unplanned event categories used are:

- **Equipment – Overhead;**
Events caused by overhead network equipment.
- **Third Party;**
Events caused by third parties such as vehicles impacting poles or substations, vandalism or theft, third parties striking underground cables or contacting overhead lines.
- **Vegetation;**
Events caused by vegetation contacting our network - usually trees near lines, but sometimes long grass, vines or creepers.
- **Unknown;**
Events where the cause is not found and the network is restored - typically vegetation, wildlife or transient equipment issues.
- **Wildlife;**
Events caused by birds, vermin or possums .
- **Equipment – Ground Mounted (GM), Under Ground (UG) or zone substation (ZS);**
Events caused by non-overhead network equipment such as cables, or equipment in distribution or zone substations.
- **Adverse Weather;**
Events caused by flooding, landslide, lightning or tornadoes (but not high wind or rain).
- **Network Incident;**
Events as a result of actions by Counties Power or their contractors.
- **Major Events;**
Any event within the calendar day defined by the DPP2 normalisation rules as a Major Event.

Events are normalised for SAIDI/SAIFI using the DPP2 methodology – i.e. If the sum total of SAIFI or SAIDI within a calendar day exceeds the corresponding boundary value, that calendar

day is treated as a ‘Major Event’. In line with our philosophy, all events in these periods are then treated as contributing events and their SAIFI/SAIDI contribution reallocated to a separate category for Major Events. This ensures the impact of these outlying days do not skew the metrics for normal day-to-day network events.

5.4.1 Events

The following figure shows the number of events by fault category in FY20 compared to the FY19 benchmark period.

Category	(FY17-19 avg.)	FY20	±% (from FY17-19)
Equipment - Overhead	116	144	24.1%
Third Party	40	26	-35.0%
Vegetation	35	42	20.0%
Unknown	28	47	67.9%
Wildlife	13	21	61.5%
Equipment - GM/UG/ZS	3	7	133.3%
Adverse Weather	6	2	-66.7%
Network Incident	4	0	-100.0%
Total for all categories	245	289	18.0%

Figure 5-1 Events by Fault Category

Although cautious to call out a single year result as a “trend”, it is noted that events in all the major contributing categories have increased in FY20 in comparison to the preceding benchmark, with the exception of third party events. The total has increased 18% compared to benchmark.

Additional to event category, internal systems also capture a more detailed cause code per event, a field that has been captured for many years. The faith in the quality of this data however is variable and is presently below the level required to reliably form deep insights into contributing factors to network reliability. To address this, it is intended the relationship between Field Operations and Network be enhanced. A regular event review meeting is now held and a joint working group has developed enhancements to the tablet system used by our reactive teams as well as a revised process for the collection of failed assets from the field for the purposes of better understanding specific failure modes or, if required, further forensic analysis. The proposed reactive works order close-out process now incorporates many more opportunities for critical failure information to be fed back into the asset management systems and both new processes are expected to go live before the start of FY22. Once live, this system will provide the bulk of useful information with the review meeting an opportunity to clarify any additional questions. These feedback loops are fundamental to the continuous improvement of the management of failure modes, with a full review of the failure mode registers presently under way, and a follow-on review of applicable controls, such as maintenance programmes, likely to follow where required. It is also intended that the increased richness of failure cause information will enable deeper trend analysis for future versions of this AMP.

In the meantime, the more variable information available relating to overhead equipment indicates possible failure mode concerns with lightning arrestors, binders and connectors. These concerns have triggered a review of the construction standards, with the intent of designing out these issues for the future. Clearances will be increased (particularly on the 22kV network), and connections between dissimilar metals avoided wherever possible or appropriate techniques adopted where unavoidable.

A dedicated Standards and Compliance Engineer joined the team as a new role in October 2020 to assist with this initiative. Identification of existing installations presently at risk of failure is covered in the maintenance inspections but the effectiveness of this will be reviewed as part of the failure mode review. Maintenance procedures have also been enhanced to increase the robustness of inspections of the overhead network. This has already started to identify conductor and joint concerns that may have been missed before. In addition, a trial of pole top photography taken from a helicopter platform is scheduled for early 2021, see Chapter 6.

The significant conductor replacement programme (details in Chapter 7) is also expected to reduce unplanned events. Not only is the smaller dimension conductor more prone to failure being targeted, but during replacement older design of ancillary equipment such as crossarms, insulators and other associated hardware is replaced too.

For vegetation related outages, the observed increase during FY20 was a key factor in the decision to include a vegetation survey within the scope for the LiDAR survey completed in early 2020 (refer Chapter 6). This enabled an enhancement to our vegetation management strategy from FY21 which is described in section 4.1.3.

On events with an unknown cause, past experience indicates that these originate from an approximate equal share of:

- Vegetation glancing contact from either trees close to conductors making brief contact, usually assisted by wind, or debris from trees further away briefly contacting line before falling clear;
- Wildlife contact where the offender wasn't discovered; or
- Transient equipment failures such as deteriorating insulators where in some cases the fault can clear until local weather conditions facilitate a repeat failure, or short-lived conductor contact, typically due to ineffective design or subsequent pole movement and then a subsequent wind.

The applicable operational procedures already include a mandatory patrol of the network in an attempt to find the cause on any network that has tripped as a result of a fault; even if the network was successfully restored before full patrol was completed, or any circuit that has experienced two or more successful auto-reclose events within a rolling seven-day window. Depending on the circuit, the target to complete these is between one and five days, with any findings fed back through our corrective or reactive maintenance processes, depending on the urgency. The existing additional monitoring technology presently under trial on six of the worst-performing feeders has also demonstrated some promise in being able to refine the location of where fault locations have not been determined. Further work is ongoing in this space (refer Chapter 6).

Finally, for third party initiated events, insights into high crash areas have been generated through an overlay of known accident sites, balanced against the locality of our assets such as poles and distribution substations, identifying areas of heightened risk posed by vehicle traffic. The data gives insights from the previous 10 years of crash data, providing a detailed pole breakdown and vulnerability by HV and LV circuits. The asset vulnerability report has been generated to show data on crashes within a 30m buffer zone of assets.

Business insight reporting shown in Figure 5-2 below, will assist planners and designers to determine whether overhead network replacement should include additional solutions to mitigate risk in high impact areas, particularly where structures support multiple voltage or configurations. Designers for customer requested connections are also aware of this information to ensure safety and security by design occurs in all instances.



Figure 5-2 Asset Vulnerability Report



5.4.2 Customers Impacted

The following figure shows the average numbers of customers impacted by a fault in each fault category in FY20 compared to the FY17-19 benchmark period.

Category	(FY17-19 avg.)	FY20	±% (from FY17-19)
Equipment - Overhead	212.7	160.6	-24.5%
Third Party	391.1	402.7	3.0%
Vegetation	378.7	285.3	-24.7%
Unknown	731.8	445.8	-39.1%
Wildlife	1096.4	459.5	-58.1%
Equipment - GM / UG / ZS	1097.9	734.3	-33.1%
Adverse Weather	485.4	873.0	79.9%
Network Incident	493.3	0	-100.0%
Average across all categories	394.4	287.4	-27.1%

Figure 5-3 Customers Impacted by Fault Category

This metric measures the average numbers of customers impacted per event, noting that in line with regulatory guidelines, events are only counted for SAIDI/SAIFI if the interruption to supply lasts for more than a minute. As such, any change in network topology that avoids customers losing supply for more than a minute due to an unplanned event can improve this metric. New protection devices such as reclosers, sectionalisers and fuses are typical examples, as is splitting parts of feeders to other dedicated circuit breakers. Prioritisation (by network criticality) of investment spend within budget constraints can also improve this metric, as effective prioritisation should mean any resulting events should impact network of a lower criticality, i.e. a smaller number of customers.

Other network automation devices such as remotely controlled ground mounted or overhead switchgear presently interface back through the SCADA system to our network operations centre. During an event, operators act on the incoming information to make human decisions on where the faulty section of network is indicated to be, and therefore sections of network that can be restored through remote controlled switching. If this happens in less than a minute, these devices could in theory therefore improve this metric. However, the primary objective and focus of the operators is to ensure accurate decisions, so they are encouraged to take the time they need rather than aim to meet the 1 minute threshold. As a result, it is most often the case that restoration switching can take between three and five minutes, to ensure the best decisions are made. Therefore, it can be assumed that additional remote controllable switchgear will improve Customer Average Interruption Duration Index (CAIDI), but will not reduce the number of impacted customers.

Note: We record separately to SAIDI/SAIFI any customer interruptions of duration < one minute as a momentary interruption, which are typically a result of successful auto-reclose or sequence restoration schemes.

This metric has improved for nearly all fault categories in FY20 when compared to the benchmark period, likely due to the focus on investment prioritisation by network criticality (for network maintenance, vegetation management, and replacement investment) as well as the improvement yielded from past recloser installations and feeder split projects.

The remaining feeder split projects require a reasonable amount of new network to be installed and were found to be of a very high cost, despite the reasonable benefits. For now, these have been deferred to start in FY24 at the earliest in order to allow time for a cost/benefit justification review.

Over the next 12 months, a separate review will analyse the network to establish whether there is opportunity for topology changes – i.e. additional network automation, network switching devices or additional alternative supply (backfeed) points where the cost is justified by the benefits. This will be supported by our network criticality model (see Chapter 6).

5.4.3 SAIFI

The following figure shows SAIFI by fault category in FY20 compared to the FY17-19 benchmark period.

Category	(FY17-19 avg.)	FY20	±% (from FY17-19)
Equipment - Overhead	0.5952	0.5356	-10.0%
Third Party	0.3792	0.2425	-36.1%
Vegetation	0.3156	0.2775	-12.1%
Unknown	0.5001	0.4852	-3.0%
Wildlife	0.3330	0.2235	-32.9%
Equipment - GM / UG / ZS	0.0887	0.1190	34.2%
Adverse Weather	0.0732	0.0404	-44.8%
Network Incident	0.0475	0.0000	-100.0%
Total to all categories	2.3325	1.9238	-17.5%
Major Event	0.6015	0.4941	-17.9%
Total	2.9340	2.4179	-17.6%

Figure 5-4 SAIFI by Fault Category

SAIFI is a product of the number of events and the customer impact as outlined in sections’ 5.4.1 and 5.4.2 above. Considering network performance outside of major events, it can be seen that events have increased relative to the benchmark, yet the average customer impact has decreased by a larger amount. The net result of this is a decrease in unplanned SAIFI in FY20 relative to the benchmark by ~18%.

Following a similar trend, the SAIFI incurred on major events days has also decreased by a similar amount. FY20 saw two SAIFI Major Event Days, with the rest of SAIFI attributed to major events incurred on days that triggered the SAIDI major event threshold (but didn’t trigger the SAIFI major event threshold).

The overall SAIFI result for FY20 was 2.418, a decrease from the benchmark period and slightly unfavourable to the target of 2.400.

5.4.4 Duration (CAIDI)

The following figure shows CAIDI by fault category in FY20 compared to the FY17-19 benchmark period.

Category	(FY17-19 avg.)	FY20	±% (from FY17-19)
Equipment - Overhead	69.9	84.2	20.4%
Third Party	100.1	96.1	-4.0%
Vegetation	59.0	44.1	-25.2%
Unknown	41.1	33.4	-18.6%
Wildlife	27.7	28.8	4.2%
Equipment - GM / UG / ZS	34.3	54.4	58.3%
Adverse Weather	37.9	61.9	63.4%
Network Incident	13.3	0.0	-100.0%
Average across all categories	57.6	58.38	1.3%

Figure 5-5 Duration (CAIDI) by Fault Category

There have been movements up and down within fault categories, but CAIDI overall has remained steady for FY20 when compared to the internal benchmark period. It should be noted the bottom four categories correspond to a relatively smaller number of events, which can make this averaging metric very volatile.

It is however recognised that for FY20 the CAIDI result for events caused by equipment indicates an increase when compared to the benchmark period. Further investigation is ongoing into what is driving this result, although it is expected that factors impacting repair durations are likely to be significant such as increased compliance requirements for traffic management. Towards the end of FY20 following a review indicating a reasonable number of events occur in late afternoon/early evening, rostering for first responders was changed to provide availability of dedicated response staff until 7pm after which conventional call-out arrangements continue. The impact of this change will be monitored and arrangements further refined as required.

5.4.5 SAIDI

Category	(FY17-19 avg.)	FY20	±% (from FY17-19)
Equipment - Overhead	41.62	45.12	8.4%
Third Party	37.95	23.30	-38.6%
Vegetation	18.63	12.25	-34.2%
Unknown	20.55	16.22	-21.1%
Wildlife	9.21	6.44	-30.1%
Equipment - GM / UG / ZS	3.04	6.47	112.5%
Adverse Weather	2.78	2.50	-9.8%
Network Incident	0.63	0.00	-100.0%
Total to all categories	134.42	112.31	-16.5%
Major Event	34.11	25.58	-25.0%
Total	168.53	137.89	-18.2%

Figure 5-6 SAIDI by Fault Category

SAIDI is a product of SAIFI and the Duration (CAIDI) as outlined in sections 5.4.3 and 5.4.4 above. Considering network performance outside of major events, it can be seen that SAIFI has decreased relative to the benchmark, and the average duration (CAIDI) has remained steady. The net result of this is a decrease in unplanned SAIDI in FY20 relative to the benchmark by ~17%.

Following a similar trend, the SAIDI incurred on major events days has also decreased by a similar amount. FY20 saw five SAIDI Major Event Days, with a small remainder of SAIDI attributed to major events incurred on days that triggered the SAIFI major event threshold (but didn’t trigger the SAIDI major event threshold).

The overall SAIDI result for FY20 was 137.89, a decrease from the benchmark period but above the target of 110.

5.5 Post Event Actions

5.5.1 Major Event Analysis

A detailed review of incidents that have a significant customer impact are formally analysed once the incident is resolved to ensure the root cause of the incident is fully understood and to check the decisions made during the restoration process to ensure they were optimal. The results of these investigations are fed into the appropriate area of our operations.

5.5.2 Post Fault Thermographic Circuit Checks

From an analysis of fault data there appears to be an increase in the number of failed jumpers and overhead connections in the days following a fault on a circuit that resulted in a significant fault current flowing.

This indicates that such connections have been stressed by the fault current and their resistance has increased. This will lead to additional localised heating and the increased deterioration of the connection leading to failure.

We have recently purchased suitable thermographic survey equipment and are instigating a process to check the jumpers and connections along a feeder within a few days after it has been subjected to a significant flow of fault current. Potential failure sites can then be identified and resolved before complete failure and further customer outages.

As data is generated from this initiative the process will be optimised to reflect the original level of fault current to initiate a survey and the optimum time after the fault to carry it out.

5.6 Methodology Improvement for the Management of Reliability

5.6.1 DPP3 (FY21-25) Methodology

With the non-exempt Electricity Distribution Businesses (EDBs) having now moved to the updated DPP3 methodology from 01 April 2020, Counties Power aim to follow. It is expected this move will happen from FY22, starting 01 April 2021 with targets and reporting to be adjusted in the future AMP accordingly. Some changes have already been made, an example being the setting of separate targets for planned (class B) and unplanned (class C) SAIDI/SAIFI.

5.6.2 Improvement of Reliability Metric Targets

At present the targets used for each of the reliability metrics have been derived from performance in the benchmark period and no further modification applied. In addition to the DPP3 alignment mentioned above in section 5.6.1, further work is ongoing to improve these targets. It is expected our SAIDI criticality model (refer section 6.3.3), once complete, will help inform what are acceptable event rates and acceptance average outage durations. This, combined with the expected benefits of network investment projects (where reasonably able to be predicted with suitable accuracy), will be used to refine the metric targets, as well as closer linking to other related internal targets and service levels such as response and repair durations for unplanned events.

5.6.3 Reliability Standards by Customer Type

It is recognised that measuring network reliability on SAIDI/SAIFI has the disadvantage that the metrics are averaged across all network connected customers. Despite the present system average unplanned outage targets for FY21 of 2.7 interruptions (SAIFI) and 140 minutes duration per year (SAIDI), there is likely to be extremes within this, where customers supplied from reliable urban networks may go years between interruptions, with the converse being true for customers on long remote rural networks where multiple interruptions can occur during a single year.

In the next 12 months, it is intended to establish internal standards for reliability at a customer level by customer type – and report on them.



5.7 Summary of Capital Expenditure

Figure 5-7 below summarises the projected costs for Other reliability, safety and environment.

It needs to be highlighted that the projects listed in this section are listed here because their primary driver is targeting reliability. However nearly every project under Asset Replacement and Renewal (refer Chapter 7) as well as System Growth (refer Chapter 8) will also have a notable impact on network reliability, despite not being the main driver. As such the project list in this section cannot be considered as an exhaustive list of projects with a network reliability benefit.

All work programmes, financial profiles and actions described throughout this plan indicate the company's intentions based on the information presently available to it. They may be amended in response to new information. They are also subject to detailed study and verification in accordance with sound engineering practice and, in respect of financial expenditure, established processes for management and Board approval.

As introduced in section 5.4.2, a full review of reliability targeted projects is scheduled for FY21 and it is expected that plans in this area will change significantly in future iterations of this Asset Management Plan.

	Estimated costs (\$'000)									
	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Cape Hill feeder split	-	-	2,571	-	-	-	-	-	-	-
Drury Hills feeder rebuild 416-646/502	-	-	1,523	-	-	-	-	-	-	-
Install cable and new RMU to reduce customer numbers on Hingaia feeder	-	-	-	1,097	-	-	-	-	-	-
Pukekohe hill feeder UG Kitchener Road	-	-	1,132	-	-	-	-	-	-	-

Figure 5-7 Projected Expenditure for Other reliability, safety and environment

Note: Forecasts are stated in real (constant) prices



6 INNOVATION AND NEW TECHNOLOGY

6.1 Improvement

While there have been ongoing individual projects seeking to improve the performance of various aspects of our operations, Counties Power recently appointed a Continuous Improvement Manager to optimise the impact of the time and system inputs required for such improvement studies.

Following consideration of the opportunities for improvement the first project launched is an “end to end study” across the full project delivery lifecycle from initial planning concept, through design, budget development, approval processes to delivery and review. To facilitate such a comprehensive study and to ensure that the identified improvements are put in place in a co-ordinated manner a cross discipline “Change Committee” has been established.

The targeted outcomes from this study cover improved financial budgeting and forecasting as well as improved material scheduling/purchasing and staff/contractor requirements. Included within the financial control aspects, will be reviewing both initial authorisations and variation control.

It is anticipated that from this overall review a number of associated improvement opportunities will be identified which can be addressed following the initial project.

From the AMP perspective this work should improve the financial integrity of the planning costing data which will lead to improved forward forecasting accuracy for both Counties Power’s financial expenditure and staff requirements to meet the planned workload.

6.2 Innovation

6.2.1 Smart Meters

A major project has been carried out over the last six years on customer metering across our network such that 97% of meters on our network are modern smart meters provided by Counties Power (Downstream Technology). The communication system adopted for this metering technology is a meshed-wireless network, which provides near instant updates for power outages and power restorations. In addition, power consumption, voltage alerts and other meter data is read remotely every four hours and updated to Counties Power’s INDI platform. INDI is a cloud based big data platform that utilises data from Google Maps and Counties Power’s GIS network data.

Outage Management

The first project to start utilising the smart meter data was an Outage Management System – INDI (Infrastructure and Network Data Interface). This system provides near real time feedback for loss of power at individual customer level enabling us to ensure rapid response and proactive outbound communication during power outages.

When an event occurs, the meter sends a signal if it is suddenly out of power – a ‘last gasp’. This reports the fault and helps the fault repair team work out exactly where the fault is, so they can get to it and fix it faster. In addition, the system provides better information during outages. The smart network interacts automatically with our Outage Website and Application so that within

minutes of a customer’s power going on or off the status will be updated. This will also assist the fault team to be able to give earlier assessment of likely repair time.

Non-Standard System Operation Voltage Monitoring

During fault conditions the normal practice, wherever possible, is to restore supplies by rearranging network switches so that areas that have lost their normal supply feeder are relivened from adjacent feeders. A similar process is adopted for planned works to minimise the number of customers affected by an outage. The primary concern at such times is to restore power; however this should be within the normal voltage limits.

Planning engineers carry out load flow studies of feeders, using computer models of the network to consider such non-normal supply arrangements. However, these models must use a number of assumptions (such as the likely distribution of load along a feeder) and may not accurately reflect the conditions at the time of the event.

The smart meter data can be used after an event to analyse the actual voltage levels recorded at customers’ properties to identify if there is a need to consider reinforcement to cope with future events. For extended events checking of the data in real time may also be adopted if there are concerns that the supplied voltage may not be within the statutory limits.

Voltage Complaints Investigations

Traditionally, investigating voltage complaints has required monitoring equipment to be installed both at the customers’ premises and on the reticulation in the street. However, with the smart meter data available in geographic form an initial assessment can be made as to the likely cause of low voltage at a customer’s premises. If the property with low voltage is some distance from the street, with a long service line, but the adjacent properties close to the street have a supply voltage within limits, this indicates the issue is likely to be the service line. Referencing the load data may help identify whether this is contributing to the problem.

Conversely if several meters report low voltage, then the aggregated load data from them can be used to check whether the likely cause is with the LV reticulation or the distribution transformer’s sizing.

Feeder Design

The planning process for proposed network upgrades on feeders involves running computer models of the network to predict the voltage along the feeder. Having access to the actual data on the voltage levels under the current supply system, provides the ability to check the outputs from the computer model. This will help optimise the actual reinforcement works to be undertaken as well as helping identify more accurately when they will be needed. This is of particular use when new subdivisions or other significant loads are proposed towards the end of a feeder.

Customer Uptime Analysis Report

Traditionally network performance has focused on outages and their measurement primarily by calculating SAIDI and SAIFI performances. This recently completed project has adopted a view of the supply experience received by customers, looking at the “uptime” or availability of power at properties as observed by the customers.

This approach has the advantage of including all occasions when there is no supply at the customers meter which includes loss of supply on low voltage equipment (distribution cables, the customer’s service line, main fuse, etc.), thus capturing the full customer experience.

Reporting is split into outages lasting less than a minute, which are classified as “Reclose” events and those over a minute, classified as “Outages”. Over two years of data is presently available and any period can be selected for study.

The output is presented graphically for each event and also presented as a dashboard performance indicator roundel (see Figure 6-1 below). Data can be selected at overall company, GXP, zone substation, distribution transformer and individual ICP level.

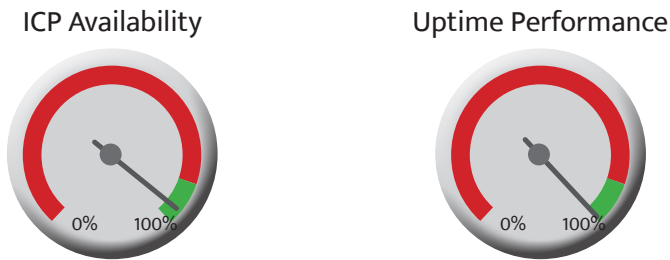


Figure 6-1 Dashboard displays

It is intended to use this data to identify specific areas where there are opportunities to improve our customers service experience.

6.3 Impact and Opportunities from New Technology

Through our planning processes, we identify possible alternatives to building traditional network and these are included in our solution list. Technology in this space continues to improve and reduce in cost, however, the largest network alternative solution we currently have in place is demand management using our ripple load control system.

Our load management system is integrated with our SCADA system and permits us to switch controllable load during peak periods to maintain our system half-hourly targets, which minimises transmission peak demand, as well as ensures our network equipment operates within its ratings. We also monitor output from large Distributed Generators through our SCADA system, which also assists in managing peak demand.

Embedded generation, energy storage, energy efficiency measures, demand side management initiatives and new load types such as Electric Vehicles (EVs) may result in modified load growth patterns. We are presently monitoring the uptake of all of these technologies, with a specific interest in EVs due to their expected level of penetration and potential for overloading the local LV network if ownership is clustered and charging is not controlled.

We continue to keep a watching brief on demand side management technologies and options, along with other new supply side technology and where appropriate undertake, or participate in trials to understand how these options could impact on our business.

In the medium term, improved metering technology will enable us to offer tariffs that better reflect delivery cost structures, an increased range of customer options and responses around demand management and energy consumption, as well as providing significant service and operational benefits to customers, network companies and retailers.

6.3.1 Light Detection and Ranging (LiDAR)

In January 2020 a LiDAR survey was undertaken across the whole Counties Power network.

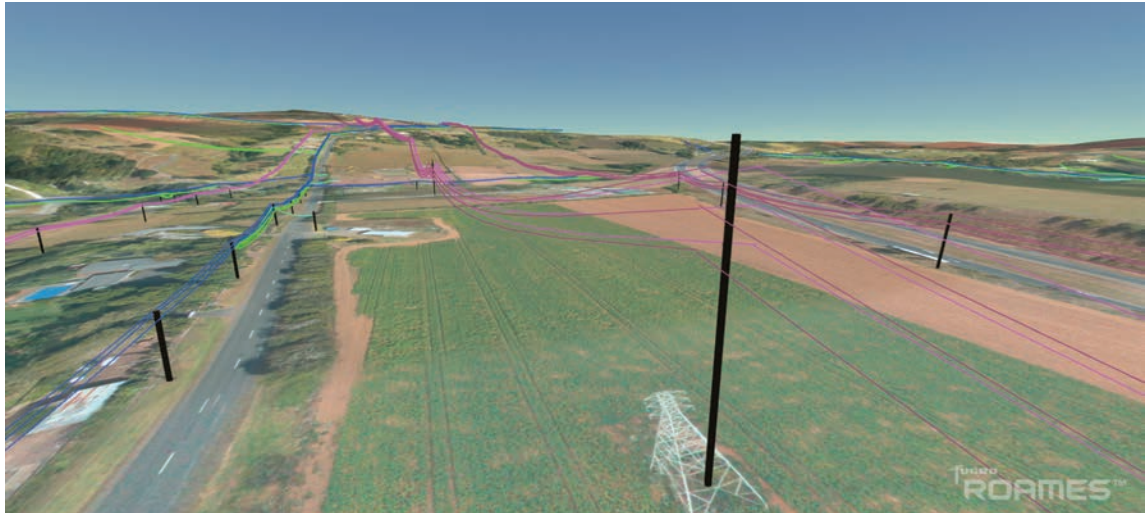


Figure 6-2 Digital Twin Display

The survey measured the clearances between network lines and other nearby objects, primarily the ground or surrounding vegetation either growing close to conductors or presenting a risk of falling through or shedding debris into lines.

The survey data has been integrated into an analytical model alongside existing known network defects, recent fault history and potential customer impact to prioritise areas of work for defect remediation and planned vegetation work to minimise planned outage frequency while maximising efficiency.

GIS Data Corrections

The data collected has been integrated into Counties Power’s GIS as a 2D spatial reference layer. This allows users to see the accurate location of poles and wire conductors (at LiDAR capture time) as well as related attributes such as height, intrusion information etc.

The GIS is planned to have pole, wire conductor and related assets automatically moved to related LiDAR locations. This code-based automation is planned to be completed by the end of early 2021. Any assets that cannot be automatically validated/moved to LiDAR locations will prompt an investigation into possibly offshoring clean-up, based on the number of remaining assets for review. The LiDAR data will significantly improve the spatial location data of the Counties Power overhead network, including aiding in LV clean-up of the GIS data.

Network Insights

The data gathered and subsequent analytics has been used to assess line heights as compared to the guidelines defined by NZECP 34, producing a remediation programme grouped by and prioritised by the criticality of the network. It also provides insights regarding pole height, pole lean and span length, with outliers being rectified based on risk.

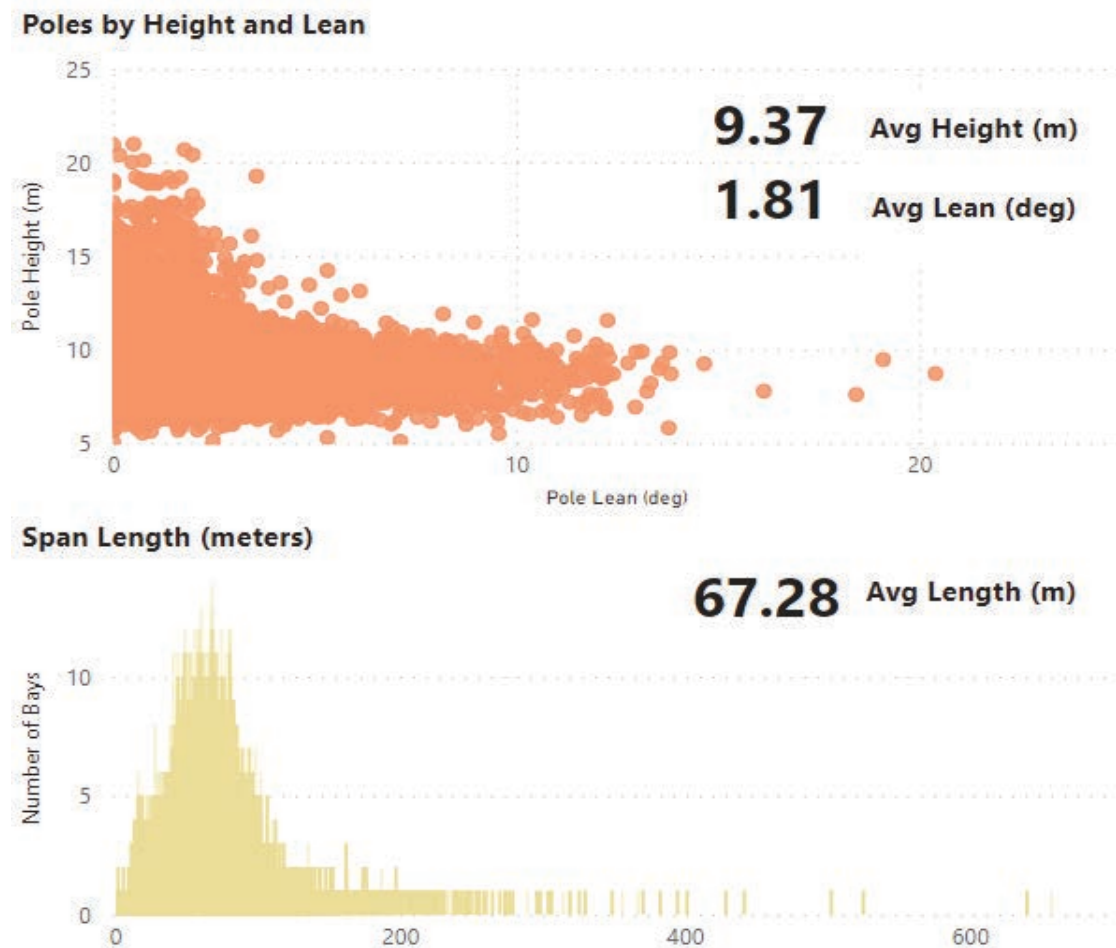


Figure 6-3 Analytic Examples

Required remediation for line height concerns has been prioritised based on:

- Public safety risk;
 - Road crossings;
 - Public access risk; and
 - Line height and voltage.
- Network impact;
 - SAIDI impact.

The data from the LiDAR survey also has other future potential use cases such as identifying line spans at risk of conductor clash or validating records relating to crossarm length/design.

Vegetation Insights

The data provided has shown us the extent of vegetation intrusions, as of January 2020.



Figure 6-4 Vegetation Insights

Like the risk presented by line clearances, the data gathered and subsequent analytics provided has been used to assess observed vegetation concerns, not just to the required clearances defined in the tree regulations for vegetation growing close to conductors, but also vegetation presenting a debris or fall risk to the network. In line with our vegetation management strategy (refer section 4.1.3), this analytical output now informs the bulk of our vegetation management programme.

It should be noted that LiDAR is not a “silver bullet” for managing vegetation as despite all the advantages, the technology is as yet unable to positively determine factors that are significant in quantifying the risk an individual tree presents to the lines. These factors include such items as its health, species and growth rate. Checking these factors still requires a specialist on site survey; however LiDAR is very effective at prioritising where this specialist resource should be deployed. In time, further LiDAR surveys offer the opportunity to refresh the data set which could be used to audit completed vegetation maintenance or, with further analytics, look to attempt to quantify growth rates, to further improve the proactive nature of the vegetation strategy.

6.3.2 Helicopter Photography

A trial of pole top photography taken from a helicopter platform is scheduled for early 2021, having been delayed from 2020 due to the border restrictions associated with the COVID-19 alert levels. Collecting this asset information from above will be used to validate the quality of existing asset inspections but may also supplement in some cases by identifying deterioration of crossarms or insulators that could be missed by traditional ground-based inspections.

6.3.3 IT Improvement Projects

Enterprise Asset Management System

The primary focus of our current IT improvement projects is the completion of our Enterprise Asset Management System which is currently to timetable for mobilisation before FY22. This project replaces several legacy systems with a proprietary MAXIMO based system. This will ensure that the parallel work on improving the data produced by our condition based assessment processes will feed into an overall management system to ensure optimal financial decisions are made regarding repair, refurbishment or replacement of our assets as they age.

The output of the system will impact across all aspects of the asset management process including works management, resourcing, and equipment selection by ensuring that the data used for decision making is accurate and sound.

Revenue Reassurance Study

Recognising the potential analysis opportunities provided by half hourly data from smart meters an overall project to build models to analyse the potential impact of new technologies and other disruptive events on revenue has been initiated. This will enable analysis of the impact on revenue from a customer resulting from their adoption of distributed generation, battery storage, EVs or other options.

The first step has been to improve the half hourly data quality. Various events can result in non-transmission/receipt of half hourly values, this is not an issue for basic revenue purposes which use the 24 hour consumption data, but it is an issue when looking to use the load data throughout a day. A project has been undertaken with the University of Auckland to develop approaches to synthesise missing half hourly data. The project is close to completion, it will create full data sets for future analysis.

The first project will analyse the increasing number and size of PV domestic installations which is leading to a detrimental impact on Counties Power's revenue and overall network costs. This will help inform decision making to ensure long term viability of Counties Power.

SAIDI Criticality Model

Our core asset management systems (refer section 4.3.1) already contain information relating to the connectivity and topology of the network so that the impact to customers of a failure or outage in a particular location can be predicted. On the distribution network, customers are grouped by feeder circuit, and recently have also been grouped by circuit segment i.e. the section of network between switching or isolation devices. This grouping has been achieved by a coded algorithm and stored in our GIS system, and is used for grouping and scheduling works on the network.

For early 2021, it is intended to further refine this into separate circuit segments for protection operation, automation operation and fault repair (isolation). Analysing these segments against typical average restoration times can provide an indication of the expected SAIFI/SAIDI impact of an unplanned event in a particular location. This indicated impact will be used as a proxy for the criticality in terms of network performance. If this is combined with an understanding of how the average event rates impact a network segment, then a view of the inherent statistical network performance can also be achieved. Impacts of reliability initiatives can then be modelled by varying topology, event rate or duration change.

Additional Distribution Monitoring

In addition to the conventional protection and power quality monitoring systems, we have previously invested additional monitoring technology on six of the worst performing feeders. This equipment monitors voltage and current from the source zone substation, but at a much higher level of detail than conventional systems. The primary intent of this system is to look for small disturbances on the network, each time adding and comparing to an international cloud based database. This comparison attempts to predict or anticipate the type of fault the small disturbance is likely to develop into. The added benefit of the system is the ability to compare the disturbance to a model of the network in an attempt to determine likely locations which can inform further inspections or investigations. Initial results have been positive with identifying potential locations of faults that previously would have been un-locatable.

Conductor Condition Monitoring

With a predominantly overhead distribution network, conductor replacement consumes a significant component of the replacement investment (refer Chapter 7). At present, this programme is largely informed by the age of the conductor and further informed by any available information relating to obvious visual condition, location and the criticality of the network section.

We are aware of emerging technologies that attempt to measure the condition of conductors. Some of these technologies are already being discussed by other New Zealand EDBs, discussions which we are keen to participate in. If successful, better condition information will greatly enhance the ability to prioritise the conductor programme.

6.4 Network Alternatives

6.4.1 Load Control

We currently use ripple load control for network demand optimisation and transmission peak demand management for transmission pricing purposes. We generally limit load control to 5 hours per day on any customer load and only during Regional Coincident Peak Demand (RCPD) periods during Upper North Island (UNI) peaks. Our network peak occurs just after the UNI peaks on a typical day.

While the precise maximum load control capacity is measurable, in reality the total amount of load that can be shifted at any one time is based on the prevailing conditions on the network. The effect of load control can vary in different areas and throughout the seasons, but typically over the winter, where Counties Power's maximum demand occurs, controllable load is between 5% and 10% of the total demand. We have approximately 32,000 controlled ICPs on the network.

The technology deployed to control load is likely to change over time with the advances in customer technology. Electric vehicles may pose a challenge in the future with the additional loading coming onto the network at times that may differ from traditional peak loading. Our advanced metering system offers functionality for load control separate to ripple load control, so applications by customers to have advanced metering will be considered appropriate.

6.4.2 Distributed Generation

Several of our customers own distributed generation systems that connect to our 11kV or 22kV distribution network.

Generally, the network can support connection of generation in a specific location of:

- Up to 4MW of generation to our 11kV distribution network;
- Between 4MW and 12MW of generation to our 22kV distribution network; and
- Above 12MW of generation to our subtransmission network.

Section 2.5.3 provides information on distributed generation numbers, in summary there are 29 embedded generators with ratings greater than 10kW and over 900 with ratings of under 10kW.

When assessing an application to connect distributed generation to the network, we consider the following effects on the network:

- Reactive power flows – to maintain correct power factor;
- Voltage control range – to ensure compliant voltage is maintained in all load circumstances; and
- Harmonics – to ensure the plant does not create excessive harmonic levels and power quality problems.

Our Distributed Generation Guideline sets out the network connection and technical requirements and is consistent with the Electricity Industry Participation Code, Part 6 – Connection of Distributed Generation. This Guideline can be downloaded from our website at www.countiespower.com.

Impact of Large Scale Generation on the Network

The establishment of a generator can impact the network in various ways, depending on the capacity and the security of the generation. It is not usual for generation of the size connected to a distribution network to have any level of security (i.e. an N-1 capacity) as in most cases there is a single generator.

In these cases, the network must be designed and installed to cater for load flows under the zero generation case. Thus, the impact will not reduce capital or operational costs, but can impact revenue. Specific negotiation is therefore required with proposed generators to reflect their needs and impact.

If the generation plant does have a true firm capacity then this may reduce the network requirements and thus costs. This can be fully reflected if the network is to be built to connect the plant, however in some cases it could lead to stranded assets reducing the benefits.

As noted above there are technical restrictions on the size of generator that can be connected at different voltage levels and locations and these must be established for each case. Significant sized generation may need connecting back to the nearest zone substation (or higher voltage lines) and in remote rural generators may be restricted to 0.5MW for connection to 11kV lines.

For the purposes of load forecasting no specific provisions have been made for potential larger scale generation being established on the network.

Impact of Small Scale Generation on the Network

To date the uptake of PV generation at a small scale in NZ has been low by comparison with many other countries, however these have had various subsidy provisions by their governments. There is considerable pressure on the NZ Government to introduce subsidies and such a move could see a significant increase in its adoption. At household levels other generation options include wind turbines, micro-hydro systems, biomass and biogas engines and diesel or bio-diesel generators. The establishment costs of these systems are currently high, and they are not normally attractive to customers.

The impact of small scale generation at present is low and localised. With the normal domestic load profiles (morning and evening peak demands) PV installations do not reduce the peak demand from a property and thus the network must be designed to meet these peak loads. The impact is thus an economic one with the reduction of income from energy sales.

The impact of household small scale generation is dependent on the provision of local storage (batteries) covered below.

For the purposes of load forecasting no separate provisions have been made for small scale generation being established on the network; however the growth rates used for each location at feeder level will reflect any impact from existing installations.

6.4.3 Batteries

Network Scale

Counties Power established a Battery Energy Storage System (BESS) at Tuakau zone substation in a spare bay in 2017 with an output capacity of 250kW and stored energy capacity of 500kWh. This has the capacity to fully power around 100 houses for two hours.

Such batteries offer the ability to reduce the peak demand on a substation and thus defer network upgrades. In this they are comparable to the provision of a diesel generator, however the generator provides a non-time limited level of capacity (subject to fuel storage) whereas the battery is a “one-shot” device that requires re-charging once utilised.

For the immediate future, the cost of network connected batteries does not appear to be an economic option, however they are considered on an individual project basis at network planning stage along with diesel powered generation peak lopping options.

Domestic Scale

The installation of a storage battery at a domestic property, coupled with on-site PV (or other non-contiguous generation) would result in a reduction in peak demand for the property. An appropriately sized system could see the property being disconnected from the network; however, customers generally wish to retain a connection for when their system does not operate for any reason.

While it has been surmised that battery prices would drop as production increases it is of note that the market leader (Tesla Powerwall 2) has just increased their prices again, this time by 7.5% (USA data). With the indicative current NZ installed costs of \$12k - \$17k at the time of writing, economic justification for their usage is still questionable and the uptake remains low.

In the longer term, one proposal is to use batteries removed from EVs due to reduced range as home storage systems. At present EV battery replacement has been on an exchange basis, however this may change. This could reduce the costs of establishing a home storage facility, however the price will need to reduce significantly for it to be economically attractive to most homes.

Impact of Storage Batteries on the Network

For the purposes of load forecasting, no separate provisions have been made for the impact of storage batteries on the network. Network connected systems are considered at project stage and should a housing development be proposed with PV/batteries the impact will be considered in the demand assessment and subsequently the capacity of the network provided.

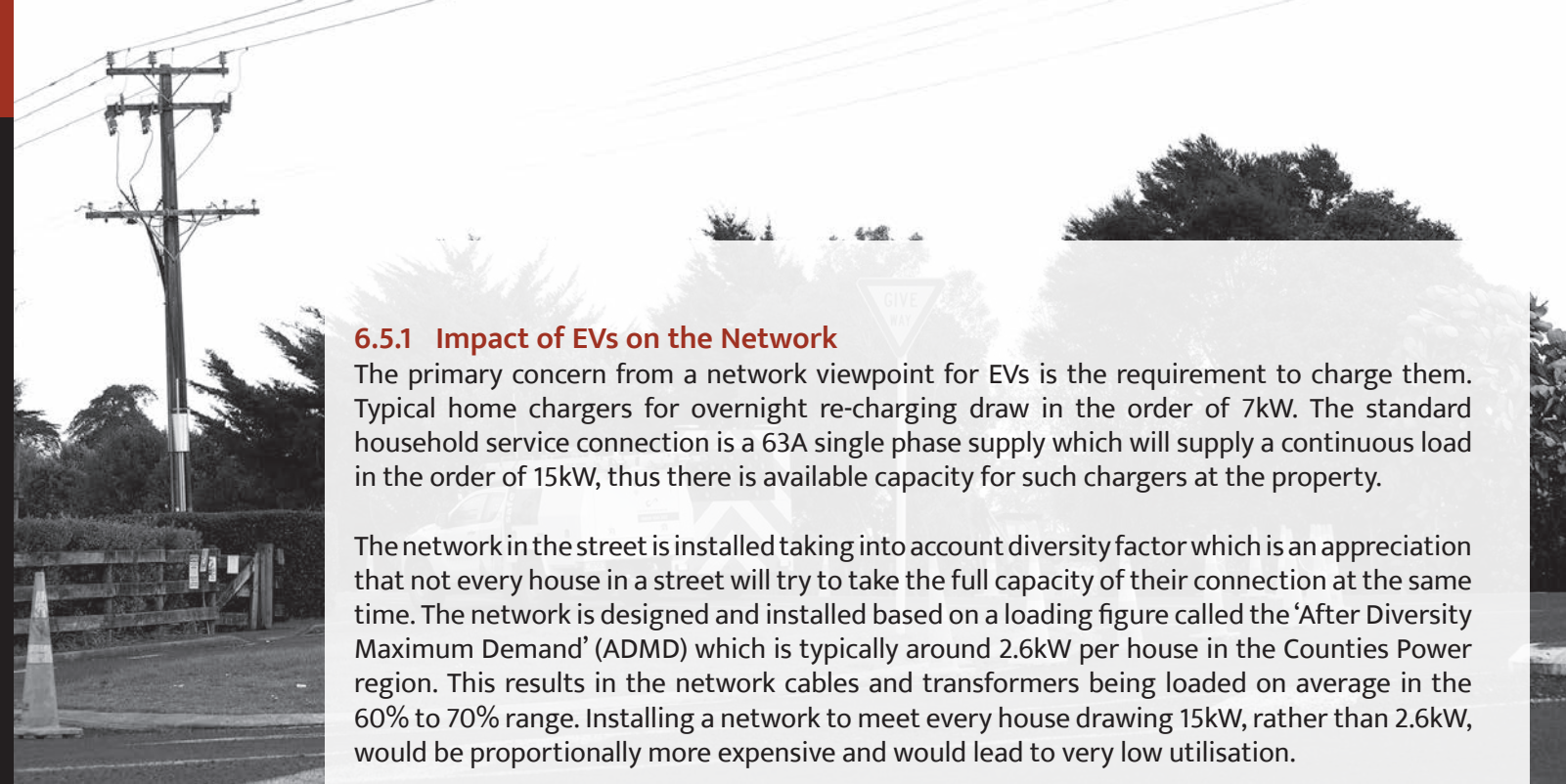
6.5 Electric Vehicles (EVs)

The adoption of EVs in New Zealand has been slower than in many other developed countries. While this will reflect the substantial government provided subsidies overseas which help reduce the additional purchase costs of an EV, the distances and usage patterns in New Zealand also appear to be a factor.

During 2018, New Zealand surpassed 10,000 registered EVs. By October 2020 this had grown to 22,000 of which approximately 50% were second hand pure EVs 25% new pure EVs and the remainder new and used hybrid vehicles. While monthly EV registrations increased until last year the typical monthly registrations (all types) had levelled by the start of 2020 but have dropped significantly during the COVID-19 alert level restrictions. The New Zealand Government had set a goal of 64,000 EV registrations by 2021, but this does not appear to be achievable at this time.

There is considerable pressure for the government to offer some form of subsidy for purchasers of electric cars, which could see a significant increase in sales. EV options for larger vehicles such as buses and trucks are currently at the trial stage, however the range available and the weight of multiple batteries (which reduced payload) means that the economics are usually less attractive for battery/hybrid heavy vehicles than cars.

Counties Power has been a strong supporter of electric vehicles and has encouraged greater uptake of low carbon technologies. It has deployed five electric vehicle fast charging stations across its distribution network which are available to all EV drivers via the OpenLoop app. New charging stations are also planned in Mercer due to additional funding from EECA. Pokeno is Counties Power's busiest charger on its EV charging network and customers have provided positive feedback for the proposed new chargers at Mercer. The popularity of Counties Power's EV charging network continues to rise as more and more people use them through the OpenLoop platform.



6.5.1 Impact of EVs on the Network

The primary concern from a network viewpoint for EVs is the requirement to charge them. Typical home chargers for overnight re-charging draw in the order of 7kW. The standard household service connection is a 63A single phase supply which will supply a continuous load in the order of 15kW, thus there is available capacity for such chargers at the property.

The network in the street is installed taking into account diversity factor which is an appreciation that not every house in a street will try to take the full capacity of their connection at the same time. The network is designed and installed based on a loading figure called the 'After Diversity Maximum Demand' (ADMD) which is typically around 2.6kW per house in the Counties Power region. This results in the network cables and transformers being loaded on average in the 60% to 70% range. Installing a network to meet every house drawing 15kW, rather than 2.6kW, would be proportionally more expensive and would lead to very low utilisation.

While the arrival of an EV at a single property is very unlikely to be an issue on the network, the arrival of several in a street with owners arriving home and plugging in at the same time could lead to local overloading and the need to install additional distribution transformers and low voltage cables. This is considered highly probable as the customers likely to purchase new EVs are most probably in a high socio-economic area and an effect called "clustering" is likely to occur with one initial purchase triggering neighbours to follow. A similar phenomenon was observed when spa pools (typically a 6 kW load) were first introduced to New Zealand. This occurred with many houses in some streets installing them, resulting in overloaded network components. However, with the substantially improved monitoring of the network offered by the smart meter data, we will be able to identify any problem areas and proactively upgrade as necessary.

The ability to control the impact of chargers (either through load control or through pricing structures) is very desirable if additional costs are to be avoided from reinforcement of the network so that it can meet a relatively short-term loading situation. Such mechanisms would encourage EVs to be charged at off peak times, allowing for connection to the network without the need for significant network investment.

Over time, major uptake of EVs would also see the need to reinforce the high voltage distribution feeder cables and zone substations, however this would be identified by the annual review of load increase at this level of the network. There are also higher rated EV chargers available, however these cannot be simply "plugged in" at household level and their impact can be addressed on an individual basis. Recent reports on battery technology identify a focus on reducing charging time which would require even larger chargers, however these would be installed in public locations and specific supplies would be provided to them. Similarly, the impact of electric buses and trucks is most likely to be concentrated at specific charging points (e.g. depots) and local reinforcement can be arranged with the customer prior to the load occurring.

6.6 Other Future Energy Options

6.6.1 Hydrogen

An alternative approach to the reduction of emissions is to replace fossil fuels (petrol/diesel/gas) with hydrogen which when burnt produces only water. The key issues have related to the production of hydrogen and its distribution.

For the production of hydrogen, the traditional method has been to use electrolysis to split water into hydrogen and oxygen, but this requires electricity. More recent developments have seen the production of hydrogen using artificial or alternatively supported natural biochemical processes which do not require an external power supply, but use energy from the sun.

The localised production of hydrogen at a household level, coupled with fuel cells to produce electricity to supply the home could ultimately impact on the utilisation of (or even the need for) the electricity network, however this appears very unlikely within the planning period.

It has recently been announced that one company plans to import 1500 heavy trucks that use hydrogen to produce electricity (via fuel cells) to provide the motive power. They plan to install hydrogen infrastructure, having the first fuelling stations by around the middle of 2021. The company aims to have eight stations across both the North and South Islands by 2022, which would cover about 95 percent of the country's freight routes. The source of hydrogen is not known at this stage and no approach has been received regarding possible electrical loads. Our investigations have identified that a typical industrial hydrogen generating facility has an electrical load in the 15 to 20MVA region which could be accommodated on our network.

No allowance has therefore been made for hydrogen based technology either at domestic or commercial levels at this stage; however developments will be monitored in case the technology develops rapidly.



7 RENEWAL AND MAINTENANCE

This Chapter outlines the population profiles, the inspection and maintenance requirements, and the replacement expenditure for each of our asset categories. Our asset categories covered in this Chapter are:

- Subtransmission;
- Zone substations;
- Distribution and LV lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear;
- Grid scale battery storage system;
- Other network assets;
- Other operational assets; and
- Assets owned by Counties Power at GXP.

The refinement of our fleet management practices is an ongoing activity within Counties Power. Accordingly, the practices recorded here are under review and further development of comprehensive asset fleet strategies will continue over the next 12 months. We also expect our management planning to continue to evolve over this time.

All asset data presented is as at the time of writing, September 2020.

7.1 Age-based Condition Profile

Condition profiles are displayed for each asset group, currently based on their age. The AHI (Asset Health Indicator) scores and age parameters used are based on the EEA AHI grades and have been applied.

H5	H4	H3	H2	H1
Asset with age less than half of the onset of unreliability age	Asset with age less than the onset of unreliability but greater than the criteria for H5	Age greater than or equal to the onset of unreliability, but less than criteria for H2	Age Greater than or equal to 50% maximum practical life and the onset of unreliability	Replacement recommended – Age greater than or equal to maximum practical life

Figure7-1 Aged-based Profile

7.2 Asset Quantity Summary

A summary of our asset quantities is provided in section 7.13. The following sections provide details by category of assets.

7.3 Subtransmission

The subtransmission network transports electricity from Transpower’s Grid Exit Points to our zone substations. It consists of:

- Overhead lines, which in turn are made up from poles, crossarms and conductors;
- Underground cables;
- Substation buses and support structures; and
- Circuit breakers.

We have seven 110kV subtransmission circuits with a total length of 65.8km, all of which is overhead line. The total length of 33kV subtransmission circuits on our network is 71.7km of overhead lines and 1.55km of underground cables. Portions of our subtransmission network have reached the end of their life expectancy or have capacity constraints and are scheduled to be rebuilt during this AMP planning period. This is discussed further in Chapter 8 – Network Development.



7.3.1 Quantity and Life Expectancy of Subtransmission Assets

Figure 7-2 below summarises the construction material, quantity and life expectancy of our subtransmission network by asset type.

Asset	Construction Type	Quantity	Life Expectancy
Subtransmission Poles	Concrete Pole	1,336	80 years
	Wooden/other Pole	9	45 years
	Steel Pole	180	55 years
	Steel Tower	10	55 years
Subtransmission Lines	110kV	65.8km	80 years
	33kV	71.7km	80 years
Subtransmission Cables	110kV	0.52km	55 years
	33kV	1.55km	55 years

Figure 7-2 Subtransmission asset summary

The age profile, condition, inspection and maintenance requirements and the 10-year forecast expenditure for each asset class are described below.

7.3.2 Management Approach

Our subtransmission assets are critical to provision of services to our stakeholders and are the backbone of our network. The impact of a failure on a subtransmission circuit has the potential to affect a large number of customers for a long duration.

Our approach is to ensure that these assets are subject to robust inspection and corrective maintenance programmes, as well as appropriate asset renewal programmes, to ensure their reliability and availability. Defects are to be addressed with high priority, and investigations into failures undertaken to identify underlying issues so as to avoid recurrence of issues given the importance of these circuits.

7.3.3 Subtransmission Lines and Poles

Our subtransmission network consists of predominantly overhead line circuits, supported by wood, concrete and steel poles, as well as a section of line supported by steel lattice towers. Older parts of our subtransmission network have copper and ACSR (Aluminium-Conductor Steel-Reinforced) conductors and since the mid-1990s, we have used AAC (All Aluminium Conductor) as the standard conductor type for our subtransmission network. We select the most appropriate type and size of conductor on a project specific basis.

Age Profile

Figures 7-3, 7-4, 7-5 and 7-6, show the age profile of our subtransmission network.

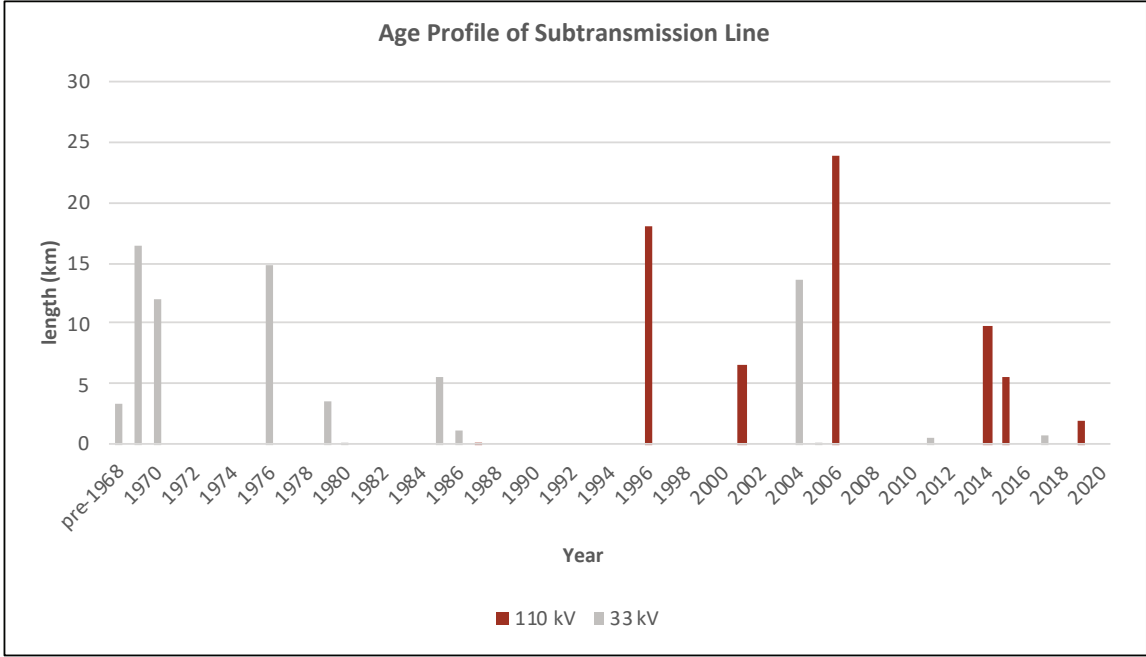


Figure 7-3 Age profile of Subtransmission Lines

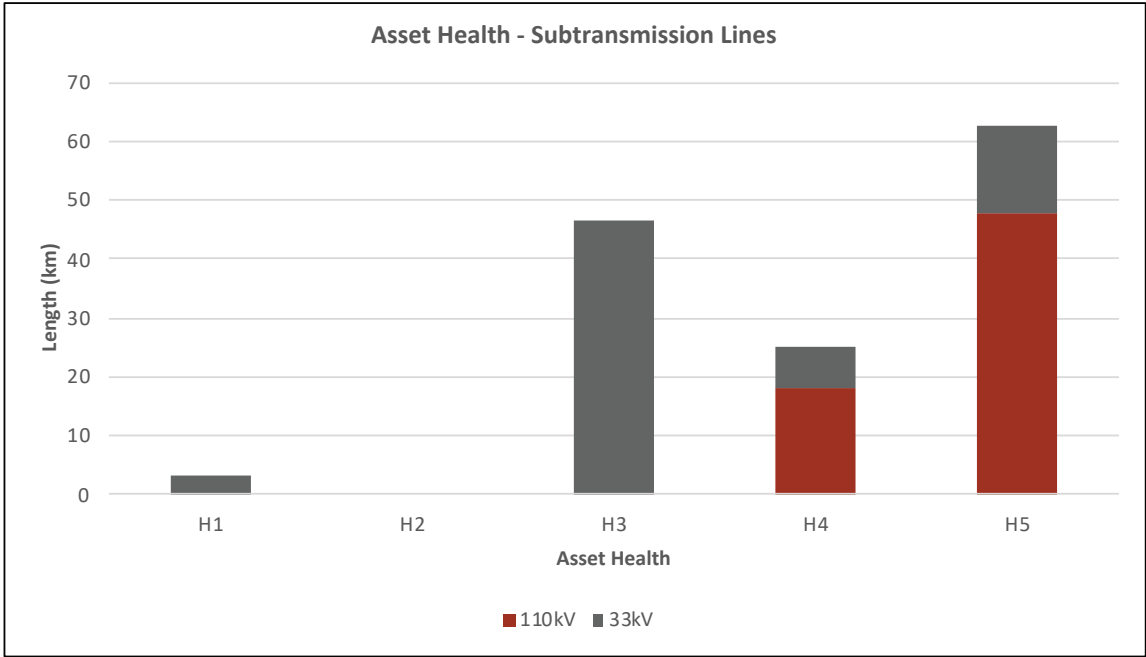


Figure 7-4 Asset health profile of Subtransmission Lines

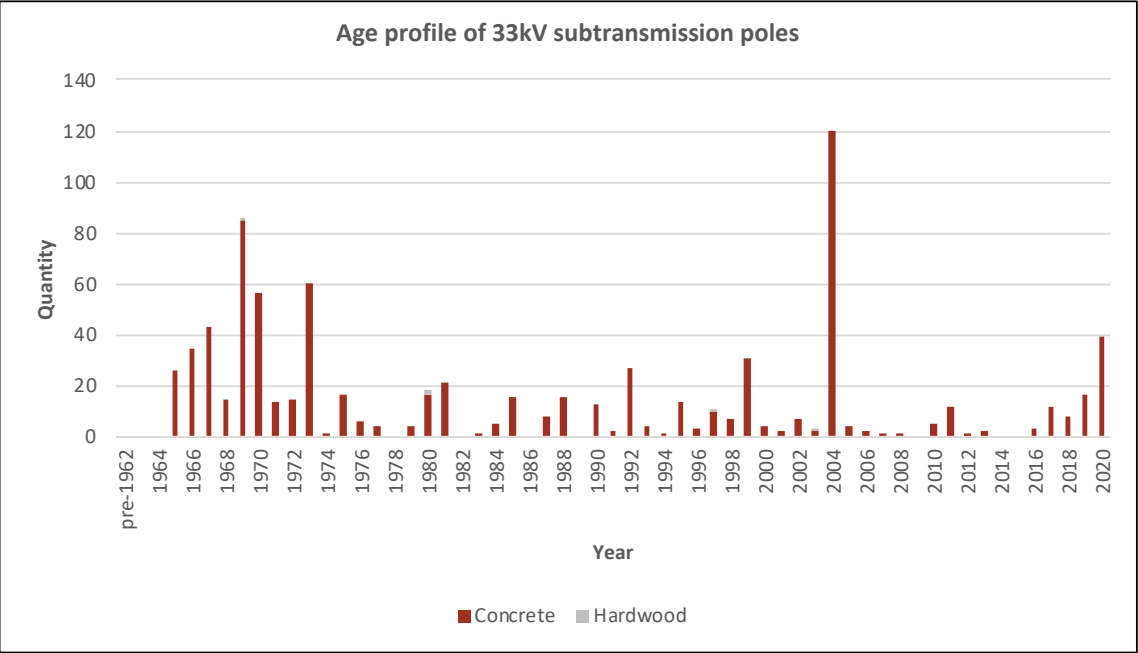


Figure 7-5 Age profile of 33kV subtransmission poles

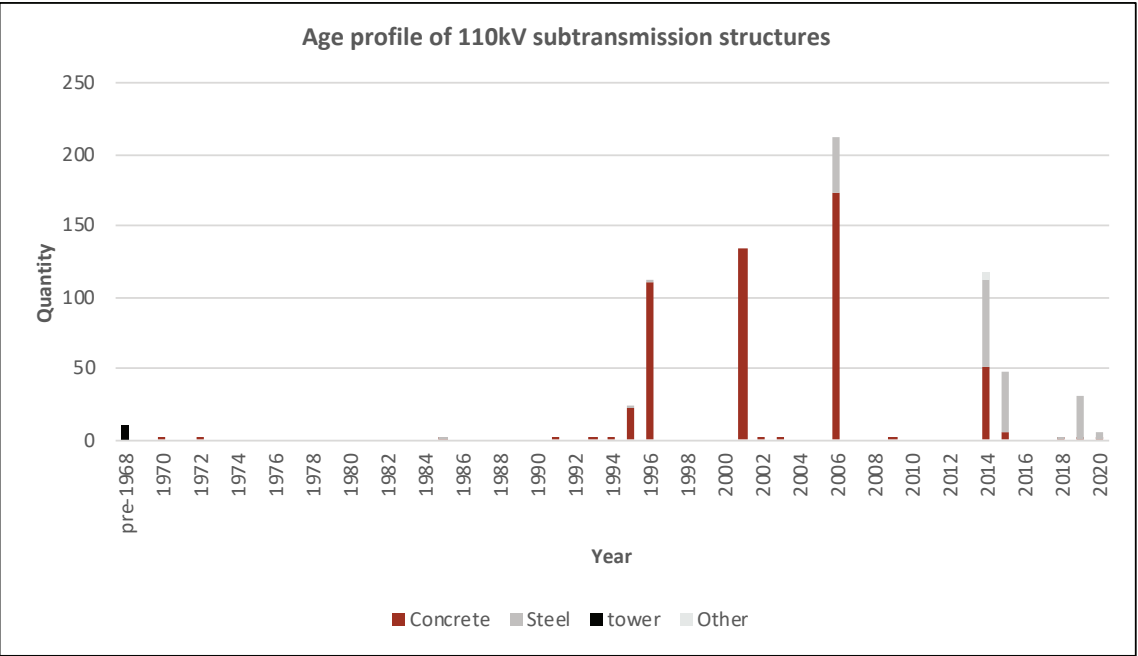


Figure 7-6 Age profile of 110kV subtransmission poles

Inspection and Maintenance Practices

Our inspection cycles for subtransmission lines and poles are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly
Insulator Washing – Glenbrook area	Routine Servicing	Annual
Vegetation Survey	Inspection	Area Specific

Figure 7-7 Inspection cycles for subtransmission lines and poles

Corrective maintenance is undertaken on overhead subtransmission lines when defects are identified as part of routine asset condition surveys. Examples include insulator and crossarm replacement, replacement of possum guards, stay wires, and other minor components.

In areas subject to heavy pollution, particularly around the Glenbrook steel mill, insulator washing is undertaken periodically to reduce contaminant build up and reduce the likelihood of tracking and flashover.

Renewal Programme

Eastern Area

The 110kV lines in the eastern area supplying Opaheke, Pukekohe, Tuakau and Pokeno are generally in good condition as they have been constructed in the past 20 years, and only require minor maintenance.

The beginning section of the 110kV Bombay-Opaheke East line is a double circuit, also supplying Ramarama substation at 33kV constructed on steel towers which were part of a transmission line originally constructed by Transpower’s predecessors but now owned by Counties Power. There are ten towers over 85 years old and at a stage of life where major component replacement will be required in this planning period, as the last major remedial works programme was undertaken in the early 2000s with some further replacements in 2018.

A detailed condition assessment and redesign will be undertaken in 2022 and the identified issues will be addressed in a major line rebuild in 2024-26 which has an estimated cost of \$9.0m.

The second 33kV line from Bombay to Ramarama substation is planned to be taken out of service and dismantled in 2025 as part of decommissioning Ramarama and Mangatawhiri substations, the line will continue to be maintained until then.

The single circuit 33kV pole line from Bombay to Mangatawhiri substation is in below average condition, with some components at end of life requiring replacement within this planning period. These issues will be addressed as part of the feeder works to establish Barber Road substation and as such no specific replacement project is included in this section of the plan. Once Barber Road substation is established in 2022/23, the Mangatawhiri line will be operating at 22kV and will form the front end of the existing Kaiaua feeder. This is discussed further in Chapter 8 – Network Development.

Western Area

The 33kV east line from Glenbrook to Waiuku had a rating study undertaken and capacity constraints have been identified within the planning period, and any condition based renewal will be undertaken as part of a capacity augmentation project detailed in Chapter 8 – Network Development.

The 33kV south line from Glenbrook to Karaka has some sections of undersized Dog conductor necessitating a line rating study to be undertaken in 2023 to identify any capacity constraints within the planning period and condition based issues. The issues identified will be addressed in a future AMP project.

Out of Service Lines

As well as in-service subtransmission lines, we also own lines which are not currently in use - however we may use these again in future. After a review of future needs, two unused lines have been removed in the past year leaving one route only which we have to inspect and maintain to ensure it does not present any public safety risks.

The remaining out of service line is the Bremner Road to Karaka 33kV line, this will remain in place and may be repurposed as a 22kV feeder out of Opaheke substation, detailed in Chapter 8 Network Development.

7.3.4 Subtransmission Cables

We have a combined length of 52m of 110kV Cross-linked polyethylene (XLPE) cables⁵ installed where two 110kV circuits enter the Pokeno substation.

We have 1.55km of 33kV Cross-linked polyethylene (XLPE) cables⁶ installed in our subtransmission network at various locations. The life expectancy of our 33kV XLPE cables is 55 years, with the first replacement expected well beyond this planning period.

Age Profile

Figure 7-8 shows the age profile of our subtransmission cables. The age of XLPE cables ranges from new to 40 years old. The average age of the 33kV subtransmission cables is 16 years.

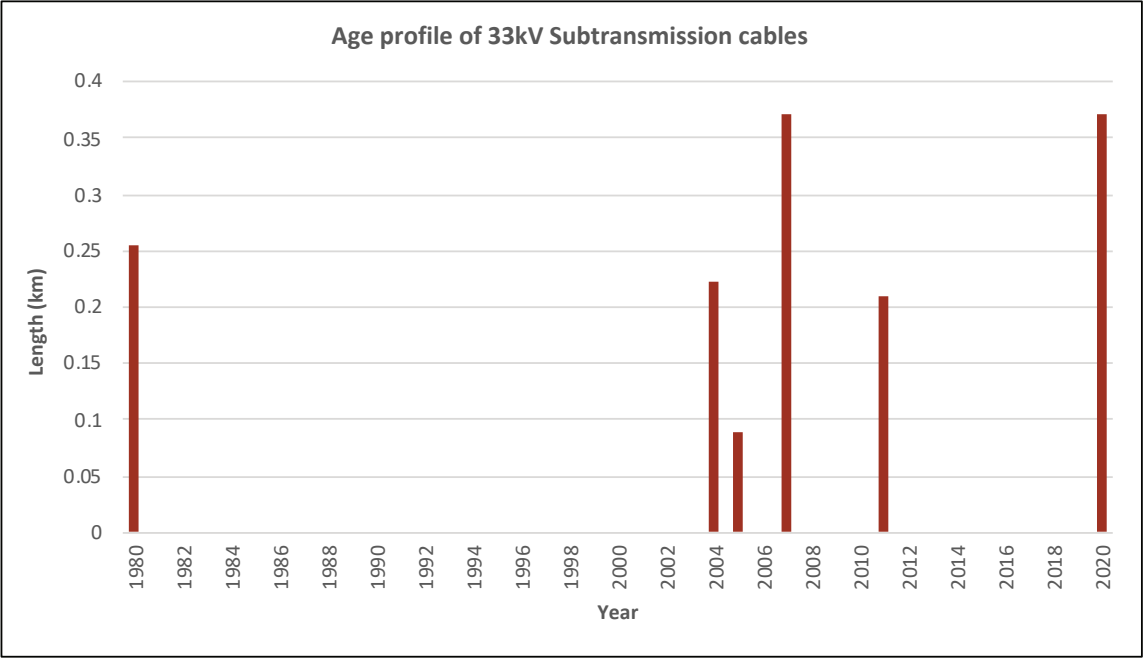


Figure 7-8 Age profile of 33kV Subtransmission Cables

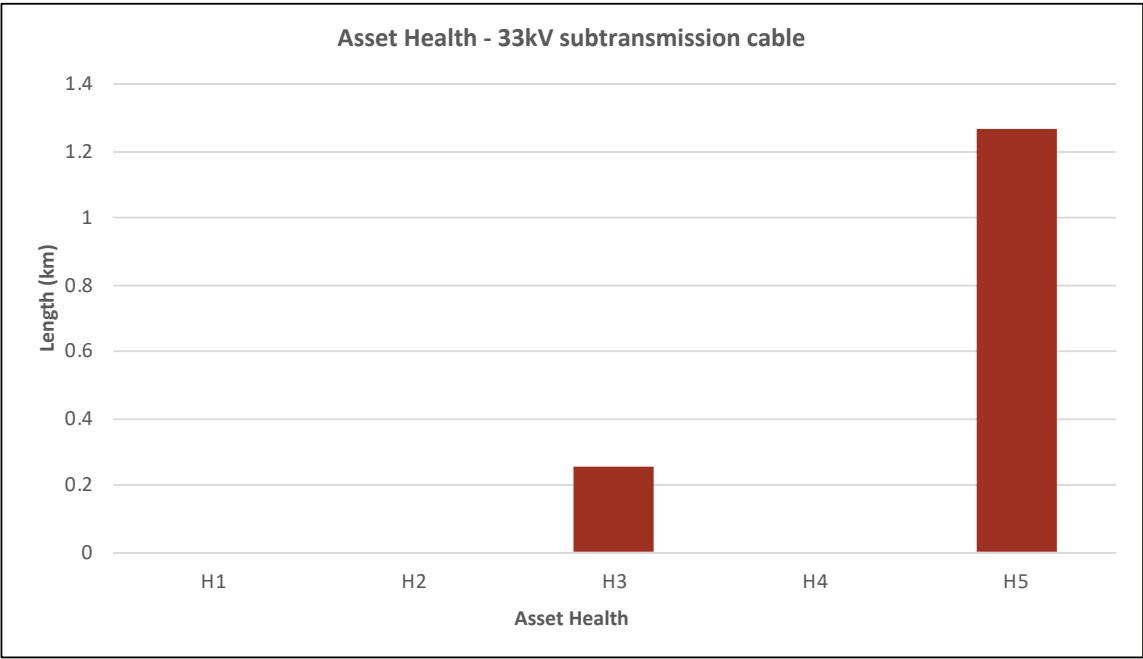


Figure 7-9 Asset health condition profile of 33kV Subtransmission Cables

⁵ Based on operating voltage.

⁶ Based on operating voltage.

Inspection and Maintenance Practices

There are no specific planned maintenance activities on subtransmission cables on our network as we have a small quantity and their construction type is generally very reliable. Cable terminations are inspected as part of the overhead line asset condition survey, and defects remediated as required.

Diagnostic tests can be undertaken on an ‘as-required’ basis where performance indicates an issue exists or following a fault. These tests include insulation resistance testing, serving tests and cable partial discharge tests.

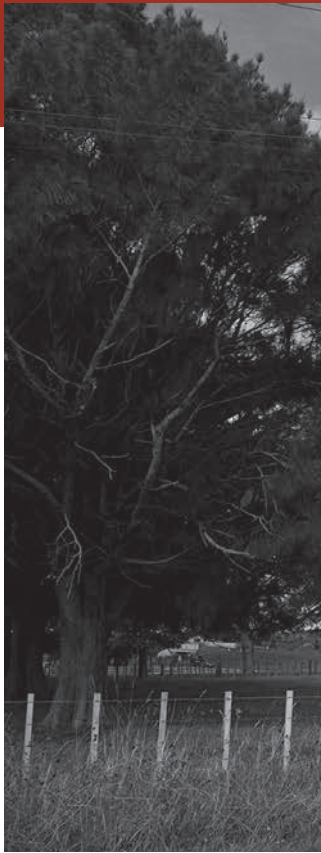
Renewal Programme

Our management strategy for 33kV cables is to reactively replace them when required. Given the age of the cables we do not expect any renewals will be required within the planning period.

7.3.5 Summary of Subtransmission Expenditure Forecast

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000s)										
Bombay-Ramarama tower rebuild	200	-	-	4,500	4,500	-	-	-	-	-
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	100
Operational Expenditure (000s)										
Subtransmission lines	150	150	150	150	150	150	150	150	150	150
Subtransmission cables	30	30	30	30	30	30	30	30	30	30

Figure 7-10 Subtransmission expenditure forecast summary



7.4 Zone Substations

Zone substations consist of power transformers, switchboards and substation buildings. Power transformers convert subtransmission voltage (110kV and 33kV) to distribution voltage (22kV and 11kV). Switchboards control and protect the network.

We own nine zone substations of which five operate at 33/11kV and four operate at 110/22kV. The construction dates of our zone substations range from 1956 to 2020. At the time of preparation a new zone substation has been built at Pokeno, but load is yet to be transferred to it. Seven of our zone substations have N-1 security and two have N security. Our security standard is discussed in further detail in Chapter 8 - Network Development. In addition to the nine zone substations, we have one 22kV switching station at Pukekawa and this is covered in this Chapter.

7.4.1 Quantity and Life Expectancy of Zone Substation Assets

Figure 7-11 below summarises the asset class, quantity and life expectancy of our zone substation assets.

Asset	Construction Type	Quantity	Life Expectancy
Network buildings		10	50 years
Power transformers	110/22kV	8	60 years
	33/11kV	9	60 years
Circuit breakers	110kV CBs	20	45 years
	33kV CBs	13	45 years
	22kV CBs	71	45 years
	11kV CBs	25	45 years
Station disconnectors	110kV Disconnectors	2	45 years
	33kV Disconnectors	28	45 years

Figure 7-11 Zone Substation asset summary (asset quantity as at Sep-20)

The age profile, condition, inspection and maintenance requirements and the 10-year forecast expenditure for each asset class are described below.

7.4.2 Management Approach

Zone substations, like subtransmission assets, are a critical part of our network and have high impact when they don't perform as expected. They are also prominent parts of the communities in which they are located, and therefore need to be 'good neighbours' – clean, tidy, secure and not causing harm to public.

Key maintenance outcomes for our zone substations are to ensure they are safe and secure, that they meet network and environment performance standards (including seismic compliance, oil containment, discharge controls, noise levels, etc.), that they are free of vermin and nesting animals and are not vandalised. Routine inspections also inform us of when major plant is deteriorating or needs corrective maintenance.

7.4.3 Renewal/Refurbishment Programme

Old Tuakau Substation

The old 33/11kV Tuakau substation has been decommissioned and dismantled and is now being used as a storage space for network assets.

Waiuku Substation

Waiuku substation is being completely rebuilt on the same site and all assets will be replaced in two stages driven by capacity, age and condition issues.

- Stage 1 replaced the building, 11kV switchboard and the remaining 33kV bulk oil circuit breaker in 2018/19; and
- Stage 2 will replace both the 33/11kV 10/20MVA transformers, the bus Voltage Transformer (VT) and rearrange the 33kV switchyard so that the Maoro line can be supplied by either of the 33kV subtransmission lines, this work is currently in progress.

Ramarama and Mangatawhiri Substations – Barber Road Substation

We are the primary user of the 33kV assets Transpower operate at the Bombay GXP.

The following assets are at end of life and are subject to policy replacement projects by Transpower in the immediate future:

- Outdoor 33kV switchgear, circuit breakers and bus structure; Associated secondary equipment; and
- Two 110/33kV supply transformers; Associated secondary equipment.

Additionally, Counties Power have assets that are also at end of life, particularly:

- The Bombay 33kV ripple injection plant;
- The Mangatawhiri 33/11kV substation;
- The Ramarama 33kV line is supported on end of life steel towers; and
- One of the Ramarama 33/11kV, 5MVA transformers.

These issues will be addressed by building a new 110/22kV substation adjacent to Bombay GXP to supply load presently fed from Mangatawhiri and Ramarama substations. This will be known as Barber Road substation.

Once the Barber Road 110/22kV substation is established, Mangatawhiri and Ramarama substations will no longer be required and will be decommissioned.

7.4.4 Power Transformers

Power transformers at our zone substations step down the subtransmission voltage (110kV or 33kV) to distribution voltage (22kV or 11kV).

We have 17 power transformers at our zone substations with installation dates ranging from 1956 to 2020. Power transformers installed prior to 1990 were 33/11kV. Since 2000, eight 110/22kV transformers have been installed in line with our plans to convert the eastern region of our network to 110kV subtransmission and 22kV distribution voltage.

Age Profile

Figure 7-12 shows the age profile of our power transformers. The average age of the transformers is 33 years.

Based on a life expectancy of 60 years, we expect to be decommissioning the oldest zone substation power transformer in our system (the 33/11kV, 5MVA T2 transformer at Ramarama) in 2022. The transformers at Mangatawhiri will get decommissioned at the same time as part of Barber Road substation establishment. Network Development Plans outlined in Chapter 8 address these issues.

The next batch of power transformers coming up for end of life replacement in the mid to late 2020s are two located at Maoro and they are also operating over their rating during peaks. The condition of the Maoro transformers will be assessed regularly and investment decisions will be made based on the condition of the transformers and the future of the Maoro site and major customer requirements.

There are two 33/11kV 10/20MVA transformers installed at Karaka substation providing an n-1 capacity of 20MVA, which will be sufficient to supply the substation load beyond 2033 and they reach their end of life beyond this planning period. T1 transformer at Karaka was replaced in 2016 with a refurbished ex Waiuku transformer to improve the firm capacity at Karaka substation. The decommissioned transformer was scrapped.

One of the ex Tuakau transformers was refurbished and replaced T1 at Waiuku substation in 2015, the other ex Tuakau transformer meant to replace T2 at Waiuku substation will be scrapped due to condition issues. T2 currently in service at Waiuku is in need of replacement due to severe rust on the main tank and will be scrapped. Therefore, two new transformers are being purchased for Waiuku substation. T1 currently in service at Waiuku becomes a system spare.

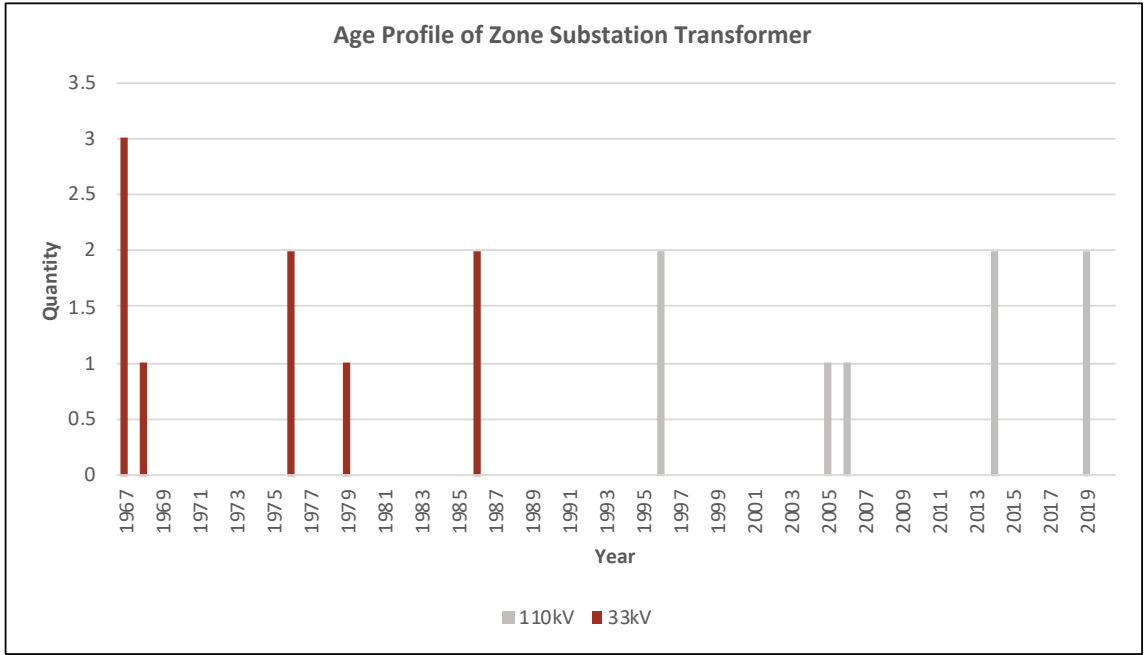


Figure 7-12 Age profile of Zone Substation Transformers

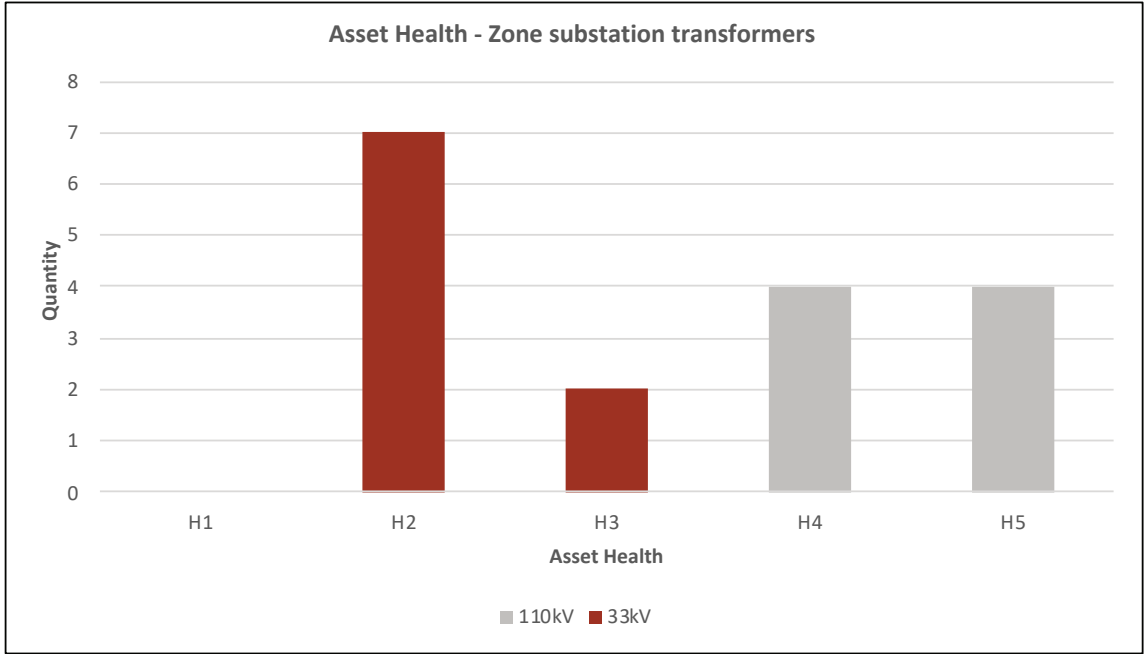


Figure 7-13 Asset health profile of Zone Substation Transformers

Inspection and Maintenance Practices

Our inspection cycles for zone substation power transformers are:

Activity	Type	Frequency
Routine Visual Inspection	Inspection	Monthly with sub visit
Detailed Inspection and Condition Assessment	Inspection	Annual
Transformer oil DGA analysis	Routine Test	Annual
Transformer and Bushing Maintenance	Routine Servicing	3 yearly

Figure 7-14 Inspection cycle for Zone Substation Power Transformers

Renewal/Refurbishment Programme

Our current practice is to carry out mid-life refurbishment on zone substation power transformers based on condition and age. Carrying out mid-life refurbishment ensures the maximum transformer life is obtained with minimum lifetime costs. This work is often carried out in conjunction with substation upgrades and involves the transformers from one location being refurbished before re-installation at a new location. Being able to exchange transformers minimises the time the substation operates at a reduced security level, i.e. only one transformer available in service.

In this AMP period, the plan is as follows:

- Two new transformers (10/20MVA) will be installed at Waiuku in conjunction with the rebuilding of the substation, the capacity is unchanged;
- The condition of the Maioro transformers will be assessed within the planning period and a decision made on their future; and
- Refurbish one (33/11kV) transformer removed from Ramarama.

Each of these sites has a development path outlined in Chapter 8 - Network Development.

7.4.5 Zone Substation Switchgear

New Schneider 22kV GHA switchboards have been commissioned at the rebuilt Waiuku substation in 2019 and Pokeno substation in 2020. This is the new standard type of switchboard to be installed at future substation sites.

Age Profile

We own 122 circuit breakers and 30 disconnectors at our zone substations. Figure 7-15 shows the age profile of our zone substation circuit breakers. The average age of the circuit breakers is 20 years.

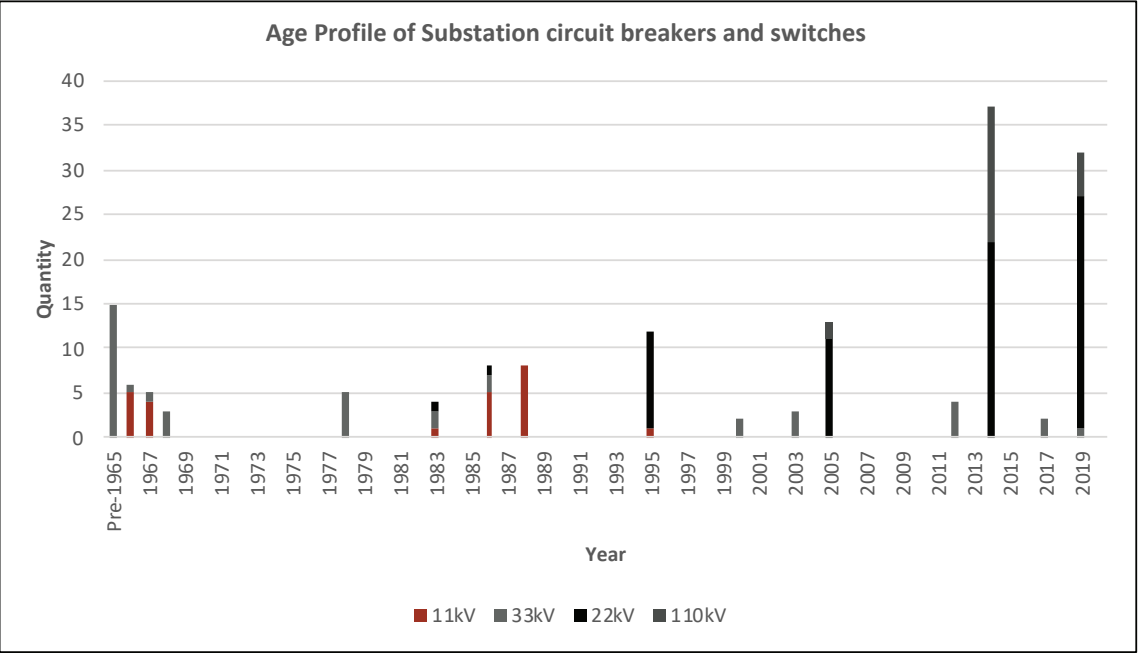


Figure 7-15 Age profile of Zone Substation Circuit Breakers and Switches

Inspection and maintenance practices

Our inspection and maintenance cycles for zone substation switchboards and switchgear are:

Activity	Type	Frequency
110kV or 33kV Circuit Breaker Inspection (incl. partial discharge and thermal imaging)	Inspection	Annual
110kV or 33kV Gas Insulated CB Maintenance	Routine Maintenance	5 yearly
33kV Oil Insulated CB Maintenance	Routine Maintenance	3 yearly or 3 fault operations
22kV or 11kV Switchboard Inspection (incl. partial discharge scan and thermal imaging)	Inspection	Annual
22kV or 11kV Circuit Breaker Maintenance (Gas/Vacuum)	Routine Maintenance	5 yearly
11kV Circuit Breaker Maintenance (Oil)	Routine Maintenance	3 yearly or 3 fault operations

Figure 7-16 Inspection and Maintenance cycles for Zone Substation Switchboards and switchgear

Renewal Programme

There will be a need to replace the 11kV switchboard at Maioro, due to age and condition, around 2024/25. Annual switchboard partial discharge testing and inspection will continue to be part of the ongoing condition monitoring of the switchboard. An option exists to utilise the switchboard from the existing Ramarama substation when it is decommissioned, and the timing is right, or to purchase a new switchboard for the site.

The 22kV bus section circuit and feeder breakers at Opaheke had additional maintenance carried out in 2018 to address a condition issue associated with partial discharge. While we continue to monitor the condition, additional maintenance will be carried out on an annual basis with an allowance of \$10,000 until switchboard replacement in 2031/32 for capacity reasons and feeder splits (see Chapter 8).

The Karaka 11kV switchboard will be replaced in 2032/33 due to end of life and to provide the required number of feeder supplies to meet the target of 1,500 customers per feeder, at an estimated cost of \$6.5m. This will be reviewed in future AMP’s when the potential new Kingseat and Glenbrook Beach substations will offload the Karaka switchboard.

7.4.6 Other Primary Equipment

This category includes primary equipment at our zone substations not covered by other categories such as outdoor bus structures, instrument transformers and earth grids. Inspection and Maintenance Practices

Our inspection and maintenance cycles for zone substation other primary equipment are:

Activity	Type	Frequency
Outdoor Bus Structures	Inspection	Annual
Instrument Transformer Inspection	Inspection	Annual
Substation Earth Grid Inspection	Inspection	Annual
Substation Earth Grid Test	Routine Test	3 yearly

Figure 7-17 Inspection and maintenance cycles for Zone Substation other primary equipment

Renewal Programme

There are no identified renewals required for other substation primary plant included in this plan and expenditure forecasts. Any replacement or renewal activity will arise from routine inspection and condition assessment, or as a result of other primary plant upgrade (e.g. new instrument transformers required with a new circuit breaker).

Opaheke substation may have 110kV outdoor bus structures built around 2032/33 at an estimated cost of \$4.0m, this is driven by the Quarry Road substation establishment and diverting the 110kV Opaheke East line detailed in Chapter 8.

7.4.7 Substation Buildings and Grounds

Substation buildings provide physical protection for indoor switchgear, metering, control, protection and communications equipment against the environment.

Age Profile

Figure 7-18 shows the age profile for our substation buildings. We have 10 buildings at our zone substations with installation dates ranging from 1960 to 2019. The oldest building was located at Waiuku substation and is being demolished. A new building has been built in 2018 on the same site. One substation building at the old Tuakau 33kV substation has been demolished in 2018. A new substation building has been built at the new Pokeno substation in 2019. The average age of our buildings is 33 years.

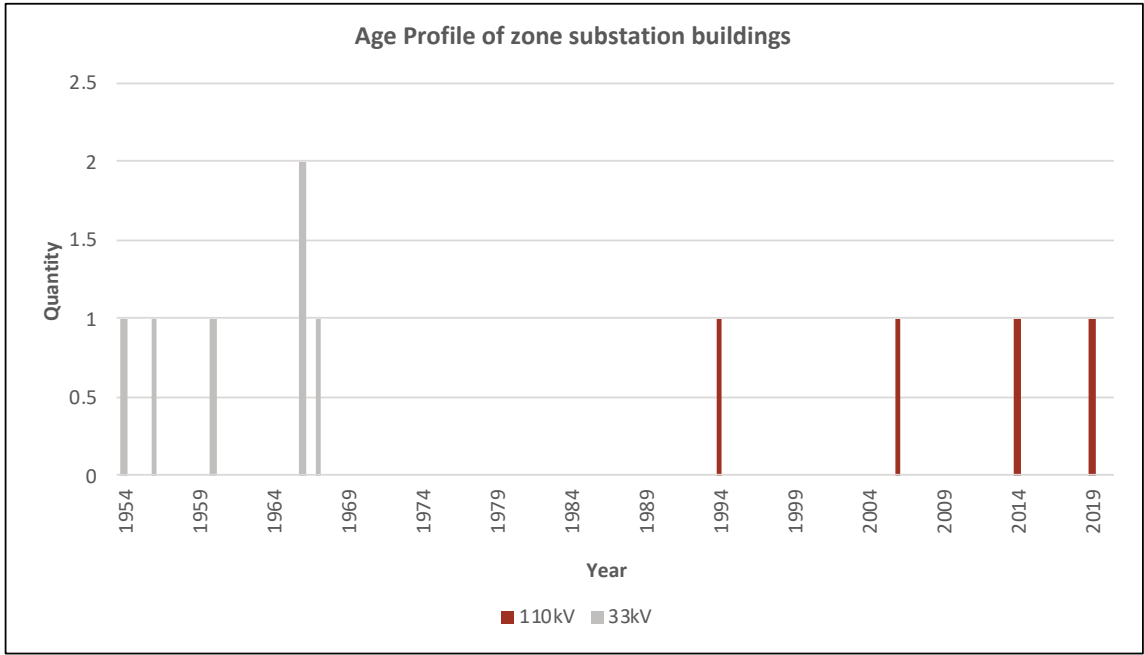


Figure 7-18 Age profile of Zone Substation Buildings

Inspection and Maintenance Practices

Our inspection and maintenance cycles for zone substation buildings and grounds are:

Activity	Type	Frequency
Routine Substation Inspection	Inspection	Monthly
Building and Grounds Maintenance	Routine Maintenance	Monthly

Figure 7-19 Inspection and maintenance cycles for Zone Substation buildings and grounds

Renewal Programme

The substation buildings are generally in good condition, with minor repair and renewal work undertaken as required.

An Initial Evaluation Procedure (IEP) has been undertaken to determine the buildings seismic strength for seismic risk according to building importance level of 4 (IL4) for all substation buildings and, with the exception of Waiuku⁷, they were found to have greater than 33% NBS which means that they are not earthquake prone and no further structural engineering investigations are required for those sites. Pukekohe, Tuakau, Opaheke and Pokeno have all been constructed within the past 20 years to modern building standards.

The Waiuku zone substation building was assessed as having less than 33% of the new building seismic standard (NBS) and would have required strengthening, however it is being redeveloped as part of the substation development plan for Waiuku (refer to Chapter 8 - Network Development).

Older industrial buildings often included materials containing asbestos which it is now recognised must be handled carefully to avoid human exposure to free asbestos particles. An inspection and testing programme was carried out in late 2018/19 of all of our substation buildings and no further action is required to manage asbestos compliance and no further remedial action is required, with ongoing management processes in place to ensure compliance.

End-of-life Ramarama and Mangatawhiri substation buildings will be decommissioned around FY25 after Barber Road substation is commissioned. This is covered in more detail in Chapter 8 - Network Development

⁷ At the time of writing the Waiuku substation building is being demolished.



Summary of Zone Substation Expenditure

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000's)										
Power Transformer refurbishment	300	300	300	-	-	-	-	-	-	-
Waiuku Substation	1,000	-	-	-	-	-	-	-	-	-
Barber Road substation	11,422	2,373	-	-	-	-	-	-	-	-
Decomission Ramarama and Mangatawhiri	-	-	-	1,000	-	-	-	-	-	-
Opaheke 22kV switchboard replacement	-	-	-	-	-	-	-	-	-	2,000
Other zone sub renewal	50	50	50	50	50	50	50	50	50	50
Operational Expenditure (000's)										
Zone Substation transformers	130	130	130	130	150	150	170	170	170	170
Zone Substation switchgear	150	150	150	150	160	160	180	180	180	180
Zone Substation other equipment	100	100	100	100	100	110	110	110	110	110
Zone Substation buildings and grounds	100	100	100	100	110	110	120	110	110	110

Figure 7-20 zone substation expenditure forecast summary

7.5 Distribution and LV Lines

We transfer electricity from our zone substations to our customers through our 22kV or 11kV distribution network and our 400V Low Voltage (LV) network which consists of both overhead lines and underground cables. Lines and cables have quite different maintenance and renewal requirements and are treated separately in asset management planning.

7.5.1 Quantity and Life Expectancy of Distribution and LV Lines

Asset	Construction Type	Quantity	Life Expectancy
Poles	Concrete	24,527	80 years
	Wooden	1,843	45 years
	Other	77	45 years
Cross Arms	Wooden/Steel	41,599	45 years
Conductors	22kV	572.12km	80 years
	11kV	887.85km	80 years
	Low Voltage (LV)	720.8km	80 years

Figure 7-21 Distribution and Low Voltage lines asset summary (asset quantity as at Sep-20)

7.5.2 Management Approach

In our management of overhead lines, our primary focus is on safety, and attention is paid to defects on lines in areas in high risk special locations, such as around schools, commercial and high population density areas.

In addressing safety there is often a secondary benefit in terms of reducing the number of failures on the network. However, sections of network or equipment which have a poor SAIDI and SAIFI performance are also investigated to identify and rectify systemic failure modes.

We carry out the following maintenance surveys to check for defects:

- Overhead line feeder patrol;
- Detailed Pole and Line Condition Assessment;
- Vegetation Survey; and
- LiDAR survey.

Presently we have the following capital programmes to address systemic issues on the network:

- Copper/Swan conductor replacement programme;
- Low lines; and
- Replacement of poor condition poles and cross arms.

Due to risks identified and increasing failure rates associated with small diameter copper conductors (16mm² or 25mm²) and ACSR conductor (Swan 20mm²), we extended our structured replacement programme to address both copper and Swan conductor risk in urban areas starting in 2016/17, with priority given to those around schools and public spaces, as well as in rural areas with repeat performance issues. Factors to consider are the fault frequency in the area, public safety risk (likelihood and consequence), as well as considering other network development needs to address capacity constraints.

Additionally, under the Electricity (Safety) Regulations 2010, we have to ensure that the structures that support our lines are capable of withstanding service loads. This requires us to inspect and, where necessary, test poles and other components and replace those found to be unsafe within specified periods. For condition assessment of both concrete and wooden poles we use visual assessment methods, and additionally for wooden poles we use an ultrasonic scan method.

We also have to make sure our lines do not get affected by trees, third parties working on and around our network, and high loads travelling along roads.

We recognise that service line ownership, and the range of issues relating to service lines from a safety, reliability and customer service perspective have been a long-term industry issue. Initial assessment indicated that there are over 1,000 private HV lines ('service lines') on our network. A project was established to offer to transfer ownership of these lines from the customer to us so that we can readily address the identified issues. The work is ongoing and the ownership transfer project provides a regular increase in the number of poles and our requirements for pole renewal and maintenance.

To mitigate against line clashes we have amended our standard installations by:

- Limiting the span lengths;
- Increasing clearance between phases by increasing the size of HV crossarms; and
- Installing HV conductors in a delta configuration where possible.

We have experienced several failures due to porcelain insulators. To prevent against future failures, we have adopted the use of 33kV polymer insulators.

7.5.3 Distribution and LV Conductors

Age Profile

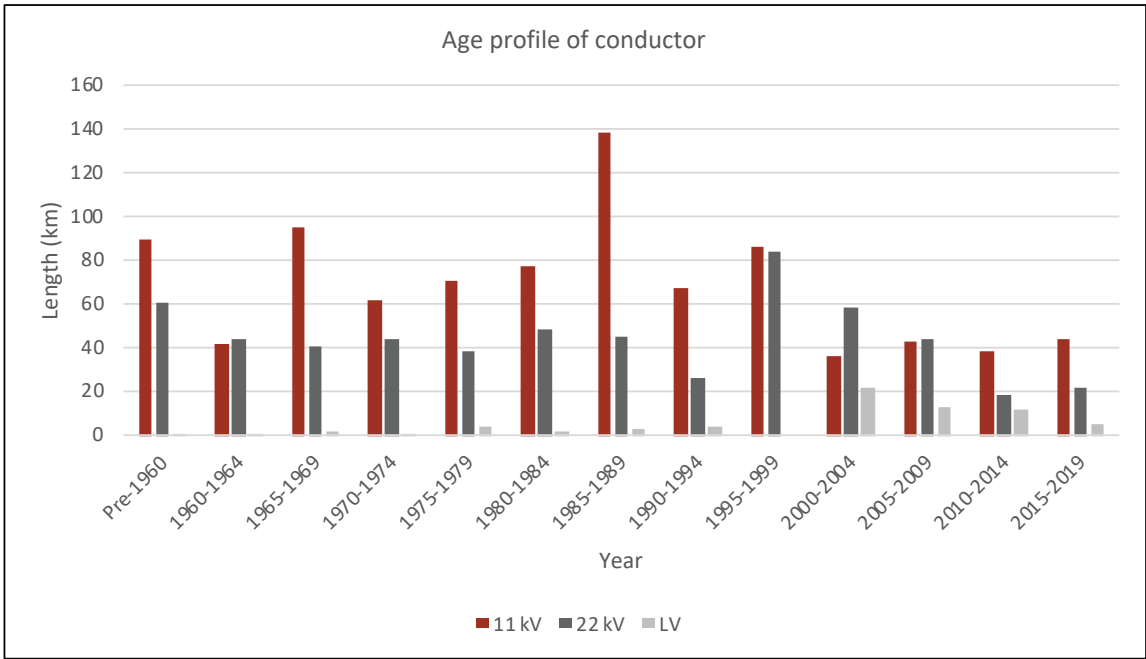


Figure 7-22 Age profile of Distribution and Low Voltage Lines

Note: Due to data input of LV conductor in 1997, with unknown age, a spike of 658km occurs which is excluded from diagram however continued survey of the network identify condition.

Condition Profile

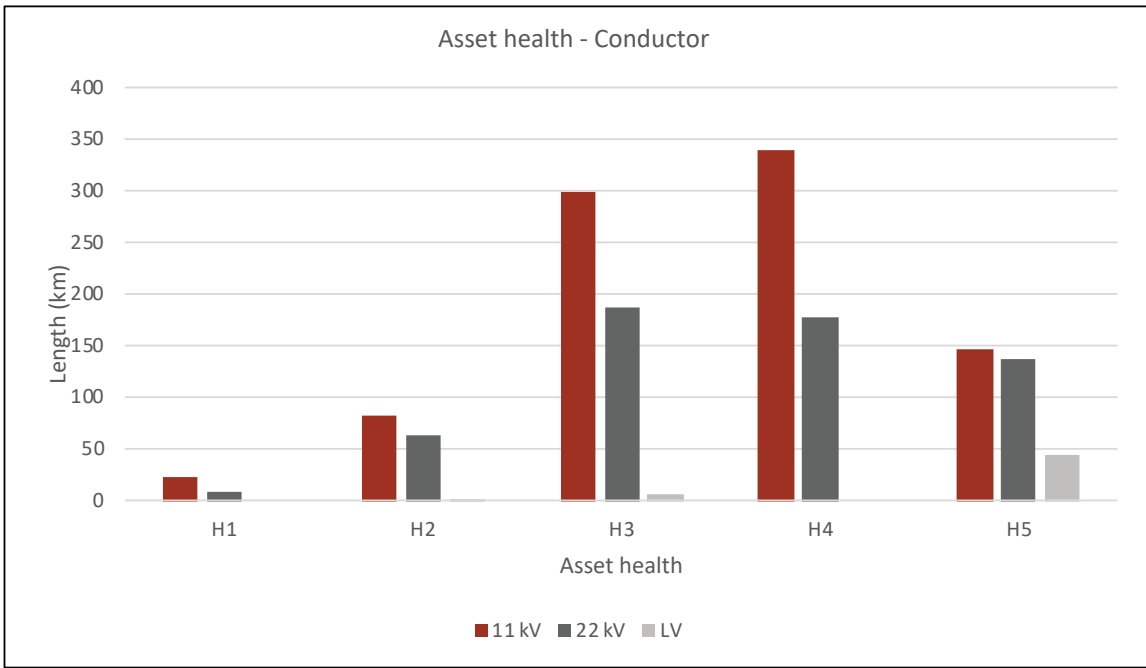


Figure 7-23 Asset health profile of Distribution and Low Voltage Lines

Inspection and Maintenance Practices

There are few components of overhead lines requiring routine servicing, and issues are identified through periodic inspections of overhead lines and their support structures, or from failure mode analysis. These surveys include assessing the condition of poles and towers, crossarms, connectors and clamps, clearances from trees, clearances from other components as well as clearance from the ground and buildings.

Defects are noted and addressed in accordance with their priority, particularly when it presents a hazard for public safety or the reliable operation of the network. Additionally, we are undertaking pole top photography within the next year on five feeders. This is to verify defect information and provide further insights into trends, areas for improvement and inform future expenditure requirements. Refer section 6.3.2 Helicopter Photography.

Our inspection and maintenance cycles for distribution and low voltage lines are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly
Vegetation Survey	Inspection	Area Specific
LiDAR survey	Inspection	3 yearly

Figure 7-24 Inspection and maintenance cycles for Distribution and Low Voltage Lines

Corrective maintenance is undertaken as required when defects have been identified and includes such activities as crossarm and insulator replacement, pole straightening, conductor resagging, fitment of stay wires, spacers, and possum guards.

We undertake vegetation management in accordance with the Electricity (Hazards from Trees) Regulations 2003. Details on our strategy are provided in Chapters 4 and 5.

Renewal Programme

There are some sections of overhead line on the west coast where Aluminium Conductor Steel Reinforced (ACSR) conductor has deteriorated prematurely due to the corrosive west coast conditions. These line lengths are relatively short, and their condition is being monitored. They are replaced by All Aluminium Conductor (AAC) or All Aluminium Alloy Conductor (AAAC) conductor where necessary.

We have two replacement programmes for small diameter overhead conductors which have reached end of life and are presenting safety and reliability issues due to their condition, with increasing failure rates year on year. These two types are copper conductors (16mm² to 35mm²) of which we have a total length of 218km and Swan ACSR (20mm²) of which we have around 340km. The forecast costs are based with the currently identified replacement solution and in some locations, we may consider undergrounding as an option where there are significant safety, reliability or community benefits by undergrounding.

Over the next few years we are focussing our copper and Swan conductor replacement programmes around the new Barber Road substation site. This is to benefit from work coordination and to maximise the benefits from the new Barber Road substation.

Copper Conductor Replacement Programme

A prioritised programme of replacing copper conductor commenced in 2016/17 in areas where there is elevated public risk, where there have been identified repeat failures or performance issues and where there is no other capacity or development need for replacement over the next three years.

The overhead copper conductor renewal projects identified for the next three years are as follows:

Feeder	Financial Year	Length (km)	Cost (000's)
Pukekohe East (Coulston Road) copper replacement	FY22	1.16	571
River Road copper replacement	FY23	1.7	647
Dominion Road copper replacement- Tuakau Feeder	FY23	1.72	1,946
Blackbridge (Lewis Road) copper replacement	FY23	5.47	1,500
Waiuku West copper replacement	FY24	0.45	566
Barber Road Establishment - Feeder Renewal Projects			
Mill Road	FY22	0.16	281
Bombay Township	FY22	0.2	1,220
Pinnacle Hill North	FY22	1.18	381
Great South Road copper replacement	FY22	8	1,441
Bombay Road	FY23	0.6	1,386
Great South Motorway Crossing	FY23	0.15	182
Barber Road North	FY23	0.6	936
Great South Road	FY23	1.01	1,660

Figure 7-25 Prioritised programme of replacing copper conductor

A further \$3.9m is forecast to be spent for the remainder of the planning period (2025-2031) to replace copper HV conductors.

Swan Conductor Replacement Programme

A prioritised programme of replacing Swan ACSR conductor commenced in 2017/18 in areas where there is elevated public risk, where there have been identified repeat failures or performance issues and where there is no other capacity or development need for replacement over the next three years.

Overhead Swan conductor renewal projects identified for the next three years are as follows:

Feeder	Financial Year	Length (km)	Cost (000's)
Tuakau Swan replacement	FY22	1.02	495
River Road Swan replacement	FY23	3.53	1,039
Racecourse Swan replacement	FY23	0.66	266
Pukekohe West Swan replacement	FY23	1.5	1,414
Puke West Feeder - Beatty Road Swan	FY23	0.3	283
Drury Hills Swan replacement	FY23	4.62	1,751
Waiuku West Swan replacement	FY24	2.04	566
Drury - Stage 2 - Swan	FY24	1.84	685
Drury - Stage 1 - Swan	FY24	7.47	2,817
Barber Road Feeders			
Hillview Road South	FY23	0.25	1,225
Paparata Road West	FY23	0.76	183
Paparata Road East	FY23	0.26	549
Pinnacle Hill North	FY23	3.03	1,860
Pinnacle Hill North	FY23	3.03	1,860

Figure 7-26 Prioritised programme of replacing ACSR (Swan) conductor

A further \$28m is forecast to be spent for the remainder of the planning period (2025-2031) to replace Swan conductors.

HV and LV line Replacement Programmes

In addition to the conductor replacement programmes above, it has been identified that replacement of other overhead lines in poor condition across the network will be required. These were identified from asset condition surveys and post fault investigations. The identified projects for high voltage line replacement in the next three years include:

Feeder	Financial Year	Length (km)	Cost (000's)
Barber Road Hillview Road North	FY22	1.4	1,091
Barber Road Mangatawhiri	FY22	0.5	500
Barber Road Barber Road feeders internal	FY22	3.6	1,598
Barber Road Barber Road South	FY22	1.4	433
Barber Road Pinnacle Hill South	FY22	2.3	815
Barber Road Barber/Lowry Paper Road	FY22	1.26	495
Barber Road Bombay Mway Crossing	FY22	0.2	210
Manukau Road OHUG	FY24	0.25	438

Figure 7-27 Prioritised programme of HV overhead conductor replacement

The identified low voltage conductor replacements from 2021/22 are prioritised based on condition and urban locations. The identified areas for low voltage line replacement for the next three years include:

Feeder	Financial Year	Length (km)	Cost (000's)
Queen St Pukekohe	FY22	0.5	370
Wellington St Pukekohe	FY23	0.46	363
Prospect Terrace Pukekohe	FY24	0.25	197

Figure 7-28 Prioritised programme of LV overhead conductor replacement

A further \$3.891m is forecast to be spent for the remainder of the planning period (2025-2031) to replace low voltage conductors.

HV and LV Low Line Rectification Programme

The latest LiDAR survey has highlighted some low LV and HV lines as defined in NZECP34. A remediation programme will address these with priority given to low lines over high traffic routes, schools and other areas where there is a greater safety issue.

The options considered for remediation will be tensioning conductors, installation of additional poles where permitted, reconfiguring the network to remove the span or undergrounding the span.

In this AMP period we have allocated \$1.0m to remediate low lines; in addition, a further \$1.5m has been allocated to re-survey the network periodically, using LiDAR. This allowance is over the next 5 years and is intended to cover the identified high risk low lines. Other overhead renewals will address known issues.

In addition to the above targeted programme, our feeder voltage conversion and conductor replacement programmes will resolve some of the identified low lines issues.

7.5.4 Poles

We have 27,972 poles in our distribution system. The majority are concrete poles, as these have been predominantly installed since the mid-1940s, with the remainder made up of hardwood, softwood and other types such as iron rail or steel.

Age Profile

The age profile of our distribution and LV poles is shown in Figure 7-29. The age profile portrays a network that has undergone significant expansion and replacement over the last 25 years. The life expectancy is 80 years for concrete poles and 45 for wooden poles.

The quantities and age profile shown is based on distribution and LV poles that we have records of in our system as being Counties Power owned. A pole survey focused on the ownership and usage of all poles in our service area which support electrical equipment was completed in 2017 and so an increase in asset numbers are reflected in that year.

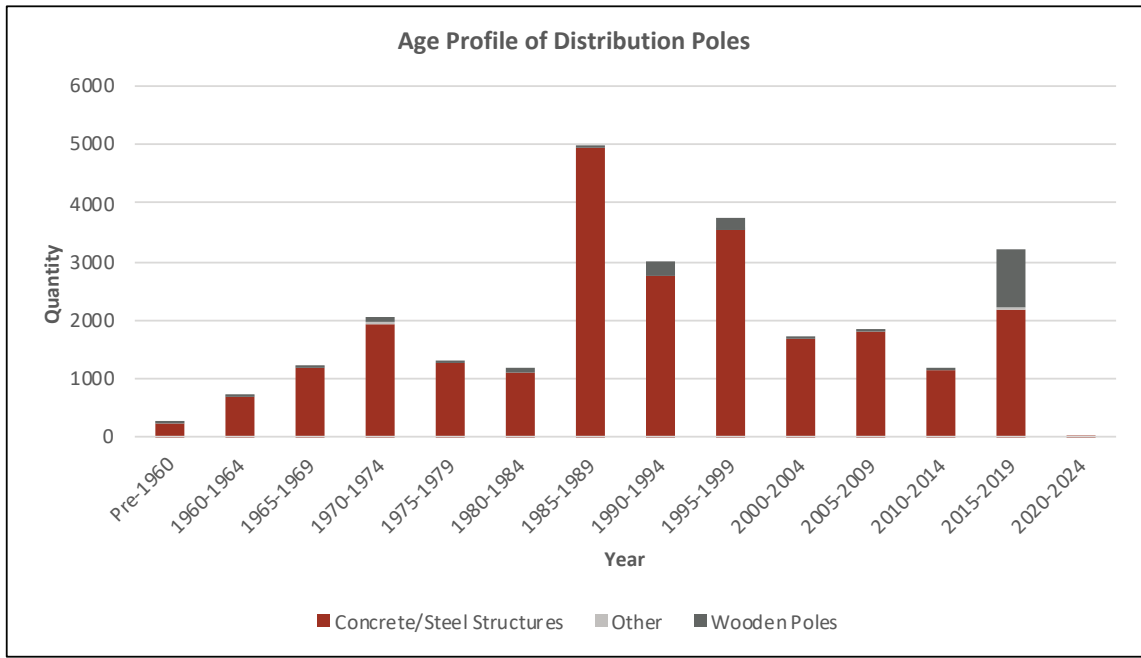


Figure 7-29 Age profile of Distribution and Low Voltage Poles⁸

⁸ Poles identified from the pole survey in 2017 were given a default date of 1 January 2017.

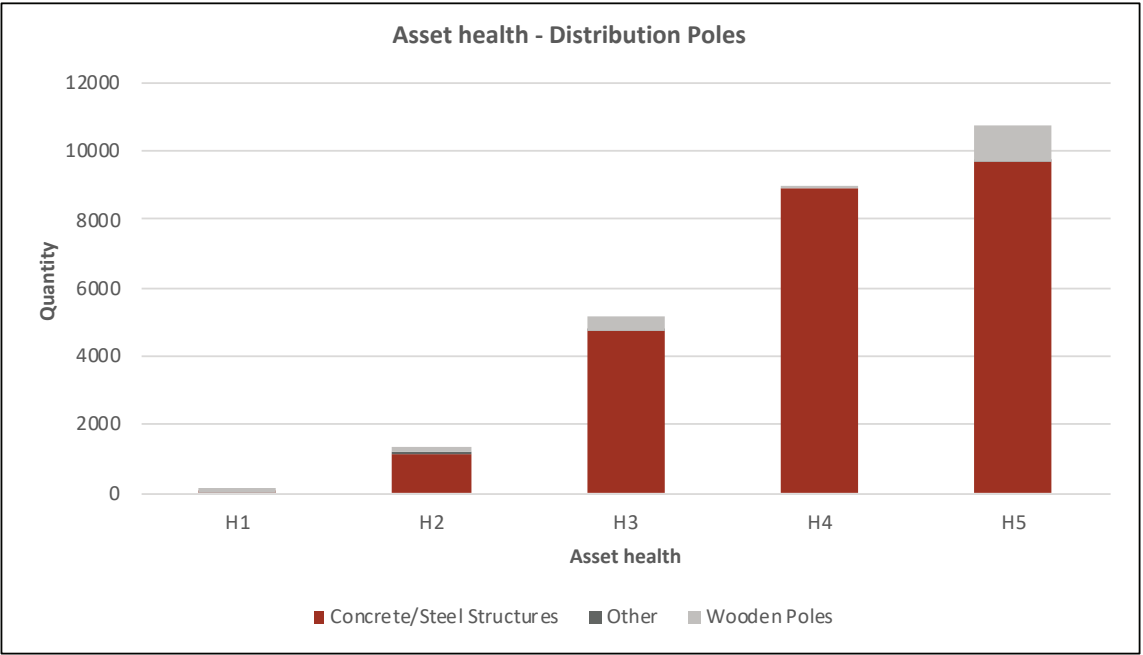


Figure 7-30 Age-Condition profile of Distribution and Low Voltage Poles⁹

Inspection and Maintenance Practices

Our inspection and maintenance cycles for poles are shared with overhead lines (previous section) and are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly

Figure 7-31 Inspection and maintenance cycles for overhead lines

Renewal Programme

There is a known issue with concrete poles manufactured around the 1960's not attaining their full life expectancy due to high levels of corrosion on the internal steel reinforcing material. This age group represents approximately 2.5% of our total pole population. We are monitoring the condition of these poles and they will be replaced when necessary but are expecting a higher than average replacement rate. These will be replaced following identification during routine inspections.

Based on age profiles and standard asset lives, a large number of concrete poles are now at the end of their typically expected life, however their condition does not yet justify replacement.

Hardwood poles have known issues with ground line and below ground rot which leads to a deterioration of the strength of the pole. Some softwood poles have been found to not reach their full expected life and generally require replacement after approximately 30 years of service.

⁹ Poles identified from the pole survey in 2017 were given a default date of 1 January 2017.

Specific replacement programmes are planned to replace hardwood, softwood and iron rail type poles from the network as these present safety risks if left in poor condition. Many of these are replaced as part of area line rebuild work, but in some cases individual replacement will be required. Figure 7-32 shows the quantity of each type of pole expected to require replacement during the planning period based on age profiles. These will be subject to a targeted condition assessment programme, with replacement driven from poor condition scores and prioritised by safety and network risks.

Type	Quantity	Estimated cost to replace (000's)
Hardwood	200	2,970
Softwood	823	12,200
Iron Rail	37	570

Figure 7-32 Number of poles expected to require replacement during the planning period based on age profiles

An increased number of defects have been identified over the past year on poles and overhead hardware, arising from routine inspections. We have allowed an annual budget to replace the worst condition poles and overhead hardware on the network and the adoption of existing private HV lines over the planning period, with an allocation of \$3.0m per annum through the planning period, including allowance for defect remediation of HV service lines after ownership transfer.

Poles are also replaced proactively when found to have poor structural condition, or reactively as a result of vehicle or storm damage.

We expect to replace poles and/or overhead hardware at over 360 sites per year under the overhead renewal programme and replace another 30 to 50 poles under other programmes of work.

7.5.5 Crossarms

We have over 41,599 crossarms installed on our poles supporting overhead lines. Multiple crossarms may be installed on a single pole depending on the function of each pole (e.g. whether the pole carries a single voltage or multiple voltages). As crossarms are installed at the same time as the poles, they share a similar age profile. The exception to this is where wooden crossarms are installed on concrete or steel poles. Wooden crossarms have a shorter life expectancy compared to concrete or steel poles so would require replacement at shorter intervals. Increasingly, steel crossarms have been used to achieve longer service lives compared to wooden crossarms.

Age Profile

The age profile of our crossarms is shown in Figure 7-33. The average age of our crossarms and conductors are slightly lower than the average age of our poles due to hardware replacement associated with reconductoring on existing poles.

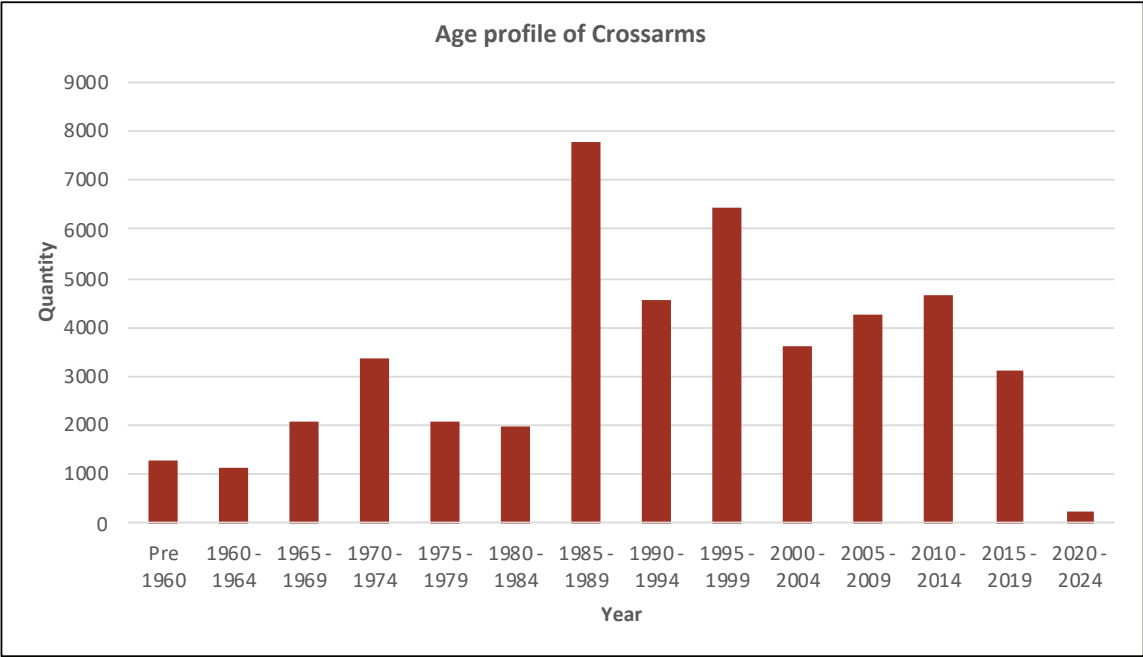


Figure 7-33 Age profile of Crossarms

Inspection and Maintenance Practices

Crossarms are inspected as part of the overhead line condition surveys undertaken annually. Defects are raised for those crossarms which are no longer serviceable, and they are scheduled for replacement.

Renewal Programme

We replace our crossarms that are near the end of their life once identified through routine inspections as opposed to having a specific programme for replacement based on age. Crossarms are also replaced in conjunction with pole replacement or reconductoring projects.



7.5.6 Summary of Distribution and LV lines Expenditure Forecast¹⁰

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000s)										
Overhead Renewals	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,550
Copper Replacement Programme	3,071	5,255	1,004	4,351	-	1,454	1,500	4,625	5,923	6,110
Swan Replacement Programme	1,495	4,754	4,068	-	-	4,644	2,094	6,738	5,520	9,060
HV Feeder section replacement	-	762	300	300	300	300	900	300	300	-
Urban LV Replacement	774	363	197	-	260	252	379	300	300	-
Overhead Safety Compliance (including Low Lines)	100	300	800	300	300	600	100	100	100	600
Barber Road - Feeder Renewal										
Barber Road - Copper & Swan Replacement	2,190	7,982	-	-	-	-	-	-	-	-
Barber Road - Feeder works and Reconfiguration	1,905	-	-	-	-	-	-	-	-	-
Operational Expenditure (000s)										
Distribution poles and crossarms	900	900	918	946	951	955	965	974	984	995
Distribution conductor	150	150	153	165	166	168	169	171	180	182
Fault indicators and Earthing	25	26	27	27	28	28	29	29	32	32

Figure 7-34 Distribution and Low Voltage Lines expenditure forecast summary

7.6 Distribution and LV Cables

In addition to our distribution and LV lines we have distribution and LV cables.

Underground cables have a higher capital and overall lifecycle cost than overhead lines but have higher reliability and lower ongoing maintenance costs.

Most new construction in the urban area uses underground cables as District Plan rules restrict the installation of new poles and overhead lines, and most land developers require electricity to be supplied underground for new subdivisions.

Our distribution cables (22kV and 11kV) are of Cross-linked polyethylene (XLPE) or paper insulated, lead covered (PILC) construction. Our 400V cables are XLPE, Polyvinyl Chloride (PVC) and PILC.

We have 160.61km of 22kV cables, 76.33km of 11kV cables and 811.5km of 400V LV cables. We also have 46.79km of street lighting cable, however there are significant lengths of street light circuits installed with LV cables which are not recorded on early plans and we do not know the length of these circuits.

7.6.1 Quantity and Life Expectancy of Distribution and LV Cables

Asset	Construction Type	Length in km	Life Expectancy
Distribution Cables 22kV	XPLE	160.61	55 years
	PILC	16.73	70 years
Distribution Cables 11kV	XLPE	59.6	55 years
	PVC	131.36	55 years
LV Cables	XLPE	609.19	55 years
	Other	70.95	70 years
	PVC	41.99	55 years
Street Light Cables	XLPE	2.37	55 years
	Other	2.43	70 years

Figure 7-35 Distribution and Low Voltage Cables asset summary (asset quantity as at Sept-20)

¹⁰ Capital Expenditure includes rollover expenditure from FY21, as indicated in Chapter 11, Evaluation of Performance.

7.6.2 Management Approach

Distribution and low voltage cables are generally reliable and maintenance free, and therefore the approach we take to managing these assets is to either repair or replace on failure. We don't have any first generation XLPE cable remaining on the network, which has known type issues and experienced premature failure on many networks due to water treeing.¹¹

7.6.3 Distribution Cables

Age Profile

Figure 7-36 shows the age profile of our distribution cables.

The life expectancy of XLPE cables is 55 years and PILC cables is 70 years with the first replacement expected beyond this planning period.

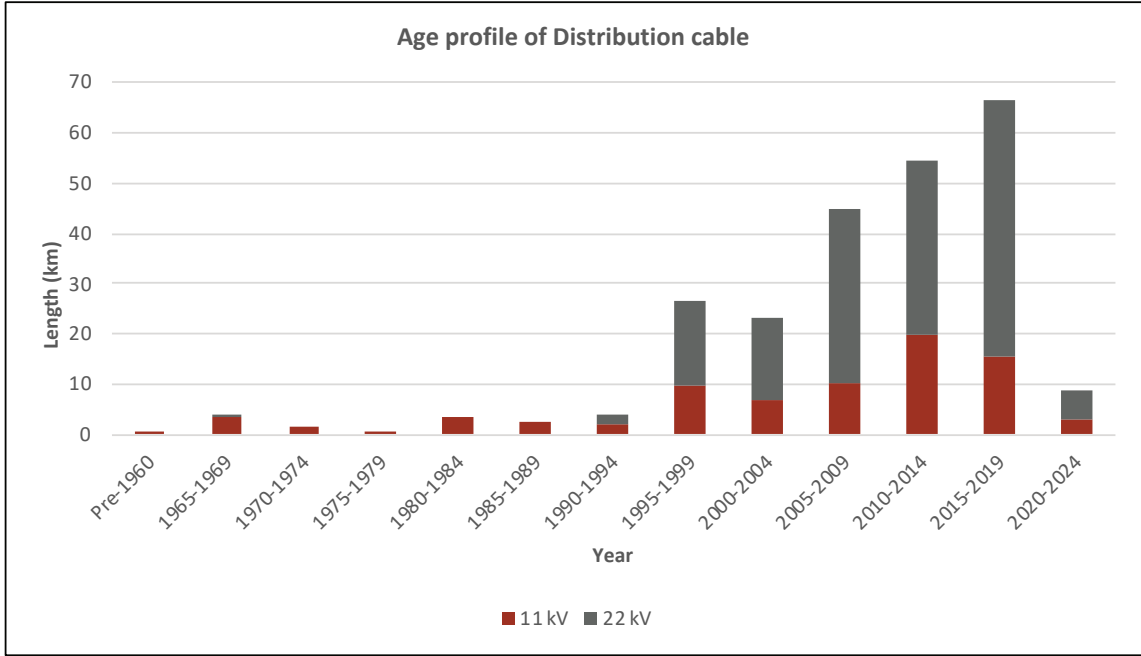


Figure 7-36 Age profile of Distribution Cables

Note: since 1994 we have only installed 22kV rated cables, the above chart shows the voltage they currently operate at.

Inspection and Maintenance Practices

Underground distribution cables are not proactively inspected or tested as they are generally maintenance free. Cable terminations and risers on poles are inspected as part of overhead line condition assessment surveys, and repair work is undertaken where defects are found. Cable terminations on ground mounted switchgear are not easily inspected; however the use of thermal imaging and partial discharge location equipment assists in identifying deteriorating cable terminations in these locations.

7.6.4 LV Cables

Age Profile

Figure 7-37 shows the age profile of our LV cables in our network.

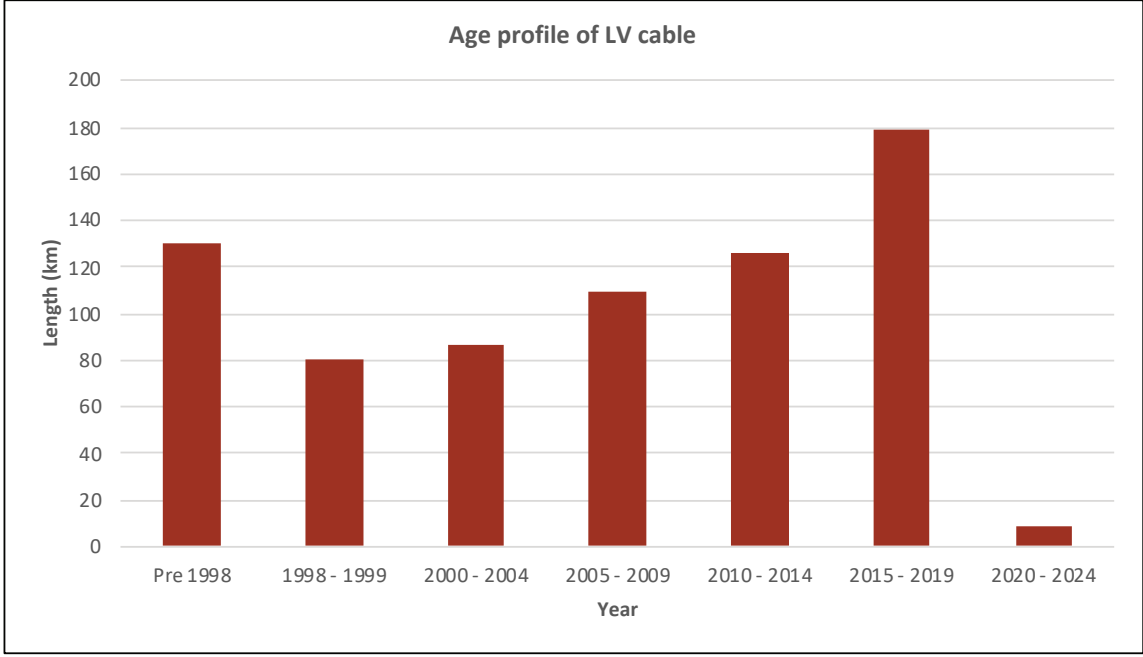


Figure 7-37 Age profile of Low Voltage cables

Inspection and Maintenance Practices

Underground LV cables are not proactively inspected or tested as they are generally maintenance free. Cable terminations and risers on poles are inspected as part of overhead line condition assessment surveys, and repair work is undertaken where defects are found.

Renewal Programme

There is no proactive renewal programme for this asset type, however an allowance of \$150,000 in FY21 increasing to \$300,000 from FY24 for replacement of cable sections found to be faulty.

¹¹ Water treeing is a form of insulation degradation observed on early XLPE cables

7.6.5 LV Pillars and Pits

We have 13,014 LV pillars and pits in our network, connected to LV cables. These generally accommodate fusing for customer supply points, but some pillars are used as link pillars between two adjacent low voltage circuits. Pits are not widely used and avoided where possible in new-build situations.

Age Profile

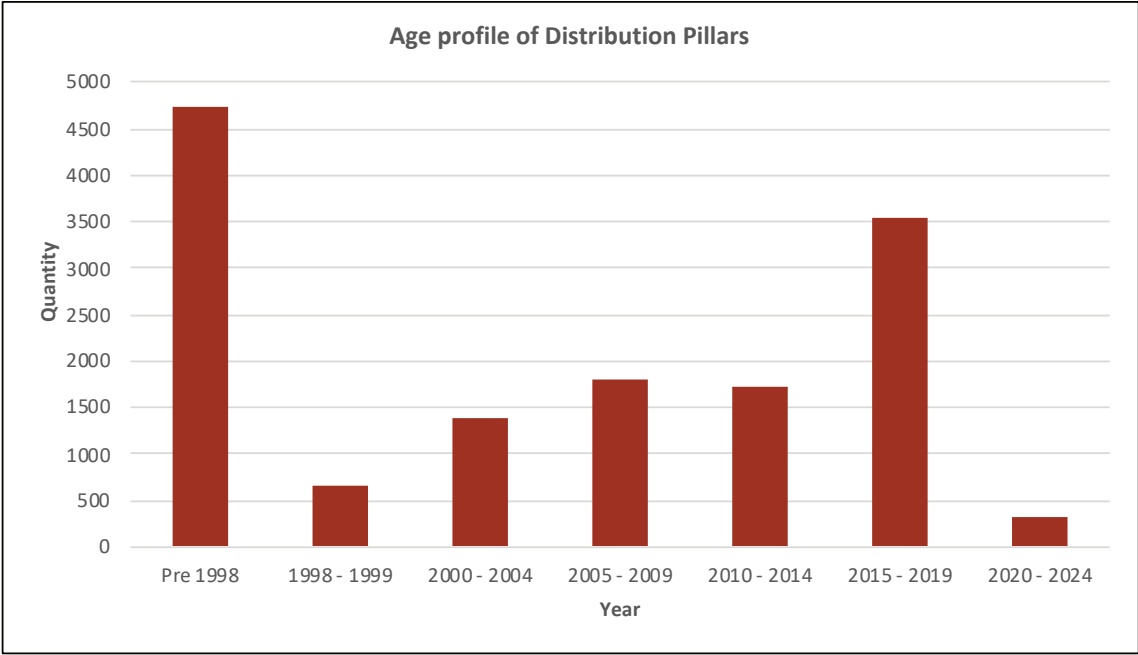


Figure 7-38 Age profile of LV Pillars

Note peak in pre1998 represents a default setting in the database

Inspection and Maintenance Practices

We carry out five yearly visual inspections and thermographic tests on our LV pillars to ensure they are safe and secure, and that the components are not overheating which is a common mode of failure.

Corrective maintenance is used to address minor issues such as insecure lids, hot connections, or alignment and siting issues (leaning, etc.). Vehicle damage is common, and entire pillar replacement is the usual remedy depending on the nature of damage.

Renewal Programme

Pillar Replacement Programme

It has been identified that a number of “mushroom” pillars on the network are deteriorating due to age. Besides the aforementioned periodic inspections, we have implemented a proactive policy to replace mushroom pillars whenever work is to be carried out on them. We have allocated \$2.0m in this AMP period for pillar renewal.

7.6.6 Summary of Distribution and LV Cables Expenditure Forecast

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000s)										
Barber Road - Feeder Cable Renewal	3,438	-	400	-	-	-	-	-	-	-
Pillar renewal	200	200	200	200	200	200	200	200	200	216
UG cable renewal	150	200	300	300	300	300	300	300	300	300
Operational Expenditure (000s)										
Distribution and LV cables	120	136	142	145	148	151	157	160	170	173
LV Pillars	90	100	102	104	106	108	115	117	125	130

Figure 7-39 Distribution and Low Voltage cables expenditure forecast summary

7.7 Distribution Substations and Transformers

Distribution substations accommodate transformers which step down higher distribution voltages (22kV or 11kV) to low voltage (400V/230V) for distribution to customers, along with other equipment such as high voltage fusing, low voltage fusing and earth grids.

Distribution switching stations accommodate switchgear such as ring main units or circuit breakers and are used to control and isolate the network by switching sections of distribution feeders, and to supply and protect transformers. This enables a section of the network to be de-energised for maintenance work, or to isolate faulted sections of the network in order to minimise the impact of faults.

Specially designed 22/11kV transformers connect our 11kV network to our 22kV network and to enable consideration of upgrading to 22kV as one of the options to address identified capacity and voltage constraints in the future. An upgrade to 22kV in each area is assessed on its individual merits, including evaluation of a range of alternatives.

7.7.1 Quantity and Life Expectancy of Distribution Substations and Transformers

Asset	Type	Quantity	Life Expectancy
Distribution Transformers	Pole mounted distribution transformers	3,180	45 years
	Ground mounted distribution transformers	929	45 years
22/11kV Transformers	Auto Transformers	46	45 years

Figure 7-40 Distribution assets summary (asset quantity as at Sep-20)

7.7.2 Management Approach

Public safety is a key driver of the maintenance programme for transformers and ground mounted substations, in particular the security of the units and ensuring members of the public cannot come into contact with live parts. Likewise, protecting the environment is a concern and making sure oil leaks do not occur due to corrosion or damage to tanks.

Some types of equipment, in particular early kiosk type substations, have restricted operating space and live parts. These require outages to work safely in them, and where justified, these are replaced with modern alternatives.

Transformers are generally low maintenance, requiring little routine servicing, so the maintenance programme is inspection based, with corrective actions taken where required.

In some parts of our network, particularly within 10km of the coast, transformers do not reach their normal service life and are likely to be replaced 10 years earlier than in other locations due to corrosion of the tank and fittings.

7.7.3 22/11kV Auto Transformers

We have 46 22/11kV auto transformers, 28 are ground mounted and 18 are pole mounted units.

Figure 7-41 shows the age profile of our 22/11kV auto transformers. The average age of these transformers is 12 years.

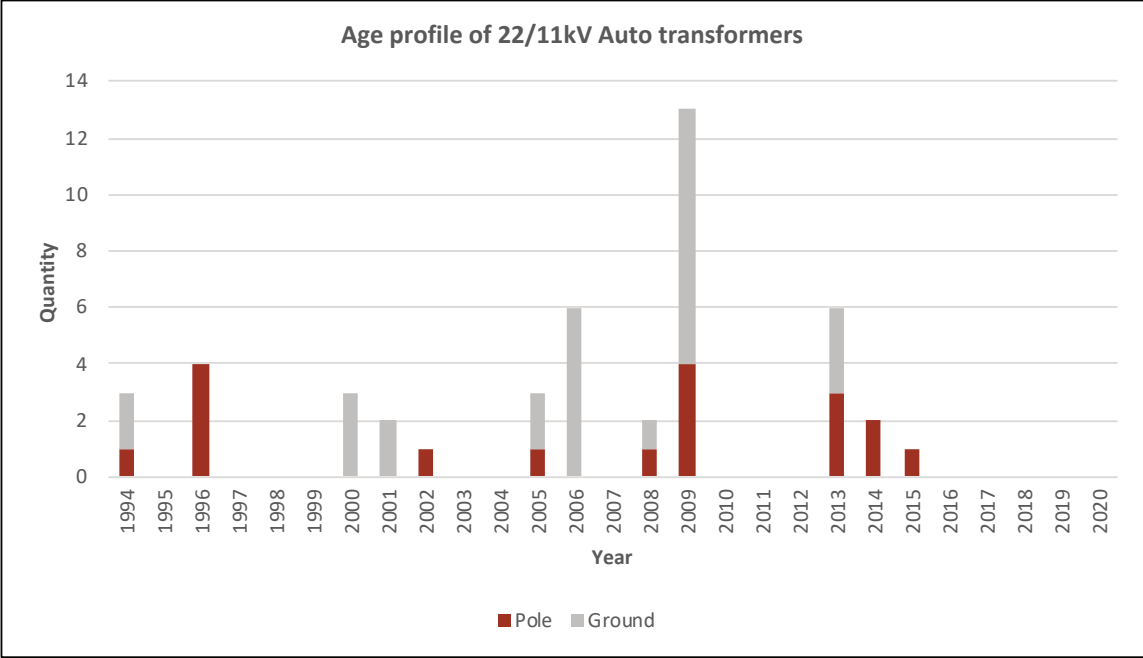


Figure 7-41 Age profile of 22/11kV transformers



7.7.4 Distribution Transformers

Figure 7-42 shows the age profile of our pole mounted distribution transformers. The average age of our 22kV pole mounted transformers is 10 years and our 11kV pole mounted transformers is 19 years. The significant investment made over the last 20 years was driven by a combination of active replacement programme of older transformers in poor condition and development of our 22kV distribution network.

We have 93 pole mounted transformers that are older than the expected life of 45 years. This represents 3% of our total pole mounted distribution transformer population.

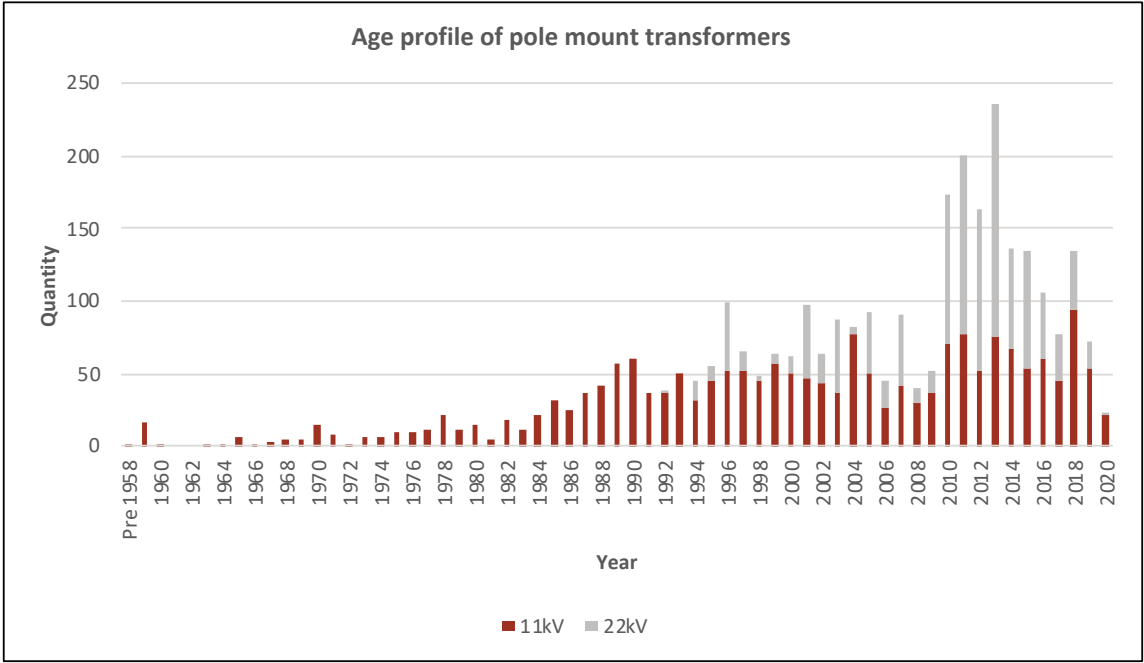


Figure 7-42 Age profile of Distribution pole-mounted transformers

We have 902 ground mounted distribution transformers, 589 on the 22kV network and 313 on the 11kV network.

Figure 7-43 shows the age profile of our ground mounted transformers. The average age of our 22kV ground mounted transformers is 10 years and the average age of our 11kV ground mounted transformers is 20 years. The significant investment made over the last 20 years was driven by significant network growth and development of our 22kV distribution network.

We have 61 ground mounted transformers that are older than the expected life of 45 years. This represents 7% of our total ground mounted distribution transformer population.

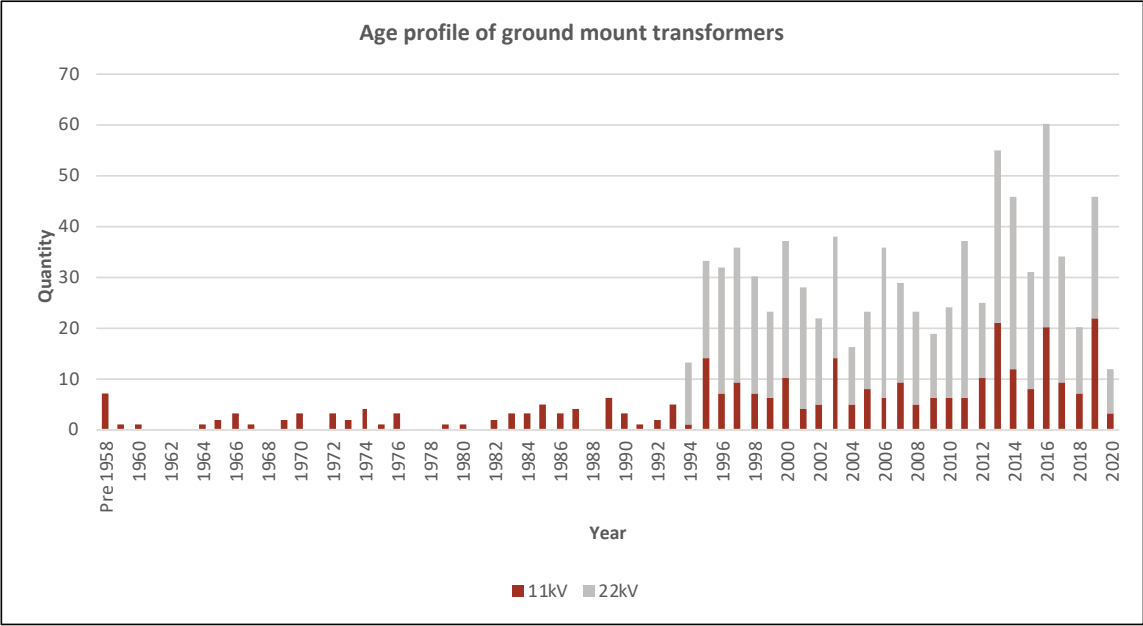


Figure 7-43 age profile of Distribution ground-mounted transformers

Inspection and Maintenance Practices

We carry out safety checks, visual inspections and thermographic tests on our distribution transformers annually to ensure that the transformers remain safe, secure and defect free.

Activity	Type	Frequency
Transformer Inspection	Inspection	Annual

Figure 7-44 Inspection frequency of distribution transformers

There is no routine servicing required, and any defects found during routine inspections are handled through the corrective maintenance programme.

Renewal Programme

We plan to replace our transformers when their condition is unacceptable for continued service or where growth requires a capacity upgrade.

Based on age profiles and quantity in service, we expect to replace around 40 transformers per annum over the next three year period, across planned upgrades (capacity and security), and as a result of condition assessment findings or reactive fault repairs. We have allowed \$400,000 in the coming year for the renewal of transformers and associated equipment due to condition.

7.7.5 Expenditure Forecast

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000's)										
Transformer Renewal Programme	400	400	400	400	450	450	450	450	450	400
Operational Expenditure (000s)										
Distribution transformers	450	459	468	470	475	477	482	490	495	500

Figure 7-45 Distribution transformer expenditure forecast summary

7.8 Distribution Switchgear

Distribution switchgear is used to protect and isolate the network. Switchgear minimises the impact of outages arising from faults and planned work by sectionalising affected parts of the network.

On the overhead network, we use air break switches (ABS), gas insulated switches (GIS), reclosers and dropout links and fuses.

On the underground network, we use ring main units (RMUs) consisting of load break switches to provide isolation, and fuses or circuit breakers to protect transformers.

7.8.1 Quantity and Life Expectancy of Distribution Switchgear

Asset	Quantity	Life Expectancy
Ring Main Units	278	40 years
Air Break Switch	176	35 years
Gas Insulated Switch	165	35 years
Spur Line Isolator	1,529	35 years
Reclosers	40	40 years

Figure 7-46 Distribution Switchgear assets summary (asset quantity as at Sep-20)

7.8.2 Management Approach

Distribution switchgear should be serviceable, free from defects and safe to operate at all times. It is a key component of operating the network safely and efficiently and providing necessary isolation of equipment. These devices are generally located in the public domain, so safety is our main consideration with regard to inspecting and maintaining these units.

Selection of good quality, low maintenance RMUs has positioned us well, with little ongoing maintenance needed apart from routine safety checks.

A small number of older RMU types remain on the network that for safety reasons are subject to operational restrictions, largely due to their age and condition. The operational restrictions often result in wider area outages occurring than are otherwise necessary. These units have been identified and will be replaced during the planning period.

A number of issues relating to overhead equipment have been identified, and programmes implemented to address these through the planning period, with priority given to higher risk issues and locations.

7.8.3 Ring Main Units

Ring main units are ground mounted switches for switching distribution cable rings and for connecting distribution transformers, generally through fused switches or circuit breakers, to the distribution network.

At time of writing, we have 287 RMUs in our distribution network, of which 270 are gas insulated, seven are oil insulated, and 10 are air/resin insulated.

The average age of our RMUs is nine years. We have 10 RMUs that are older than the expected life of 40 years. This represents 3% of our RMU population.

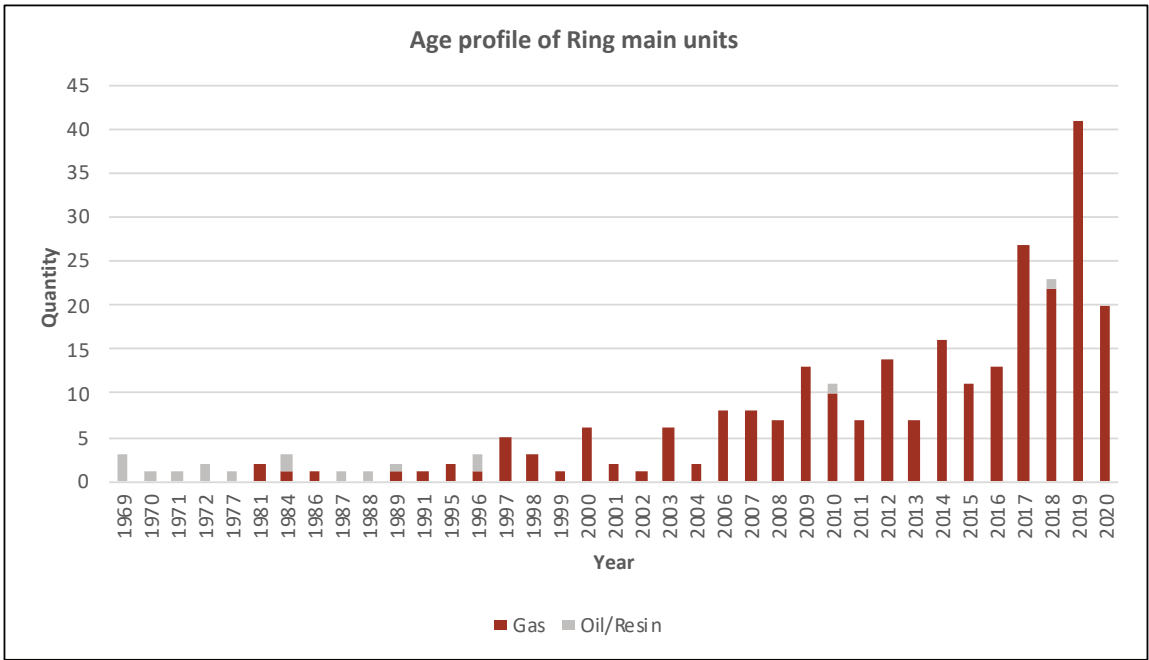


Figure 7-47 age profile of Ring main units

Inspection and Maintenance Practices

We carry out annual visual inspections on our RMUs to ensure that they are safe, secure and free of defects.

The majority of the RMUs on the network are modern gas insulated Schneider RM6 units and require very little maintenance. Some of these units have automation fitted, which requires battery replacement every five years.

There are some types of RMU of older designs, particularly oil filled units such as Andelect/ABB SD series switchgear and Hazemeyer Magnefix which require higher levels of routine servicing to ensure they operate safely and correctly.

Activity	Type	Frequency
Ring Main Unit – Annual Inspection	Inspection	Annual
Ring Main Unit Maintenance – Oil Filled	Routine Maintenance	5 yearly
Ring Main Unit Maintenance – Hazemeyer	Routine Maintenance	5 yearly
Ring Main Unit Battery Renewal	Replacement	5 yearly

Figure 7-48 Inspection frequency for RMUs

Renewal Programme

We plan to replace all our air/resin insulated and oil filled RMUs within the two years. There are two Andelect switchgears which are targeted for replacement by 2022 while the rest of the Hazemeyer, Long & Crawford and Andelect switchgears are being replaced in FY21 renewal programme. These replacements are driven by age and condition. A standard procedure is in place to restrict operation of this equipment to a de-energised state to manage the operational risks.

There are two units identified for replacement in FY22, with an estimated replacement cost of \$934,000. The associated cost includes replacement for distribution cables and transformers which are covered in the respective renewal programmes.

Financial Year	Feeder	Andelect	Cost (000's)
FY22	Drury Hills	2	934

Figure 7-49 RMU replacement programme

7.8.4 Overhead Distribution Switchgear

Overhead distribution switchgear consists of reclosers, air break switches (ABS), gas switches, and isolators. They are used to protect and isolate the distribution network.

Network	Asset	Quantity	Life Expectancy
22kV	Air Break Switch	71	35 years
	Gas Insulated Switch	79	35 years
	Spur Line Isolator	664	35 years
	Reclosers	27	40 years
11kV	Air Break Switch	98	35 years
	Gas Insulated Switch	86	35 years
	Spur Line Isolator	865	35 years
	Reclosers	11	40 years

Figure 7-50 Overhead Distribution Switchgear



Condition Profile

Figure 7-51 shows the age based condition profile of our distribution switchgear and switches.

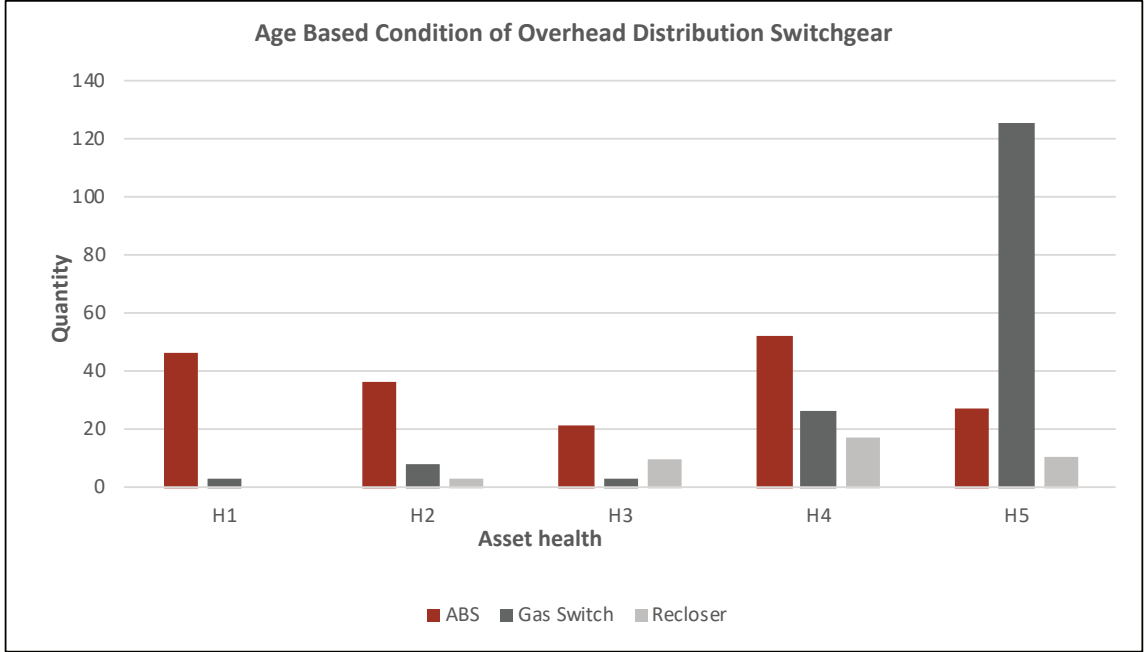


Figure 7-51 Age based condition profile of Distribution switchgear and switches

Inspection and Maintenance Practices

Our inspection and maintenance cycles for distribution switchgear are:

Activity	Type	Frequency
Overhead Switch – Annual Inspection	Inspection	Annual
Air Break Switch Service	Routine Maintenance	5 yearly
Gas Switch Service	Routine Maintenance	5 yearly
Remote Switch Battery Renewal	Replacement	5 yearly
Recloser Service	Routine Maintenance	5 yearly
Recloser Battery Renewal	Replacement	5 yearly
Overhead Switch Earth Test	Routine Test	5 yearly

Figure 7-52 Inspection and maintenance cycles for distribution switchgear

All overhead equipment is part of the annual overhead condition assessment programme, to identify any safety concerns or deterioration which can be addressed through the corrective maintenance programme. Overhead switchgear (except isolators) is also subject to routine servicing to ensure it operates safely and correctly. Automated devices require their batteries to be replaced periodically, which is done in conjunction with routine servicing.

Renewal Programme

Issues were identified with porcelain insulators on one particular type of air break switch (ABS) in FY18.

- A replacement programme begun in FY18 to replace all air break switches on the network, prioritising the ABS with the known issue. Counties Power had a total of 267 ABS on the network in FY18 as of 2020 the network has 172. Counties Power will continue to replace ABS on the network for the foreseeable future, with the aim to have no ABS on the network in FY35;
- The replacement programme will continue to prioritise switches based on their make, model, switch location and network function. Counties Power’s network has 73 ABS which had a known failure type in FY18; Counties Power has replaced 48 of the critical switches with the remaining 25 to be replaced in the upcoming years; and
- The replacement programme uses new automated gas switches which provide several benefits in addition to addressing the identified condition issues. These include lower whole of life costs due to reduced maintenance requirements, automation to provide operational flexibility, and having capability for the future possibility of establishing a “self-healing” network that automatically isolates a faulted section and re-routes power to the remaining areas; and trials have begun on the use of vacuum type switches to reduce Counties Power SF₆ use.

Known types of HV ‘dropout’ style fusing will be identified and replaced where required, as well as some surge arrestors in coastal areas experiencing premature failure due to the harsh environment. These are handled as corrective replacements when found.

We do not forecast any renewal of reclosers during the planning period. However, more may be added for network performance improvements.



7.8.5 Summary of Distribution Switchgear Expenditure Forecast¹²

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000's)										
RMU replacement	2,877	-	-	480	480	480	480	480	480	
Overhead switchgear replacement	480	480	450	480	480	480	480	480	480	600
Operational Expenditure (000s)										
Ring main units	150	155	158	160	163	166	170	173	180	180
Overhead switchgear	150	155	155	155	155	160	160	165	170	173

Figure 7-53 Distribution switchgear expenditure forecast summary

7.9 Grid-scale Battery Storage System

Our first grid-scale battery storage system was commissioned at the Tuakau zone substation in mid-2017. This system consists of the isolating transformer, power converters, battery cells, monitoring and control systems, cooling and auxiliary supply systems.

7.9.1 Inspection and Maintenance Practices

Our inspection and maintenance cycles for grid-scale battery system are:

Activity	Type	Frequency
Routine battery inspection	Inspection	6 monthly
Cooling and auxiliary systems	Routine Maintenance	6 monthly

Figure 7-54 Inspection and maintenance cycles for grid-scale battery system

7.10 Other System Fixed Assets

7.10.1 Quantity and Life Expectancy of other Network Assets

Asset	Quantity	Life expectancy
Capacitor banks	19	55 years
Voltage Regulators	15	55 years
Protection relays	184	40 years
Load control relays	3271	20 years
Ripple Injection plant	6	20 years
Auxiliary Battery Banks	35	8 years
Remote Terminal Unit	284	15 years

Figure 7-55 Other system fixed assets summary (asset quantity as at Sep-20)

7.10.2 Capacitor Banks and Voltage Regulators

Due to the electrical impedance of the line, the voltage at the end of feeders is lower than at the supply end, defined as voltage drop along the line. For long distribution feeders, this voltage drop can be significant resulting in unacceptably low voltages at the end of those feeders. We have installed voltage regulators partway on some of our long distribution feeders to maintain the correct voltage at the end of those feeders.

We have 15 voltage regulators in our network operating at six sites; i.e. three sites of three units in a delta configuration and three sites of two units operating in an open delta configuration.

Age Profile

Figure 7-56 shows the age profile of our voltage regulators. The average age of our voltage regulators is 16 years.

¹² Capital Expenditure includes rollover expenditure from FY20, as indicated in Chapter 11, Evaluation of Performance.

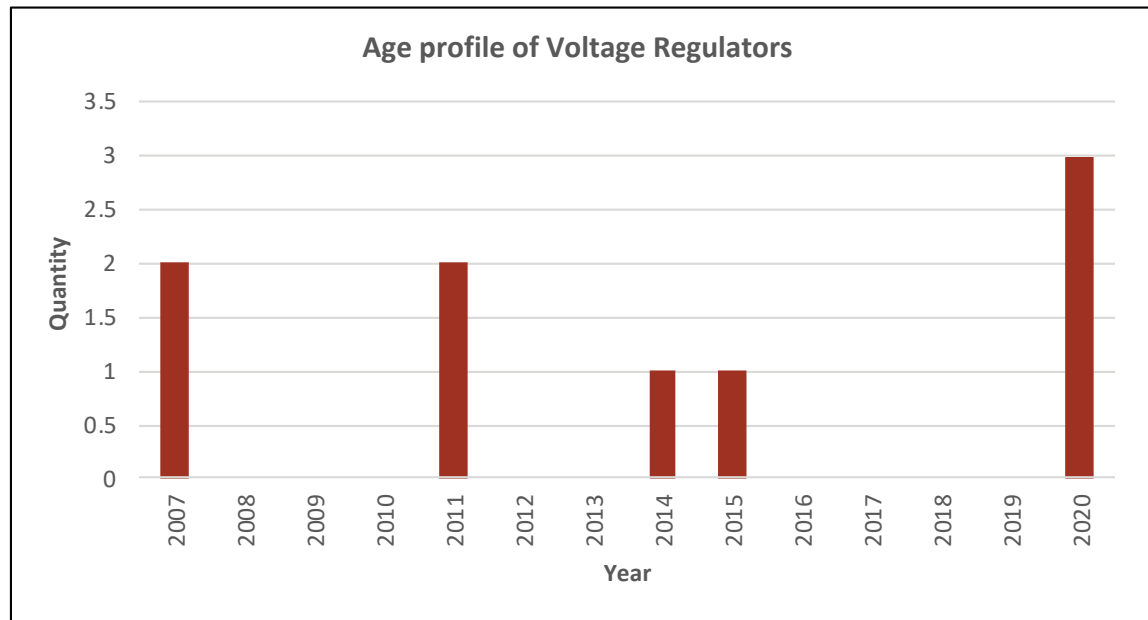


Figure 7-56 Age profile of Voltage Regulators

Capacitors provide power factor correction and help maintain the correct voltage by providing reactive support on long lines with high impedance.

We have 19 capacitors on our distribution network with installation dates ranging from 1998 to 2007. The average age of our capacitors is 20 years.

Figure 7-57 shows the age profile of our capacitors.

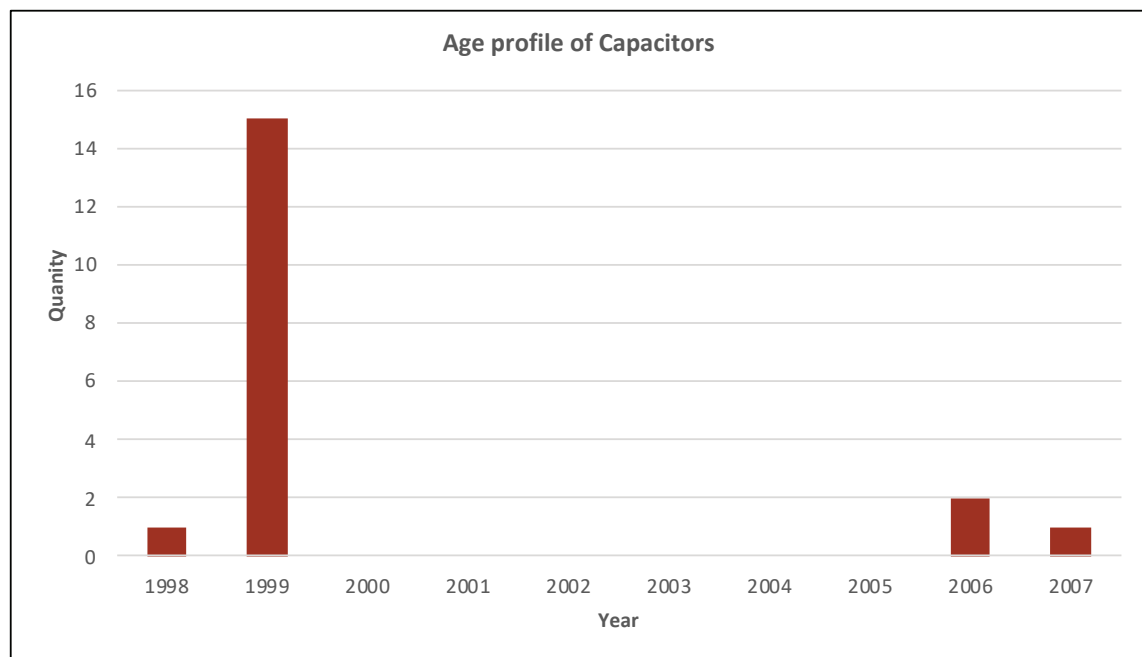


Figure 7-57 Age profile of Capacitors

Inspection and Maintenance Practices

Our inspection and maintenance cycles for our voltage support equipment are:

Activity	Type	Frequency
Capacitor Bank	Inspection	Annual
Voltage Regulator	Inspection	Annual
Voltage Regulator Servicing	Routine Maintenance	3 yearly

Figure 7-58 Inspection and maintenance cycles for our voltage support equipment

Renewal Programme

Our voltage regulators and capacitors are in acceptable condition. There are no identified renewal needs for the voltage regulator or capacitors. Two new voltage regulator sites are planned to be established over the next ten year period, one on Otaua feeder and one on Te Hihi feeder.

7.10.3 Protection Relays

Protection relays rapidly detect and initiate the operation of circuit breakers to isolate electrical faults to ensure safety of our staff and the public, and to protect equipment from short circuits and overloads.

We have 144 protection relays installed at our zone substations and at Transpower’s Bombay and Glenbrook GXPs. The average age of our protection relays is 18 years.

Age Profile

Figure 7-59 shows the age profile of our protection relays.

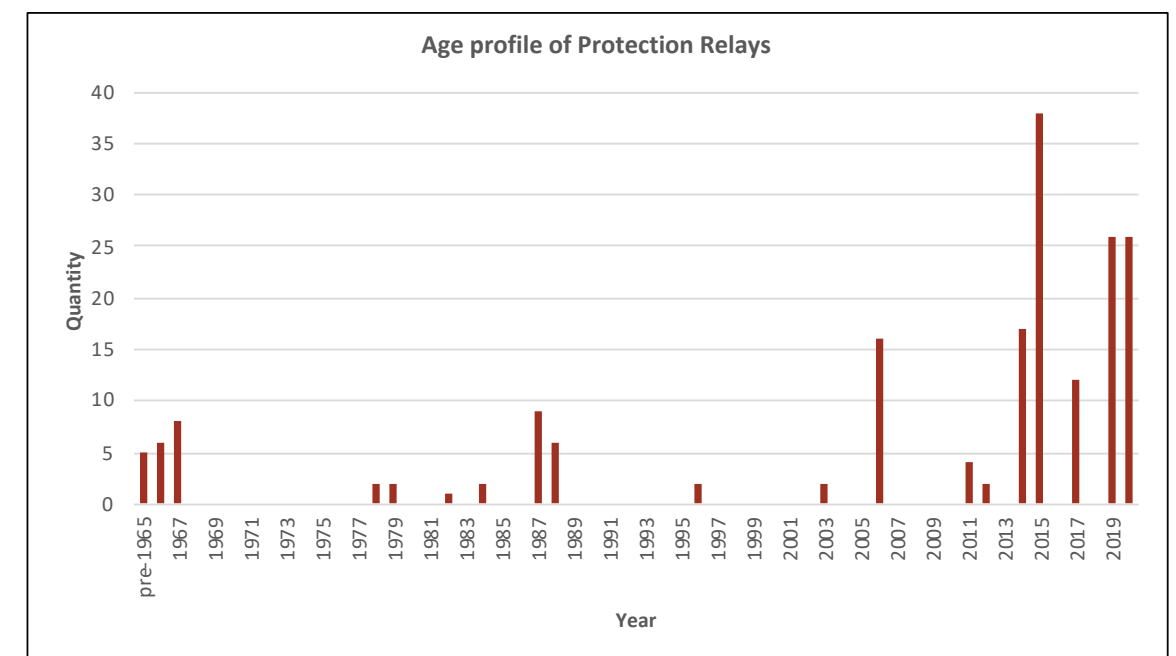


Figure 7-59 Age Profile for Protection Relays

Inspection and Maintenance Practices

We test our protection relays every three years to ensure they operate correctly.

Renewal Programme

We typically replace protection relays when we replace the primary plant which they relate to, for example replacement of feeder protection when we replace the corresponding circuit breakers. As a result of this, we include relay replacement in the cost of replacing the major primary plant. During this planning period we will replace end of life relays at Karaka, Bombay, Pukekawa and Tuakau.

In some cases, we replace relays due to performance issues, or where we require different functionality. Our replacement programme for protection relays is planned for:

- Replacement of feeder and subtransmission protection relays at Karaka zone substation and Glenbrook GXP. These are approximately 18 years old and have been found to have emerging performance and reliability issues at the end of life (20 years). We have recovered spare relays to manage the reliability issues and plan to replace these relays in 2021 for an estimated cost of \$1.01m;
- Replacement of protection relays at Tuakau, Pukekawa, Bombay and Pukekohe due to emerging performance and reliability issues at an estimated cost of \$3.5m; and
- The Electricity Authority issued an amendment to the Electricity Industry Participation Code (EIPC) (the “Code”) in 2017 which changes the nature of the Automatic Under Frequency Load Shedding (AUFLS) scheme and replaces it with the Extended Reserves scheme. Changes to the new system were to start in April 2018 and be completed by mid-2019. The Electricity Authority paused the project in October 2017 to assess options for more reliable delivery of the scheme, we will programme any required works once we receive advice on how the scheme will be changed. Based upon the specified requirements for implementation of this scheme, we will need to change some relays to provide the required functionality to meet new technical requirements. Any new relays we install before then will be compatible with the proposed requirements.

7.10.4 SCADA Communications Systems

We operate an analogue SCADA radio network, as well as a digital voice radio network. We have repeaters in seven locations for our analogue system and one for our digital voice system to provide coverage and redundancy. The digital voice network was installed in 2015 and is performing as anticipated. Our analogue SCADA radio systems and associated equipment however are either obsolete or nearing end of life. Commencing in 2021, we will be progressively upgrading our SCADA communications system to a digital platform. This will require new repeater sites, hardware and software upgrades. Due to the size and complexity, this programme will be phased over the next five years. In the interim, the current in service system will be maintained to ensure SCADA operations are not impacted.

We have 284 SCADA Remote Terminal Units (RTUs) installed on our network with 14 located at Grid Exit Points and zone substations, and 270 installed on switchgear and devices across the network to provide remote control and indication. An age profile is shown in Figure 7-59.

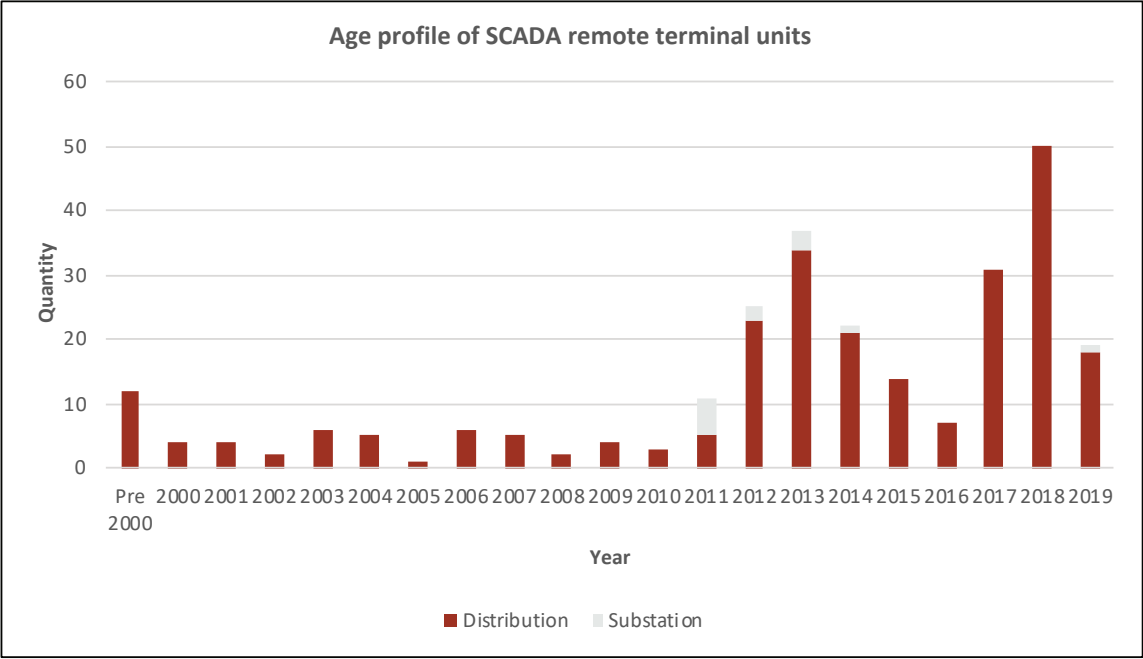


Figure 7-60 Age profile of SCADA Remote Terminal Units

Renewal Programme

We will replace the communication systems at Karaka substation to align with the upgrading of the new protection relays at an estimated cost of \$0.5m.

We are undertaking a five year project to replace our analogue SCADA radio equipment which will include introduction of new repeater sites and replacement of remote terminal units at an estimated cost of \$10m over the five years.

Based on the age profiles of SCADA RTUs, we expect to replace around 70 units during the planning period as older electronic RTUs tend to become unreliable after 25 years and are generally replaced as part of overhead switchgear replacement programme.

RTUs are generally replaced during distribution switchgear replacement.

7.10.5 Load Control Equipment

Load control equipment consists of ripple injection plant located at substations, and load control relays located at each of our customers premises connected to some form of interruptible load. For residential customers, the interruptible load is generally hot water heating.

When we need to manage the load on our system, we send a signal from our SCADA master station to the relevant ripple injection plant(s) which in turn send a signal to the assigned load control relays.

We have six ripple injection plants installed on the network at Bombay, Glenbrook, Opaheke, Pukekohe, Pokeno and Tuakau with an average age of 18 years. The operating frequency of our load control system is 317Hz.

Age Profile

Figure 7-61 shows the age profile of our ripple injection plants.

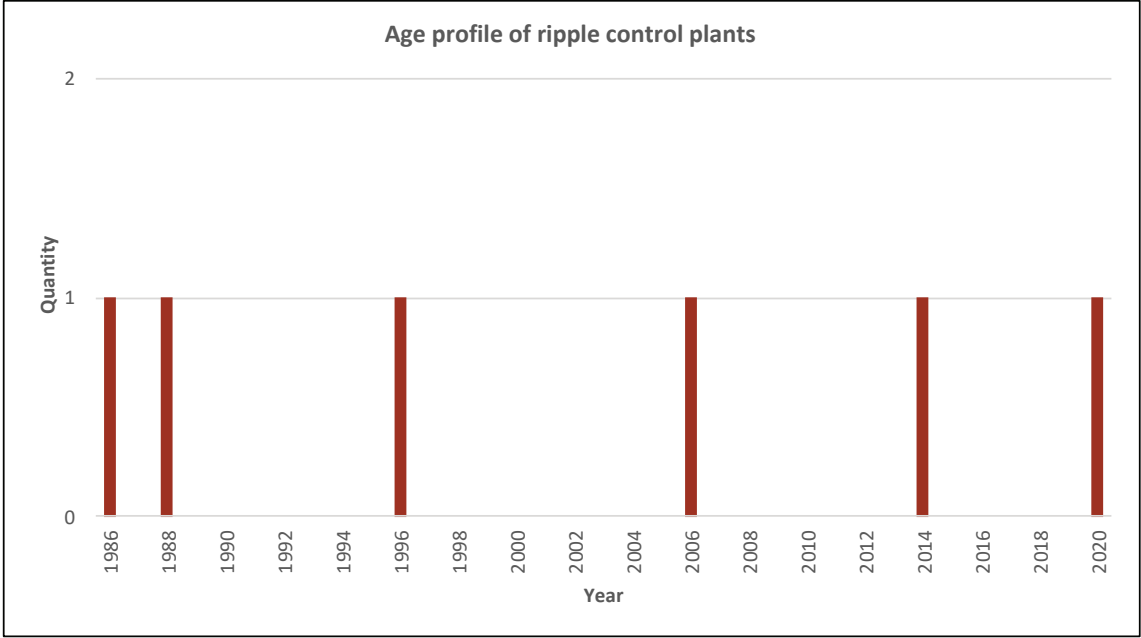


Figure 7-61 Age profile of ripple injection plants

We have over 3,217 load control relays installed on our network associated with legacy meter installations. We have reduced the number of individual load control relays by introducing smart meters on our network which have the ripple receiver inbuilt.

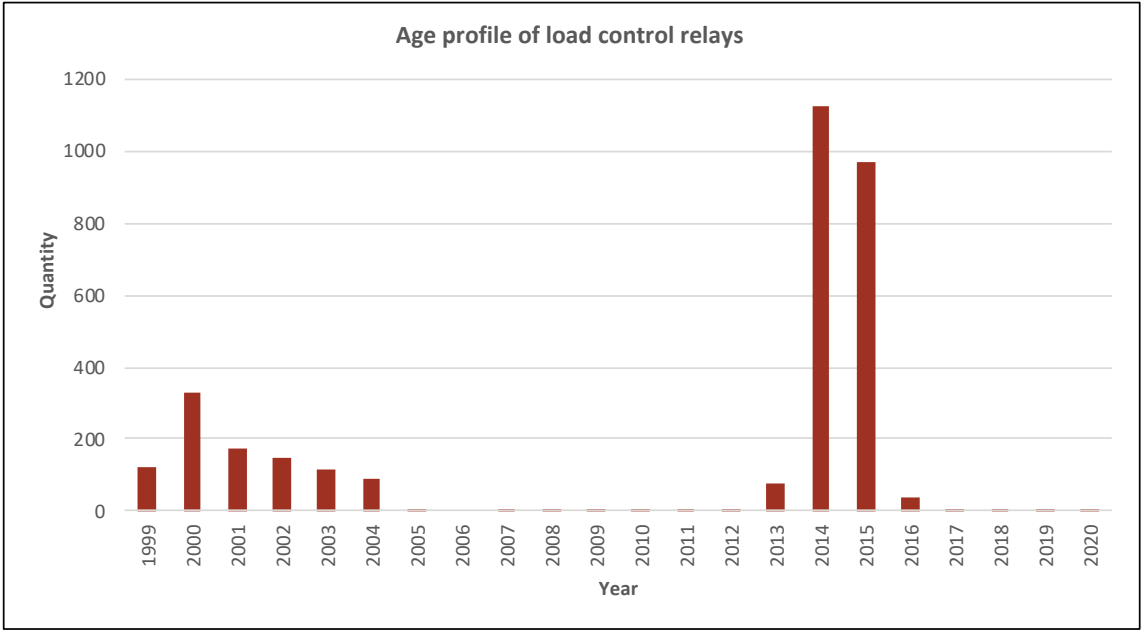


Figure 7-62 Age profile of Load Control Relays

Inspection and Maintenance Practices

Our inspection and maintenance cycles for our ripple injection plants are:

Activity	Type	Frequency
Ripple Plant – Visual Inspection	Inspection	6 Monthly
Ripple Plant – Test and Service	Routine Maintenance	Annual

Figure 7-63 Inspection and maintenance cycles for our ripple injection plants

Renewal Programme

The load control plant at Opaheke substation is planned to be replaced within the ten year planning window at an estimated cost of \$0.45m. This load control plant is being replaced to align with the network standard and the planned new switchboard for the substation. As we upgrade legacy meter installations to smart meters, we will remove the standalone ripple receivers, so no future expenditure is expected on these.

7.10.6 Auxiliary Battery Banks

110V and 24V DC battery banks are installed in our network to supply power to protection schemes, control and metering and equipment components (such as circuit breaker operating coils) that need DC supplies to operate.

We have 35 battery banks installed in our network with installation dates ranging from 2009 to 2018. We have eight units of 110V battery banks and 23 units of 24V battery banks. The average age of our battery banks is three years.

Age Profile

Figure 7-64 shows the age profile of our auxiliary battery banks.

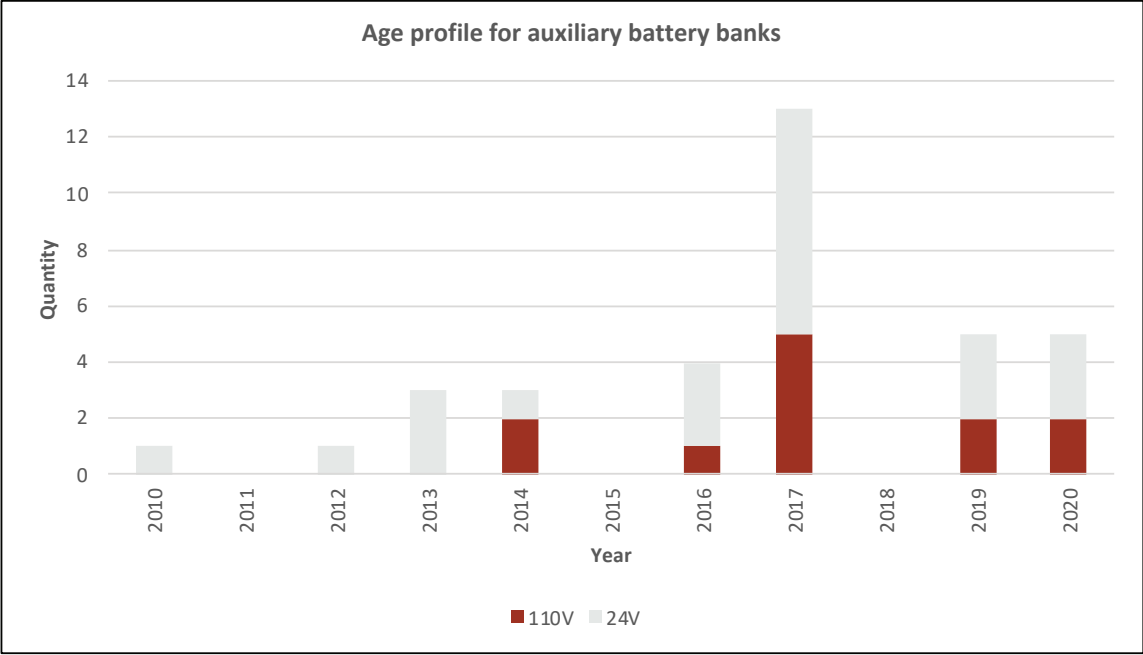


Figure 7-64 Age profile of Auxiliary Battery Banks

Inspection and Maintenance Practices

We carry out periodic visual inspections and tests ensure that the auxiliary battery cell voltages remain within acceptable ranges and the battery chargers operate as required depending on site criticality.

Activity	Type	Frequency
Battery Inspection and Test – GXP	Routine Test	3 Monthly
Battery Inspection and Test – Zone Sub	Routine Test	3 Monthly
Battery Inspection and Test – Radio Site	Routine Test	12 Monthly

Figure 7-65 Inspection cycle for Auxiliary Battery Banks

Renewal Programme

As auxiliary battery banks have an expected life of eight years (80% of their design life of 10 years), conservative financial planning assumes we will replace our entire auxiliary battery bank fleet at least once during this planning period, although actual replacements, particularly as technology improves, may be favourable to this assumption. The trade-off between the relatively low replacement cost and high impact of failure will be considered when planning the renewal programme. Battery banks close to their end of life at the start of the planning period will be replaced twice during this period. We also replace batteries in remote field devices; however these are undertaken as part of their routine maintenance and are not included in this forecast.

7.10.7 Substation Security

Legacy security systems continue to be phased out across the network. A new standard has been established and integrated with the SCADA system. The new system has been installed at the new Pokeno site and the recently rebuilt Waiuku site, and retrofitted to the existing Tuakau site. Projects to roll out the system at the remaining sites are planned with \$1.4m allocated in FY22.

7.10.8 Summary of other System Fixed Asset Expenditure Forecast

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000s)										
Opaheke LCP control module replacement	-	-	-	-	-	-	-	-	-	450
Relay replacement	2,000	-	-	2,000	-	-	-	-	-	-
RTU, battery renewal	100	90	120	140	105	100	90	100	100	105
Substation security	1,410	-	-	-	-	-	-	-	-	-
SCADA Radio equipment upgrade	1,000	2,000	3,500	1,000	1,000	-	-	-	-	-
Operational Expenditure (000s)										
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	100	120	120	140	150	180	180	180	180	180
Load control equipment	40	40	40	40	40	40	40	40	40	40
Battery banks	30	30	30	30	30	30	30	30	40	40
SCADA and Communications	650	650	650	650	650	660	650	702	713	713

Figure 7-66 Other system fixed asset expenditure forecast summary

7.11 Renewal and Maintenance of Other Assets

7.11.1 Backup Generators

We have three mobile generators, which do not form part of our regulated asset base, which are used to maintain supply during planned and unplanned outages, and one fixed generator at our head office to maintain supply to our SCADA and the control room. In addition, we have generator service provider agreements with two generator rental companies for use under works or emergency situations.

Age and Size Profile

The generators range in size and age from six years to 22 years, and from 15kVA to 250kVA.

Inspection and Maintenance Practices

These are maintained at 250 hours running time, and the fixed generator at our head office is checked every month and run every six months.

Renewal Programme

We have no firm plans to replace these generators in the short term, however given the age profile, replacement during the planning period is almost certain.

Expenditure Forecast

We have no capital expenditure forecast in the short term on generators, and operating costs are allocated to the projects which they are used on or corporate overheads for the building generator.

7.11.2 Emergency Critical Spares

Description and Quantity

We hold a number of critical spares at our main depot in Pukekohe, such as distribution transformers, distribution switchgear, cables, overhead line conductors, poles and cross arms. Some of these are new, and others have been recovered from projects and are now held as spares. We have repurposed the old Tuakau 33kV substation site to create an alternative storage site and are redeveloping space in our depot for storage of critical spares.

A 33/11kV transformer at Waiuku is being repurposed as a critical spare. We are currently investigating requirements and sourcing opportunities for a 110/22kV transformer critical spare.

Inspection and Maintenance Practices

During 2021, we will review our current processes and update our critical spares list and stock requirements. Additionally, we will implement a critical spares management process, which will look at periodic inspection, refurbishment and maintenance of spares held.

Expenditure Forecast

We do not forecast any material expenditure on critical spares in the short term but will be compiling a plan to ensure sufficient stock levels in the medium term.

7.11.3 Head Office and Depot

Description

We own the land and buildings used for our head office and depot. We operate all of our activities from this one site, located in Pukekohe.

Our site is approximately 3.2 hectares in size, and we have offices, storage buildings and workshops covering just over 4,000 square metres.

Renewal Programme

We have commenced a site redevelopment at our Glasgow Road head office and depot. The first stage of redeveloping the operational yards and workshop space began in 2018 and the redevelopment of the main office building to accommodate increased staff numbers, and provide a more modern and usable working space, will continue into 2021.

7.12 Assets Owned by Counties Power at Transpower Grid Exit Points

In addition to the assets we own at our own substations, or as part of our distribution system, we also own assets located at Transpower's GXPs.

These assets are included in the asset category which are maintained by Counties Power.

7.12.1 Bombay GXP

Within the substation building, the following equipment is installed:

- One 24V DC battery bank;
- Two sets of overcurrent and earth-fault line protection;
- Three sets of Line differential protection;
- Three sets of UHF inter-trip communication links;
- One set of metering equipment (33kV only); and
- One SCADA RTU and associated equipment.

A 33kV load control plant and an aerial mast are installed within the grounds of the substation, as well as a Disaster Recovery container which has a backup SCADA control terminal.

The disaster recovery shed is proposed for relocation in FY23 and investigation is underway to establish suitable sites.

7.12.2 Glenbrook GXP

Within the substation building, the following equipment is installed:

- Four sets of line differential protection;
- One set of metering equipment;
- One SCADA RTU; and
- Two fibre optic cables to the Glenbrook load control plant.

The 33kV Glenbrook load control plant is located near the Transpower Glenbrook substation on land owned by Counties Power.

7.13 Summary of Asset Quantities

Asset	Construction Type	Quantity	Life Expectancy
Subtransmission Poles	Concrete Pole	1336	80 years
	Wooden/other Pole	9	45 years
	Steel Pole	180	55 years
	Steel Tower	10	55 years
Subtransmission Lines	110kV	65.8	80 years
	33kV	71.7	80 years
Subtransmission Cables	110kV	0.52	55 years
	33 kV	1.55	55 years
Substation Buildings		10	50 years
Power Transformers	110/22kV	8	60 years
	33/11kV	9	60 years
Circuit Breakers	110kV CBs	20	45 years
	33kV CBs	13	45 years
	22kV CBs	71	45 years
	11kV CBs	25	45 years
Station Disconnectors	110kV Disconnectors	2	45 years
	33kV Disconnectors	28	45 years
Poles	Concrete	24,527	80 years
	Wooden	1,843	45 years
	Other	77	45 years
Cross Arms	Wooden/Steel	41,599	45 years
Conductors	22kV	572.12	80 years
	11kV	887.85	80 years
	Low Voltage (LV)	720.8	80 years
Distribution Cables 22kV	XPLE	160.61	55 years
Distribution Cables 11kV	PILC	16.73	70 years
	XLPE	59.6	55 years

Asset	Construction Type	Quantity	Life Expectancy
LV Cables	PVC	131.36	55 years
	XLPE	609.19	55 years
	Other	70.95	70 years
Street Light Cables	PVC	41.99	55 years
	XLPE	2.37	55 years
	Other	2.43	70 years
Distribution Transformers	Pole mounted distribution transformers	3,180	45 years
	Ground mounted distribution transformers	929	45 years
22/11kV Transformers	Auto Transformers	46	45 years
Switchgear 22kV	Air Break Switch	71	35 years
	Gas Insulated Switch	79	35 years
	Spur Line Isolator	663	35 years
	Reclosers	27	40 years
Switchgear 11kV	Air Break Switch	97	35 years
	Gas Insulated Switch	86	35 years
	Spur Line Isolator	867	35 years
	Reclosers	10	40 years
Other system fixed assets	Capacitor banks	19	55 years
	Voltage Regulators	15	55 years
	Protection relays	184	40 years
	Load control relays	3271	20 years
	Ripple Injection plant	6	20 years
	Auxiliary Battery Banks	35	8 years
	Remote Terminal Unit	284	15 years

Figure 7-67 Summary of Assets



7.14 Summary of Capital and Operating Expenditure

7.14.1 Replacement and Renewal Capital Expenditure¹³

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000's)										
Subtransmission Network										
Bombay-Ramarama Tower Rebuild	200	-	-	4,500	4,500	-	-	-	-	-
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	100
Zone Substations										
Power Transformer refurbishment	300	300	300	-	-	-	-	-	-	-
Waiuku substation	1,000	-	-	-	-	-	-	-	-	-
Barber Road substation	11,422	2,373	-	-	-	-	-	-	-	-
Decomission Ramarama and Mangatawhiri	-	-	-	1,000	-	-	-	-	-	-
Opaheke 22kV switchboard replacement	-	-	-	-	-	-	-	-	-	2,000
Other zone sub renewal	50	50	50	50	50	50	50	50	50	50
Distribution and LV Lines										
Overhead renewals	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,550
Copper replacement programme	3,071	5,255	1,004	4,351	-	1,454	1,500	4,625	5,923	6,110
Swan replacement programme	1,495	4,754	4,068	-	-	4,644	2,094	6,738	5,520	9,060
HV Feeder section replacement	-	762	300	300	300	300	900	300	300	-
Urban LV replacement	774	363	197	-	260	252	379	300	300	-
Overhead safety compliance (including low lines)	100	300	800	300	300	600	100	100	100	600
Barber Road - Copper & Swan replacement	2,190	7,982	-	-	-	-	-	-	-	-
Barber Road - HV & LV rehabilitation	1,905	-	-	-	-	-	-	-	-	-

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Distribution and LV Cables										
Barber Road - Feeder Cable Renewal	3,438	-	400	-	-	-	-	-	-	-
Pillar renewal	200	200	200	200	200	200	200	200	200	216
UG cable renewal	150	200	300	300	300	300	300	300	300	300
Distribution Transformers										
Transformer Renewal Programme	400	400	400	400	450	450	450	450	450	400
Distribution Switchgear										
RMU replacement	2,877	-	-	480	480	480	480	480	480	-
Overhead switchgear replacement	480	480	450	480	480	480	480	480	480	600
Other System Fixed Assets										
Opaheke LCP control module replacement	-	-	-	-	-	-	-	-	-	450
Relay replacement	2,000	-	-	2,000	-	-	-	-	-	-
RTU, battery renewal	100	90	120	140	105	100	90	100	100	105
Substation security	1,410	-	-	-	-	-	-	-	-	-
SCADA Radio equipment upgrade	1,000	2,000	3,500	1,000	2,500	-	-	-	-	-
Subtotal	37,613	28,559	15,139	18,551	12,975	12,360	10,072	17,173	17,253	23,540
Capitalised Maintenance	955	955	955	955	955	955	955	955	955	955
Capital Expenditure Total	38,568	29,514	16,094	19,506	13,930	13,315	11,027	18,128	18,208	24,495

Figure 7-68 Summary of Planned Renewal and Replacement Network Capital Expenditure

Note: Forecasts are shown in Real (constant) prices.

¹³ Capital Expenditure includes rollover expenditure from FY20, as indicated in Chapter 11, Evaluation of Performance.

7.14.2 Network Operating Expenditure

Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Operational Expenditure (000's)										
Subtransmission Network										
Subtransmission lines	150	150	150	150	150	150	150	150	150	150
Subtransmission cables	30	30	30	30	30	30	30	30	30	30
Zone Substations										
Zone Substation transformers	130	130	130	130	150	150	170	170	170	170
Zone Substation switchgear	150	150	150	150	160	160	180	180	180	180
Zone Substation other equipment	100	100	100	100	100	110	110	110	110	110
Zone Substation buildings and grounds	100	100	100	100	110	110	120	110	110	110
Distribution and LV Lines										
Distribution poles and crossarms	900	900	918	946	951	955	965	974	984	995
Distribution conductor	150	150	153	165	166	168	169	171	180	182
Fault indicators and Earthing	25	26	27	27	28	28	29	29	32	32
Distribution and LV Cables										
Distribution and LV cables	120	136	142	145	148	151	157	160	170	173
LV Pillars	90	100	102	104	106	108	115	117	125	130
Distribution Substations and Transformers										
Distribution transformers	450	459	468	470	475	477	482	490	495	500



Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Distribution Switchgear										
Ring main units	150	155	158	160	163	166	170	173	180	180
Overhead switchgear	150	155	155	155	155	160	160	165	170	173
Other System Fixed Assets										
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	100	120	120	140	150	180	180	180	180	180
Load control equipment	40	40	40	40	40	40	40	40	40	40
Battery banks	30	30	30	30	30	30	30	30	40	40
SCADA, Communications & Control	650	650	650	650	650	660	650	702	713	713
Vegetation										
Vegetation	2,000	2,049	2,081	2,132	2,184	2,237	2,292	2,348	2,406	2,465
Public Safety Services										
Public Safety Services	100	100	100	100	100	100	100	100	100	150
Faults and Reactive Maintenance										
Faults	2,100	2,151	2,185	2,238	2,293	2,349	2,407	2,466	2,526	2,588
Capitalisation										
less Capitalised Maintenance	-955	-955	-955	-955	-955	-955	-955	-955	-955	-955
Operational Expenditure (Total)	6,780	6,946	7,053	7,226	7,403	7,584	7,770	7,961	8,156	8,356

Figure 7-69 Summary of Network Operating Expenditure

Note: Forecasts are shown in Real (constant) prices.

8 NETWORK DEVELOPMENT

8.1 Planning Approach

Our long-range plan focuses on developing our subtransmission network and zone substations by taking into consideration:

- Plans for new areas of supply (e.g. new subdivisions) and anticipated demand growth in existing areas of supply;
- Adequacy of distribution feeder network to meet future security and capacity requirements; and
- Adequacy of our points of supply, subtransmission network and zone substations to meet future security and capacity requirements.

Our short-range plan focuses on developing our distribution network, in particular feeder performance and capacity to meet our operational objectives. Factors we consider in our short-range plan include:

- Network safety;
- Customer connections;
- Overload relief;
- Voltage correction and control;
- Power factor correction;
- Service quality improvement;
- Operation and maintenance;
- Loss reduction; and
- Operating efficiency improvement.

We have continued to adopt a longer planning timeframe to take into account the increasing time required to negotiate and agree on land-rights for new work for upgrades requiring land purchase, designations or easements.

8.1.1 Planning Drivers and Assumptions

The key drivers and assumptions for our investment plans include:

- The network is to meet all safety requirements;
- Selected options should maintain flexibility for future development if they can be economically justifiable;
- We will invest (where economically feasible) to meet our security standards (see section 8.1.2);
- We will invest to meet the demand forecast (see section 8.2); and
- We will make investment choices that minimise the risk of asset stranding.

When determining network investments, a number of options are always considered. The investments presented in our plan have been chosen because they represent the best value long term solutions for our network and customers. In all instances we have considered options based on non-network solutions using new technology. However, based on current costs none are considered economically viable and so have not been chosen. We continue to monitor the costs of these options and will continue to consider them in future.

8.1.2 Security Criteria

Our security criteria has been established based on the level of service sought by the customers connected to our network, but also reflects historical network requirements and geographical constraints. We commission an annual survey of our customers, and from this, and other feedback, we have established that, in general, customers are satisfied with the level of service they receive (outage frequency, response to faults, and restoration). Where customers are less satisfied, they are rarely willing to pay more for a higher level of service. We use the customer service levels outlined in Chapter 3 to inform our security criteria.

Security criteria are one part of the overall mix of factors that result in the level of reliability that customers receive. The other factors include adverse weather, third party events, asset condition and operations and maintenance.

The Counties Power network uses the EEA ‘Guidelines for Security of Supply in New Zealand Electricity Networks’ as the basis for its network planning and seeks, as a minimum, to meet its requirements. In 2016 an independent review of our previous security of supply guidelines was carried out comparing these with those of our peer group. This was followed by an independent review recommending we reduce the number of categories and simplify them. Figure 8.1 below sets out the security criteria we use to design our network.

Class of Supply	Group Peak Demand (GPD) MVA	Examples	First Outage	Second Outage
C1	0-0.5	Customer connection Urban LV distributor/substation	Repair time	Repair time
C2	0-1.5	HV radial feeder (or spur from main feeder)	Repair time	Repair time
C3	Up to 12	Rural zone substations feeders (22kV and 11kV)	within 3hrs 50% GPD Repair time 100% GPD	Repair time
C4	12 to 40	Zone substations (includes subtransmission feeders) (33kV or 110kV)	Immediately 100% GPD less 12MVA Remaining 12MVA - 3 hrs	Repair time
C5	Large Customers	Large industrial customers	By agreement in connection contract	

Figure 8-1 Counties Power planning security criteria

Notes to Figure 8-1:

- **GPD** is the Group Peak Demand
- **Repair time** is defined as the total time from the start of the outage until customer(s) have power restored (i.e. the total outage time as seen by the customer).
- **Immediately** means either an uninterrupted supply or restoration in less than one minute.

The term “first outage” means the loss of any single supply system component. Similarly, “second outage” means the concurrent and independent loss of a second supply system component.

To limit the impact of outages on customers, the maximum substation size will normally be based on a firm capacity of 40MVA (i.e. two 20/40MVA transformers and associated subtransmission circuits). While outages of a substation are infrequent this limits the number of customers affected by an event to around 15,000. Past plans were based on higher capacity substations (i.e. two 30/60MVA or three 20/40MVA transformers); however studies have shown that the customer impact of this configuration is not desirable.

The impact of this together with the changes to the number of customers per feeder (further information below) will impact on forward planning, resulting in a larger number of smaller substations than previously considered, with the overall aim of improving (reducing) our SAIDI and SAIFI performance figures, i.e. providing better customer service in addition to improving resilience under HILP events. Limiting substation firm capacities to 40MVA has the added benefit of making it easier to restore load following HILP events, as this will result in more substations and therefore increased interconnectivity. We believe this is an appropriate response to the increasing number of storm events observed in recent times.

Criteria for Customers

For larger individual customers, we set the security criteria for their supply based on the size of their load, their location, and any special conditions agreed in their supply contracts. Such customers may make a price-quality trade-off and pay a larger annual amount for higher levels of service compared with the average customers.

For most customers, who are fed by shared assets, it is not possible to set individual service levels and thus our approach is to aim to meet the targets developed above.

A further factor influencing network design is the adoption, in recent years, of monitoring network performance by SAIDI, SAIFI and CAIDI. These factors include both planned outages and unplanned (fault) outages.

With our aim to continuously improve network performance and in line with our security criteria, we have adopted the limits shown in Figure 8-2 towards the desirable number of customers fed off a high voltage feeder.

Feeder section	Max No Customers
Switch segment	300
Total feeder	1,500

Figure 8-2 Customer numbers for feeders

We have identified that we currently have five feeders which exceed this number of customers and we are investigating ways of achieving the new target. Two of the five feeders have had interim measures implemented to reduce the customer impact due to unplanned outages whereas feeder splits have been scheduled for the remaining three feeders over the fifteen-year planning period. In addition, the maximum number of customers between isolating switches on HV feeders is being targeted at 300 to assist with restoration when a fault occurs, where back-feeds from other feeders are available.

Criteria for Feeders

Feeders are designed to meet the statutory voltage level requirements under normal operating conditions. Under emergency conditions these levels may not be met for short periods while switching or repairs take place.

In designing new or upgraded feeders we review the level of losses and seek to minimise these where economically viable.

A developing problem as new building takes place is that of rural feeders supplying pockets of urban customers as land use changes and former small settlements are developed into towns or industrial centres. Rural feeders are typically overhead construction and have a lower reliability than urban feeders due to their exposure to external factors such as vegetation, wildlife, and weather.

Urban feeders also often have substantial sections of underground cable which normally provides a more reliable service than overhead lines. As urban boundaries of the network extend, some rural feeder sections can be reconfigured to connect the high-density residential load to urban feeder sections to improve reliability. These feeder reconfigurations will generally utilise existing switches to change network open points but may require conductor upgrade in some cases.

8.1.3 Design Standards

Our distribution network is predominantly rural with earlier subtransmission built at 33kV and distribution built at 11kV. At these voltages we can experience voltage constraints and high network losses typical of a rural distribution network. To mitigate these issues, where economically justified, we have been progressively introducing two new voltage levels:

- 110kV as a standard subtransmission voltage; and
- 22kV as a standard distribution voltage.

Introducing a higher subtransmission and distribution voltage should also enable us to reduce the number of our zone substations that we need on our network as we can supply the demand from fewer sites, which should lead to lower costs overall.

However, an independent review of the significant impact of an outage of a very large zone substation on both SAIDI and SAIFI performance has resulted in us looking to limit the total load (and thus the number of customers) on our existing larger zone substations below the theoretical maximum and to similarly limit the capacity of new substations. This matches the approach adopted to the maximum number of customers on a feeder.



The capacity of these existing larger zone substations will be utilised as part of the resilience of the network by being able to support load through the network if a major event affects another adjacent substation.

The move to 110kV/22kV has progressed steadily for our eastern area (i.e. the area fed from the Bombay GXP) and it is intended that the remaining pockets of 33kV/11kV will be removed with the project to establish the new Barber Road 110/22kV substation to allow the decommissioning of the old 33/11kV substations at Mangatawhiri and Ramarama.

The western area of our network is supplied at 33kV from the Glenbrook GXP with two circuits each to Karaka and Waiuku substations and a single 33kV spur line from Waiuku to Maoro substation.

The establishment of Special Housing Areas (SHAs) at Glenbrook Beach and Clarks Beach together with subdivisions at Kingseat and Waiau Pa has resulted in the need for new substations in this area. The Glenbrook GXP does not have 110kV supplies available and this would be a significant expense by Transpower to provide this. We have established that a 33kV subtransmission system in this area is appropriate for the foreseeable future. Similarly retaining 11kV as the feeder voltage is appropriate for normal purposes, noting that for very long rural feeders, conversion of them (or parts of them) to 22kV, using autotransformers, may be appropriate in future to address voltage drop issues.

Subtransmission and Zone Substation Design

The District Plans in our network area presently allow for construction of overhead lines of up to 110kV as a permitted activity in rural and formerly non-residential areas. To meet the security of supply levels in Figure 8-1 the subtransmission circuits (either at 110kV or 33kV) are arranged such that there are at least two circuits into class C4 substations. These circuits may be either on a ring arrangement or parallel circuits from the GXP.

There will be two transformers at such C4 class substations capable of meeting the requirement that in the event of a fault, 100% of the peak load, less 12MVA, can be supplied continuously with the balance being restored within three hours. The preferred transformer size is 40MVA for 110/22kV substations and 20MVA for 33/11kV substations. Transformer impedances are chosen to limit the maximum fault current to 16kA (at 22kV) and 13.1kA (at 11kV), with margins built in to accommodate increases in source fault levels and distributed generation. The power transformer tap changer range at our zone substations defines the minimum voltage levels for our subtransmission network.

New substations (and existing substations as they are re-built) follow good engineering practice adopting non-oil circuit breakers, bus section switches, unit protection, increased arc containment and multiple fire zones.

To provide flexibility for future load developments, the switchboards are rated to be supplied with 60MVA transformers and provision is made to extend the switchboard to connect additional distribution feeders. Most of the existing outdoor substations have space for a third transformer, future substations will be designed for two transformers and capacity will be expanded by alternate engineering solutions. Smaller substations (Class C3) may be fed on a spur line, however where possible a ring feeder approach will be adopted to allow for future growth and provide greater security. A single transformer may be installed, however provision for a back-up (on site or transported in) will be made to cater for a transformer failure.



Distribution Network Design

We generally run our feeders radially out from the zone substations. Our preferred feeder configuration, where geography allows, is for a Y construction with the bottom of the Y starting near the zone substation and the ends of the two arms of the Y being open parallels with other feeders, where possible from another zone substation. In this configuration we divide our feeders into three by installing reclosers (in rural areas) at the Y junction of the feeder and remotely operable switches at each end arm of the top of the Y. In the urban network, the feeder architecture can differ due to the greater number of switching points, however through the use of ring main units placed in strategic locations, switching of feeders allows for quick isolation and response to unplanned outages.

Where possible we will locate main feeder routes off high traffic routes or underground where significant traffic hazards exist. We generally avoid double circuit overhead lines along high traffic routes where possible.

Figure 8-3 specifies our standard distribution network conductor and cable ratings.

Feeder Type	Cable	Rating	Design Rating	Overhead Conductor	Cross-section	Rating	Design Rating	Notes
Distribution	630mm ² Al	590A	590A	Cockroach	256mm ²	560A	560A	1,2,3,4
	240mm ² Al	360A	240A	Cricket	160mm ²	420A	280A	3
	95mm ² Al	200A	140A	Grasshopper	85mm ²	290A		3, 5
				Fluorine	40mm ²	190A		5, 6

- Notes:
- 1. Include fibre optic cables in our underground cables for protection, SCADA and cable temperature functions;
 - 2. Use underground cables in urban areas;
 - 3. Use AAC conductor where possible. AAAC may be used as an alternative for long spans;
 - 4. Use maximum span lengths of 80-100 metres; and
 - 5. Run spurs for volt drop considerations rather than capacity.

Figure 8-3 Cable and conductor ratings

The design criteria we utilise for our distribution switchgear (RMUs) is that they shall have:

- A fault rating of 16kA;
- A bus rating of 630A;
- Three phase switching; and
- Remotely operable disconnectors on four function units.

Equipment Ratings

We design and operate our network to the following acceptable equipment load limits:

- 100% of nameplate zone substation power transformer ratings, with short duration overload to 120% under fault conditions;
- 100% of the switchgear, line and cable ratings; and
- The acceptable load limit on distribution transformers depends on the period of maximum demand and whether it is a winter or summer peak load:
 - 100% of the transformer rating where the maximum transformer load is spread over many hours; or
 - 150% of the transformer rating where the load is peaky over one to two hours, such as supplying a residential subdivision.

We will consider the use of cyclic ratings of circuits as loading on them increases, as this may provide an appropriate way of delaying further investment – particularly where such loading only occurs for short durations such as during plant outages (planned or unplanned).

8.1.4 Network Development Options

Network Development Philosophy

Our network design philosophy consists of the following elements:

- We make sure any development option we consider has public and employee safety as a primary requirement;
- Where appropriate, we shall implement phased solutions to defer major subtransmission and distribution investment;
- Our network is primarily radial with the ability to inter link various feeders if the need arises;
- We continually reassess and re-configure our network configuration to respond to load increases and changes in demand patterns to optimise overall performance;
- Upgrade of our distribution feeder network allows better utilisation of tie-lines and alternative feeds. This has also allowed us to defer upgrading some zone substations by temporarily re-allocating load to adjacent zone substations;
- Where we identify potential increase in demand (see Section 8.2), we plan for significant line routes and substation sites to serve the demand and seek designations well in advance;
- The security criteria recognise that it is not economic to provide full redundancy to all customers on our network; and
- We continue to improve our network performance by employing effective design and construction techniques, such as delta line construction and strategic deployment of pole-mounted circuit breakers, remote controllable switchgear and fault passage indicators.

Subtransmission Development

When identifying subtransmission development options, we consider:

- Long term load and usage forecasts in the area, considering customer type and needs;
- How the subtransmission system will support new zone substation transformer capacity within growth areas;
- Alternative solutions using existing assets or taking advantage of technological innovations;
- Optimising capital investment on the network;
- Minimising the risk of stranding; and
- The impact of existing and proposed embedded generation developments.

Distribution Development

When identifying distribution network development options, we consider:

- Industrial, commercial and residential developments affecting specific areas of supply and requiring capacity augmentation;
- The need for feeder reinforcement or distribution tie-line construction for security reasons;
- Voltage regulation, particularly on rural feeders, and the need or otherwise for regulators, reactive compensation or voltage conversion;
- Loss reduction through correct conductor selection and optimised switching configurations; and
- The impact of existing and proposed embedded generation developments.

Development on the Network Boundaries

We share common boundaries with two electricity networks, Vector to the north, WEL Networks to the south, and although not immediately on our border, Powerco's 'Eastern' network is adjacent to the south-east of our network.

When considering development options, including capacity and security projects we will look to share investment with our neighbours as the most economical solution may be one that satisfies a number of mutual needs.

We share interconnection points with Vector in two locations and WEL Networks in one location.

Conversion to 22kV

Conversion to 22kV operation can be used to increase our network capacity to meet load growth and service requirements effectively. This involves upgrading the 11kV distribution network to 22kV where there are identified capacity and voltage constraints, and each area for conversion is assessed on its individual merits, including consideration of a range of alternatives. For all new work, we install insulators, cables and switchgear to be capable of 22kV operation. Where practical and cost effective we will convert the relevant distribution network to 22kV when 11kV capacity or voltage constraints occur and there are no cost-effective solutions to improving 11kV capability (e.g. the use of voltage regulators, reconductoring or network reconfiguration).

Low Voltage Reticulation

New subdivision developments drive the extent of underground low voltage reticulation augmentation. We liaise closely with local surveyors and property developers who are responsible for most of the subdivision works in the area to identify their needs. Planning of network augmentation also considers the growth plans developed by local councils. The majority of overhead low voltage augmentation work comes from smaller rural subdivision developments.

In the longer term, we expect alternative technologies to change the way in which our LV network is used, ranging from periods where electric car charging systems significantly increase LV demands, through to periods where high levels of distributed generation output could lead to reverse power flows and voltage rise. To assist with network performance under either scenario, we have moved to shorter runs of low voltage feeder, and to use uniform cable sizes for the length of the feeder.

New Equipment Types

We regularly investigate new equipment types to determine if they are cost effective in enhancing our network performance. We follow the process identified in Chapter 6 to ensure that any new equipment meets construction, technical and safety standards. Our teams identify potential new equipment as part of carrying out compliance and safety surveys, asset renewal policies for aging assets and new customer requirements.

8.1.5 Network Alternative Solutions and Technology Impacts

Refer to Chapter 6 - Innovation and New Technology.

8.2 Demand Forecast

The maximum demand on our system is the main driver for system growth investment in our network. Our demand forecast defines future network requirements and is a key input into determining the appropriate timing for capacity and security related investment in our subtransmission and distribution networks for the AMP period.

Demand forecasts estimate the peak electrical load required in different parts of the geographical area served by the network. Forecasting future demand is subjective and uncertain; and only provides an indication of when potential capacity and security issues are likely to occur on our network.

We have traditionally been a small, predominantly rural, distribution network, with demand particularly sensitive to changes in industrial demand within our area. However, this is already starting to change, and planned developments and local authority zoning should see our domestic customer numbers more than double in the next 20 years. The majority of this growth is in urban areas although some is in urban pockets in more rural locations. Major industrial/commercial load growth is also already occurring in Pokeno and is expected in the Drury area and elsewhere.

Thus, we are facing a period of ongoing load growth with the associated need to invest in new zone substations and associated subtransmission circuits to supply the new developments. This will see the network develop into a predominantly urban one based on the location of ICPs although it will still have an extensive network of rural lines.

Counties Power recognises the potential changes in demand characteristics from increased energy efficiency in new homes, new energy usage patterns through the use of energy storage systems and increases in electric vehicle charging over time as the technology matures. Our demand forecast assumptions and approach are based on historical demand data and are reviewed each year as we see new trends emerge for energy consumption on the network.

We accommodate the sensitivity in our demand forecast by monitoring demand trends continuously, revising our forecast periodically and varying the timing of our planned work. If demand growth is slower than forecast, we may defer investment and conversely if the demand growth is faster than forecast, we may bring forward investment.

Figures 8-4, 8-5 and 8-6 show our winter maximum system demand forecasts to 2035.

Figure 8-4 shows our expected maximum system demand with a projection tolerance band to accommodate alternative growth rates and the variable impact of temperature at the time of system peak.

Figures 8-5 and 8-6 show the forecast is a single “most likely” projection for illustrative purposes.

When considering the options for individual areas we prepare additional load forecasts to reflect both a higher growth rate (e.g. to reflect new housing being developed faster) and also a lower growth rate to reflect a possible slowing of the regional economy.

Overall consumption and peak demand in 2020 were in line with 2019 forecasts. However, the anticipated residential, commercial and industrial load growth in the short to medium term is uncertain as the impacts of COVID-19 are still not fully known. Requests for new connections are being received at a higher rate than had been anticipated and this is in line with what has been observed in the New Zealand housing market in 2020. Due to the uncertainty our demand forecasts are generally in line with the 2019 forecasts and will be continuously reviewed as more information becomes available.



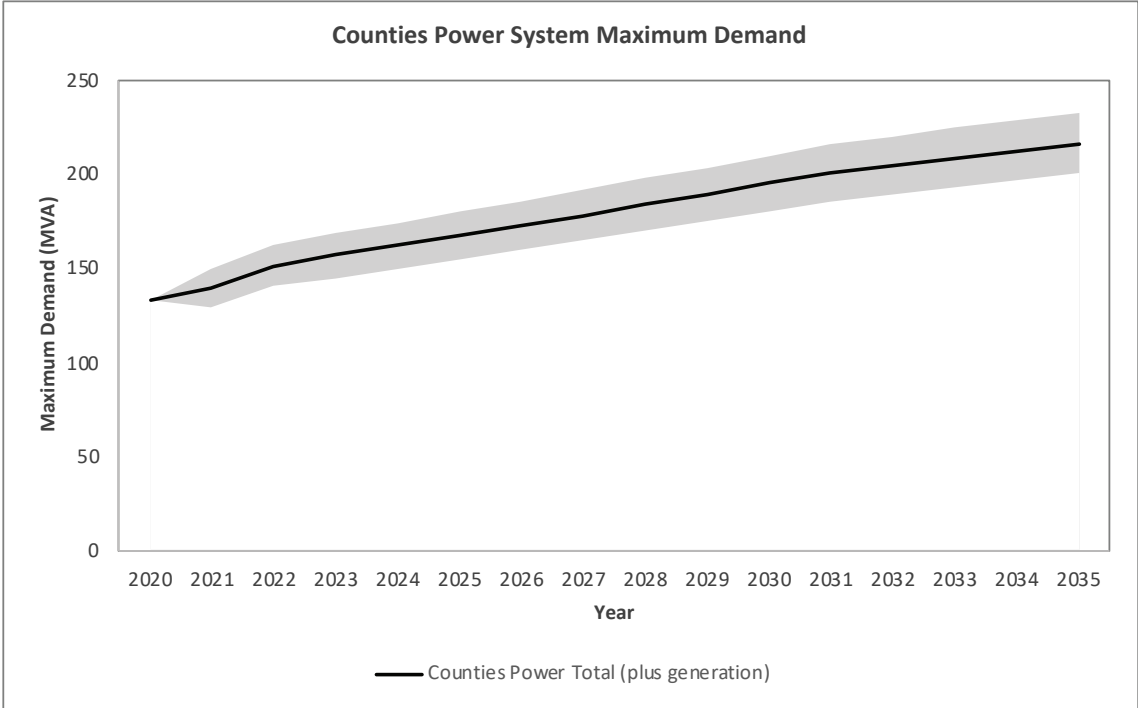


Figure 8-4 Winter Maximum System Total Demand with Tolerance Band Graph

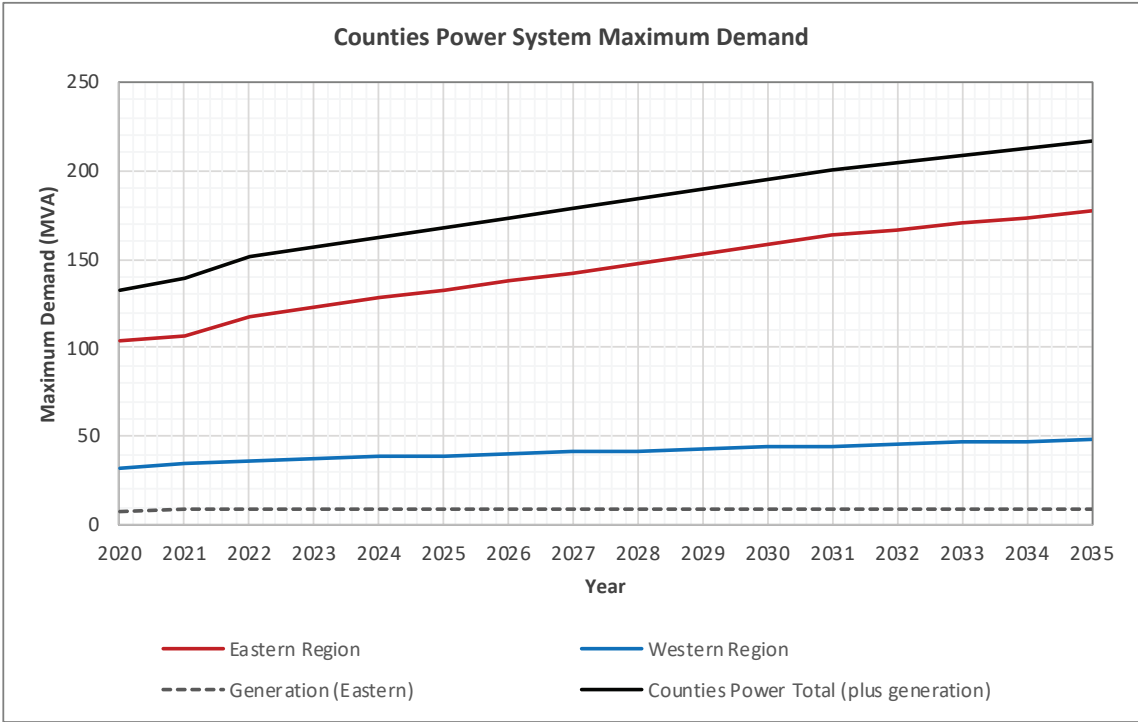


Figure 8-5 Winter Maximum System Demand Graph

Description	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Eastern Area	103.3	108.1	119.5	124.5	129.4	134.4	139.1	143.8	149.4	154.7	160.0	165.0	168.4	171.7	175.1	178.5	4.8%
Western Area	31.9	35.0	36.5	37.4	38.4	39.3	40.2	41.1	42.0	42.9	43.8	44.7	45.6	46.5	47.4	48.1	3.4%
Generation (Eastern)	8.2	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	9.0	0.6%
Counties Power Total (plus generation)	132.8	140.8	152.7	158.2	163.7	169.1	174.3	179.5	185.5	191.2	197.0	202.4	206.4	210.3	214.3	218.1	4.3%

Figure 8-6 Winter Maximum System Demand Table¹⁴

Our analysis of the load duration curves, for the period September 2018 to August 2020, indicates that the peak demand on our network exceeds:

- 90% of peak demand 0.1% of the time; and
- 80% of peak demand 1.5% of the time.

8.2.1 Demand Forecast Methodology

We utilise our load forecasting model to forecast the future demand on our network for the planning period. We start by developing forecasts for individual feeders based on historical trends and the anticipated growth of various sectors the feeder supplies. We then roll the individual feeder forecasts up to zone substation and ultimately back to the two Transpower GXP’s supplying our network, Bombay and Glenbrook.

We use the following inputs to develop our demand forecast:

- **Substation demand data:** We use fifteen minute average demand data collected from our SCADA system to monitor loads on all substations and feeders on our network. We use this data to analyse trends, load shifts and power factor for each feeder;
- **Embedded generation:** Every month we collect half-hourly data for generators over 200kW and analyse the data using applications we have developed internally for this purpose;
- **Coincident demands:** We extract the coincident maximum demand from the half-hourly data for our zone substations and embedded generation into our load forecasting spreadsheet;
- **System changes:** We record system changes and network reconfigurations to monitor load transfer between feeders and in various areas. We review these changes and consider spikes in active and reactive demands to verify the maximum demand for each feeder or zone substation;

¹⁴ We have included any known development that could result in significant increase in demand in our area when developing our network development plan, although we have treated the Drury South business park and Pokeno industrial area developments separately given their potential magnitude and sensitivity to assumptions regarding reticulation timeframes and the nature of the load.

- **Key customer demand:** We review the half-hourly energy data for key customers using demand meters installed at the various premises. We then examine demand trends to see if there is any change in growth at these sites. We also consult with our major customers to identify any planned future expansion and changes in their load demand;
- **Subdivision activity:** We track subdivision activities by feeder for the planning period based on our knowledge of local authority and developer's plans. Where load requirements are unavailable, we assume after-diversity maximum demands of 2.6kW per lot for new domestic subdivisions. Demand estimates for industrial/commercial subdivisions are based on customer requests;
- **Land zoning:** To set long term loading expectations we consider the relevant Council zoning plans to identify the ultimate developments likely for an area and their impact on our network; and
- **General demographic and economic trends:** We collect demographic trend information from publicly available census data and on new connections to our substations¹⁵. We use this data to verify our demand forecast.

8.2.2 Load Forecasting Assumptions

Within the load forecasting model assumptions are made regarding:

- Demand management;
- Distributed generation;
- Load developments; and
- Other drivers.

Each of these are described below.

Impact of Demand Management

Ripple control forms an integral part of our load management strategy and provides a vital network investment deferral option. We assume that peak demand on the network has the most efficient level of load control in place, and thus peak demand observed is inclusive of the impact resultant from load control.

We incorporate power factor penalty charges in major supply agreements, which encourage our customers to maintain an efficient power factor. We monitor the impact of this scheme and adjust our future load forecasts accordingly once we determine that a major customer has lowered their demand through power factor correction.

Impact of Distributed Generation

We consider how likely a distributed generator will be available when required when deciding if it is to be included in our demand forecast. Factors we consider are:

- **Generation availability:** is it run continuously or is it only run for limited periods at a time; and
- **Generation redundancy:** does the generation connection to our network have an appropriate level of redundancy. For example, if the generation is on radial feeders, we do not include it to reduce zone substation maximum demand forecasts (as it is on N security). However, we can aggregate a number of such generators into our regional and system maximum demand forecasts as they are spread over a number of feeders and zone substations and not subject to a single common mode failure.

Given the nature of the large-scale distributed generation currently on the network, we do not rely upon generation capacity for network support. However, we assume that peak periods include a level of distributed generation operating based on historic operating profiles. With the exception of Hampton Downs and Dent Place (Papakura) generation, no single generator would have a material impact on network demand at peak times.

Impact of Uncertain Load Developments

Large scale residential subdivisions do not pose the same problems as industrial subdivisions as we can assume their contribution to demand with a reasonable degree of certainty.

For residential subdivisions, we work with the developer to understand the timeframes for subdivision stages to progress and assume that new housing developments will be evenly spread over a number of years. We normally assume uptake over a period of 18 months following reticulation of the subdivision, however for SHAs a faster uptake is also considered.

Industrial subdivisions provide a high level of uncertainty as often at development time the eventual occupier of the sites is not known, nor is their load size and type. We provide a standard three phase supply point unless more specific requirements are known. Often, we install dedicated transformers for large customers as development progresses.

Other Assumptions

We have used the following assumptions in developing our demand forecast:

- We have assumed a 2.6kVA ADMD for each domestic dwelling¹⁶;
- Power factor: as we know the power factor for most feeders from demand data, our load forecasting is in MVA; and
- Energy efficient appliances and industrial plant using power electronic devices will cause distortion of supply resulting in poor power factor and higher harmonics. This also applies to energy efficient lighting including both compact fluorescent bulbs and LEDs (this could ultimately lead to increased feeder loading). So far, the impact of such devices has been limited to localised issues and thus only their overall impact on slowing load growth has been factored into our demand forecasts.

¹⁵ Obtained from our daily operations

¹⁶ 2.6kVA ADMD (After Diversity Maximum Demand) per dwelling is based on historical demand data and is subject to review particularly with changing energy usage in new homes. The current figure has recently been verified by checking smart meter data in subdivision developments undertaken in the last few years.

Together our security criteria, design standards and our view on demand growth combine to form the basis for the investment programme over the period covered by this plan. While the assumptions above are used in this plan, as reinforcement projects are required, more detailed localised load forecasts are prepared considering a spread of development possibilities which feed into the detailed business case prepared before investment.

8.3 Development Programme

The following sections provide an overview of current development programmes in our network. The development programme is split into the two network regions, the eastern region where most of the growth occurs, and the western region which is dominated by rural and industrial customers. More information on the development programmes for each region is provided below.

8.4 Eastern Region Development Plan

The eastern region is supplied from Transpower's Bombay Grid Exit Point and covers areas supplied by our Opaheke, Pokeno, Pukekohe, Tuakau, Mangatawhiri and Ramarama zone substations.

Our subtransmission network in the eastern region consists of:

- One 110kV ring from Bombay supplying Pokeno, Pukekohe and Tuakau;
- Two 110kV lines from Bombay to Opaheke;
- Two 33kV lines from Bombay to Ramarama; and
- One 33kV line from Bombay to Mangatawhiri.



Figure 8-7 and 8-8 below show the single line schematics for the subtransmission network supplied from the Bombay GXP.

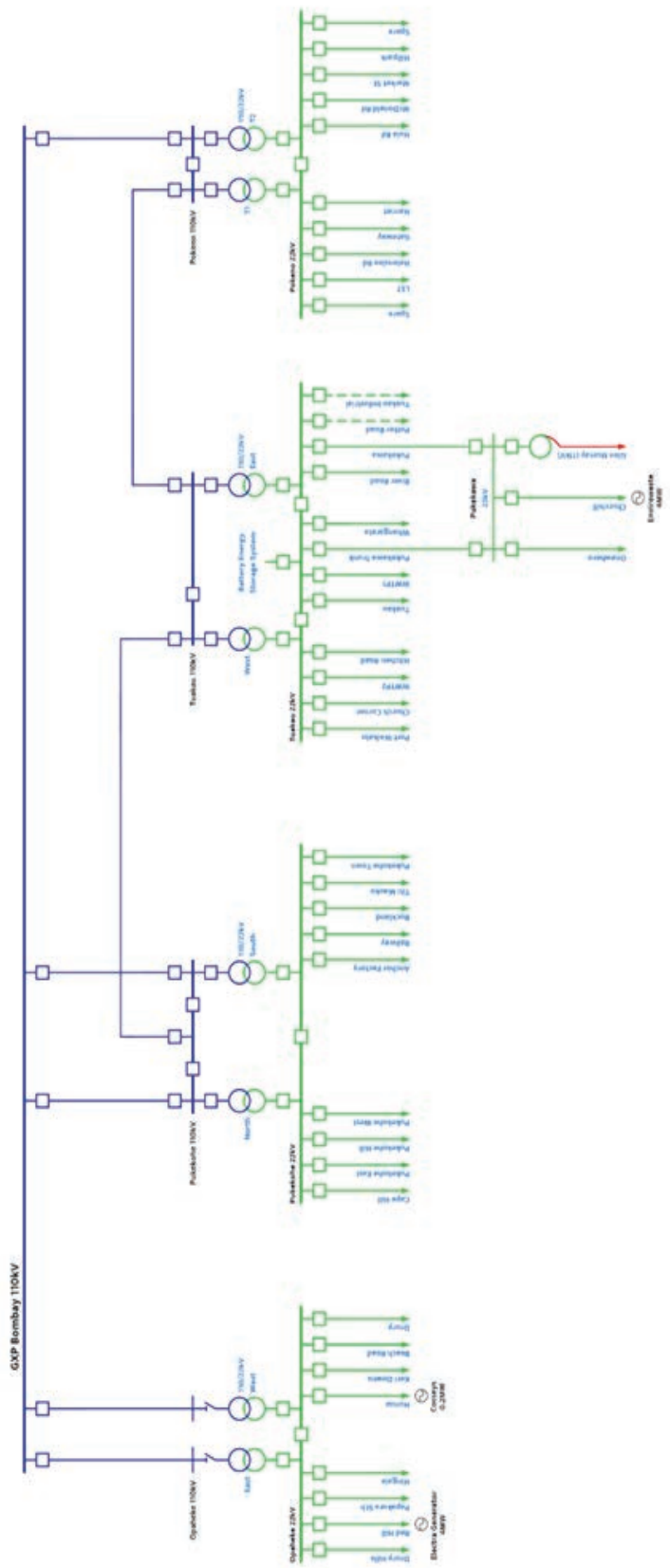


Figure 8-7 Single Line Schematic of the Eastern Region 110kV subtransmission network

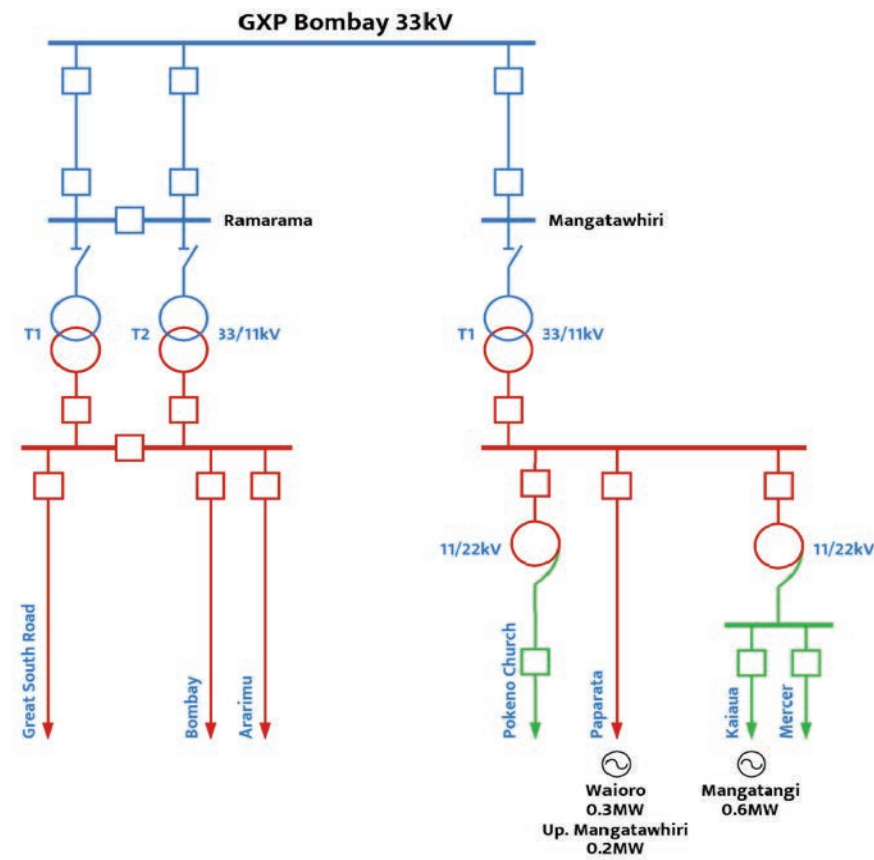


Figure 8-8 Single Line Schematic of the Eastern Region 33kV subtransmission network

Figure 8-9 and 8-10 show the demand forecast for the eastern region and the eastern region zone substations. The Bombay supply limit shown below is for the high south flow. Further detail on this is in section 8.4.1.

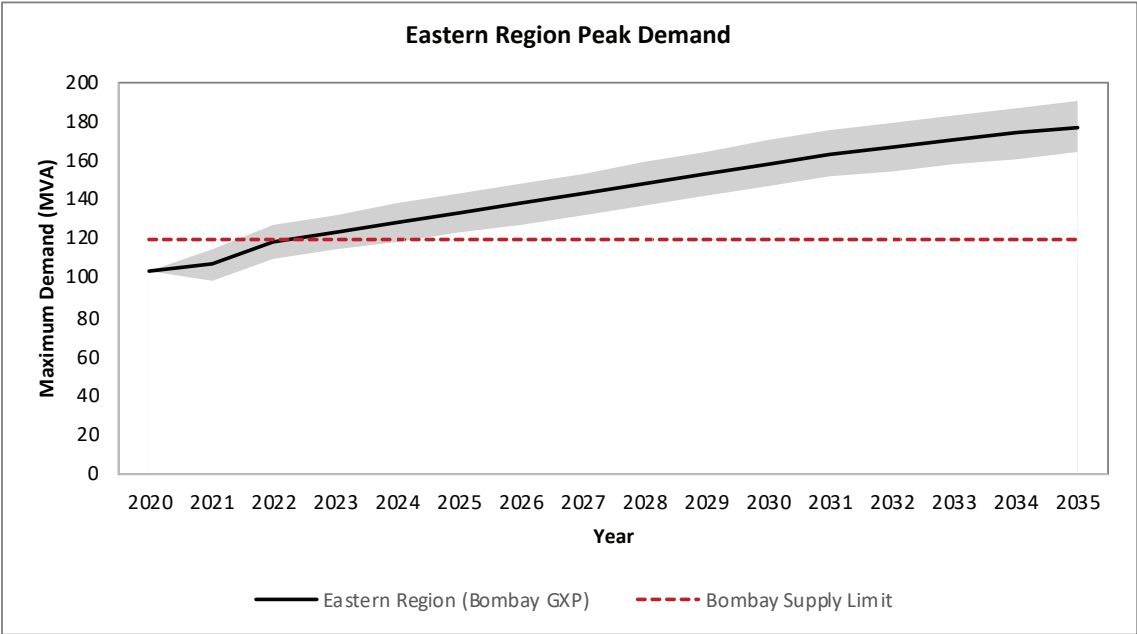


Figure 8-9 Winter Maximum Demand Eastern Region Graph

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak																Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Pukekohe	110/22kV	42.0	43.2	45.2	46.1	47.1	48.0	49.0	50.0	51.4	52.9	54.4	55.8	57.3	58.8	60.2	61.7	3.1%
Opaheke	110/22kV	27.3	27.8	31.1	34.3	37.6	40.9	43.9	47.0	50.1	53.5	56.9	60.3	62.1	63.8	65.5	67.3	9.8%
Tuakau	110/22kV	22.5	18.3	21.1	21.2	21.3	21.4	21.5	21.6	21.7	21.8	21.9	22.0	22.1	22.2	22.3	22.4	0.0%
Pokeno	110/22kV	0.0	14.7	18.4	19.1	19.9	20.6	21.3	22.1	22.8	23.5	24.3	24.4	24.6	24.7	24.9	25.0	2.8%
Ramarama	33/11kV	6.6	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-6.7%
Mangatawhiri	33/11kV	7.4	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-6.7%
Barber Road	110/22kV	0.0	0.0	14.0	14.4	14.8	15.1	15.5	15.9	16.0	16.2	16.3	16.4	16.6	16.7	16.9	16.9	0.8%
Eastern Region (Bombay GXP)		103.3	106.8	118.2	123.2	128.1	133.1	137.8	142.5	147.9	153.2	158.5	163.4	166.8	170.2	173.6	177.0	4.7%

Figure 8-10 Winter Maximum Demand Eastern Region Table

We can expect significant residential growth in the Auckland Council area over the next 10 years. The Future Urban Land Supply Strategy (FULSS) states that there are currently 15,000 dwellings proposed on live zoned or special housing areas both within the large future urban areas of the Hingaia Peninsula, Drury-Opaheke and Pukekohe-Paerata areas, with a further 4,000 dwellings proposed on development ready sites throughout the rural settlements of Clarks Beach, Glenbrook Beach, Karaka North, Kingseat and Patumahoe. In 2019 Auckland Council adopted the Drury-Opaheke Structure Plan and Pukekohe-Paerata Structure Plan, which could see up to 22,000 new dwellings in the Drury-Opaheke area and 12,500 dwellings in the Pukekohe-Paerata area in the next 30 years.

Within the Waikato District Council area, Pokeno continues to see significant residential and industrial expansion, with further rezoning of land from rural to residential likely if the Proposed Waikato District Plan is adopted.

In the Drury area where significant development is in progress (and expected to introduce new load in 2022) we are aware of a number of significant developments which have the potential to add new demand to the network. These include Drury South Crossing (previously referred to as the Drury South Business Park), the Auranga subdivision west of SH1, Kiwi Property Trust and Oyster Capital developments south of the existing Drury area.

We will continue to review demand growth in the Drury area, and if it is higher than anticipated, we will bring forward building the Quarry Road substation (see Section 8.4.2).

The following sections’ (Section 8.4.1 to Section 8.4.6) describe the subtransmission and distribution issues and plans for each of the zone substation areas within the eastern region.

8.4.1 GXP and Eastern Area Investment Requirements

Transpower’s Bombay substation has a transmission capacity limit¹⁷ of:

- 170MW for high north flow into the Bombay bus from the Waikato; and
- 120MW for high south flow into the Bombay bus from the Auckland Region.

The south power flow limit could be reached by 2022 and the north power flow limit by 2035 given current demand forecasts.

Distributed generation within our network, approximately 12MW, could defer the issue by one to two years. However, at present, 7MW of this generation is connected to our network by a single rural distribution line so may not be relied on to be available if required.

Completion of the eastern supply project will allow us to decommission our 33kV supply from Transpower’s Bombay substation around 2022, to coincide with their need to replace end of life 33kV equipment.

Transpower has indicated that they intend to install interconnecting 220/110kV transformers at Bombay to reduce loading on the 110kV circuits into Bombay. The timing of this work is anticipated in 2023 – 2025 and will address the risk of supply vs. demand highlighted above.

KiwiRail has approached Counties Power to build and own the 25kV circuits needed for their Papakura to Pukekohe rail electrification project. These will run from Transpower’s Drury GXP to KiwiRail’s feeder station which is expected to be nearby. This is in the process of being scoped, and an allowance has been included in FY23 for the completion of this work.

Description	Scope	Timing	Estimated Costs (\$'000)
KiwiRail 25kV circuits	Build two new 25kV circuits from Drury GXP to KiwiRail Drury feeder station	2022/23	3,500

Figure 8-11 Eastern GXP development plan

8.4.2 Opaheke Zone Substation

We expect significant residential growth in the area through the planning period associated with continued residential development in Karaka, Drury, Papakura and significant development in the Drury area.

The Opaheke 110/22kV zone substation is supplied by two 110kV circuits from Bombay GXP. Opaheke zone substation supplies 502 distribution substations in the urban areas of Beach Road, Keri Downs, Hingaia, south of Papakura and Red Hill and some rural areas in Hunua, Drury and east of Karaka. The load is predominantly residential, except for the Keri Downs area which is predominantly industrial. Opaheke is classed as a zone substation (C4) and is fully compliant with our security criteria (Refer to Figure 8-1). Major customers in this area include Asahi Beverages, Winstone Aggregates and Van den Brink Poultry.

¹⁷ There is no apparent seasonal pattern to the high north and south load flows

Figure 8-12 below shows the Rural-Urban Boundary (RUB) map for the Opaheke zone substation supply area (Papakura area), outlining the areas for future growth (green boundary line).

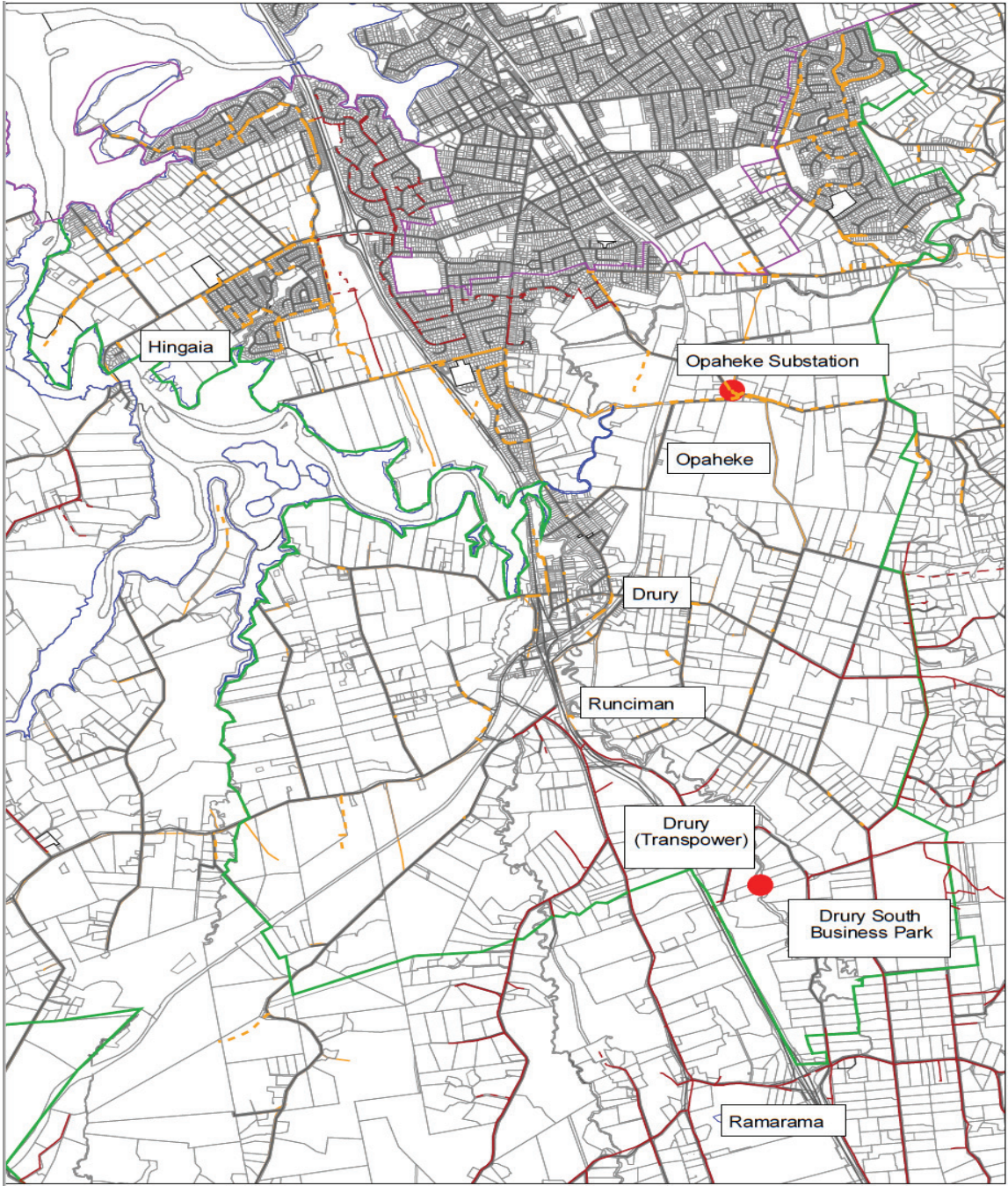


Figure 8-12 Opaheke Zone Substation Rural Urban Boundary (Papakura area)

The Opaheke load is largely residential and has a winter peak. The forecast peak demand for Opaheke zone substation and the distribution feeders from the substation is shown in Figure 8-13.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Beach Road	6.4	6.5	7.0	7.5	8.0	8.6	9.1	9.6	10.1	10.6	11.1	11.7	12.2	12.7	13.2	13.7	7.7%
Drury	4.1	4.6	7.2	9.7	12.2	14.7	17.2	19.8	21.8	23.8	25.8	27.8	27.9	27.9	27.9	27.9	38.6%
Drury Hills	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	4.3	4.7	5.2	5.7	6.2	6.7	7.1	7.6	7.3%
Hingaia	2.9	3.3	3.7	4.2	4.6	5.0	5.4	5.9	6.3	6.7	7.1	7.6	8.0	8.4	8.9	9.3	14.8%
Hunua	4.8	5.3	5.4	5.5	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.0	6.1	6.2	6.3	6.3	2.2%
Keri Downs	3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	7.6%
Papakura South	4.2	4.5	4.8	5.1	5.4	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	3.3%
Red Hill	3.2	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.9	3.9	3.9	1.5%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Opaheke	27.3	29.2	32.4	35.7	39.0	42.2	45.3	48.3	51.7	55.1	58.5	61.9	63.7	65.4	67.2	68.9	10.2%

Figure 8-13 Winter Maximum Demand at Opaheke Zone Substation and Feeders

Opaheke Zone Substation Investment
The Opaheke zone substation demand forecast is shown in Figure 8-14.

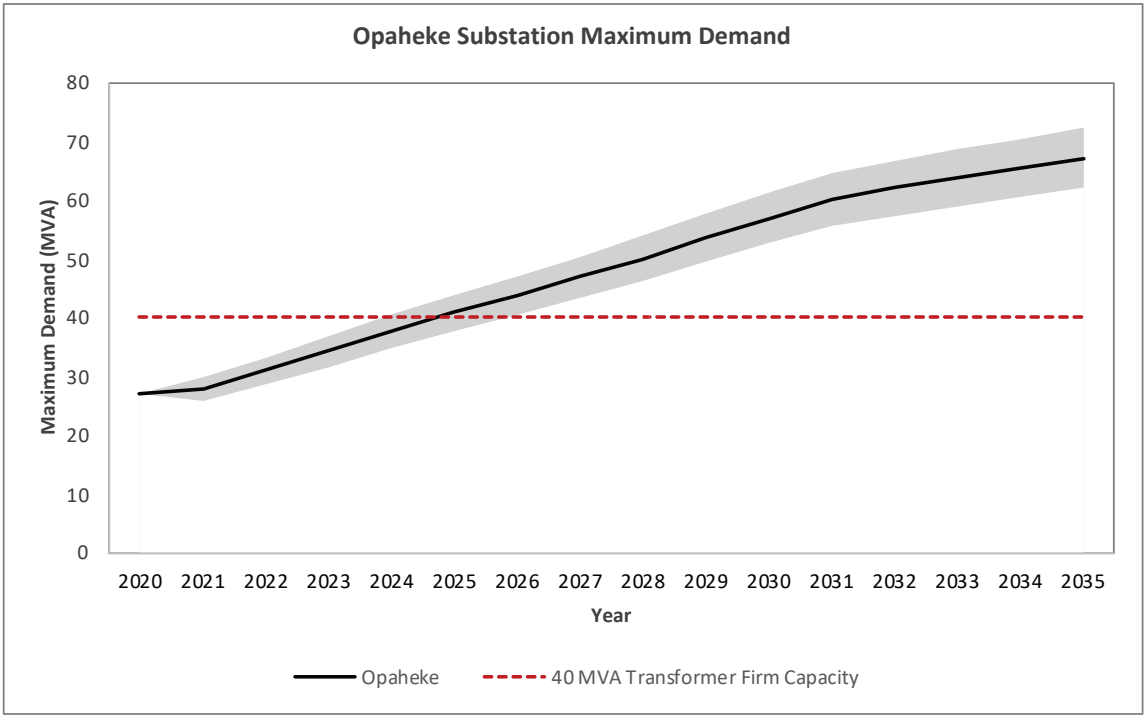


Figure 8-14 Opaheke Zone Substation Demand Forecast

Two 110/22kV, 20/40MVA transformers supply the load at Opaheke providing N-1 capacity of 40MVA. The Opaheke maximum winter demand is forecast to exceed the N-1 capacity of the transformers from 2028, or from 2026 if Opaheke supplies Drury South Business Park.

Development in the Drury area continues to progress. However, as any significant load is still at least a year away from requiring supply, we do not know how much load will be added to the network from the area, although initial approaches have been made by potential customers. Industrial/commercial load could, over 10 years, contribute up to 10-30MVA of load to our network given a typical mix of use.

In 2019, Auckland Council adopted the Drury-Opaheke Structure Plan which could see up to 22,000 new dwellings in the Drury-Opaheke area over the next 30 years. The load for these dwellings with associated services and commercial load could be significant in the long term. To cater for the uncertainty in demand and timing in the Drury area we have assumed an initial load of 2MVA in 2022 with an annual increase of 2MVA per annum up to a maximum load of 20MVA in 2031.

With the present network configuration, we would supply this load from our Opaheke substation in the short term with existing distribution feeders for which upgrades were completed in 2018.

For the medium to long term, the following four options were considered:

Option 1: Opaheke substation upgrade.

This would involve the upgrade of existing transformers and switchgear at Opaheke substation, and the construction of two new distribution feeders from Opaheke substation to reinforce supply to the Drury South Business Park and other anticipated load south of the Auckland City Rural Urban Boundary;

Option 2: Quarry Road substation establishment (supplied from Bombay GXP)

This would involve establishment of a new substation with supply from Bombay GXP at 110kV and a new section of 110kV line from the rebuilt 110kV tower line section to the new substation; or

Option 3: Quarry Road substation establishment (supplied from proposed new Drury GXP)

This would involve establishment of a new substation with supply from a new 220/110kV Grid Exit Point arising from redevelopment of the Drury 220kV switching station by Transpower. The new substation could also be used to reinforce supply to Opaheke substation, and potentially new developments in the north-eastern part of our network. By supplying this new substation, as well as potentially the Opaheke substation from the new GXP, this would also provide diversity benefits and reducing the high impact, low probability (HILP) risk of all supplies coming from Bombay GXP.

Option 4: Non – network alternatives

Use of localised energy storage or distributed generation to reduce peak demand under N-1 scenarios. However, this option is, at present, costly for the level of utilisation and required capacity to supply the additional load at Drury South Business Park development. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of the investment planning process.

Proposed investment

Our proposed investment is to build a new 110/22kV Quarry Road Substation to supply this additional load at the Drury South Business Park and anticipated additional load south of the Auckland City Rural Urban boundary. This new substation would supply the business park area, reducing the reliance on Opaheke substation and existing distribution feeders, and providing supply diversity.

When the load requires it, this substation will be supplied from the proposed new Drury GXP, which is also required by KiwiRail, who will require a supply from Transpower to electrify rail services in the area. KiwiRail will take a separate supply as they operate on voltages which are not standard for Counties Power. Counties Power will build, own and operate the 25kV lines from Drury GXP to KiwiRail's feeder station in Drury.

This option was chosen because:

- The expected load growth in the area justifies a substation ahead of feeder reinforcement from Opaheke;
- Load growth in industrial/commercial developments is often very uneven, and a substation enables us to respond to requests for supplies for significant loads in a short timeframe;
- The establishment of an additional GXP in the eastern region reduces Counties Power's reliance upon Bombay GXP. Following the establishment of Drury GXP, it will supply two substations and Bombay GXP will supply three existing substations (Pukekohe, Pokeno and Tuakau). At present all five existing substations in the eastern region are supplied from Bombay GXP;
- The diversion of the existing Bombay-Opaheke lines into the new zone substation will allow 160 MVA of load to be transferred between Bombay GXP and Drury GXP if necessary, which would offer significant operational flexibility if a HILP event were to occur, thus improving network resilience; and
- Furthermore, a 110kV switching station is required to supply the proposed Pukekohe North substation (see section 8.4.4).

We are monitoring load growth for the appropriate time to proceed as we do not want to invest a significant sum of money to supply a small load, however at the same time we will have the ability to mobilise quickly and establish a new substation quickly (similar to what was achieved at Pokeno) should the need arise. Land for this 110/22kV site has been secured for the establishment of this substation.

In the 2020 Asset Management Plan Update, the proposed timing for the Drury South area substation was 2023/24. This has now been deferred to beyond 2030/31. The reason for this is that based on discussions with developers and potential customers in the area, we expect load to require supply in mid-2022 and can be supplied from the existing distribution network. We note that in industrial/commercial developments, load growth is often very uneven, and it is important that we can respond to requests for supply for significant loads in a short timeframe. The timing of the new substation will be reviewed annually as new information becomes available from the developer and potential customers.

Note that the timing for Transpower to convert Drury to a 110kV GXP is currently FY32. In the interim, the Quarry Rd substation could be supplied from our Bombay-Opaheke 110kV lines if they are diverted into the substation as these lines have enough capacity to supply Opaheke and Quarry Rd substations with the required level of security.

Refer to figure 8-32 for the proposed subtransmission single line diagram for the proposed new Quarry Rd substation and 110kV supply from the proposed new Drury GXP.

Opaheke Zone Substation Feeder Investment

The Opaheke area of supply includes the expanded Papakura Rural-Urban Boundary, and this area is characterised by being the area of supply nearest to central Auckland, its proximity to the motorway (SH1) and rail corridors (North Island Main Trunk). Included in its area is the Hingaia Peninsula just west of Papakura and Bremner Road just west of Drury, both of which have been designated as Special Housing Areas (SHA). The area of supply also currently includes land that will be the future Drury South Business Park as detailed earlier in this section.

- The Hingaia Peninsula has already undergone significant subdivision. In the load forecast we have assumed that 3,000 lots will be developed over the next 20 years;
- The Auranga subdivision has commenced and is expected to incur demand over the next 10 years, with approximately 1,400 lots. Subdivisions in the neighbouring Jesmond Road area are expected to introduce a similar number of dwellings in the next 10 to 15 years. The total Drury West area has the potential of the order of 11,200 lots;
- The Opaheke-Drury development is constrained by wastewater capacity and the wastewater upgrade works are expected between 2028 and 2032, triggering the start of the development. The development has potential of the order of 8,200 lots;
- The Hunua Views development, in the southern area of the Drury South Business Park, has around 700 lots. These have been assumed to incur demand over the next 5 years;
- We are aware of significant potential development in the area between Drury and the Drury South Business Park area. This would include 2,400 new dwellings plus businesses and other supporting amenities over the next ten years; and
- Other smaller subdivisions could be developed around the North Opaheke area. Typical sizes are between 50 and 300 lots. These have been allowed for in the demand forecast.

Figure 8-15 shows the demand forecast for Opaheke substation feeders.

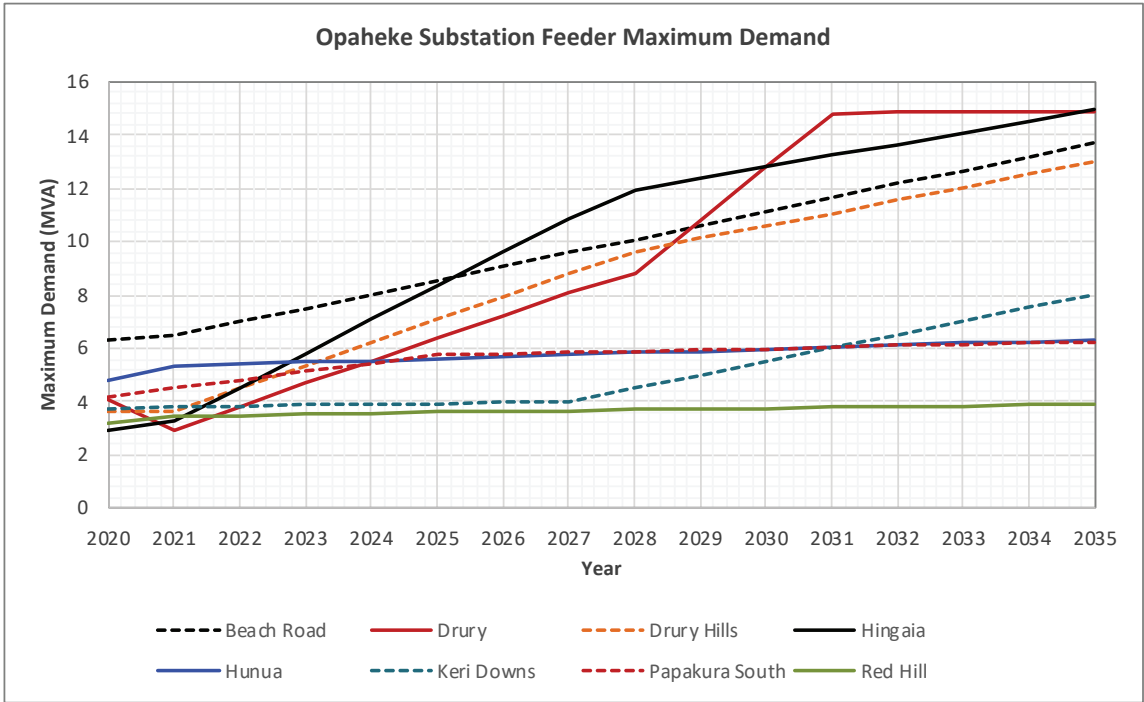


Figure 8-15 Feeder Demand Forecast at Opaheke Zone Substation

Summary of Opaheke Area Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Quarry Road 110kV Substation establishment	Build a new Quarry Road 110kV Substation	2023/24-2024/25	23,000
Beach Road / Hingaia feeder link	Create a link between Beach Road and Hingaia feeders to improve backfeed options	2027/28	353

Figure 8-16 Summary of Opaheke Area Development Plan

8.4.3 Pokeno Zone Substation

Changes in the Pokeno Structure Plan have seen increases in residential and industrial load in the Pokeno area. Several large industrial customers are now operating, some of whom have signalled their intention to expand their operations within the next five years. In response to this, we have established a new 110/22kV zone substation in Pokeno. This new substation, which was commissioned in 2020, provides the required capacity, security and supply quality for these customers.

No further projects are scheduled within the planning period for Pokeno as no specific customer requirements have been identified. However, if a major load were to require supply, this can be accommodated quickly as the substation has spare capacity to supply new load.

8.4.4 Pukekohe Zone Substation

The 110/22kV Pukekohe zone substation is supplied by three 110kV circuits from Bombay GXP, of which two are directly connected to Bombay and the third is connected via Tuakau and Pokeno. Pukekohe supplies 666 distribution substations in the urban areas of Buckland, Cape Hill and Pukekohe and the rural residential loads towards the eastern parts of Pukekohe and Mauku. The load is predominantly residential and commercial with some industrial load in Buckland. Pukekohe is classed as a zone substation (C4) and is fully compliant with our security criteria (refer to 8.1.2). Major loads supplied by this substation include the Pukekohe town centre.

Figure 8-17 below shows the Rural-Urban Boundary (RUB) map for the Pukekohe zone substation supply area, outlining the areas for future growth (green boundary line).

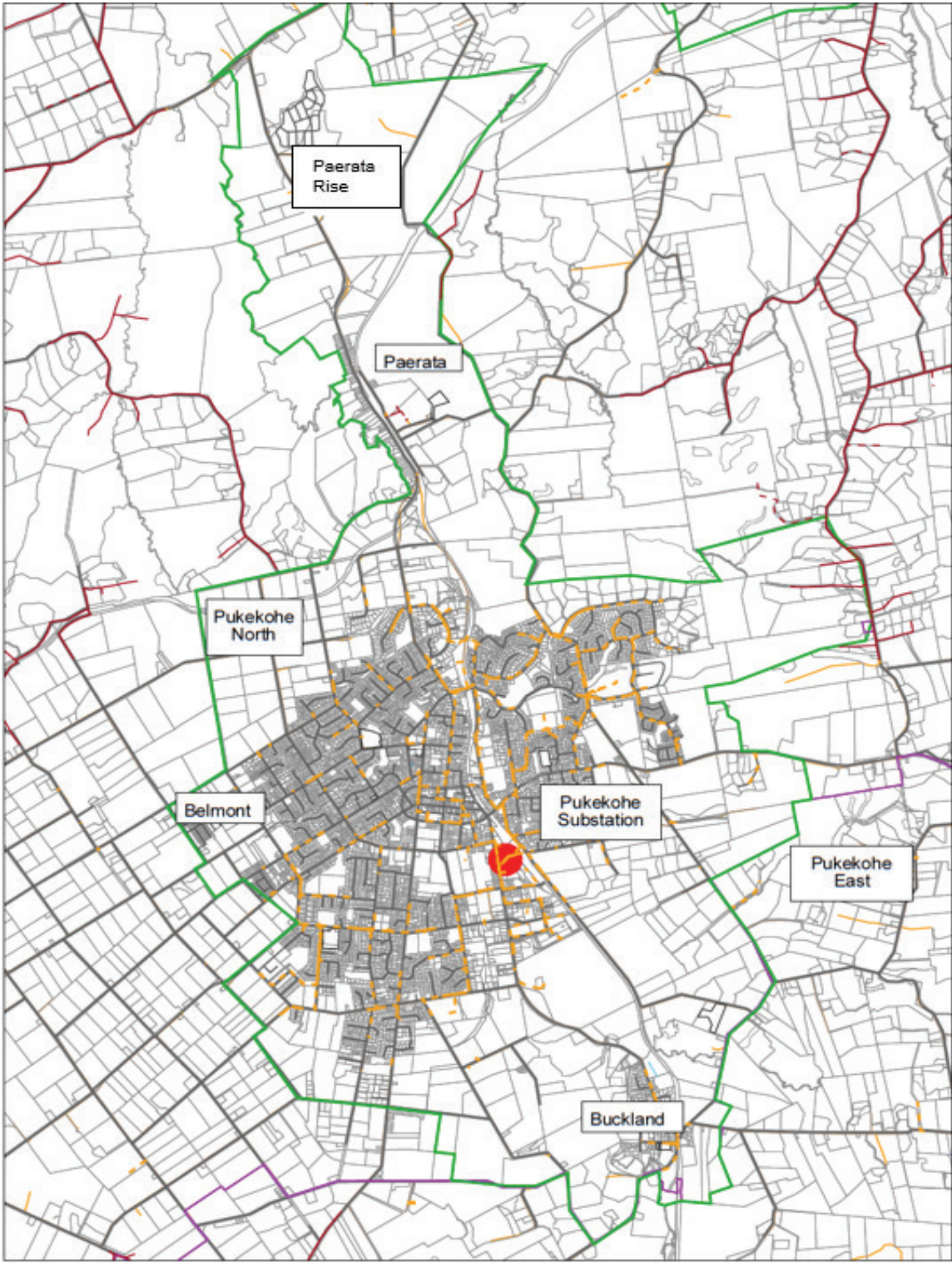


Figure 8-17 Pukekohe Zone Substation supply area

The Pukekohe load has a winter peak. The forecast peak demand for Pukekohe zone substation and the distribution feeders from the substation is shown in Figure 8-18.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Anchor Factory	5.1	5.6	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10.5	11.0	11.4	8.3%
Buckland	2.7	2.8	2.8	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.2	1.0%
Cape Hill	8.0	8.1	8.2	8.4	8.5	8.6	8.7	8.8	9.0	9.1	9.2	9.3	9.4	9.6	9.7	9.8	1.5%
Pukekohe East	1.9	1.9	4.0	4.1	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3	8.3%
Pukekohe Hill	7.8	7.9	8.1	8.2	8.4	8.6	8.7	8.9	9.0	9.2	9.3	9.5	9.6	9.8	10.0	10.1	2.0%
Pukekohe Town	4.3	4.4	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.0	5.1	5.2	5.3	5.4	5.5	5.5	2.0%
Pukekohe West	9.2	9.3	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.1	10.2	10.3	10.4	10.5	10.6	10.7	1.1%
Railway	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	10.0%
Titimauku	4.0	4.2	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	0.9%

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Pukekohe	42.0	43.2	45.2	46.1	47.1	48.0	49.0	50.0	51.4	52.9	54.4	55.8	57.3	58.8	60.2	61.7	3.1%

Figure 8-18 Winter Maximum Demand at Pukekohe Zone Substation and Feeders



Pukekohe Zone Substation Investment

The Pukekohe zone substation demand forecast is shown in Figure 8-19 below.

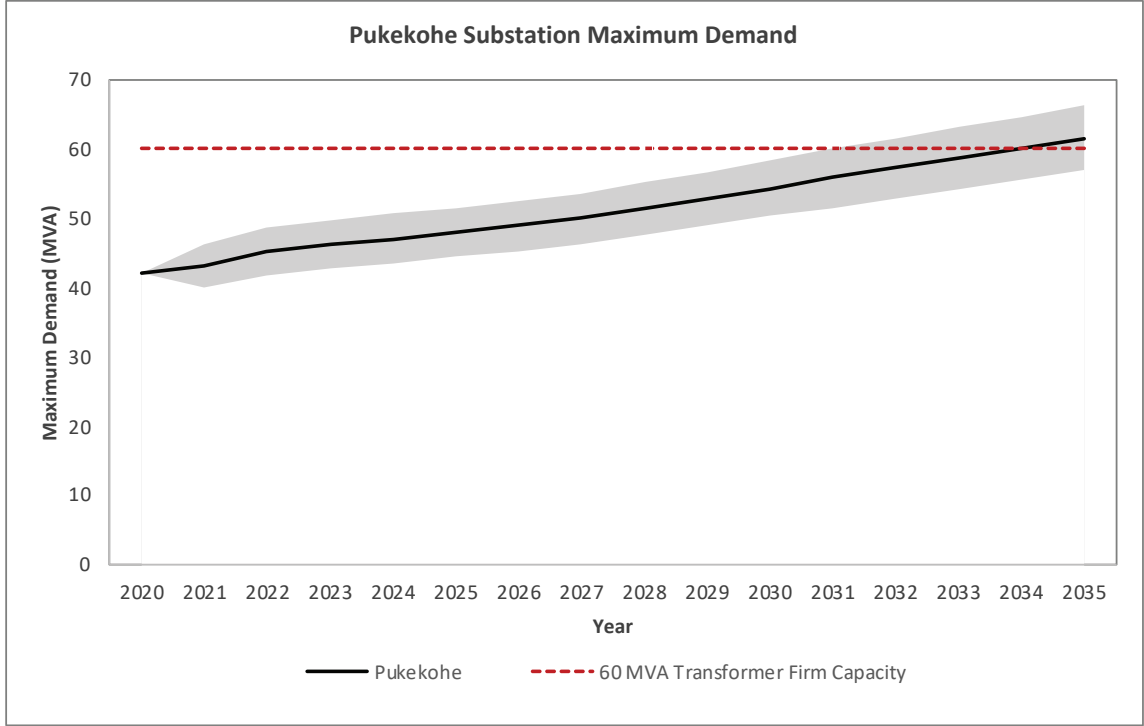


Figure 8-19 Pukekohe Zone Substation Demand Forecast

Two 110/22kV, 30/60MVA transformers supply the load at Pukekohe providing N-1 capacity of 60MVA. The 22kV switchboard supplying the load at Pukekohe also has a capacity of 60MVA. The Pukekohe maximum winter demand is forecast to exceed the transformers’ N-1 and switchboard capacity beyond 2035. This is discussed later in this section.

In 2019 Auckland Council adopted the Pukekohe-Paerata Structure Plan, which could see 12,500 new dwellings in the area over the next 30 years. Growth in Pukekohe North is expected first, followed by Pukekohe South over the planning period.

The Auckland Council has zoned areas surrounding Pukekohe and Paerata as future urban zone in the Auckland Unitary Plan. As part of the urbanisation of Pukekohe and Paerata areas, a large town centre is being built on land that used to be owned by Auckland’s Wesley College. This development is called Paerata Rise and is expected to house 4,550 dwellings with a local retail and services centre.

Pukekohe Zone Substation Feeder Investment

We expect significant residential growth in the area currently supplied by Pukekohe substation through the planning period.

- The northern Pukekohe area includes the Paerata Rise Special Housing Area of 4,500 dwellings (Anchor Factory Feeder). The first dwellings were completed in 2019 and indications are that this will be developed at a rate of 150-200 dwellings per year. The proposed investment is further discussed in the next section;
- From 2020, further subdivision in the east of Pukekohe (Cape Hill and Buckland feeders) and in the south (Buckland feeder) can be expected based on planning information we have received; and
- Pukekohe South development of 7,200 lots urban zone expected to come live by 2027.

Figure 8-20 shows the demand forecast for Pukekohe substation feeders.

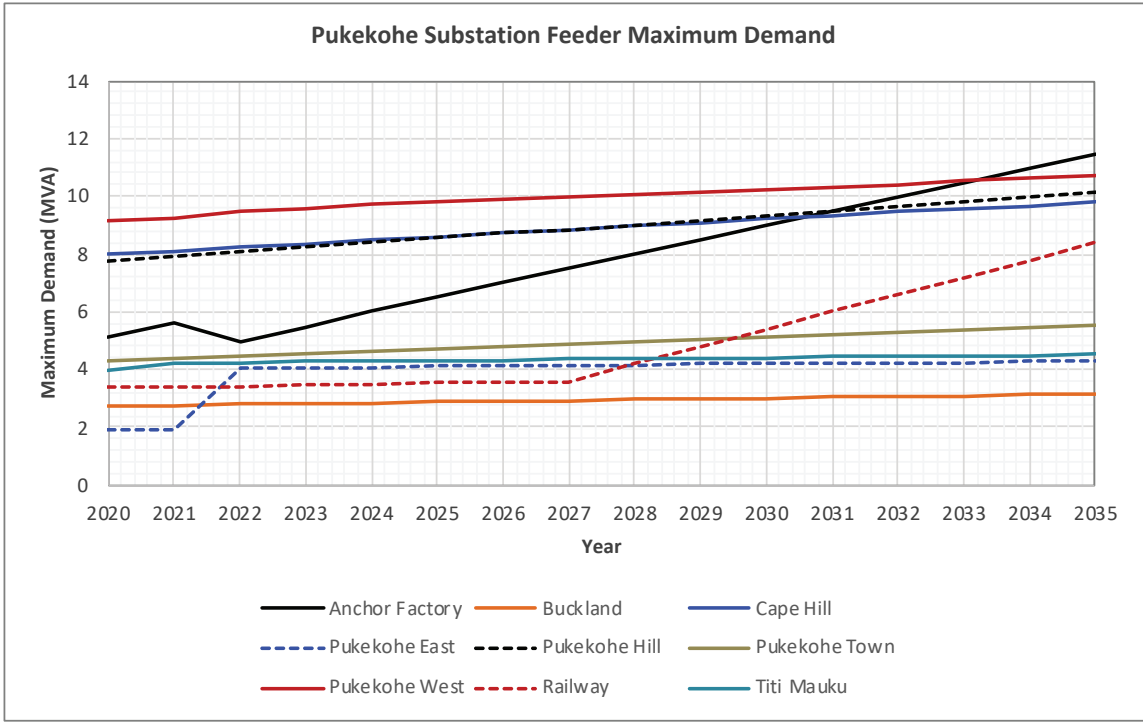


Figure 8-20 Feeder Demand Forecast at Pukekohe Zone Substation

Summary of Pukekohe Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Anchor Factory conductor upgrade	Upgrade sections of Copper and Swan conductor on Anchor Factory feeder	2024/25	571

Figure 8-21 Summary of Pukekohe Development Plan

Pukekohe North Zone Substation

In the Pukekohe North area major housing developments have begun at Paerata Rise (formerly Wesley College) and Karaka North. Paerata Rise will include a town centre and railway station.

An increase in load of 20MVA from these two developments is expected. Options to supply this load growth from the existing Pukekohe substation, Karaka substation and the proposed Quarry Road substation were assessed and determined to not be feasible long-term solutions.

In the short term, the early stages of Pukekohe North will be supplied from existing feeders from Pukekohe substation with sufficient backfeed support from other feeders. For the later stages in the medium to long term (2024/25 onwards) there will be capacity constraints and the target number of ICPs on feeders will also be exceeded.

Three options of supply were considered:

Option 1 – Extend and Increase Pukekohe Zone Substation Capacity, install additional 22kV feeders

This option would consist of the following at the existing Pukekohe Zone Substation to raise firm capacity above 60MVA for N-1 events:

- Increase the transformer capacity at Pukekohe by installing an additional 110/22kV 30/60 MVA transformer, taking the firm (N-1) capacity to 120MVA; and
- Extend the control room at the substation to make provision for a third 22kV bus and install a new 22kV switchboard and related equipment.

This option would introduce several HILP risks, namely the common mode failure of the 22kV switchboard, the vulnerability due to a fire or explosion in the outdoor yard, the risk of targeted vandalism and the risk of an incident when plant is out of service for maintenance.

Our security of supply and planning guidelines note the risks of having very large numbers of customers supplied from a single zone substation and future developments are planned to utilise two 40MVA transformers which will supply around 15,000 domestic customers. Utilising the full 60MVA firm capacity at Pukekohe would supply over 21,000 customers. Installing a third 60MVA transformer would allow the supply of some 43,000 customers. The impact on SAIDI and SAIFI of an outage with such customer numbers is very significant. Additionally, as the largest areas of growth are to the north of Pukekohe, additional feeder capacity would incur a high cost given the distance (Pukekohe Zone Substation is to the south of the town).

This option is therefore not considered desirable and has not been investigated further.

Option 2 – Development of a new ‘Pukekohe North’ substation

This option would develop a new 110kV/22kV Zone Substation to the north or north east of Pukekohe, providing supply into Pukekohe North, Paerata, and the Paerata Rise Special Housing Area.

This option has an estimated cost in the order of \$33m, which is a higher cost, and added complexity given the need for new 110kV subtransmission corridors and new distribution feeder configurations. It does however provide several advantages over extension of the existing Pukekohe substation, specifically:

- Closer to the load centres of Paerata Rise and the future northern development areas;
- Releasing of capacity at Pukekohe to accommodate more localised growth;
- Diversity of supply and provision of interconnection into Pukekohe; and
- Improved resilience against HILP events.

With the target numbers of customers per feeder (1,500) and over 6,000 proposed lots, we will need at least four feeders. This can be easily accommodated from a new Pukekohe North substation but would be uneconomical from the existing Pukekohe substation, as well as facing difficulty in finding additional line routes.

- The option to install dedicated high-capacity trunk feeders from an upgraded Pukekohe substation and develop a switching station in the Paerata Rise and Paerata area located north of Pukekohe, after 2029, has been investigated. This has been ruled out because, based on Council land zoning, the total development load is ultimately expected to grow to around 21MVA and at that scale a new substation is necessary;
- The proposed Pukekohe North substation will be strategically situated to support Karaka, Pukekohe, Drury South and Opaheke substations and will help with network resilience.; and
- The Auckland Future Urban Land Supply Strategy 2017 (FULSS) states that of the total future urban land area in the south of Auckland comprising of Opaheke-Drury, Drury West, Hingaia and Drury South make up 23,400 lots. The load for these dwellings with associated services and commercial load could be up to 73MVA long term. This load will be shared between the existing Opaheke substation (27MVA peak), proposed Quarry Road substation and the proposed Pukekohe North substation.

Option 3 – Non-network alternatives

Localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is presently uneconomical for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Proposed investment

Our proposed investment is to establish Pukekohe North and utilise the existing Pukekohe substation to meet the growth in its immediate vicinity. The Pukekohe North substation will be supplied at 110kV from the Quarry Road substation in Drury and established from 2025 – 2028 at an estimated cost of \$33m.

The timing of the substation establishment will be reviewed annually by monitoring the uptake rates of the residential developments. To prepare for when the substation will be needed, land parcels are being assessed with consideration of possible subtransmission line route options to that site from Quarry Road substation. The substation site will be acquired along with investigations towards subtransmission line routes in 2021/22 at an estimated cost of \$2.75m.

Figure 8-22 below summarises the proposed Pukekohe North substation development plan.

Description	Scope	Timing	Estimated Costs (\$'000)
Pukekohe North area substation land acquisition	Procure land for the establishment of Pukekohe North area substation	2021/22	2,750
Pukekohe North area substation 110kV line 1	Build 110kV line to supply Pukekohe North area substation	2025/26	5,000
New feeders from Pukekohe North area substation	Install 4km of cable from substation to Paerata Rise	2026/27	3,000
Pukekohe North area substation establishment including 2nd 110kV line	Build a new Pukekohe North area substation with two 110/22kV 40MVA transformers and 22kV switchboard	2025/26 - 2027/28	22,000

Figure 8-22 Pukekohe North substation development plan

8.4.5 Tuakau Zone Substation

The Tuakau 110/22kV zone substation is supplied by two 110kV circuits from Bombay GXP, of which one is connected via Pokeno and the other is connected via Pukekohe.

The Tuakau zone substation supplies 757 distribution substations in the urban areas of Tuakau, Church Corner, and River Road and the rural areas of Port Waikato and Whangarata. The load is predominantly residential in the Church Corner, Port Waikato and Tuakau areas. The Pukekawa and Pukekawa Trunk feeders from Tuakau supply the Pukekawa switching station which in turn supplies the Churchill Road, Glen Murray and Onewhero feeders. Tuakau is classed as a zone substation (C4) and is fully compliant in accordance with our security criteria (refer to 8-1).

The Tuakau residential load is winter peaking. The forecast peak demand for Tuakau substation and the distribution feeders from the substation is shown in Figure 8-23 below.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Church Corner	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.6	2.6	1.3%
Port Waikato	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.0%
River Road	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.8	1.0%
Tuakau	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.6	1.2%
Whangarata	4.3	5.2	5.9	6.6	7.2	7.9	8.6	9.2	9.9	10.6	11.2	11.3	11.4	11.5	11.6	11.7	11.6%
WWTP 1	3.4	5.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	5.9%
WWTP 2	3.1	4.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	4.4%
Hitchen Road	6.4	9.4	12.5	12.6	12.6	12.7	12.8	12.8	12.9	13.0	13.0	13.1	13.1	13.2	13.3	13.3	7.3%
Tuakau Industrial	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	0.5	0.0%
Potter Road	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Pukekawa	2.0	3.0	5.0	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	10.6%
Pukekawa Trunk	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.9	0.0%

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Tuakau with Generation	22.5	18.3	21.1	21.2	21.3	21.4	21.5	21.6	21.7	21.8	21.9	22.0	22.1	22.2	22.3	22.4	0.0%
Hampton Downs Generation	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	5.5	0.0%
Tuakau without Generation	28.0	23.8	26.6	26.7	26.8	26.9	27.0	27.1	27.2	27.3	27.4	27.5	27.6	27.7	27.8	27.9	0.0%
Pokeno	0.0	14.7	18.4	19.1	19.9	20.6	21.3	22.1	22.8	23.5	24.3	24.4	24.6	24.7	24.9	25.0	5.0%

Figure 8-23 Winter Maximum Demand at Tuakau Zone Substation and Feeders

Tuakau Zone Substation Investment

The Tuakau zone substation demand forecast is shown in Figure 8-24 below. For clarity, the upper and lower limits are not shown on the demand forecast including impact of distributed generation.

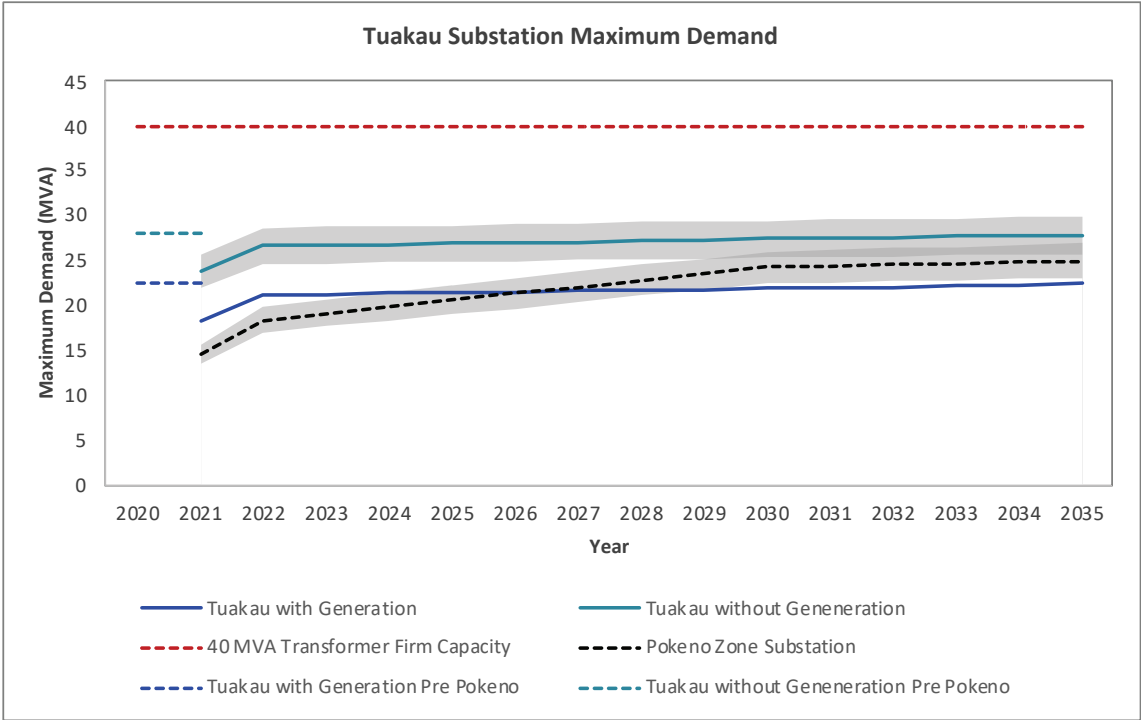


Figure 8-24 Tuakau Zone Substation Demand Forecast

Two 110/22kV, 20/40MVA transformers supply the load at Tuakau providing N-1 capacity of 40MVA. Note that with the establishment of Pokeno zone substation (as discussed in section 8.4.3), a significant amount of the load shown above will be supplied from there rather than Tuakau zone substation after 2020.

Tuakau Zone Substation Feeders Investment

The majority of this load growth is in the Pokeno area and will be supplied from Pokeno zone substation as discussed in section 8.4.3. We also anticipate additional load from Watercare’s Waikato Water Treatment Plant in the planning period, which has been catered for in our load forecasts.

Figure 8-25 shows the demand forecast for Tuakau substation feeders.

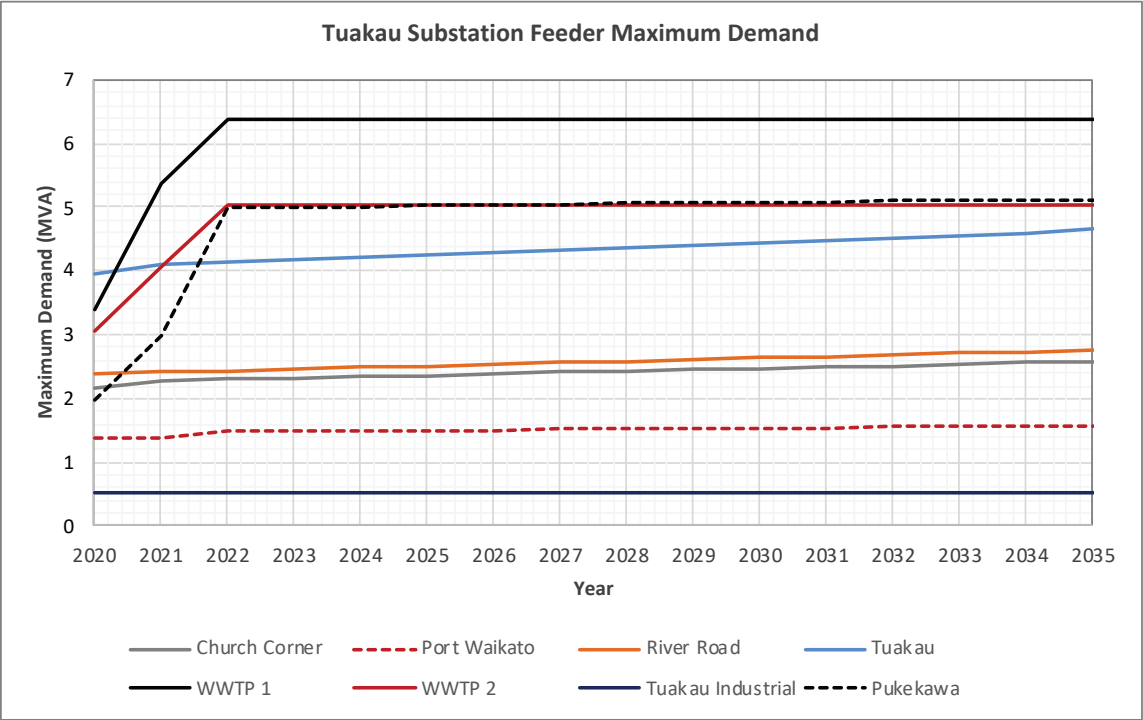


Figure 8-25 Feeder Demand Forecast at Tuakau Zone Substation

Figure 8-26 shows the demand forecast for the Tuakau substation feeders including load that will be picked up by the Pokeno substation in 2021.

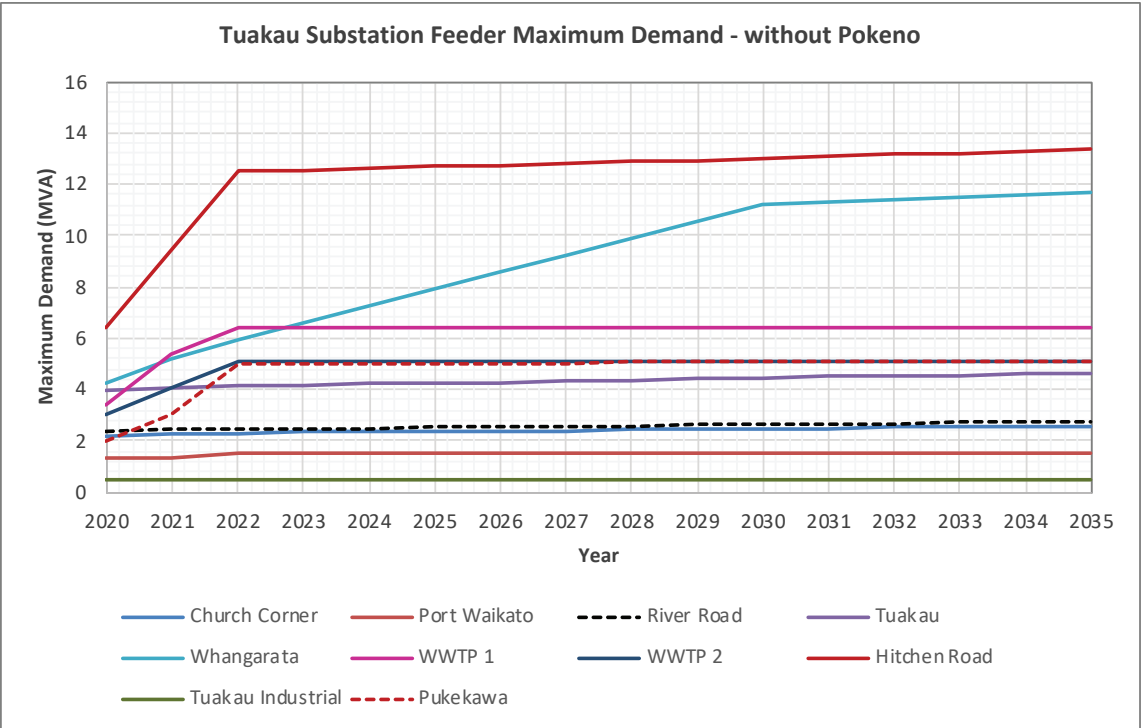


Figure 8-26 Feeder Demand Forecast at Tuakau Zone Substation without Pokeno

Summary of Tuakau Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Increase Glen Murray feeder backfeed capacity	Upgrade auto transformer and install voltage regulator on Glen Murray feeder	2021/22	220

Figure 8-27 Summary of Tuakau Development Plan

8.4.6 Mangatawhiri and Ramarama

The present supply configuration is made up of:

- One 33/11kV, 7.5MVA transformer supplying the load at Mangatawhiri with no N-1 capacity; and
- Two 33/11kV, 5MVA transformers supplying the load at Ramarama providing N-1 capacity of 5MVA.

Mangatawhiri and Ramarama Zone Substation Investment Need

Figure 8-29 shows the demand forecast for Mangatawhiri and Ramarama substations¹⁸

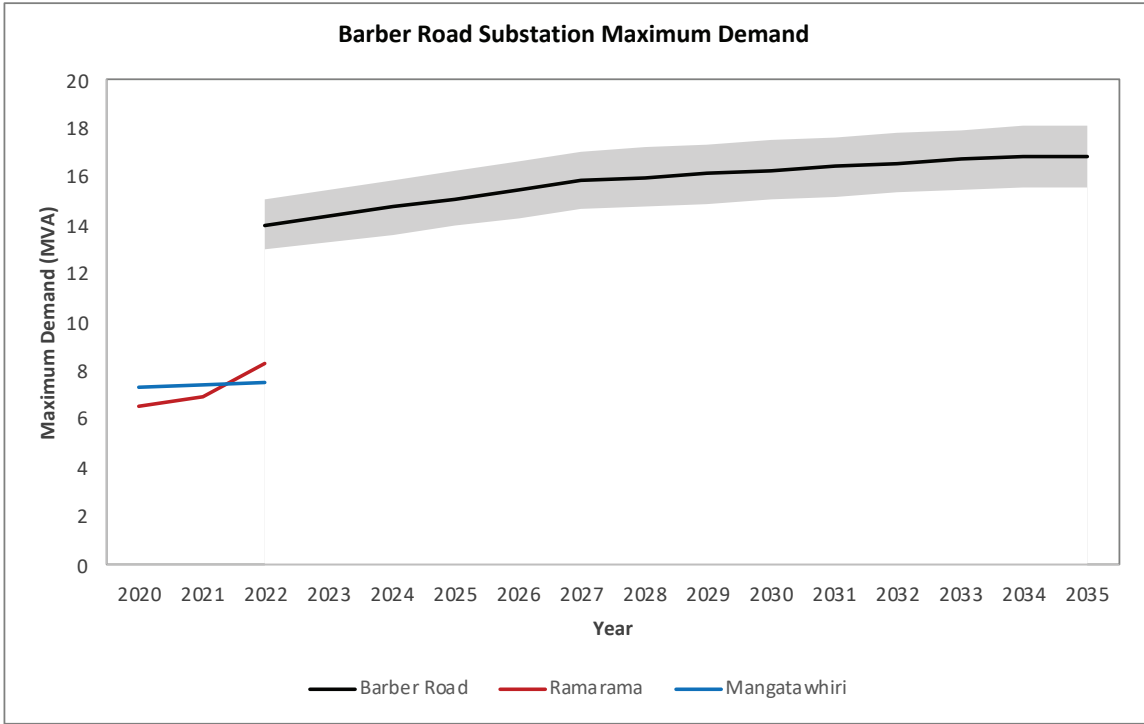


Figure 8-29 Mangatawhiri and Ramarama Substations Demand Forecast

The supply assets at these substations are at end of life. The following options, across five broad alternatives were considered to maintain supply to customers supplied from Mangatawhiri and Ramarama:

Retain 33kV as subtransmission voltage

- Rebuild Mangatawhiri and Ramarama substations, retain 33kV supply from Transpower; or
- Rebuild Mangatawhiri and Ramarama substations at 33kV, take supply at 110kV from Transpower and establish own 110/33kV substation at Bombay.

Build new 110/22kV substation at Barber Road

- Establish new Barber Road zone substation – take supply from Transpower at 22kV;
- Establish new Barber Road zone substation – take supply from Transpower at 110kV; or
- Establish new Barber Road zone substation – tap into existing 110kV circuits.

Other full solution

- Rebuild Mangatawhiri and Ramarama substations, uprate to 110kV supply from Transpower.

Mixed solutions

- Rebuild Mangatawhiri substation, supply at 33kV; Build Quarry Road and use new Quarry Road substation to supply Ramarama area;
- Rebuild Mangatawhiri substation, supply at 110kV; Build Quarry Road and use new Quarry Road substation to supply Ramarama area;
- Rebuild Ramarama substation, supply at 33kV and use Pokeno substation to supply Mangatawhiri area; or
- Rebuild Ramarama substation, supply at 110kV and use Pokeno substation to supply Mangatawhiri area.

Non-network solutions

- Non-network solutions to utilise localised energy storage or distributed generation, however this option is presently uneconomical for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of the investment planning process.

Proposed investment

Our proposed investment is to build a new 110/22kV substation (supplied at 110kV from Transpower’s Bombay GXP) to supply load presently fed from Mangatawhiri and Ramarama substations. This will be adjacent to Bombay GXP and will be known as Barber Road substation.

This option was chosen because:

- It will rationalise existing assets by standardising on 110kV as subtransmission voltage in the eastern region and 22kV distribution supplies at all eastern region substations;
- It will provide resilience for HILP events at Opaheke, Pokeno, Pukekohe and Quarry Rd substations by providing improved feeder interconnections at 22kV; and
- Provide savings in our Annual Operational Charges with Transpower at the Bombay Grid Exit Point and allowing them to remove 33kV supply – rationalising their assets.

The concept of a single, centralised zone substation located in the approximate load centre of the supply area is a valid concept based on the number of identified issues at the two zone substations and the Bombay 33kV supply being disestablished (or requiring significant investment to address age and condition).

In addition to our substation assets, 12 steel lattice towers which support our 110kV Opaheke East and 33kV Ramarama West circuits are rapidly nearing end of life. These towers will be replaced or refurbished within the planning period. At the time of writing, optionality investigations are underway to determine the best solution for these towers. A full rebuild has been included in our capital forecasting for the purposes of this AMP at \$9m, however this will be updated in future AMP's based on the outcomes from investigations currently underway.

Mangatawhiri and Ramarama Area (Barber Road Substation) Demand Forecast

Figure 8-28 shows the winter maximum demand forecast for Mangatawhiri and Ramarama substations (to be replaced by a new 110kV substation in 2021/22 – 2022/23).

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Ararimu	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	1.0%
Bombay	3.2	3.6	3.6	3.7	3.8	3.8	3.9	4.0	4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	2.6%
Great South Road	1.5	1.5	2.8	3.0	3.3	3.6	3.9	4.1	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	13.8%
Kaiaua	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.8	1.0%
Mercer	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	1.6	1.6	1.6	1.0%
Paparata	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	0.5%
Pokeno Church	3.3	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.9	1.0%

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Barber Road	0.0	0.0	14.0	14.4	14.8	15.1	15.5	15.9	16.0	16.2	16.3	16.4	16.6	16.7	16.9	16.9	1.0%

Figure 8-28 Winter Maximum Demand for Mangatawhiri and Ramarama Substations and Feeders

The Mangatawhiri and Ramarama load is winter peaking and is made up of a mix of commercial and residential load. We anticipate some residential growth around Bombay and on the areas immediately to the north and south along SH1, as far as Pokeno.

Mangatawhiri and Ramarama Zone Substation Feeders Investment Need

The supply area of Mangatawhiri covers part of the Pokeno area around the State Highway 1 and 2 junctions. We expect significant growth from the Pokeno subdivisions through the planning period.

Figure 8-30 shows the demand forecast for feeders at Mangatawhiri and Ramarama substations.

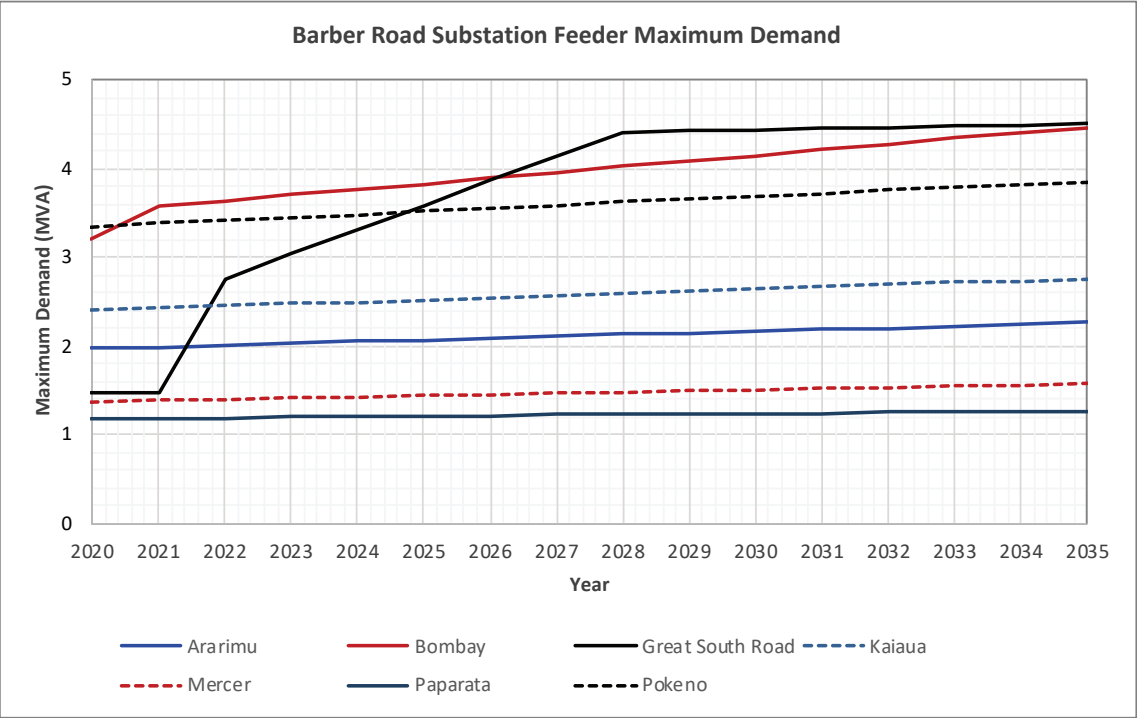


Figure 8-30 Feeder Demand Forecast for Mangatawhiri and Ramarama Substation Feeders

¹⁸ The proposed Barber Road substation replaces Mangatawhiri and Ramarama from 2021/22 – 2022/23.

Summary of Bombay Area Development Plan

The investment summary for the Bombay area is shown below. The majority of this is renewal driven, however it’s shown in here to provide a clear picture of the overall area development.

Description	Scope	Timing	Estimated Costs (\$'000)
Barber Road substation establishment	Construct new substation including transformers, switchgear and protection and control to replace existing Ramarama and Mangatawhiri substations	2021/22-2022/23	13,795
Barber Road substation feeder works	New conductor and feeder reconfigurations to supply feeders from Barber Road substation.	2021/22-2022/23	15,515
Great South Road 22kV feeder conversion	Reinsulate Great South Road feeder to 22kV	2021/22	2,225
Bombay-Ramarama Tower line rebuild design	Design replacement for Bombay-Ramarama Tower line	2021/22	200
Bombay-Ramarama Tower line rebuild	Rebuild Bombay-Ramarama Tower line	2024/25-2025/26	9,000
Decommission Mangatawhiri and Ramarama zone substations	Decommission Mangatawhiri and Ramarama zone substations after establishment of Barber Road substation	2023/24-2024/25	1,400
Paparata reconductor	Upgrade Paparata feeder to improve backfeed	2029/30	533

Figure 8-31 Summary of Bombay Area Development Plan

Note: Works are already in progress on the Barber Road Substation establishment with an allocated expenditure of \$3.205m for the current 2020/2021 year.

Figure 8-32 below shows the single line schematic for the future eastern subtransmission network supplied from the Bombay and Drury grid exit points.

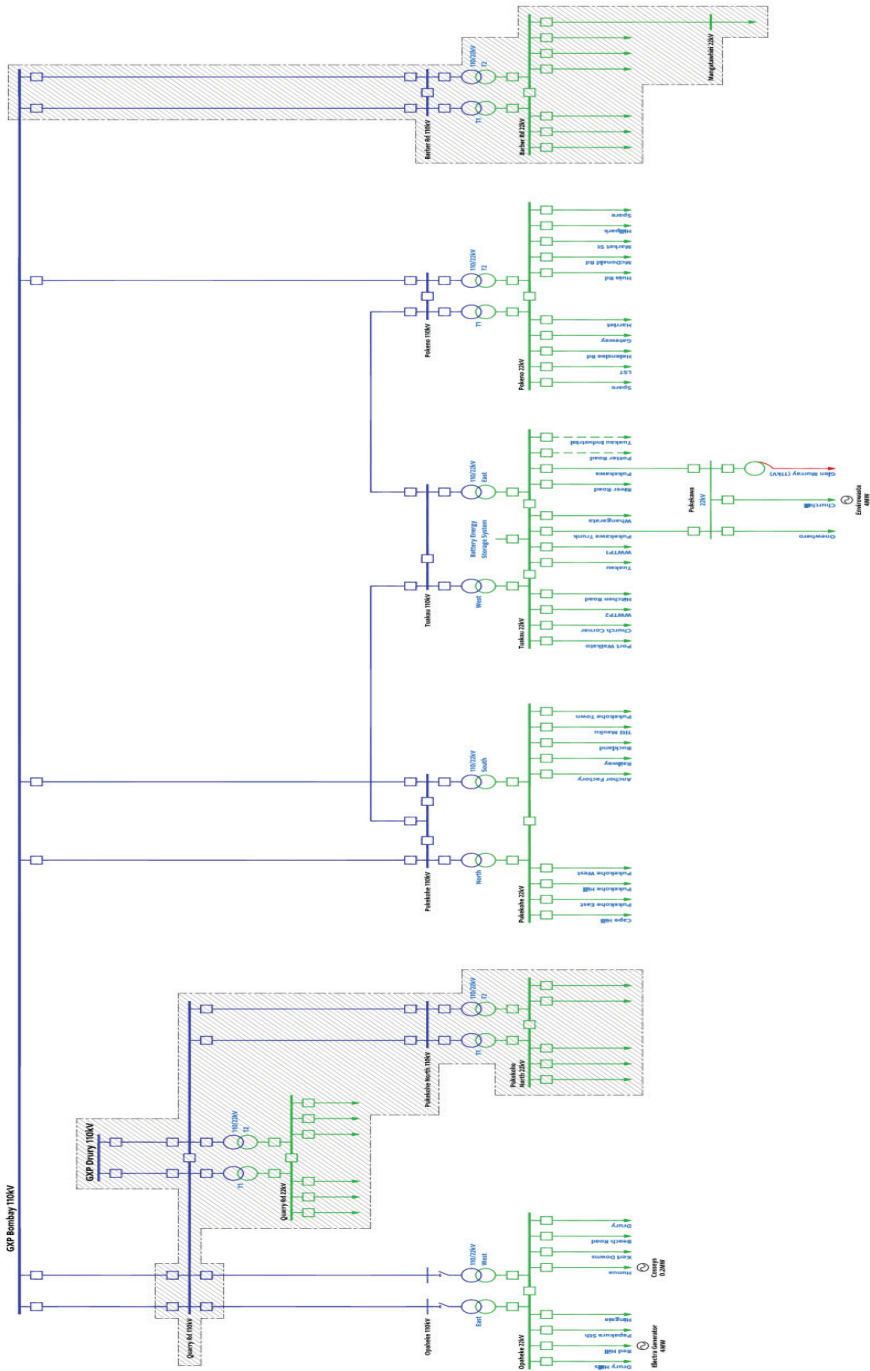


Figure 8-32 Single Line Schematic of the Future Eastern Region 110kV subtransmission network

8.5 Western Region Development Plan

The western Region is supplied from Transpower’s Glenbrook GXP and covers areas supplied by our Karaka, Maioro and Waiuku zone substations and a 33kV point of supply at Storey Road. Figure 8-33 and 8-34 show the total western region forecast demand.

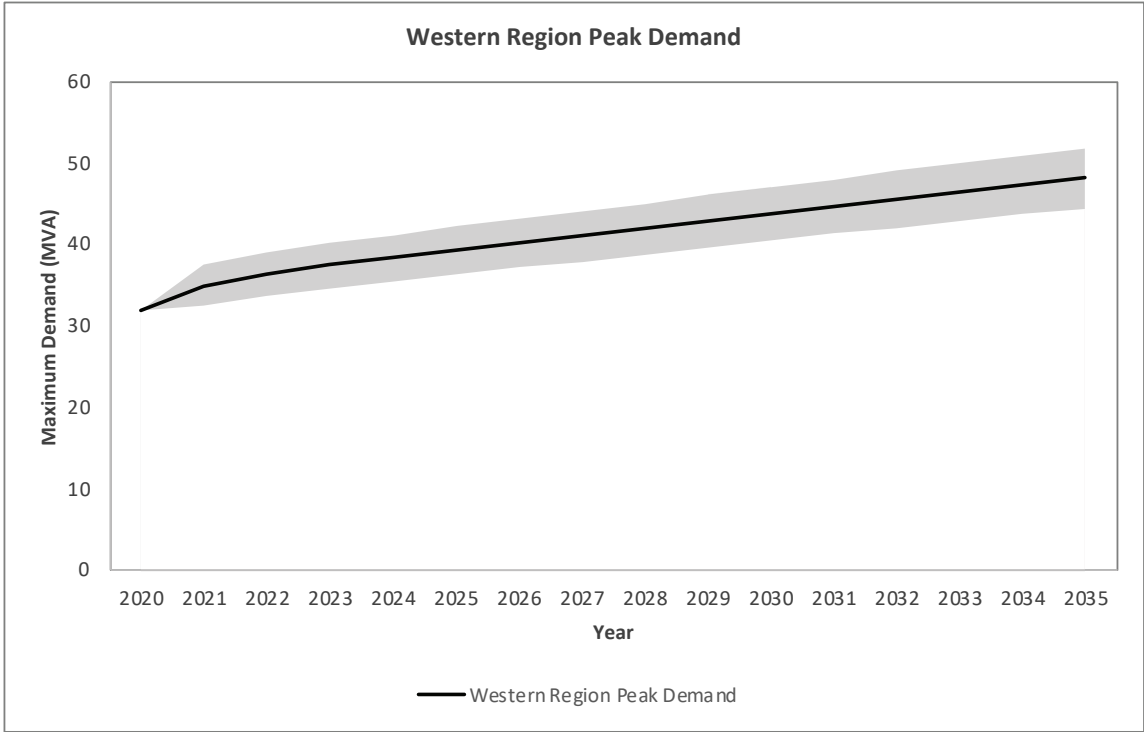


Figure 8-33 Winter Maximum Demand for Western Region Graph

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak																Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Waiuku	33/11kV	16.1	16.5	17.4	17.8	18.2	18.6	19.0	19.3	19.7	20.1	20.5	20.9	21.3	21.7	22.0	22.4	2.6%
Karaka	33/11kV	11.5	12.4	13.1	13.8	14.5	15.1	15.7	16.4	17.0	17.6	18.2	18.8	19.5	20.1	20.7	21.2	5.6%
Maioro	33/11kV	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	0.0%
NZS (Storey Road)	33/11kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.0%
Western Region		31.9	35.0	36.5	37.4	38.4	39.3	40.2	41.1	42.0	42.9	43.8	44.7	45.6	46.5	47.4	48.1	3.4%

Figure 8-34 Winter Maximum Demand for Western Region Table

Our subtransmission network in the western region supplies zone substations and the 11kV distribution network via:

- Two 33kV lines from Glenbrook GXP to Waiuku;
- One 33kV line from Waiuku to Story Road Pump Station and Maioro; and
- Two 33kV lines from Glenbrook GXP to Karaka.

Figure 8-35 shows the single line schematic for the western region subtransmission network supplied from the Glenbrook GXP.

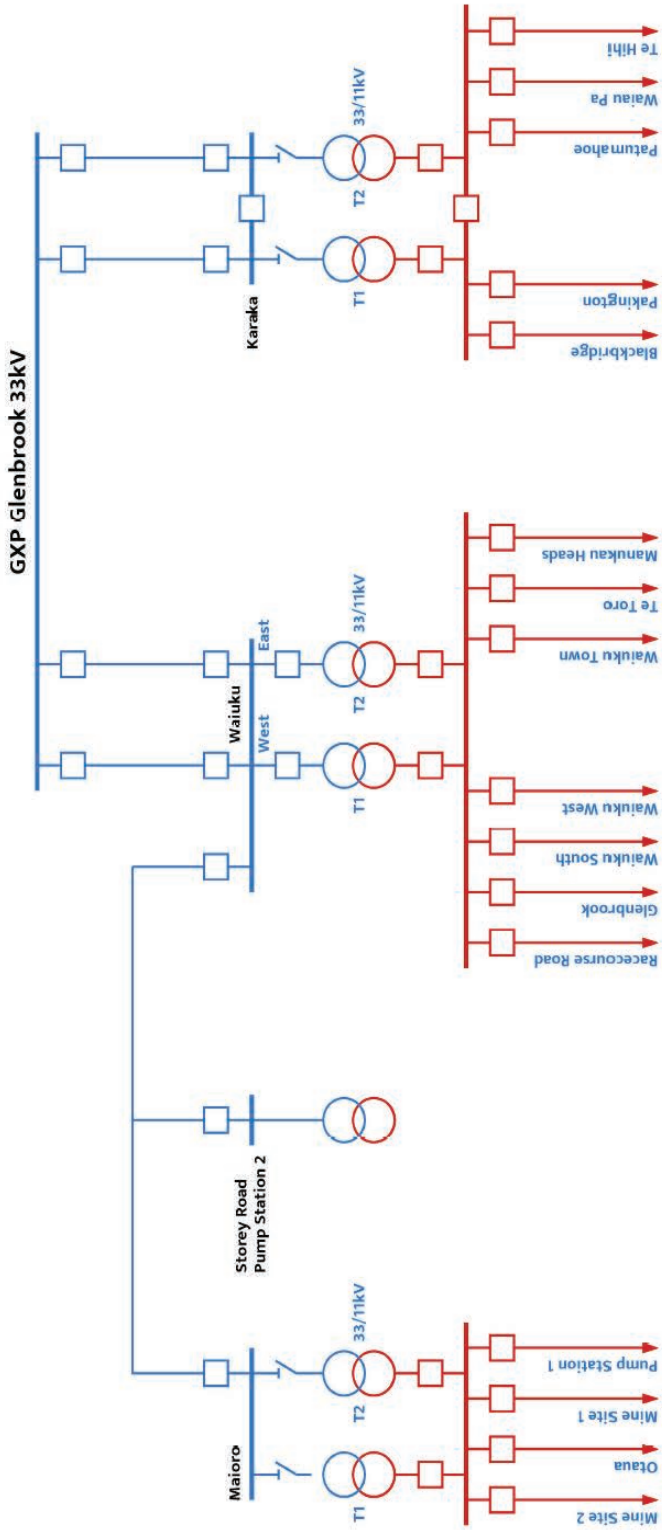


Figure 8-35 Single Line Schematic of the Western Region subtransmission network

This system has the following constraints:

- The distances between the load centres and our substations are too great for efficient 11kV distribution, in particular the distance and demands of Waiau Pa, Clarks Beach and Kingseat from the existing Karaka substation is too great for 11kV distribution. Similarly, for Glenbrook Beach from Waiuku substation; and
- The 33kV network is not suitable for connecting any major distributed generation.

As there is no 110kV supply from Transpower’s Glenbrook GXP, it would require significant load or generation increase in the area to make it economic to convert to a 110kV subtransmission network and a 22kV distribution network. In the longer term, there are two potential options to increase supply capacity for the area. One option is to continue with the existing 33/11kV network architecture and to upgrade the 11kV to 22kV in places to achieve the required voltage performance on the longer feeders. An alternative is to establish 110/22kV architecture as used in the eastern region.

We expect some growth in the western region over the next ten years with:

- Designation of special housing areas at Glenbrook Beach;
- Proposed developments at Clarks Beach and Kingseat; and
- Subdivisions at Patumahoe, Waiau Pa and Waiuku.

8.5.1 South Western Subtransmission

South Western Area Subtransmission Investment Requirements

Two 33kV lines from Glenbrook supply Waiuku and the rest of the south western area (Maioro and Storey Road). The Waiuku West line is strung with Cockroach conductor (rated at 32MVA) while the Waiuku East line is strung with lower rated Cricket conductor (rated at 24MVA) for the total length of the line.

The loading on the 33kV Glenbrook to Waiuku East line exceeded its N-1 capacity (the standard rating for the Cricket conductor section) from 2016. Use of cyclic ratings have enabled deferment of investment until 2025/26.

Summary of South Western Area Subtransmission Development

Description	Scope	Timing	Estimated Costs (\$'000)
Reconductor Glenbrook to Waiuku East line	Address capacity constraints on the Glenbrook to Waiuku East line	2025/26	1,955

Figure 8-36 Summary of south western area subtransmission development

8.5.2 North Western Subtransmission

North Western Area Subtransmission Investment Need

Two 33kV lines from Glenbrook supply Karaka. The Karaka North line is strung with Cricket conductor. The Karaka South line is strung with parts of Cricket (24MVA) and parts of lower rated Dog conductor (17MVA).

The loading on the 33kV Glenbrook to Karaka South line is expected to exceed its N-1 capacity (the rating for the Dog conductor section) in 2029 during the peak load period and is forecast to reach 110% of the N-1 rating by 2031. Reinforcement can be deferred if a cyclic rating can be applied to the Karaka South line. As such, investigations will be required in 2021/22, at an estimated cost of \$400,000 to confirm that there are sufficient clearances on the line to operate with a cyclic rating.

Our proposed investment to address the identified constraint on the Karaka South line will be developed following the investigations to either reconductor the 33kV South line from Glenbrook to Karaka with higher rated Cricket conductor or restring the conductor and define operating limits to defer investment.

Summary of North Western Area Subtransmission Development

Description	Scope	Timing	Estimated Costs (\$'000)
Glenbrook to Karaka South line capacity constraint investigations	Investigate options to address capacity constraints on the 13km of 33kV concrete pole line in Dog and Cricket conductor	2022/23	400

Figure 8-37 Summary of north western area subtransmission development

8.5.3 Karaka Zone Substation

The Karaka 33/11kV zone substation is supplied by two 33kV circuits from Glenbrook GXP. Karaka zone substation supplies 476 distribution substations in the mainly rural areas of Blackbridge, Pakington, Patumahoe, Te Hihi and Waiau Pa. The load is predominantly residential. Karaka is classed as a zone substation (C3) and is fully compliant with our security criteria (refer to 8.1.2).

The Karaka load is winter peaking. The forecast peak demand for Karaka zone substation and the distribution feeders from the substation is shown in Figure 8-38.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Blackbridge	1.4	1.5	1.7	1.9	2.0	2.2	2.4	2.6	2.7	2.9	3.1	3.3	3.4	3.6	3.8	3.8	11.5%
Pakington	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	1.8%
Patumahoe	2.1	2.2	2.3	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	1.9%
Te Hihi	2.3	2.5	2.7	3.0	3.2	3.4	3.6	3.9	4.1	4.3	4.5	4.8	5.0	5.2	5.5	5.7	10.0%
Waiau Pa	2.9	3.1	3.2	3.4	3.5	3.7	3.9	4.0	4.2	4.4	4.5	4.7	4.8	5.0	5.2	5.3	5.5%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Karaka	11.5	12.4	13.1	13.8	14.5	15.1	15.7	16.4	17.0	17.6	18.2	18.8	19.5	20.1	20.7	21.2	5.6%

Figure 8-38 Winter Maximum Demand at Karaka Zone Substation and Feeders

Karaka Zone Substation Investment

The Karaka zone substation demand forecast is shown in Figure 8-39

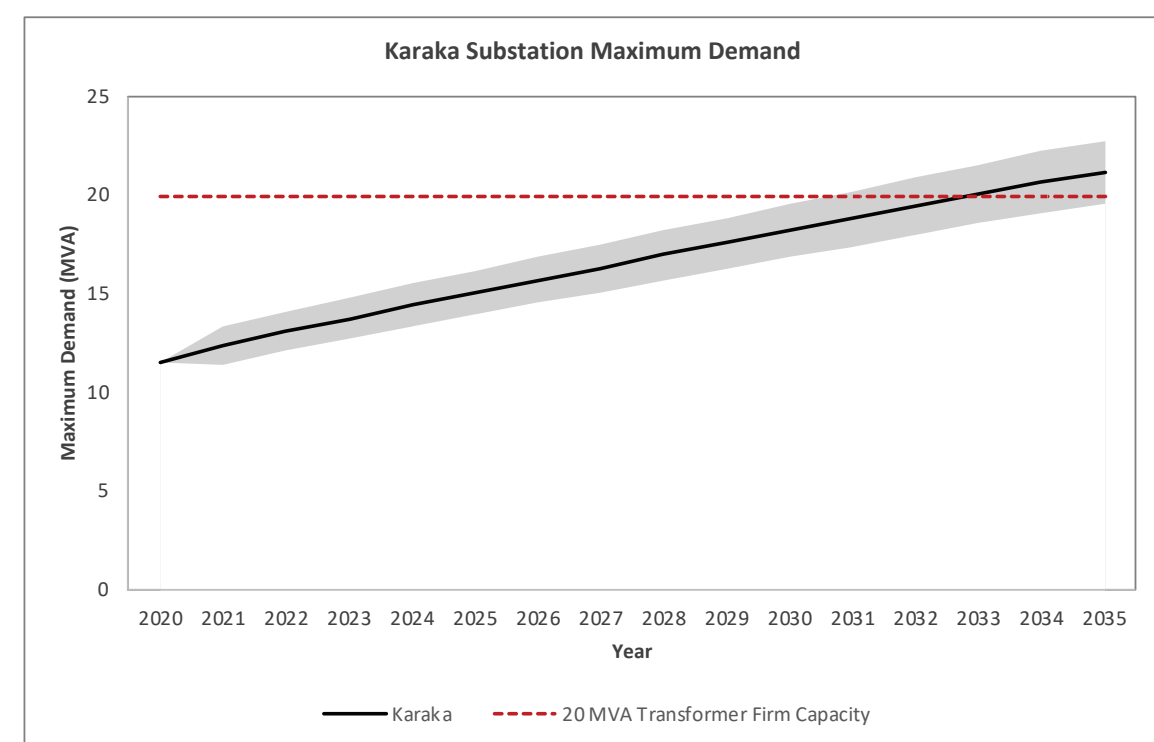


Figure 8-39 Karaka Zone Substation Demand Forecast

There are two 33/11kV 10/20MVA transformers installed at Karaka substation providing a N-1 capacity of 20MVA, which will be exceeded in 2033. The switchboard rating will be exceeded after 2035 which is also beyond its end of life date of 2033. We expect significant growth from the Kingseat, Clarks Beach and Karaka North special housing area developments. The Kingseat area has been assumed to incur demand of up to 1,850 lots through the next 15 years. The Clarks Beach and Karaka North areas are expected to add up to 1,351 lots and 744 lots respectively over the planning period.

Some load from our Waiuku substation has been transferred to Karaka substation to relieve the loading on the 33kV Glenbrook - Waiuku circuits. To accommodate this transferred load, as well as to accommodate additional load on the Karaka substation arising from growth in Glenbrook Beach, Clarks Beach, Karaka North and Kingseat areas, the previous year’s asset management plan proposed that Blackbridge, Waiau Pa and Te Hihi feeders’ distribution feeders from Karaka be reconfigured and converted to 22kV operation to address the capacity and voltage constraints identified.

However, following the review of network security criteria where the target number of customers per feeder was revised from 3,000 to 1,500, this has revised our approach. Converting feeders to 22kV cannot be justified for feeders supplying only 1,500 customers and carrying total load under 5MVA. The system planning studies have also identified that the Karaka subtransmission lines’ N-1 firm capacity, the Karaka substation power transformers and 11kV switchboard will progressively exceed their ratings as the Glenbrook Beach, Clarks Beach, Karaka North and Kingseat area developments approach completion regardless of whether the feeders are operating at 11kV or 22kV. Therefore, the existing Karaka substation and distribution feeders can support the growth in the north western areas in the short to medium term beyond which upgrades at subtransmission and substation levels will be required. For medium to long term, five options of supply were considered.

Option 1 – Extend and Increase Karaka Zone Substation Capacity

This option would consist of the following upgrades at the existing Karaka Zone Substation to raise firm capacity above 20 MVA for N-1 events:

- Increase the transformer capacity at Karaka by replacing the transformers with nonstandard 33/22kV 20/40 MVA transformer;
- Increase the subtransmission capacity of both Glenbrook Karaka 33kV lines 13km each;
- Extend the control room at the substation to make provision for a new 22kV switchboard and related equipment;
- Convert to 22kV operation, five feeders of average length 12km to each development; and
- Convert to 22kV operation one feeder of 15km length out of Waiuku substation.

This option would introduce a number of HILP risks, namely the common mode failure of the 22kV switchboard, the vulnerability due to a fire or explosion in the outdoor yard, the risk of targeted vandalism and the risk of an incident when plant is out of service for maintenance. There is introduction of nonstandard power transformers and less flexibility of supply options. Any new feeders required for future growth will have to be at least 12km long and cost more to maintain over its lifetime with higher losses ultimately recovered from the customers.

This option does however provide a number of advantages, specifically:

- Converting feeders to 22kV distribution voltage will address the capacity and voltage constraints for 20 years at 45% to 60% of the cost of a substation beyond which time substations upgrades or new feeders would be required; and
- Existing land and line routes are utilized. It is not necessary to buy new land or find new line routes.

Option 2 – Development of smaller substations at Kingseat and Glenbrook Beach

This option would consist of the following upgrades at the proposed new substations located at Kingseat and Glenbrook Beach to supply load in their locality and reduce the load at Karaka below its firm capacity of 20 MVA:

Kingseat substation

- Purchase land for the substation development;
- Secure 33 kV line routes for the Kingseat Substation; and
- Build the new 33kV substation and feeder works.

Glenbrook Beach substation

- Purchase land for the substation development;
- Secure 33 kV line routes for the Glenbrook Beach Substation; and
- Build the new 33kV substation, install sub transmission circuits and feeder works.

This option provides a number of advantages, specifically:

- Closer to the load centres of Glenbrook Beach, Clarks Beach, Karaka North and Kingseat areas and the future northern development areas. No feeder conversion required;
- Releasing of capacity at Karaka and Waiuku substations to accommodate more localised growth; Karaka substation upgrades can be deferred;
- Diversity of supply and provision of interconnection into Karaka, Pukekohe North and Waiuku;
- Improved resilience against HILP events (subtransmission and distribution);
- Shorter feeders (average 4km) are lower cost to maintain over the lifetime of the feeder with lower losses. It is easier to acquire line routes for shorter feeders direct to load centres with the new developments areas having more road route options;
- Customer numbers per feeder can be managed and back-feeding is easier to achieve during fault conditions; and
- New substations closer to the load centres is a more open ended solution and has the option of servicing load growth for at least a further 20 years compared to option 1, if appropriate associated upgrades are made, as required.

Option 3 – Increase Karaka Zone Substation Capacity and establish Glenbrook Substation

This option would consist of the following upgrades at the existing Karaka Zone Substation to raise firm capacity above 20 MVA for N-1 events:

- Increase the transformer capacity at Karaka by replacing the transformers with nonstandard 33/22kV 20/40 MVA transformer;
- Without extending the control room at the substation, the existing Te Hihi feeder is upgraded to a greater capacity cable and connected ring main units outside the substation to operate as two feeders, one existing overhead and a second 10km feeder cable to Kingseat development via an 11kV/22kV autotransformer;
- Backfeed is provided by the existing Pakington feeder that is upgraded to greater capacity cable and connected ring main units outside the substation to operate as two feeders, one existing overhead and a second 10km feeder cable to Kingseat development via ab 11kV/22kV autotransformer; and
- The load at Glenbrook Beach and Clarks Beach will be addressed by establishing the Glenbrook Beach substation.

The HILP risk exposure is reduced with this option as there now will be two sources of supply. There is added complexity given the need for new 33kV subtransmission corridors and new distribution feeder configurations.

It does however provide a number of advantages, specifically:

- Closer to the load centres of Glenbrook Beach, Clarks Beach but same distances from Karaka North and Kingseat areas and the future northern development areas. New feeders will be built at 22kV with minimal additional costs rather than converting existing feeders;
- Offloading Glenbrook Beach, Clarks Beach from Karaka and Waiuku substations to accommodate more localised growth;
- Karaka substation sub transmission lines upgrades can be deferred;
- Diversity of supply and provision of interconnection into Pukekohe North and Waiuku; and
- Improved resilience against HILP events (subtransmission and distribution).

This is a hybrid solution using one new substation and one existing substation. This results in significant deferment of costs by delaying one substation beyond the planning period. The Glenbrook and Clarks Beach areas will have the advantages of shorter feeders but not the longer new feeders out of Karaka, however being largely underground construction will significantly improve their reliability and this solution also addresses the customer number targets. Longer term a second substation will have to be built at Kingseat or the Karaka substation will require rebuilding.

Option 4 – Establish Kingseat Substation

This option would consist of the following upgrades at the proposed new substations located at Kingseat to supply Kingseat, Glenbrook and Clarks Beach developments and reduce the load at Karaka below its firm capacity of 20 MVA:

Kingseat substation

- Purchase land for the substation development;
- Secure 33kV line routes for the Kingseat Substation;
- Build the new 33kV substation and feeder works;
- The load at Glenbrook Beach and Clarks Beach will be addressed by converting the Waiau Pa feeder for 22kV operation;
- Backfeed is provided by installing a new 12km cable feeder to Glenbrook Beach; and
- The Glenbrook Karaka North line supplying the Kingseat substation will be assessed for short term overload ratings and could need capacity upgrades.

The HILP risk exposure is increased as there is now one source of supply. The 33kV subtransmission supply is by installing short tee connections to the existing Glenbrook Karaka North line. It does however provide a number of advantages, specifically:

- Closer to the biggest load centre of Kingseat but same distances from Glenbrook Beach, Clarks Beach and Karaka North areas and the future northern development areas. New feeders will be built at 22kV with minimal additional costs, however one existing feeder will be converted unless an alternate route is available and that will reduce the investment;
- Offloading Kingseat from Karaka substation to accommodate more localised growth; Karaka substation sub switchboard and transformer upgrades can be deferred; and
- Diversity of supply and provision of interconnection into Pukekohe North and Waiuku.

This is a hybrid solution using one new substation and one feeder conversion. This results in significant deferment of costs by delaying the most expensive substation beyond the planning period. The Kingseat and neighbouring areas will have the advantages of shorter feeders but not the longer feeders to Glenbrook and Clarks Beach, however the second feeder being largely underground construction will significantly improve their reliability and this solution also addresses the customer number targets. Longer term a second substation will have to be built at Glenbrook Beach and Karaka substation can be decommissioned at end of life or retained as a switching station.

Option 5 – Non-network alternatives

Localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is presently uneconomical for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Proposed investment

Our proposed investment is to build two new 33/11kV 20MVA Kingseat Area and Glenbrook Beach Area substations to supply the Kingseat, Clarks Beach and Glenbrook Beach housing developments’ anticipated load south of the Auckland City Rural Urban boundary. These new substations would supply the developments, reducing the reliance on Karaka substation and existing rural distribution feeders.

Our network development plan allows for the proposed new 33kV Glenbrook Beach Area substation to be supplied directly from the Glenbrook GXP and the proposed new 33kV Kingseat Area substation to be supplied via a diversion from the Glenbrook-Karaka North line.

On present projections the Kingseat developments is progressing much faster than the developments at Glenbrook and Clarks Beaches. As such, the development will be staged with a Kingseat substation established first subsequently followed by Glenbrook Beach substation with one single 33kV line built initially and the second line added when the load reaches 12MVA. The proposed investment represents the optimum long-term solution when considering factors including value, security of supply and customer experience. The new substation establishment solutions will factor in future decisions for the Karaka substation when it reaches end of life.

Based on our updated load forecast, the need for Glenbrook Beach substation is beyond the planning period, however land will be procured within the planning period in advance of this. Refer to figure 8-51 for the proposed subtransmission single line diagram for the proposed new Kingseat and Glenbrook Beach area substation and 33kV supply from the Glenbrook GXP.

Figure 8-40 summarises the proposed north western area substation development plan.

Description	Scope	Timing	Estimated Costs (\$'000)
Kingseat area substation land acquisition	Procure land for the establishment of Kingseat area substation	2021/22-2022/23	3,050
Kingseat area substation 33kV line design	Design 33kV line routes to supply Kingseat area substation	2021/22	500
Glenbrook Beach area substation land acquisition	Procure land for the establishment of Glenbrook Beach area substation	2022/23	2,300
Kingseat area substation 33kV line construction	Construct 33kV line routes to supply Kingseat area substation	2025/26-2026/27	3,713
Kingseat area substation establishment	Build a new Kingseat area substation with two 33/11kV 20MVA transformers and 22kV switchboard	2025/26-2026/27	9,000
Kingseat area substation feeder works	Build new 11kV feeder connections for Kingseat area substation	2025/26-2027/28	5,646

Figure 8-40 North Western Area substation development plan

Karaka Zone Substation Feeder Investment

Figure 8-41 shows the demand forecast for Karaka substation feeders.

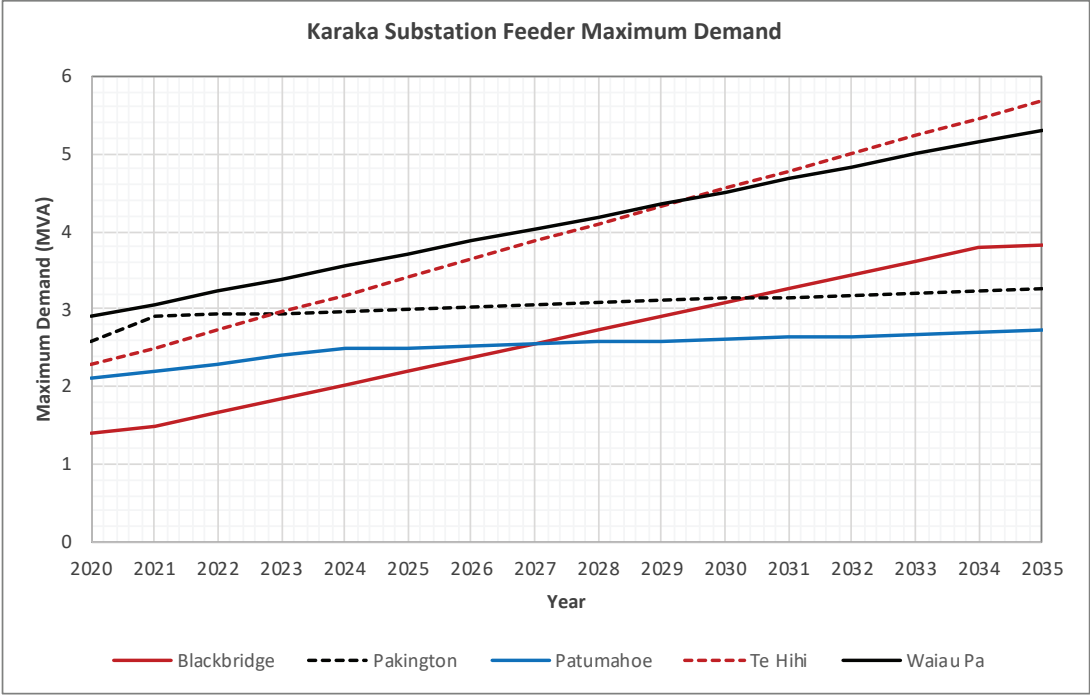


Figure 8-41 Feeder Demand Forecast at Karaka Zone Substation

Summary of Karaka Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Te Hihi feeder	Install voltage regulator at switch 47	2021/22	360
Pakington feeder reconductor	Reconductor 1.5 km of Pakington feeder	2026/27	571

Figure 8-42 Summary of Karaka Development Plan

8.5.4 Waiuku Zone Substation

The 33/11kV Waiuku zone substation is supplied by two 33kV subtransmission lines from Glenbrook GXP. Waiuku zone substation supplies 676 distribution substations in the urban areas of Waiuku, Racecourse Road and rural areas of Glenbrook, Te Toro and Manukau Heads. The load is a mix of residential and commercial. Waiuku is classed as a large zone substation (C4) and is fully compliant with our security criteria (refer to 8.1.2).

The Waiuku load has a winter peak. The forecast peak demand for Waiuku zone substation and the distribution feeders from the substation is shown in Figure 8-43.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Glenbrook	1.7	1.9	2.0	2.2	2.4	2.5	2.7	2.9	3.0	3.2	3.3	3.5	3.7	3.8	4.0	4.2	9.7%
Manukau Heads	1.8	1.8	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.1%
Racecourse	2.4	2.4	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	2.2%
Te Toro	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.0%
Waiuku South	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	1.0%
Waiuku Town	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.8	3.9	4.0	4.0	4.1	4.2	4.2	2.0%
Waiuku West	4.0	4.1	4.2	4.3	4.3	4.4	4.5	4.6	4.7	4.8	4.8	4.9	5.0	5.1	5.2	5.2	2.0%

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Waiuku	16.1	16.5	17.4	17.8	18.2	18.6	19.0	19.3	19.7	20.1	20.5	20.9	21.3	21.7	22.0	22.4	2.6%

Figure 8-43 Winter Maximum Demand at Waiuku Substation and Feeders

Waiuku Zone Substation Investment

The Waiuku zone substation demand forecast is shown in Figure 8-44.

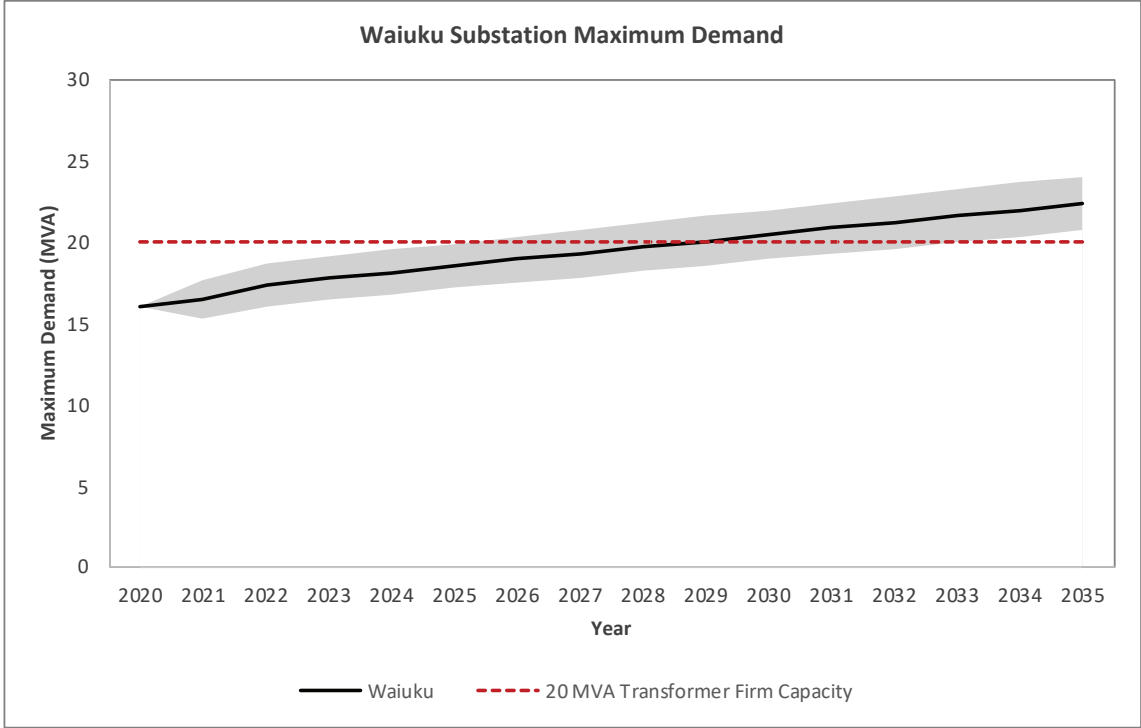


Figure 8-44 Waiuku Zone Substation Demand Forecast

Two 33/11kV, 10/20MVA transformers supply the load at Waiuku providing N-1 capacity of 20MVA. The Waiuku maximum winter demand will exceed the transformer N-1 capacity by 2028.

Short term cyclic ratings in excess of nominal ratings have been investigated and will be adopted to defer the need for transformer upgrades at Waiuku beyond 2035. With the current plans to establish the Kingseat and Glenbrook zone substations, transfer of load from Waiuku will further defer the investment need.

Waiuku Zone Substation Feeder Investment

Figure 8-45 shows the demand forecast for Waiuku substation feeders.

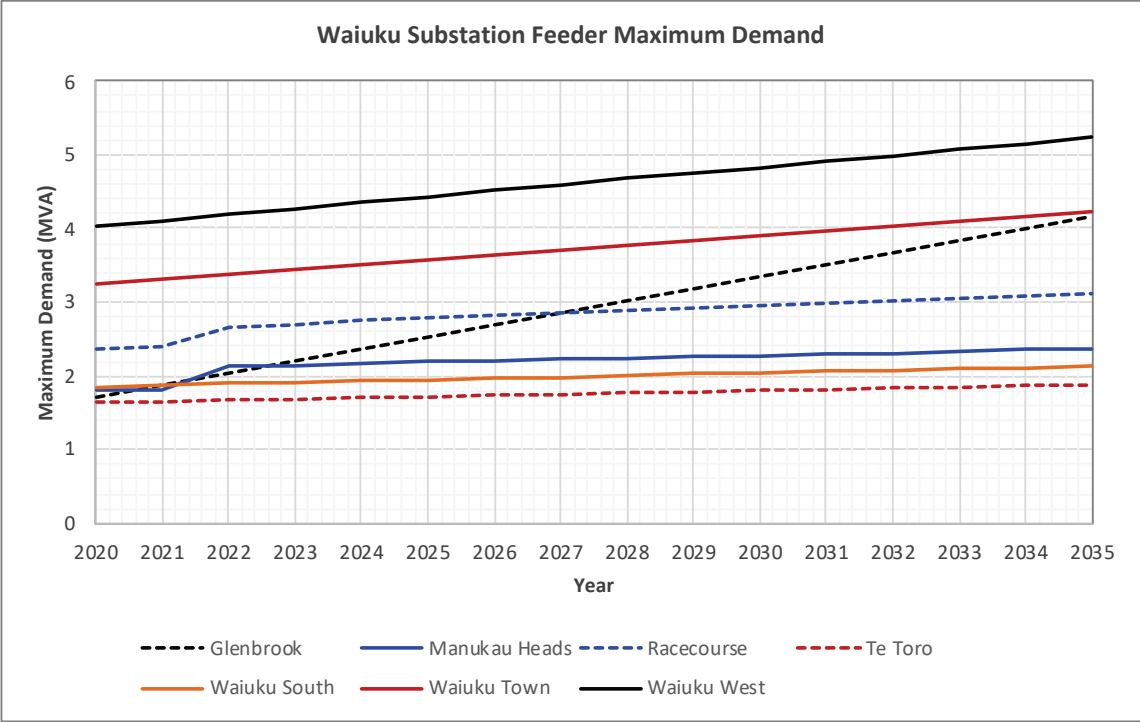


Figure 8-45 Feeder Demand Forecast at Waiuku Substation

Summary of Waiuku Development Plan

No specific network development projects are required within the planning period for the Waiuku area. However, there is an asset renewal driven project in place to replace the existing end of life 33/11 transformers which will be delivered in 2021/22. This is shown in the Figure 8-46 below for reference purposes.

Description	Scope	Timing	Estimated Costs (\$'000)
Waiuku transformer replacement (renewal project)	Finish replacement of end of life 33/11kV transformer at Waiuku	2021/22	1,000

Figure 8-46 Summary of Waiuku Development Plan

8.5.5 Maoro Zone Substation

The Maoro 33/11kV zone substation is supplied by one 33kV circuit from the Waiuku zone substation 33kV bus, and ultimately from the Glenbrook GXP. Maoro zone substation supplies 114 distribution substations in the rural area of Otatau, with a mix of residential and industrial load. Most of the demand on this substation is used by a major customer, NZ Steel, at their iron sands mine. Maoro is classed as a small zone substation (C3) and is not compliant with our security criteria (refer to 8.1.2) for maintaining maximum demand for both first and second outages. However, we have commercial arrangements in place with the major customer supplied from this substation for the reduced security and capacity constraints. This in effect makes Maoro zone substation compliant under category C5.

Figure 8-47 shows the winter maximum demand for Maoro substation and the distribution feeders from the substation.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Otaua	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0%
NZS Mine site & Pump Station 1	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	0.0%

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Maoro	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	0.0%

Figure 8-47 Winter Maximum Demand at Maoro Substation and Feeders

We do not anticipate any significant load growth in the area supplied from Maoro over the next ten years. As such, only minor increases have been allowed for in the demand forecasts and an increase of this magnitude will not lead to any new constraints on the supply assets.

As Maoro is predominantly used for the supply to NZ Steel, and the Otatau feeder can be fully backed from Waiuku (following upgrades to address capacity and voltage constraints), the future of the NZ Steel site brings uncertainty into future investment decisions. As such any asset replacement will only be undertaken once agreed with NZ Steel through appropriate commercial arrangements, and the nature of work will be done to minimise stranded asset risk should NZ Steel cease their operation.

Maoro zone substation Investment

The Maoro zone substation demand forecast is shown in Figure 8-48.

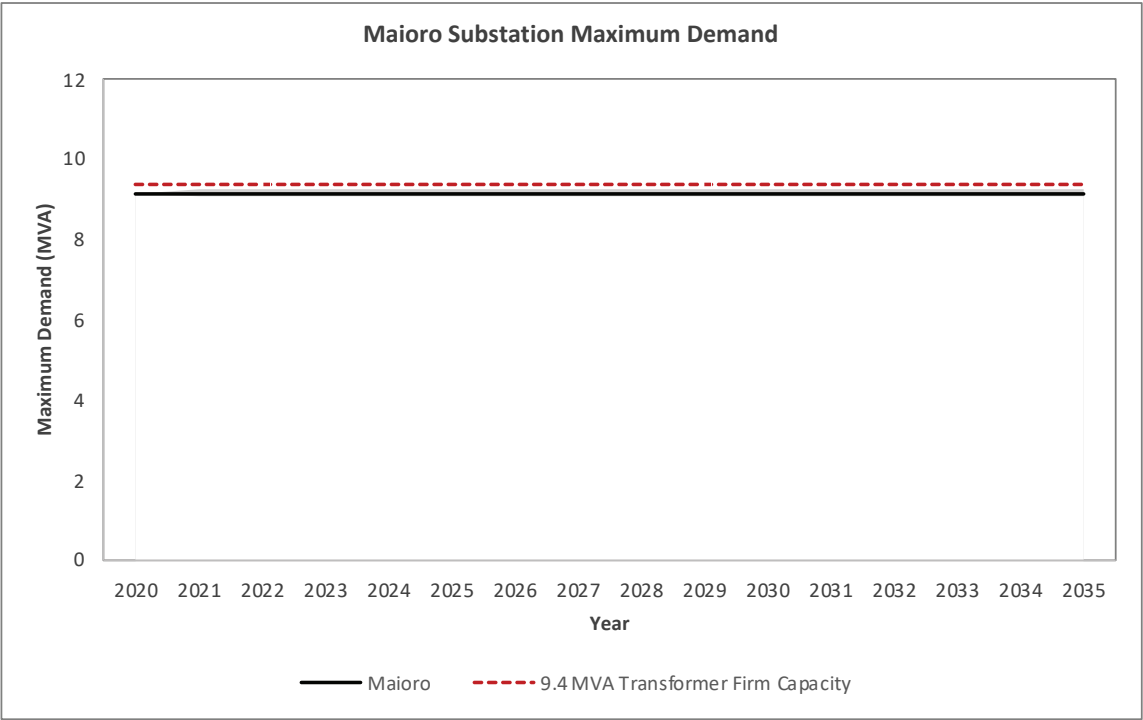


Figure 8-48 Maoro Zone Substation Demand Forecast

Two 33/11kV, 7.5MVA transformers supply the load at Maoro, providing an N-1 capacity of 7.5MVA (9.4MVA allowing for 25% short duration overload). The winter maximum demand in some years exceeds the firm capacity of the transformers.

The only material project in our development plan for Maoro zone substation is to replace the 11kV switchboard due to age and condition, which is detailed in Section 7.

Additionally, should the major customer require a higher level of firm capacity, closer to their demand of 10MVA compared with the existing firm capacity of 9.4MVA, we could relocate existing transformers to Maoro, from Karaka substation as part of the renewal and maintenance plan for power transformers, which is detailed in Section 7.

Maioiro Zone Substation Feeder Investment

Figure 8-49 shows the demand forecast of Maioiro substation feeders.

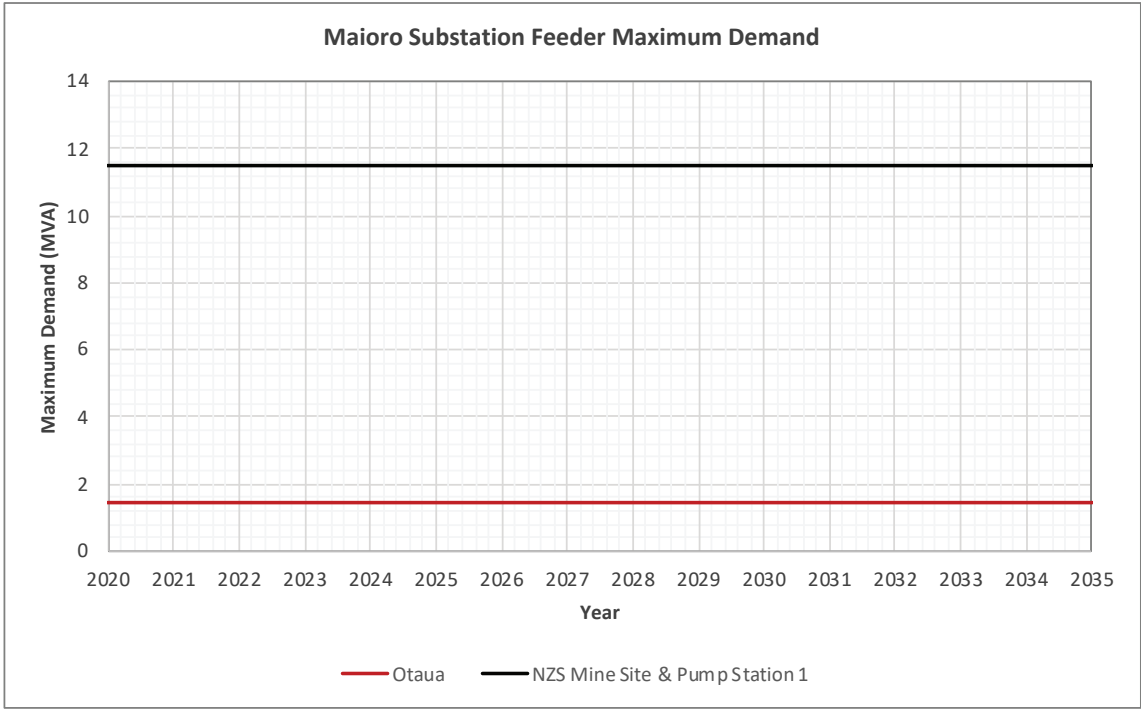


Figure 8-49 Feeder Demand Forecast at Maioiro Zone Substation

Summary of Maioiro Development Plan

Description	Scope	Timing	Estimated Costs (\$'000)
Otaua feeder voltage support upgrade (Hoods Landing Road)	Install a voltage regulator on Otaua feeder	2025/26	360

Figure 8-50 Summary of Maioiro Development Plan

8.5.6 33kV Storey Road Point of Supply

Storey Road Point of Supply is supplied off the 33kV Maioiro-Waiuku line and supplies No. 2 pump station on the New Zealand Steel slurry pipeline. We have no assets on this site apart from a 33kV disconnecter. We do not expect any load growth from this point of supply and consider the existing arrangement adequate for the foreseeable future.

Figure 8-51 shows the single line schematic for the future western region subtransmission network supplied from the Transpower Glenbrook GXP.

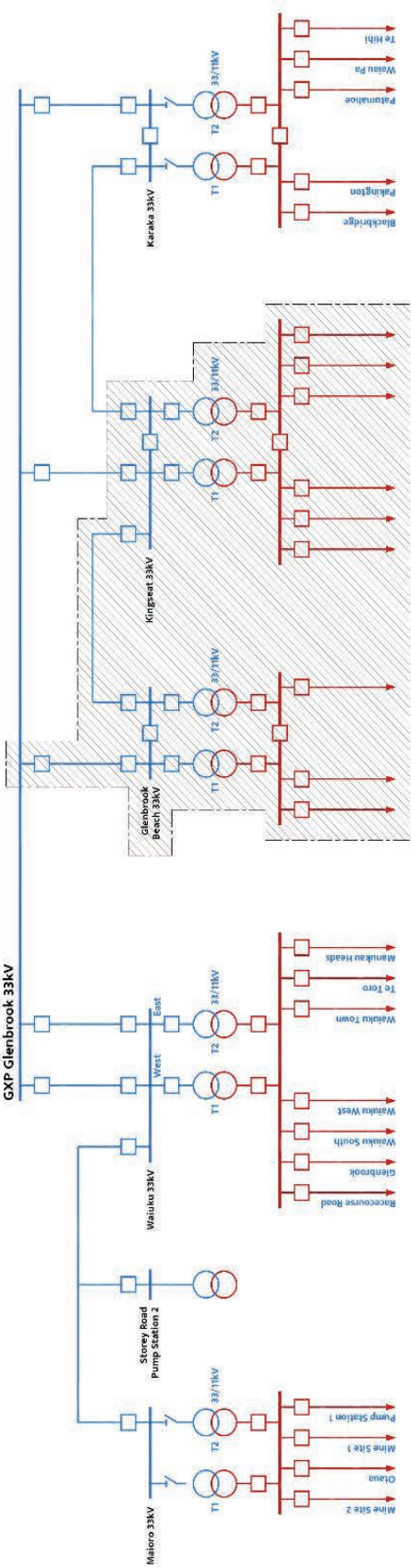


Figure 8-51 Single Line Schematic of the future western region subtransmission network

8.6 Summary of Capital Expenditure

Figure 8-52 below summarises the projected costs for subtransmission and distribution system development.

All work programmes, financial profiles and actions described throughout this plan indicate the Company’s intentions based on the information presently available to it. They may be amended in response to new information. They are also subject to detailed study and verification in accordance with sound engineering practice and, in respect of financial expenditure, established processes for management and Board approval.



Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Eastern Region										
Eastern Supply Programme - Substation and Subtransmission Renewal	19,156	10,355	400	5,500	4,500	-	-	-	-	-
Eastern Supply Programme - Feeder upgrades system growth	2,225	-	-	-	-	-	-	-	533	-
Opaheke Substation Supply Area	-	-	-	-	-	-	353	-	-	-
Drury Development Area (Quarry Road Substation)	-	-	11,500	11,500	-	-	-	-	-	-
Pukekohe North Substation Supply Area	2,750	3,500	-	5,000	9,000	11,000	5,000	-	-	-
Pukekohe Substation Supply Area	-	-	-	571	-	-	-	-	-	-
Tuakau Substation Supply Area	220	-	-	-	-	-	-	-	-	-
Pokeno Substation Supply Area	-	-	-	-	-	-	-	-	-	-
Western Region										
Karaka Substation Supply Area	360	400	-	-	-	571	-	-	-	-
Glenbrook Substation Supply Area	-	2,300	-	-	-	-	-	-	-	-
Kingseat Substation Supply Area	2,550	1,000	-	-	9,933	7,199	1,227	-	-	-
Maioro Substation Supply Area	-	-	-	-	360	-	-	-	-	-
Waiuku Substation Supply Area	-	-	-	-	1,955	-	-	-	-	-
Total Substation and Subtransmission Renewal	19,156	10,355	400	5,500	4,500	-	-	-	-	-
Total System Growth	8,105	7,200	11,500	17,071	21,248	18,770	6,580	-	533	-

Figure 8-52 Projected Expenditure for Subtransmission and Distribution System Development

Note: Forecasts are stated in real (constant) prices

9 NON-NETWORK INVESTMENT

The non-network operational expenditure has increased from \$127m forecast for the 2020 AMP planning period to \$142m in this update (constant \$).

We have increased the level of expenditure in the IT area to address high growth on the network and upgrade systems to meet business and cyber security requirements. The Company continues to invest in improving the customer experience and views this area as a priority. Other business support including HR, Finance and Corporate has also increased to meet business requirements.

9.1 Non-Network Investment Plan

In addition to the planned maintenance, renewal and development of network assets detailed in Section 7 and Section 8 we have identified expenditure requirements on non-network assets including our Information Technology hardware and software, our tools and equipment, as well as our vehicle fleet.

9.2 Information Technology Upgrades and Replacement

The following major systems upgrades have been identified as requiring capital investment in the short to medium term of the plan. Other minor systems are expected to require replacement or upgrade during the planning period, however their cost is not material in terms of the non-network investment forecast.

Function	System	Year	Estimated Cost ('000s)
ERP Upgrade	Upgrade of the Microsoft NAV Dynamics platform.	2021/22	250
Digital & Mobility Transformation	Application of digital technology across all business functions	2021/22	400
Customers	CRM and customer experience	2021/22	450
Asset Management	SCADA	2021/22	1,100
Other	IT system and security enhancements	2021/22	1,370
Routine Replacement			
Core Network Infrastructure	Network Infrastructure such as switches, servers, UPS, etc. to maintain network reliability.	3-5 year replacement cycle	200
PCs, Laptops and Field Mobile Devices	Replacement of devices to ensure fit for purpose	2-4 year replacement cycle	125

9.3 Buildings

The 2021/22 capital programme includes \$14.7m for the upgrade and extension to the offices and yard layout improvements at Glasgow Road, Pukekohe due to the growing needs of the business.

The new addition to the main office building will be built in accordance with importance level 3 to improve the seismic performance during a severe ground event.

The new yard layout will be designed to better handle the increased level of stock movements and accommodate the storage of additional inventory to meet growth in minimum stock levels. Similarly, the new office layout will incorporate more modern work space design to meet newer work practices which nowadays are more agile and team based.

9.4 Tools and Equipment

Our non-network expenditure forecasts allow for the ongoing replacement of tools and equipment used by our teams. It is also expected that new test and inspection equipment will be purchased in 2021/22 to support the maintenance programme.

9.5 Vehicle Fleet and Machinery

We own our fleet of light and heavy vehicles, as well as field machinery such as excavators and directional drilling machines, along with their transport trailers.

Our expenditure forecasts allow for the replacement of these as required through the planning period, as well as operational expenditure for the ongoing maintenance to ensure safety and reliability.

Capital Expenditure Forecast (\$000)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Total	17,748	3,925	2,011	2,013	2,014	2,016	2,018	2,019	2,021	2,023

Figure 9-2 Summary of Non- Network Capital Expenditure

Note: Forecasts are stated in real (constant) prices



10 EXPENDITURE SUMMARIES

This Chapter provides a summary of the forecast expenditure from the three investment Chapters – Renewals and Maintenance, Network Development and Non-Network.

10.1 Capital Expenditure Summary

10.1.1 Renewal and Replacement Expenditure

Note: Forecasts are stated in real (constant) prices



Asset Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital Expenditure (000's)										
Subtransmission Network										
Bombay-Ramarama tower rebuild	200	-	-	4,500	4,500	-	-	-	-	-
Other subtransmission renewal	50	50	50	50	50	50	50	50	50	100
Zone Substations										
Power transformer refurbishment	300	300	300	-	-	-	-	-	-	-
Waiuku substation	1,000	-	-	-	-	-	-	-	-	-
Barber Road substation	11,422	2,373	-	-	-	-	-	-	-	-
Decomission Ramarama and Mangatawhiri	-	-	-	1,000	-	-	-	-	-	-
Opaheke 22kV switchboard replacement	-	-	-	-	-	-	-	-	-	2,000
Other zone substation renewal	50	50	50	50	50	50	50	50	50	50
Distribution and LV Lines										
Overhead renewals	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,550
Copper replacement programme	3,071	5,255	1,004	4,351	-	1,454	1,500	4,625	5,923	6,110
Swan replacement programme	1,495	4,754	4,068	-	-	4,644	2,094	6,738	5,520	9,060
HV feeder section replacement	-	762	300	300	300	300	900	300	300	-
Urban LV replacement	774	363	197	-	260	252	379	300	300	-
Overhead safety compliance (including Low Lines)	100	300	800	300	300	600	100	100	100	600
Barber Road - copper & Swan replacement	2,190	7,982	-	-	-	-	-	-	-	-
Barber Road - HV & LV rehabilitation	1,905	-	-	-	-	-	-	-	-	-
Distribution and LV Cables										
Barber Road - feeder cable renewal	3,438	-	400	-	-	-	-	-	-	-
Pillar renewal	200	200	200	200	200	200	200	200	200	216
UG cable renewal	150	200	300	300	300	300	300	300	300	300
Distribution Transformers										
Transformer renewal programme	400	400	400	400	450	450	450	450	450	400
Distribution Switchgear										
RMU replacement	2,877	-	-	480	480	480	480	480	480	-
Overhead switchgear replacement	480	480	450	480	480	480	480	480	480	600
Other System Fixed Assets										
Opaheke LCP control module replacement	-	-	-	-	-	-	-	-	-	450
Relay replacement	2,000	-	-	2,000	-	-	-	-	-	-
RTU, battery renewal	100	90	120	140	105	100	90	100	100	105
Substation security	1,410	-	-	-	-	-	-	-	-	-
SCADA radio equipment upgrade	1,000	2,000	3,500	1,000	2,500	-	-	-	-	-
Subtotal	37,613	28,559	15,139	18,551	12,975	12,360	10,072	17,173	17,253	23,540
Capitalised maintenance	955	955	955	955	955	955	955	955	955	955
Total	38,568	29,514	16,094	19,506	13,930	13,315	11,027	18,128	18,208	24,495

Figure 10-1 Summary Capital Expenditure – Renewal and Replacement

Note: Forecasts are shown in Real (constant) prices

10.1.2 System Growth Expenditure

Region \$ (000's)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Eastern Region										
Eastern supply programme - Feeder upgrades system growth	2,225	-	-	-	-	-	-	-	533	-
Opaheke substation supply area	-	-	-	-	-	-	353	-	-	-
Drury development area (Quarry Road substation)	-	-	11,500	11,500	-	-	-	-	-	-
Pukekohe North substation supply area	2,750	3,500	-	5,000	9,000	11,000	5,000	-	-	-
Pukekohe substation supply area	-	-	-	571	-	-	-	-	-	-
Tuakau substation supply area	220	-	-	-	-	-	-	-	-	-
Pokeno substation supply area	-	-	-	-	-	-	-	-	-	-
Western Region										
Karaka substation supply area	360	400	-	-	-	571	-	-	-	-
Glenbrook substation supply area	-	2,300	-	-	-	-	-	-	-	-
Kingseat substation supply area	2,550	1,000	-	-	9,933	7,199	1,227	-	-	-
Maioro substation supply area	-	-	-	-	360	-	-	-	-	-
Waiuku substation supply area	-	-	-	-	1,955	-	-	-	-	-
Total System Growth	8,105	7,200	11,500	17,071	21,248	18,770	6,580	-	533	-

Figure 10-2 Summary Capital Expenditure – Network Development

10.1.3 Customer Programme Expenditure

Customer Programme Expenditure \$(000's)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Customer connections	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Asset relocations	300	300	300	300	300	300	300	300	300	300
Total	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800
less Customer Contributions of	9,000	9,500	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925

Figure 10-3 Summary Capital Expenditure – Customer Related

10.1.4 Non-Network Investment

Asset Category \$ (000's)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Non-Network expenditure	17,748	3,925	2,011	2,013	2,014	2,016	2,018	2,019	2,021	2,023
Total	17,748	3,925	2,011	2,013	2,014	2,016	2,018	2,019	2,021	2,023

Figure 10-4 Summary Capital Expenditure – Non-Network investment

10.1.5 Total Capital Expenditure by Disclosure Category

Asset Category \$ (000's)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Consumer connection	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
Asset replacement	38,568	29,514	16,094	19,506	13,930	13,316	11,027	18,128	18,208	24,495
System growth	8,105	7,200	11,500	17,071	21,248	18,770	6,580	-	533	-
Asset relocations	300	300	300	300	300	300	300	300	300	300
Quality of supply	350	350	350	350	350	350	350	350	350	350
Other reliability, safety and environment	-	-	5,225	1,098	-	-	-	-	-	-
Subtotal Network	55,823	45,864	41,969	46,825	44,328	41,236	26,757	27,278	27,891	33,645
WIP carry-over from FY20 to FY21	2,500									
Non-Network	17,748	3,925	2,011	2,013	2,014	2,016	2,018	2,019	2,021	2,023
Total	76,071	49,789	43,980	48,838	46,342	43,252	28,775	29,297	29,912	35,668

Figure 10-5 Total Capital Expenditure – By Disclosure Category

Note: Forecasts are stated in real (constant) prices

10.2 Operating Expenditure Summary

10.2.1 Network Operating Expenditure by Asset Category

Asset Category \$ (000's)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Subtransmission Network										
Subtransmission lines	150	150	150	150	150	150	150	150	150	150
Subtransmission cables	30	30	30	30	30	30	30	30	30	30
Zone Substations										
Zone Substation transformers	130	130	130	130	150	150	170	170	170	170
Zone Substation switchgear	150	150	150	150	160	160	180	180	180	180
Zone Substation other equipment	100	100	100	100	100	110	110	110	110	110
Zone Substation buildings and grounds	100	100	100	100	110	110	120	110	110	110
Distribution and LV Lines										
Distribution poles and crossarms	900	900	918	946	951	955	965	974	984	995
Distribution conductor	150	150	153	165	166	168	169	171	180	182
Fault indicators and Earthing	25	26	27	27	28	28	29	29	32	32
Distribution and LV cables										
Distribution and LV cables	120	136	142	145	148	151	157	160	170	173
LV Pillars	90	100	102	104	106	108	115	117	125	130
Distribution Substations and Transformers										
Distribution transformers	450	459	468	470	475	477	482	490	495	500
Distribution switchgear										
Ring main units	150	155	158	160	163	166	170	173	180	180
Overhead switchgear	150	155	155	155	155	160	160	165	170	173
Other System Fixed Assets										
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	100	120	120	140	150	180	180	180	180	180
Load control equipment	40	40	40	40	40	40	40	40	40	40
Battery banks	30	30	30	30	30	30	30	30	40	40
SCADA, Communications & Control	650	650	650	650	650	660	650	702	713	713
Vegetation										
Vegetation	2,000	2,049	2,081	2,132	2,184	2,237	2,292	2,348	2,406	2,465
Public Safety Services										
Public Safety Services	100	100	100	100	100	100	100	100	100	150
Faults and Reactive Maintenance										
Faults	2,100	2,151	2,185	2,238	2,293	2,349	2,407	2,466	2,526	2,588
Capitalisation										
less capitalised maintenance	-955	-955	-955	-955	-955	-955	-955	-955	-955	-955
Total	6,780	6,946	7,053	7,226	7,403	7,584	7,770	7,961	8,156	8,356

Figure 10-6 Summary Operating Expenditure – By Asset Category

10.2.2 Network Operating Expenditure by Disclosure Category

Asset Category \$ (000's)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Service interruptions and emergencies	2,100	2,151	2,185	2,238	2,293	2,349	2,407	2,466	2,526	2,588
Vegetation management	2,000	2,049	2,081	2,132	2,184	2,237	2,292	2,348	2,406	2,465
Routine and corrective maintenance and inspection	1,650	1,690	1,717	1,759	1,802	1,846	1,891	1,937	1,985	2,034
Asset replacement and renewal	1,030	1,055	1,072	1,098	1,125	1,152	1,180	1,209	1,239	1,269
Total	6,780	6,946	7,053	7,226	7,403	7,585	7,771	7,961	8,156	8,356

Figure 10-7 Total Operating Expenditure – By Disclosure Category

Note: Forecasts are stated in real (constant) prices

11 EVALUATION OF PERFORMANCE

11.1 Performance Against Previous Plan

Assessing performance against previous plans is a part of our continual improvement in asset management and overall business performance.

This Chapter provides an assessment of performance against the last complete financial year (FY20) as well as comparing against the forecast performance of the current financial year at the time of writing.

Our financial year runs from 1 April to 31 March, which aligns with the regulatory year. Network performance and other service levels are compared against previous targets in Chapter 3 – Service Levels.

11.2 Financial Performance FY20 Plan to Actual

11.2.1 Capital Expenditure FY20

Disclosure Categories	Target (\$000)	Actual (\$000)	Variance	Reasons for variance (>10%)
Consumer connection	12,690	9,241	-27%	Consumer connection expenditure were below target due to lower commercial connections.
System growth	26,420	26,698	1%	
Asset replacement and renewal	13,360	12,537	-6%	Asset relocations were lower than target with some anticipated third party asset relocation projects not progressing and design alterations meaning relocation work was not needed in the final network configurations.
Asset relocations	300	48	-84%	
Other reliability, safety and environment	1,545	2,108	36%	Focus on improvement of reliability reflected in a higher than expected spend.
Non-network assets	6,433	3,134	-51%	Expenditure on non-network assets was lower than forecast due to a delayed start for the Glasgow site upgrade.
Total	60,748	53,766	-11%	

Figure 11-1 Capital expenditure FY20

11.2.2 Operational Expenditure FY20

Disclosure Categories	Target (\$000)	Actual (\$000)	Variance	Reasons for variance (>10%)
Service interruptions and emergencies	1,900	2,038	7%	
Vegetation management	1,350	1,512	12%	Additional work was carried out to improved network reliability.
Routine and corrective maintenance and inspection	1,350	900	-33%	The routine and corrective maintenance programme was completed but fell below target with higher levels of upgrades carried out that were capital in nature.
Asset replacement and renewal	700	269	-62%	Asset Replacement and Renewal was below forecast reflecting higher capitalisation of expenditure
System operations and network support	4,084	3,747	-8%	
Business support	6,179	7,275	18%	Higher spend reflects continued investment in the areas of Network support, IT and customer relationship management.
Total	15,563	15,741	1%	

Figure 11-2 Operational expenditure FY20

11.2.3 Project Performance FY20 Plan to Actual

Project	Scope	Project Budget (\$000)	Actual completion
Pukekohe East feeder upgrade	Upgrade conductor, including copper and Swan	460	FY21
Investigation review timing for new Opaheke substation		20	FY21
Patumahoe feeder split	Two feeders out of Karaka substation, the limb going to anchor factory 2.1km of Grasshopper is upgraded, Upgrade Auto Tx to 3MVA	540	FY21
Rerating/engineering study for Waiuku 33kV line		300	FY21
Upgrade auto-transformer and install voltage regulator on Port Waikato feeder		200	Deferred
Purchase land in the vicinity for Kingseat substation		2000	FY22
Purchase land in the vicinity for Pukekohe North substation		2300	FY22
Pukekawa trunk	Build Pukekawa trunk	690	FY20
Replace ABS140 switch with a new automated switch (Whangarata)	Replace ABS140 switch with a new automated switch (Whangarata)	35	FY20
Replace ABS189 switch with a new automated switch (Port Waikato)	Replace ABS189 switch with a new automated switch (Port Waikato)	35	FY20
Replace ABS222 switch with a new automated switch (Port Waikato)	Replace ABS222 switch with a new automated switch (Port Waikato)	35	FY20
Replace ABS261 switch with a new recloser (Manukau Heads)	Replace ABS261 switch with a new recloser (Manukau Heads)	35	FY20
Waiau Pa (Clarks Beach)	OHUG Clarks Beach, including copper conductor	1450	FY20
Papakura South RMU replacement Stage 1	Replace kiosk & oil filled switchgear	1170	FY21
Racecourse RMU replacement Stage 1	Replace kiosk & oil filled switchgear	900	FY20
Otaua copper & Swan replacement (247)	6km of Copper and Swan conductor, and new backfeed link	1,500	FY21
Waiuku West feeder (Victoria Ave and Valley Road)	HV and LV rehabilitation	770	FY20
Glen Murray voltage regulator replacement		360	FY20
Karaka eight relay replacement		320	Deferred to FY22 due to design constraints and standard alignment
Glenbrook LCP coupling cell replacement		300	FY21
Opaheke substation earthing transformers procurement		250	FY20

Project	Scope	Project Budget (\$000)	Actual completion
Pukekohe substation earthing transformers procurement		250	FY20
Opaheke substation earthing transformers installation		300	FY21
Waiuku substation rebuild		1300	FY21
Drury feeder	Upgrade 200m of cable section and 800m of overhead section	300	FY21
Install recloser at 810 (Railway feeder)		35	FY21
Replace recloser 905 (Manukau Heads feeder)		35	FY21
Karaka oil separator	Installation of oil separator	300	FY20
Maioro oil separator	Installation of oil separator	300	FY20
Substation locks replacement		270	FY20
Network locks replacement	Procurement of new substation locks	150	FY20
Build new distribution feeder from Pokeno industrial area via Potter Road		1560	Deferred
Pokeno substation establishment		3500	FY21
Waiuku substation rebuild		1800	FY21
Connect existing distribution feeders to the new Pokeno substation		1000	FY21
Pokeno substation establishment		3000	FY21
Pokeno substation establishment		1600	FY21
Pukekohe substation earthing transformers installation		300	FY21
Connect existing distribution feeders to the new Pokeno substation		1000	FY21
Ararimu feeder rebuild 445		35	FY20
Pokeno substation establishment		1600	FY21
Connect existing distribution feeders to the new Pokeno substation		1000	FY21
Drury South area substation electrical procurement		1500	Deferred

Figure 11-3 Project performance FY20 Plan to Actual

11.2.4 Financial Performance FY21 Plan to Forecast

Forecast Capital Expenditure FY21

Disclosure Categories	Target (\$000)	Forecast (\$000)	Variance	Reasons for variance (>10%)
Consumer connection	9,500	9,500	0%	
System growth	6,620	9,005	36%	Completion of the new Pokeno Substation rolled into the early months of FY21 vs completion in FY20.
Asset replacement and renewal	30,909	28,524	-8%	
Asset relocations	300	300	0%	
Other reliability, safety and environment	350	350	0%	
Non-network assets	11,792	6,336	-46%	Lower spend due to the delay in the Glasgow site upgrade to FY22.
Total	59,471	54,015	-9%	

Figure 11-4 Forecast capital expenditure FY21

Forecast Operational Expenditure FY21

Disclosure Categories	Target (\$000)	Forecast (\$000)	Variance	Reasons for variance (>10%)
Service interruptions and emergencies	2,100	2,100	0%	
Vegetation management	1,500	1,700	13%	Additional spend targeted to improve network reliability.
Routine and corrective maintenance and inspection	1,550	1,550	0%	
Asset replacement and renewal	1,130	1,130	0%	
System operations and network support	3,104	3,286	6%	
Business support	7,876	7,867	0%	
Total	17,260	17,633	2%	

Figure 11-5 Forecast operational expenditure FY21



11.2.5 Project Performance FY21 Plan to Forecast

Project	Scope	Project Budget (\$000)	Expected completion
Barber Road design		1200	FY21
Bombay feeder Razorback Road CU conductor replacement	Reconductor Razorback Road	600	FY21
Glen Murray copper & Swan replacement	Replace 0.7km Swan, 0.7km LV copper	260	FY21
Maioro 33kV line refurbishment	Replace end of life assets on 33kV OH line, including tag poles	650	FY21
Papakura South and Beach Road Kiosk replacements and rehabilitation	Replace 11 Kiosk substations in Papakura South and Beach Road feeders, and Beach Road HV rehabilitation	6000	\$2,867k spent YTD FY21. Carried over for completion in FY22 – Q1
Pukekohe Hill Swan replacement (Anzac Road)	Reconductor 0.5km Swan conductor and associated poles and hardware	490	FY21
Railway feeder (Outside Racecourse) copper replacement	Reconductor outside Racecourse	280	FY21
Substation security integration		200	FY21/22
Tuakau/Pukekawa Micom relay replacement	Replace Micom relays at Tuakau and Pukekawa zone substations	360	\$723k spent YTD FY21. Commenced in FY21, due completion FY22 – Q1
Waiuku transformer replacement - design		200	FY21
Waiuku transformer replacement - procurement		300	FY21/22
Barber Road substation road construction		800	FY22
Barber Road transformer procurement (Transpower)		500	FY22
Bombay GXP RTU link upgrade		100	FY22
Church Corner Swan replacement	Reconductor 3.45km of copper and Swan & OHUG Geraghtys Road. Replace ABS 578	250	FY21

Project	Scope	Project Budget (\$000)	Actual completion
Install voltage regulator at switch 730 (Blackbridge), upgrade Auto Tx to Hingaia	Installation of voltage regulator and auto transformer	400	Deferred due to changes in load growth and no longer required.
Railway feeder (Jericho Road, Harrisville)	Replace 2.4km Copper, 2.8km Swan and close gap between Harrisville/Jericho Road	1150	FY21
Underground Waiuku Town and Te Toro feeders along Kitchener Road	OHUG Waiuku and Te Toro feeders along Kitchener Road	600	FY21
Barber Road substation feeder connections		1200	FY22
Great South Road copper replacement - backbone	Replace 9km of copper conductor on Great South Road & Runciman Road	2509	\$430k spent YTD FY21. Carried over for completion in FY22 – Q1
Patumahoe (Township) copper replacement	OHUG Patumahoe township	780	FY21
Racecourse RMU replacement Stage 2	Replace Kiosk oil filled switchgear on Kauri Drive	500	FY21
Red Hill feeder Swan replacement	OHUG Overhead section of Red Hill feeder	2700	\$374k spent YTD FY21. Carried over for completion in FY22 – Q1
Waiuku transformer replacement - civil work		150	FY21
Waiuku transformer replacement - electrical work		400	FY21
Barber Road substation civil work		600	FY21
Kingseat substation land procurement		1950	FY22
Pukekohe North substation land procurement		2350	FY22
Pukekohe North substation line design		400	FY22
Waiuku Town feeder (Norfolk Rise)	LV Rehabilitation, replacement of Kiosk Transformer and OHUG of LV and service lines	280	FY21

Figure 11-6 Project performance FY21 Plan to Forecast

APPENDICES



Appendix A – AMP 2021 Information Disclosure Schedules

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 lockdown year and a 10-year planning period. The forecasts should be consistent with it commissioned assets (i.e., the value of Net additions).

EoB 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	Company Name AMP Planning Period													
	1 April 2021 – 31 March 2031													
	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
\$'000 (In nominal dollars)														
11(a): Expenditure on Assets Forecast														
Consumer connection	9,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	9,385	9,572	9,764	9,959	10,158
System growth	9,005	8,105	7,344	11,905	18,116	22,993	20,724	27,410	22,993	20,724	27,410	22,993	20,724	27,410
Asset replacement and renewal	28,524	38,568	30,044	16,744	15,073	14,701	12,418	20,823	20,823	21,344	20,823	21,344	20,823	21,344
Asset reductions	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Reliability, safety and environment:														
Quality of supply	350	350	357	364	371	379	386	394	402	410	418	426	434	442
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	350	350	357	364	371	379	386	394	402	410	418	426	434	442
Expenditure on network assets	47,679	55,823	46,781	43,664	49,691	47,882	45,527	50,133	49,817	50,133	50,133	50,133	50,133	50,133
Expenditure on non-network assets	6,336	17,748	4,003	2,093	2,136	2,180	2,226	2,272	2,319	2,368	2,417	2,467	2,517	2,567
Expenditure on assets	54,015	73,571	50,784	45,757	51,827	50,062	47,713	52,403	52,136	52,491	52,550	52,600	52,650	52,700
plus	250	147	121	110	123	116	108	70	72	71	71	71	71	71
less	9,005	8,500	9,103	9,206	9,471	9,663	9,854	10,051	10,253	10,457	10,660	10,863	11,066	11,269
plus														
Capital expenditure forecast	45,265	64,217	41,803	36,551	42,478	40,614	38,891	40,126	38,879	39,077	39,077	39,077	39,077	39,077
Assets commissioned	26,863	50,736	45,318	40,061	38,891	38,891	38,891	38,891	38,891	38,891	38,891	38,891	38,891	38,891
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	31 Mar 32	31 Mar 33	31 Mar 34
\$'000 (In constant prices)														
Consumer connection	9,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500
System growth	9,005	8,105	7,200	11,500	17,071	21,248	18,720	25,580	22,993	20,724	27,410			
Asset replacement and renewal	28,524	38,568	29,514	16,094	19,506	13,910	13,316	11,027	18,138	18,088	24,495			
Asset reductions	300	300	300	300	300	300	300	300	300	300	300			
Reliability, safety and environment:														
Quality of supply	350	350	350	350	350	350	350	350	350	350	350			
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-			
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-			
Total reliability, safety and environment	350	350	350	350	350	350	350	350	350	350	350			
Expenditure on network assets	47,679	55,823	45,864	41,969	46,825	44,328	41,236	26,757	27,278	27,891	33,645			
Expenditure on non-network assets	6,336	17,748	3,925	2,011	2,013	2,014	2,016	2,018	2,019	2,021	2,023			
Expenditure on assets	54,015	73,571	49,789	43,980	48,838	46,342	43,251	28,775	29,297	29,912	35,668			
Subcomponents of expenditure on assets (where known)														
Energy efficiency and demand side management, reduction of energy losses														
Overhead to underground conversion														
Research and development														
	500	300	300	300	300	300	300	300	300	300	300			

[illegible]

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 lifecycle year and a 10-year planning period. The forecasts should be consistent with the commissioned assets (i.e., the value of RFA additions)

EBS 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.

Company Name

Counties Power Limited

AMP Planning Period

1 April 2021 – 31 March 2031

	for year ended	Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
11a(iv): Asset Replacement and Renewal							
Subtransmission		260	250	50	50	4,550	4,550
Zone substations		6,150	12,772	2,723	350	1,050	50
Distribution and LV lines		12,348	13,481	27,659	10,324	8,082	4,812
Distribution and LV cables		3,753	3,788	1,182	900	500	500
Distribution substations and transformers		400	400	400	400	400	400
Distribution switchgear		3,250	3,357	480	450	960	960
Other network assets		1,915	4,510	2,050	3,620	3,140	2,805
Asset replacement and renewal expenditure less Capital contributions funding asset replacement and renewal		28,524	38,568	29,514	16,094	19,506	13,930
Asset replacement and renewal less capital contributions		28,524	38,568	29,514	16,094	19,506	13,930
11a(v): Asset Relocations							
Project or programme*							
Others		300	300	300	300	300	300
*Include additional rows if needed							
All other project or programmes - asset relocations							
Asset relocations expenditure less Capital contributions funding asset relocations		300	300	300	300	300	300
Asset relocations less capital contributions		300	300	300	300	300	300
11a(vi): Quality of Supply							
Project or programme*							
Voltage quality resolution		350	350	350	350	350	350
*Include additional rows if needed							
All other projects or programmes - quality of supply							
Quality of supply expenditure less Capital contributions funding quality of supply		350	350	350	350	350	350
Quality of supply less capital contributions		350	350	350	350	350	350

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Company Name

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AMP Planning Period

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 requires a breakdown 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 lengthed

sch ref		Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)							% of asset forecast to be replaced in next 5 years
						H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	
7		All	Overhead Line	Concrete poles / steel structure	No.	0.07%	4.62%	19.66%	34.91%	40.74%	0.00%	3	3.95%
8		All	Overhead Line	Wood poles	No.	8.93%	9.69%	22.79%	3.09%	55.44%	0.05%	3	9.90%
9		All	Overhead Line	Other pole types	No.	-	30.99%	9.86%	2.87%	47.89%	8.45%	3	-
10		HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	4.71%	-	65.10%	9.56%	20.63%	-	3	4.74%
11		HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	3	-
12		HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	16.78%	27.67%	72.33%	-	3	5.16%
13		HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	83.22%	-	3	-
14		HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-	-
15		HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILQ)	km	-	-	-	-	-	N/A	-	-
16		HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A	-	-
17		HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A	-	-
18		HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILQ)	km	-	-	-	-	-	N/A	-	-
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+ (PILQ)	km	-	-	-	-	-	N/A	-	-
23		HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A	-	-
24		HV	Zone substation Buildings	Zone substations up to 66kV	No.	100.00%	-	-	-	-	-	3	33.33%
25		HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	25.00%	50.00%	-	25.00%	3	-
26		HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	N/A	-	-
27		HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	100.00%	-	-	-	-	-	3	33.33%
28		HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-	-
29		HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	74.15%	6.45%	9.68%	9.68%	-	-	3	50.00%
30		HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	N/A	-	-
31		HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-
32		HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	47.37%	26.32%	26.32%	N/A	3	-
33		HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	15.22%	-	11.96%	58.70%	10.87%	3.26%	3	26.25%
34		HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	N/A	-	-

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Asset condition at start of planning period (percentage of units by grade)

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
38		Zone Substation Transformers	No.	-	41.18%	11.76%	23.53%	23.53%	-	3	23.53%
39	HV	Distribution Transformer	km	2.19%	10.05%	33.16%	35.16%	19.44%	-	3	4.10%
40	HV	Distribution Line	km	-	-	-	-	-	-	-	-
41	HV	Distribution Line	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	km	-	-	-	-	-	-	-	-
43	HV	Distribution Cable	km	0.24%	-	2.04%	22.63%	75.05%	0.04%	3	0.13%
44	HV	Distribution Cable	km	-	21.68%	27.62%	44.65%	6.05%	-	3	55.80%
45	HV	Distribution Cable	km	-	-	-	34.07%	65.93%	-	4	-
46	HV	Distribution switchgear	No.	-	7.65%	23.08%	41.03%	28.21%	-	3	-
47	HV	Distribution switchgear	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	No.	10.59%	12.71%	39.44%	25.00%	32.85%	0.42%	3	6.55%
49	HV	Distribution switchgear	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	No.	3.14%	4.88%	11.15%	37.28%	42.86%	0.70%	3	6.62%
51	HV	Distribution Transformer	No.	3.24%	11.57%	31.10%	40.50%	13.21%	0.38%	3	7.50%
52	HV	Distribution Transformer	No.	0.97%	3.55%	29.39%	40.58%	24.65%	0.86%	3	3.49%
53	HV	Distribution Transformer	No.	-	-	-	22.22%	66.67%	11.11%	4	-
54	HV	Distribution Substations	No.	1.11%	2.43%	29.76%	41.81%	24.00%	0.88%	4	-
55	LV	LV Line	km	-	0.12%	0.80%	92.70%	6.30%	0.08%	3	8.34%
56	LV	LV Cable	km	0.25%	1.05%	0.93%	43.42%	52.90%	1.44%	3	-
57	LV	LV Streetlighting	km	-	1.03%	0.02%	9.34%	89.55%	0.05%	3	-
58	LV	Connections	No.	-	-	-	-	-	100.00%	3	-
59	LV	Protection	No.	0.70%	11.27%	6.34%	27.46%	54.23%	-	3	52.11%
60	All	SCADA and communications	Lot	12.07%	4.48%	4.14%	34.48%	44.83%	-	3	96.90%
61	All	Capacitor Banks	Lot	-	-	84.22%	15.78%	-	-	3	-
62	All	Load Control	Lot	26.24%	6.91%	0.49%	66.36%	-	-	3	26.24%
63	All	Load Control	No.	4.59%	30.03%	0.47%	63.78%	1.13%	-	3	5.52%
64	All	Civils	km	-	-	-	-	-	-	N/A	-

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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 ts s assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

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12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

Consumer types defined by EDB*

Standard domestic

Low user domestic

Mass market business

Time of use business

Distributed Streetlights

Direct Charge

Connections total

*Include additional rows if needed

Distributed generation

Number of connections

Capacity of distributed generation installed in year (MVA)

12c(ii) System Demand

Maximum coincident system demand (MW)

plus

less

Maximum coincident system demand

Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumers' connection points

Electricity volumes carried (GWh)

Electricity supplied from GXPs

Electricity exports to GXPs

Electricity supplied from distributed generation

Net electricity supplied to (from) other EDBs

Electricity entering system for supply to ICPs

Total energy delivered to ICPs

Losses

Load factor

Loss ratio

Company Name

Counties Power Limited

1 April 2021 – 31 March 2031

AMP Planning Period

Current Year CY

for year ended

31 Mar 21

31 Mar 22

31 Mar 23

31 Mar 24

31 Mar 25

31 Mar 26

CY+1

CY+2

CY+3

CY+4

CY+5

Current Year CY

for year ended

31 Mar 21

31 Mar 22

31 Mar 23

31 Mar 24

31 Mar 25

31 Mar 26

CY+1

CY+2

CY+3

CY+4

CY+5

Current Year CY

for year ended

31 Mar 21

31 Mar 22

31 Mar 23

31 Mar 24

31 Mar 25

31 Mar 26

CY+1

CY+2

CY+3

CY+4

CY+5

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY						
This schedule requires information on the EDR's self-assessment of the maturity of its asset management practices.						
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The Asset Management Policy had previously been captured and detailed in the Asset Management Plan, with the EDR's senior management at the high level company policy. A standalone policy was developed and approved by management in 2016, updated in 2020, with alignment to the requirements of PAS 55 / ISO 55000 and is loaded into the policy library on our document management system. The Policy is fully endorsed and supported by the Senior Management Team.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg. as required in PAS 55 para 4.2.1). A key pillar of effective asset management is that the asset 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 bodies, who need to be made aware of it.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Service levels are set via consultation with those stakeholders.		To 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, it is good practice to ensure that the organisation's asset management requirements are covered in drafting the asset management policy but at a greater level of detail.
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	Treatment of all parts of the asset lifecycle is set out in the AMP for major asset categories including planning, construction, operation, maintenance and disposal. Asset lifecycle are well covered across all asset categories but further development is required for all asset categories. Work is in progress to refine and develop asset lifecycle documentation, including FMECA and review cycles.		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.
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?	3	Currently the AMP details lifecycle asset management plans for all major asset classes and maintenance and life-extension activities for the planning period. This is supported by working documents created by the EDR's Senior Management Team take into account the long term optimisation of asset investments and trade-offs required. In the medium term we are developing improved documentation for standalone lifecycle management plans for major assets and asset groups.		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.
Company Name County's Power Limited AMP Planning Period 1 April 2021 – 31 March 2031 Asset Management Standard Applied						
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The Asset Management Policy had previously been captured and detailed in the Asset Management Plan, with the EDR's senior management at the high level company policy. A standalone policy was developed and approved by management in 2016, updated in 2020, with alignment to the requirements of PAS 55 / ISO 55000 and is loaded into the policy library on our document management system. The Policy is fully endorsed and supported by the Senior Management Team.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg. as required in PAS 55 para 4.2.1). A key pillar of effective asset management is that the asset 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 bodies, who need to be made aware of it.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Service levels are set via consultation with those stakeholders.		To 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, it is good practice to ensure that the organisation's asset management requirements are covered in drafting the asset management policy but at a greater level of detail.
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Company Name County's Power Limited AMP Planning Period 1 April 2021 – 31 March 2031 Asset Management Standard Applied						
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10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Service levels are set via consultation with those stakeholders.		To 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, it is good practice to ensure that the organisation's asset management requirements are covered in drafting the asset management policy but at a greater level of detail.
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	Treatment of all parts of the asset lifecycle is set out in the AMP for major asset categories including planning, construction, operation, maintenance and disposal. Asset lifecycle are well covered across all asset categories but further development is required for all asset categories. Work is in progress to refine and develop asset lifecycle documentation, including FMECA and review cycles.		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.
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?	3	Currently the AMP details lifecycle asset management plans for all major asset classes and maintenance and life-extension activities for the planning period. This is supported by working documents created by the EDR's Senior Management Team take into account the long term optimisation of asset investments and trade-offs required. In the medium term we are developing improved documentation for standalone lifecycle management plans for major assets and asset groups.		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.
Company Name County's Power Limited AMP Planning Period 1 April 2021 – 31 March 2031 Asset Management Standard Applied						
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10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Service levels are set via consultation with those stakeholders.		To 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, it is good practice to ensure that the organisation's asset management requirements are covered in drafting the asset management policy but at a greater level of detail.
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	Treatment of all parts of the asset lifecycle is set out in the AMP for major asset categories including planning, construction, operation, maintenance and disposal. Asset lifecycle are well covered across all asset categories but further development is required for all asset categories. Work is in progress to refine and develop asset lifecycle documentation, including FMECA and review cycles.		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.
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?	3	Currently the AMP details lifecycle asset management plans for all major asset classes and maintenance and life-extension activities for the planning period. This is supported by working documents created by the EDR's Senior Management Team take into account the long term optimisation of asset investments and trade-offs required. In the medium term we are developing improved documentation for standalone lifecycle management plans for major assets and asset groups.		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.
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10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Service levels are set via consultation with those stakeholders.		To 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

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
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.

Company Name	Countries Power Limited
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)									
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?	3	The AMP is available to all Asset Management staff and those within the business who rely upon key information in it such as commercial, finance, field operations management and customer services. Major customers, territorial authorities and other utilities receive updates during planning exercises, some of them formally initiated account management meetings. Internal circulation is supplemented with briefings during monthly meetings; team meetings; and presentations of work programmes, key projects and project management deliverables.		Plans will be effective if they are communicated to all those, including contracted suppliers and those who undertake enabling functions). 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 of plan(s). Documented from plan(s) which detail the receiver's role in plan delivery. Evidence of communication.	
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The team structure set out in the AMP, job descriptions, business plan responsibilities and personal performance plans establish responsibilities for delivery of AM actions.		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 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 resources required for training and development, 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.	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)	3	The AMP establishes financial estimates and resourcing arrangements for implementation. Plans may be adjusted for timing to ensure efficient utilisation of resources, and to allow for forward, or deferring, programmes of work to match resource capacity within an acceptable risk profile). Medium and Long Term plans inform the organisation of future skills requirements and allow training or external contractors to be found to meet specific requirements, as well as procure in-house requirements. Whilst preferring to use internal resources, arrangements are in place for use of external resources as necessary.			The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and other departments 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 dealing with incidents and emergency situations and ensuring continuity of critical asset management activities?	2	The AMP considers network and environmental risk, and the potential for cascading assessment of all 9 events. Participation in CODEM and Engineering Lifelines activities ensures alignment with other infrastructure operators for regional events. Contingency plans are in place for planning activities, operational contingency plans have been developed for all 9 events. FEMA exercises will help identify possible specific failure risks and this will then enable targeted contingency plans to be developed.		Widely used AMI practice standards require that an organisation has plan(s) to identify and respond to emergency situations. The 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 process. It is not sufficient that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment and procedures for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
Company Name AMP Planning Period Asset Management Standard Applied							
Counties Power Limited 1 April 2021 – 31 March 2031							
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 inconsistent.	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 established in 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.
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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Company Name AMP Planning Period Asset Management Standard Applied						
Counties Power Limited 1 April 2021 – 31 March 2031						
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why
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 can deliver the requirements of the asset management strategy, objectives and plan(s)?	3	As outlined by the Asset Management Policy, the responsibility for AM activities sits with the Gilt Network. The responsibility for delivery of the physical implementation of work programmes and projects relating to core network assets. Accountabilities are established through job descriptions and assigned activities. Appropriate delegations are in place.		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 individuals. (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).
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	The development of the programmes of work presented in this AMP consider resourcing – financial, and physical resources – required to deliver the expected outcomes in the timeframes required. When developing the annual plan, consideration is given to the type of work, the skills sets required to deliver resource constraints to ensure efficiency and sustainability in the long term. Consideration is given to outsourcing some activities where physical resource capacity is not available. Significant effort has been made to resource the team to deliver on the AMP and associated activities including an increase in engineering, field delivery and support functions within the business.		Top management. The management team that has overall responsibility for asset management. Risk 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 communicate the importance of meeting its asset management requirements?	3	The significance of core asset management activities and the importance of meeting its asset management requirements is communicated to all staff through new letters, management communication, team meetings, company meetings, programme successes, detailed reviews of issues and other asset related communications.		Top management. The management team that has overall responsibility for asset management. People involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.
45	Outsourcing of authority and responsibilities	Where the organisation has outsourced some of its management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	The organisation has an established policy for limited outsourcing of asset management activities. Contractors have to meet the requirements of the "Preapproved Contractor Scheme" which covers safety, competence and commercial requirements. Work is supervised by internal staff and the scope of work is typically very prescribed (e.g. civil works, tree felling, etc). Audits and contract reviews are used to ensure compliance and expected progress with corrective actions noted and addressed.		Top management. The management team that has overall responsibility for asset management. People involved in the procurement of the outsourced activities. The people within the organisation that are performing the outsourced activities. The people impacted by the outsourced activity.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Company Name AMP Planning Period Asset Management Standard Applied						
Counties Power Limited 1 April 2021 – 31 March 2031						
Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3
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 person 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.
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 need to deliver asset management.	The organisation's 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.
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 its asset management requirements.	The organisation's 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.
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 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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)								
Company Name AMP Planning Period Asset Management Standard Applied								
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information
48	Training, awareness and competence	How does the organisation develop plant(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)?	3	Resource requirements are evaluated during annual planning activities and in the course of asset management delivery. In-house resource competency planning and skills development is managed via formal training plans, personal development plans and specific business plan objectives. A dedicated Asset Management team has been developed to deliver required processes and objectives.	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 plant(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 plant(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plant(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plant(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. Documents containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.	
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency requirements are identified through the job descriptions for different roles, as they relate to the asset management, as well as company standards for certain competencies for specified activities. Through the performance review and development plan process, new skills and competency requirements are identified and training is provided as necessary. Training and competency records are kept by HR.	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 plant(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.	
50	Training, awareness and competence	How does the organisation ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Formal competency processes are in place for external providers and field service staff however are being revised to align to wider industry practice. Internal asset management staff competency and training is managed via formal training plans and professional development planning in conjunction with the relevant body (eg. IPENZ for professional engineering qualifications).	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 should assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership, UK Standard for Professional Engineering Competence, Engineering Council, 2005.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
Company Name County Power Limited AMP Planning Period 1 April 2021 – 31 March 2031 Asset Management Standard Applied							
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 plant(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 plant(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 plant(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) surpasses 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 plant(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 plant(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) surpasses the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organisation ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organisation has not recognised the need to assess the competence of persons 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) surpasses the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)									
Company Name: Counties Power Limited									
AMP Planning Period: 1 April 2021 – 31 March 2021									
Asset Management Standard Applied									
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 management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	The AMP is made available to all staff. The AMP is communicated to stakeholders via the website. Internal circulation is supplemented with briefings during monthly meetings, team meetings and presentations of work programmes, key projects and other asset management initiatives. Beyond the AMP, the organisation has specific information, some improvement is required in two way communication and feedback processes. Improvements are occurring in the provision of forecast.		Widely used AM practice standards require that information maintain up to date documentation that ensures that its asset management systems (ie the standards) can be used by all relevant personnel. The maintenance of up to date documentation of the asset management system requirements specified throughout 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	Asset management policy statement prominently displayed on the 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	Main systems and functions are detailed in the AMP. There is no clear documentation outlining the relationships between different systems and functions. The systems identified and will be addressed with the introduction of a new asset management information system (whole process mapping) which is expected to be completed during 2021.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie the standards) can be used by all relevant personnel. The maintenance of up to date documentation of the asset management system requirements specified throughout 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 management information system(s) should contain in order to support its asset management system?	2	The asset management information systems supports the organisation's asset management system. It has been implemented and in progress to roll out through the business, and is a deliverable for completion in FY22. The geospatial asset information system was upgraded in 2019.		Effective asset management requires appropriate information to be available. Widely used AM practice standards require that information maintain up to date documentation that ensures that its asset management systems (ie the standards) can be used by all relevant personnel. The maintenance of up to date documentation of the asset management system requirements specified throughout 4 of PAS 55).	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 management system(s) 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 management information system(s) is of the requisite quality and accuracy and is consistent?	3	Asset information is primarily maintained within the company ERP. This provides the context of assets, geographic context of assets, and also to a lesser degree to record some asset information. Effective rule based systems are in place to ensure quality and audit of the geospatial and specific asset information. Analytic tools provide access to information held in different systems and data is aggregated in a holistic manner to support asset management practices.		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. 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, 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, procedures(s), improvement initiatives and audits regarding information controls.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)									
Company Name: Counties Power Limited									
AMP Planning Period: 1 April 2021 – 31 March 2021									
Asset Management Standard Applied									
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 management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	The AMP is made available to all staff. The AMP is communicated to stakeholders via the website. Internal circulation is supplemented with briefings during monthly meetings, team meetings and presentations of work programmes, key projects and other asset management initiatives. Beyond the AMP, the organisation has specific information, some improvement is required in two way communication and feedback processes. Improvements are occurring in the provision of forecast.		Widely used AM practice standards require that information maintain up to date documentation that ensures that its asset management systems (ie the standards) can be used by all relevant personnel. The maintenance of up to date documentation of the asset management system requirements specified throughout 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	Asset management policy statement prominently displayed on the 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	Main systems and functions are detailed in the AMP. There is no clear documentation outlining the relationships between different systems and functions. The systems identified and will be addressed with the introduction of a new asset management information system (whole process mapping) which is expected to be completed during 2021.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie the standards) can be used by all relevant personnel. The maintenance of up to date documentation of the asset management system requirements specified throughout 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 management information system(s) should contain in order to support its asset management system?	2	The asset management information systems supports the organisation's asset management system. It has been implemented and in progress to roll out through the business, and is a deliverable for completion in FY22. The geospatial asset information system was upgraded in 2019.		Effective asset management requires appropriate information to be available. Widely used AM practice standards require that information maintain up to date documentation that ensures that its asset management systems (ie the standards) can be used by all relevant personnel. The maintenance of up to date documentation of the asset management system requirements specified throughout 4 of PAS 55).	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 management system(s) 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 management information system(s) is of the requisite quality and accuracy and is consistent?	3	Asset information is primarily maintained within the company ERP. This provides the context of assets, geographic context of assets, and also to a lesser degree to record some asset information. Effective rule based systems are in place to ensure quality and audit of the geospatial and specific asset information. Analytic tools provide access to information held in different systems and data is aggregated in a holistic manner to support asset management practices.		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. 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, 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, procedures(s), improvement initiatives and audits regarding information controls.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							Company Name Counties Power Limited AMP Planning Period 1 April 2021 – 31 March 2031 Asset Management Standard Applied	
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	The AMP outlines the core business systems relating to asset management. Asset information geo spatial system is now in place and undergoing continuous audit and improvement providing data as required by the business. COWS asset information system is in place and data requirement are being established and rolled out across asset groups through FY20, due completion in FY22.		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) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	The corporate risk framework and audit programme are in place and cover risks relating to asset management activities with corresponding controls in place. These are assessed periodically for effectiveness. Asset specific risk is addressed through the planning process and maintenance programmes in place and detailed in the Risk Register. Remedial studies are underway to close gaps in these processes.		Risk management is an important foundation for proactive asset management. Its overall purpose is to ensure that the organisation is able to manage such 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 team. 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). Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Actions arising from risk assessments relating to training, competency development and resourcing are captured in training and development plans, as well as in the organisation's competencies and position descriptions.		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 opportunities for training 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 organisation's 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 this information incorporated into the asset management system?	3	The business has established a compliance framework, and through active monitoring of the regulatory environment, along with participation in industry bodies such as the EA, the organisation is ensuring requirements, and new or amended requirements, practices and processes are updated as required to ensure ongoing compliance. Senior Management team members report on compliance issues periodically.		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 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and amended requirements, and ensure that standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es)).	Top management. The organisation's regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							Company Name Counties Power Limited AMP Planning Period 1 April 2021 – 31 March 2031 Asset Management Standard Applied	
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) surpasss 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) 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 plans 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) surpasss 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 of 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) surpasss 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 this information 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 of 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) surpasss the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)									
Company Name AMP Planning Period Asset Management Standard Applied									
Counties Power Limited 1 April 2021 – 31 March 2031									
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/Documented Information	
88	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) 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	Procedures for planning, design and inspection of assets exist in varying forms, with some not as current as others. Project management planning standards have been developed and implemented to improve design processes, modification, procurement and construction. Asset management processes have been implemented to ensure standards are followed through planning and concept design.		Life cycle activities are about the implementation of project management plan(s) and procedure(s) in a phase. They need to be 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, eg. Procurement	Documented process(es) and procedure(s) which are used to ensure the effective implementation of asset management and control of life cycle activities 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 its 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 condition of its assets?	2	Procedures for maintenance and inspection of assets exist in varying forms, with some not as current as others. A standards framework (including policies and procedures) has been complete and individual procedures are now undergoing update following a gap analysis review.		Having documented process(es) which ensure the asset management plan(s) are implemented in a manner consistent with the asset management plan(s), 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 ensure that process(es) and/or procedure(s) for the implementation of its 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 condition of its assets?	2	Procedures for maintenance and inspection of assets exist in varying forms, with some not as current as others. A standards framework (including policies and procedures) has been complete and individual procedures are now undergoing update following a gap analysis review.	Unreframe?	Widely used AM standards require that organisations establish implement and maintain 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 project management plan(s) and procedure(s) which are used to ensure the effective implementation of asset management and control of life cycle activities including design, modification, procurement, construction and commissioning.	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 responses are clear, unambiguous, understood and communicated?	3	An incident reporting process in place, and asset-related failures, worksite incidents and emergency situations all initiate processes for investigation and mitigation. Investigations are available to all staff. The intranet is used as a common internal communication system. Non-conformances with processes and procedures are routinely reported, with an emphasis on health and safety impacts.		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 for the organisation to establish and implement 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 and project managers. Common descriptions, Audit reports. Common descriptions of investigation systems i.e. all jobs Descriptions on Internet etc.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances. Documented assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common descriptions of investigation systems i.e. all jobs Descriptions on Internet etc.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)									
Company Name AMP Planning Period Asset Management Standard Applied									
Counties Power Limited 1 April 2021 – 31 March 2031									
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 ensure that process(es) and/or procedure(s) 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 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 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 its 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 condition of its assets?	The organisation does not have process(es)/procedure(s) in place to manage and control 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 are clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.		

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)									
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/documentation information	
105	Audit	What has the organisation achieved for the audit of its asset management system (process(es))?	2	Procedures for audit exist in the form of written systems and processes, such as safety, quality of process and financial. Some areas of process and systems do not yet have established audit procedures and these are developed on a case by case basis to address identified issues, or risks.		This question seeks to explore what the organisation has achieved for the audit of its asset management system, including 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 system, including 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 management team responsible for the audit has determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.	
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Results of inspections and investigations of failures are reviewed by subject experts and used as inputs into the AM programme. Follow-through is recorded in action plans, minutes and the contents of the programme are reviewed. Analysis is used to assess ongoing conformance.		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 investigation records are only useful if appropriate actions are taken as a result to assess changes to a management system. The organisation should have arrangements in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews	
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	Selection of improvement is evident in action: in the execution of innovative projects and process improvements; and in recognition within the industry. Specific initiatives are recorded in the business plan for development, with opportunity registers regularly reviewed by management. Additional asset information has been gathered via LIDAR, and verification of asset information has been completed to enhance and improve lifecycle planning and condition information. Continual improvement manager has been appointed and AM process are being		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 than 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. 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 than reviews and audit (which are separately examined).	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 technology and their potential benefit to the organisation?	3	Participation in industry forums, conferences, joint initiatives, participation in research and development and research and reduction of appropriate goals in personal development and business plans. Business case assessment for new technologies and spending arrangements/partnerships is actively undertaken.		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 out there that may improve the way you do things. People that monitor the 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 that monitor the 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.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of exploration relating to knowledge acquisition. Examples of changes related to asset management tools, techniques linked to asset management strategy and objectives.	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
Company Name AMP Planning Period Asset Management Standard Applied							
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) surpasses 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 investigate 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 investigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to investigating 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 investigation 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 investigation 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) surpasses 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 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) surpasses 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) surpasses the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8. *Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)*

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between nominal and constant prices reflects inflation of 2% per annum.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The difference between nominal and constant prices reflects inflation of 2% per annum.



Appendix B – Assessment against Information Disclosure Requirements

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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	Plan Summary
3.2 Details of the background and objectives of the EDB’s asset management and planning processes	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	2
3.3.2 States the corporate mission or vision as it relates to asset management	2
3.3.3 Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2
3.3.4 States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	2
3.3.5 Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	1.2
3.5 The date that it was approved by the Directors	1.3
3.6 A description of stakeholder interests (owners, customers etc.) which identifies important stakeholders and indicates -	
3.6.1 How the interests of stakeholders are identified	2.4
3.6.2 What these interests are	2.4
3.6.3 How these interests are accommodated in asset management practices; and	2.4
3.6.4 How conflicting interests are managed	2.4
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	2.1.3
3.7.2 Executive—an indication of how the in-house asset management and planning organisation is structured and	2.1.2

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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	2.1.2; 2.1.3
3.8 All significant assumptions	
3.8.1 Quantified where possible	1.6 and throughout AMP
3.8.2 Clearly identified in a manner that makes their significance understandable to interested persons, including	1.6 and throughout AMP
3.8.3 A description of changes proposed where the information is not based on the EDB’s existing business	1.6 and throughout AMP
3.8.4 The sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.6 and throughout AMP
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.	On forecasts;
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	1.6 and throughout AMP
3.10 An overview of asset management strategy and delivery	4.1; 4.2; 4.4
3.11 An overview of systems and information management data	4.3
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	4.3.2
3.13 A description of the processes used within the EDB for-	
3.13.1 Managing routine asset inspections and network maintenance	4.4.1
3.13.2 Planning and implementing network development projects	4.4.1; 6.3.3
3.13.3 Measuring network performance.	4.3.2; 6.2.1
3.14 An overview of asset management documentation, controls and review processes	4.3.1
3.15 An overview of communication and participation processes	4.3.1
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	Throughout AMP
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.	Throughout AMP

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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-	2.1
4.1.1 The region(s) covered	2.1; Appendix D
4.1.2 Identification of large consumers that have a significant impact on network operations or asset management priorities	2.5.2
4.1.3 Description of the load characteristics for different parts of the network	2.5:8
4.1.4 Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.5.4
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;	2.6; 8.4; 8.5
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;	2.6.1; 8.4; 8.5
4.2.3 A description of the distribution system, including the extent to which it is underground;	2.6.2
4.2.4 A brief description of the network's distribution substation arrangements;	2.6.2
4.2.5 A description of the low voltage network including the extent to which it is underground; and	2.6.2
4.2.6 An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	7.10
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 must be disclosed for each sub-network.	N/A
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;	2.6.1; 2.6.2
4.4.2 Description and quantity of assets;	7.1 to 7.14
4.4.3 Age profiles; and	7.1 to 7.14

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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.	7.1 to 7.14
4.5 The asset categories discussed in subclause 4.4 should include at least the following-	
4.5.1 The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (iii)	7.1 to 7.14
4.5.2 Assets owned by the EDB but installed at bulk electricity supply points owned by others	7.12
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand	7.11.1
4.5.4 Other generation owned by the EDB.	N/A
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.	3.2 to 3.8
6 Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	3.6.2
7 Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1 Consumer oriented indicators that preferably differentiate between different consumer types;	3.6
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.	3.7
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.	3
9 Targets should be compared to historic values where available to provide context and scale to the reader.	3
10 Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	3
Network Development Planning	
11 AMP's must provide a detailed description of network development plans, including—	
11.1 A description of the planning criteria and assumptions for network development;	8.1

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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;	8.1
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	8.1.3; 8.1.4
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss -	
11.4.1 The categories of assets and designs that are standardised;	8.1.3
11.4.2 The approach used to identify standard designs.	8.1.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	4.2.4
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.	8.1.3
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.	8.1; 4.2
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;	8
11.8.1 Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	8.2
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;	8.4; 8.5
11.8.3 Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	8
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.	8
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-	8.4; 8.5
11.9.1 The reasons for choosing a selected option for projects where decisions have been made;	8.4; 8.5
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;	8.4; 8.5
11.9.3 Consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	8.1.4; 8.1.5; 8.4; 8.5; 6
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-	8.4 to 8.6
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;	8.4 to 8.5
11.10.2 A summary description of the programmes and projects planned for the following four years (where known); and	8.4 to 8.5

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
11.10.3 An overview of the material projects being considered for the remainder of the AMP planning period.	8.4 to 8.5
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.	8.14; 6.4.2
11.12 A description of the EDB's policies on non-network solutions, including-	
11.12.1 Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	8.1.5; 6
11.12.2 The potential for non-network solutions to address network problems or constraints.	8.1.5; 6
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;	4.1
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-	7.3 to 7.11
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;	7.3 to 7.11
12.2.2 Any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	7.3 to 7.11
12.2.3 Budgets for maintenance activities broken down by asset category for the AMP planning period.	10.1; 10.2
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;	4
12.3.2 A description of innovations that have deferred asset replacements;	4.1.3; 5; 6
12.3.3 A description of the projects currently underway or planned for the next 12 months;	7.3 to 7.10
12.3.4 A summary of the projects planned for the following four years (where known); and	7.3 to 7.11
12.3.5 An overview of other work being considered for the remainder of the AMP planning period.	7.11 to 7.12
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in subclause 4.5.	7.3 to 7.11

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
Non-Network Development, Maintenance and Renewal	
13 AMP's must provide a summary description of material non-network development, maintenance and renewal plans, including—	9
13.1 A description of non-network assets;	9
13.2 Development, maintenance and renewal policies that cover them;	9
13.3 A description of material capital expenditure projects (where known) planned for the next five years;	9
13.4 A description of material maintenance and renewal projects (where known) planned for the next five years.	9
Risk Management	
14 AMP's must provide details of risk policies, assessment, and mitigation, including—	
14.1 Methods, details and conclusions of risk analysis;	4.5
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;	4.7
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2;	4.7
14.4 Details of emergency response and contingency plans.	4.8
Evaluation of Performance	
15 AMP's must provide details of performance measurement, evaluation, and improvement, including—	
15.1 A review of progress against plan, both physical and financial;	11
15.2 An evaluation and comparison of actual service level performance against targeted performance;	3.2 to 3.7
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.	Schedule 13 attached to AMP
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	3.2 to 3.6; 4.10; 5; 6

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
Capability to Deliver	
16 AMP's 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;	Throughout AMP
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1

Appendix C – Director’s Certificate

Schedule 17 Certificate for Year-beginning Disclosures
Clause 2.9.1

We, Vernon John Dark and Hamish William Stevens being Directors of Counties Power Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

- a. The following attached information of Counties Power Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.5, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- b. The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.
- c. The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Counties Power Limited’s corporate vision and strategy and are documented in retained records.



Vernon John Dark
(Director)



Hamish William Stevens
(Director)

Certified this 24th day of March 2021



Appendix D – Network overview diagrams

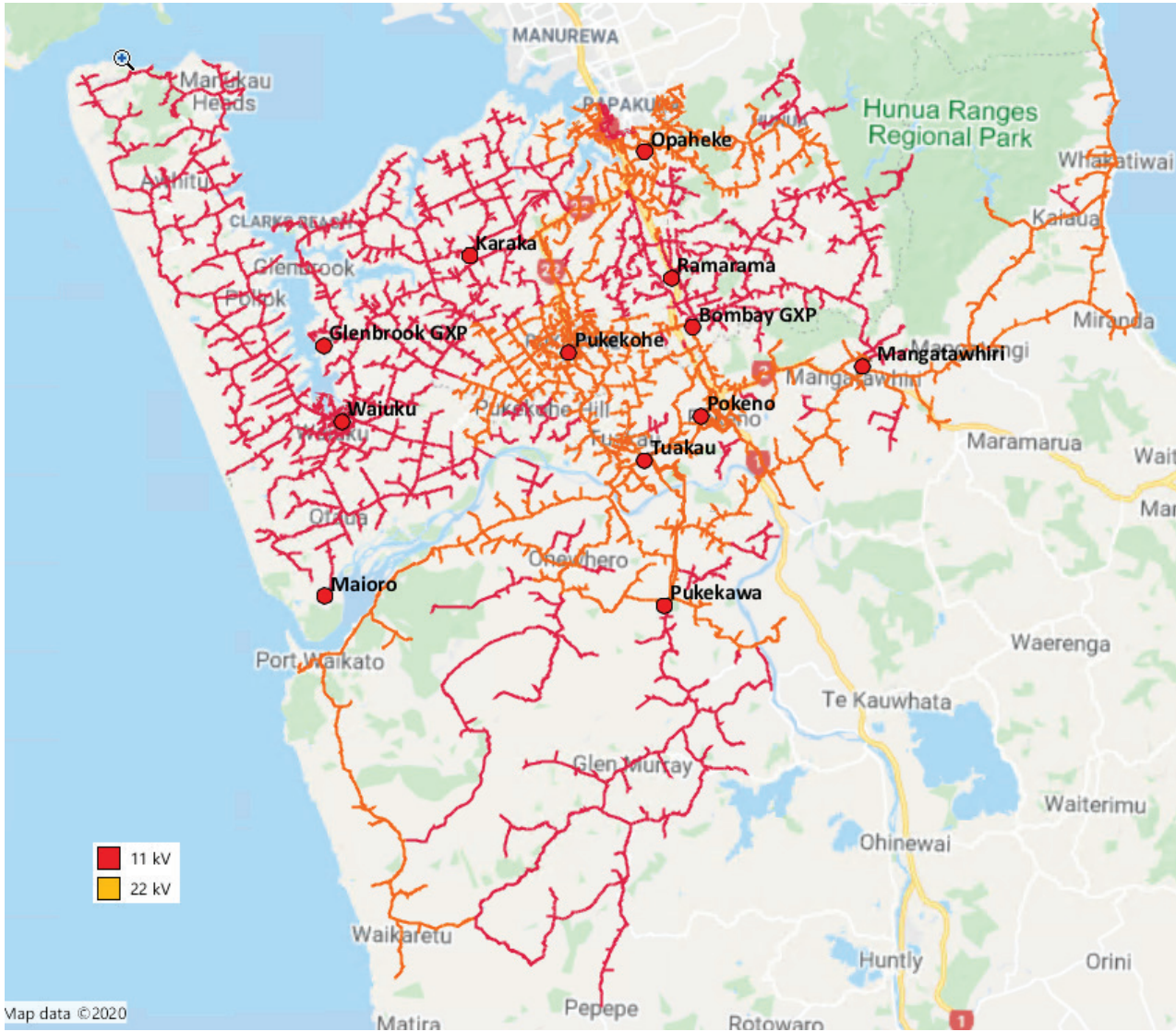


Figure App. D-1 Overview of network feeders with operating voltages

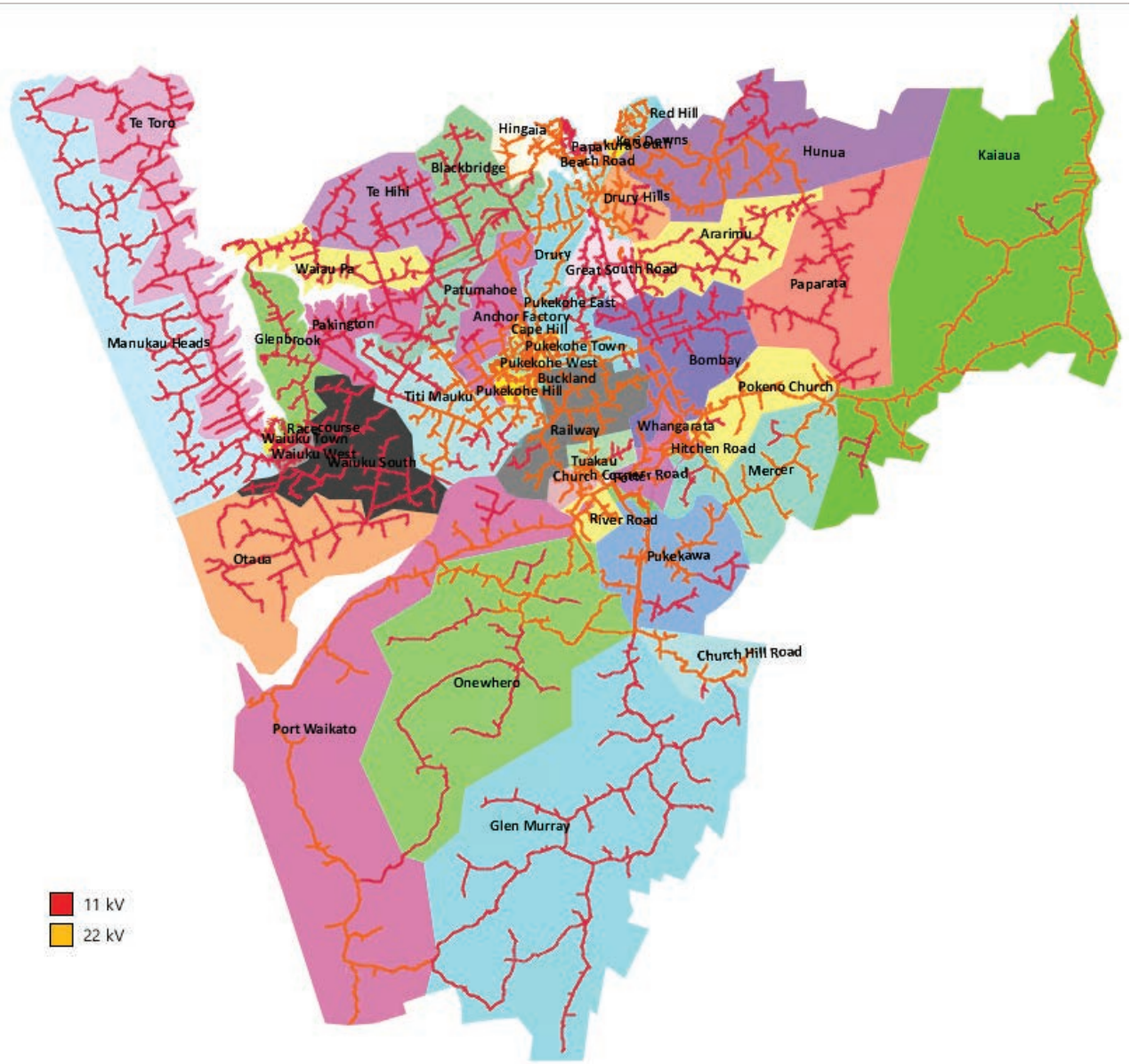


Figure App. D-2 Overview of network feeder coverage areas

Appendix E – Glossary

Term	Description
A	Ampere - Unit of electrical current flow or rate of flow of electrons
AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ADMD	After Diversity Maximum Demand
AMMAT	Asset management maturity assessment tool
AMP	Asset Management Plan
AUP(OP)	Auckland Unitary Plan (Operative in Part)
Ampere (A)	Unit of electrical current flow, or rate of flow of electrons.
Bus	(Busbar) A common connection point between multiple circuits and equipment.
Bushing	An electrical component that insulates a high voltage conductor passing through a metal enclosure.
CAIDI	Customer Average Interruption Duration Index is the average total duration of interruption per interrupted customer.
Capacity	The greatest amount of load a circuit can carry.
CB	Circuit Breaker
CDEM	Civil Defence and Emergency Management
Conductor	‘Wire’ that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.
CT	Current Transformer
CVM	Customer Value Management model
Demand	The amount or energy sought by the consumers.
DDO	Dropout Fuse Switch or Disconnecter/Isolator
Disconnecter	Also known as a disconnecting switch, isolator, or dropout
Distribution Line	[Ref NZECP 34] Means works that are owned by Counties Power used for the conveyance of electricity to one or more electrical installations.
DPP	Default Price-Quality Path (Commerce Commission)
Easement	An easement is a right given to another person or entity to access upon land that person or entity does not own
Earth-fault	A circuit conductor unintentionally grounded.
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association NZ (Inc)

Term	Description
EIPC	Electricity Industry Participation Code 2010 (the “Code”)
ENA	Electricity Networks Association
ESI	Electricity Supply Industry
EV	Electric vehicle
FY	Financial Year e.g. FY19 is Financial Year 2020 which covers 1st April 2019 to 31st March 2020
Fault	A physical condition that causes a device, component or network element to fail to perform in the required manner and includes third party actions impacting the network.
Feeder	A physical grouping of conductors that originate from a district/zone substation circuit breaker.
FEMCA	Failure Mode, Effects & Criticality Analysis
Fixed Asset	A purchase normally over \$1,000 with an intended life cycle of at least over one year.
Flashover	A disruptive discharge around or over the surface of an insulator.
FULSS	(Auckland) Future Urban Land Supply Strategy
GIS	The Geographic Information System used for electronic mapping of the network.
GPD	Group Peak Demand
Grid Exit Point (GXP)	The point at which Counties Power Equipment is deemed to connect to the Transpower Grid System.
GWh	Giga-watt hour
GSA	Geospatial Analysis
Harmonics	Distortion of the sine wave which represents ideal AC power. Usually by super imposed higher frequencies.
High Voltage (HV)	Any voltage exceeding 1000 V a.c. or 1500 V d.c. but usually pertaining to the 11kV or 33kV distribution system.
HILP	High Impact Low Probability
ICAM	Incident Cause Analysis Methodology
ICP (Installation Control Point)	A number that uniquely identifies each connection to an electrical lines network that is recorded in a national registry.
IEP	Initial Evaluation Procedure
INDI	Infrastructure and Network Data Interface
Injection Plant	Injects a signal onto 50Hz network, for controlling ripple relays.
JSA	Job Safety Analysis
JSEA	Job Safety & Environmental Analysis
Kiosk	A small structure, often open on one or more sides.
kV	kilo-volt

Term	Description
Lines	The LV and HV network of overhead and underground electricity conductors and cables and their associated equipment such as insulators, poles, crossarms etc.
LiDAR	Light Detection and Ranging, a pulsed laser measurement technology
Load Break Switch	A switch that can be operated under load.
Low Voltage (LV)	Any voltage exceeding 32 VAC or 115 VDC but not exceeding 1000 VAC or 1500 VDC
LTIFR	Lost Time Injury Frequency Rate
LTISR	Lost Time Injury Severity Rate
MW	mega-watt
Maximum Demand	The highest value of the power or apparent power taken within the account period, such as, month or year.
MVA	mega-volt-ampere
N-1 security	A load is said to have n-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies.
NAV	ERP and accounting software package; version used in Counties Power is Microsoft Dynamics NAV R2 2009
NZECp	New Zealand Electrical Code of Practice (A series of Publications)
Outage	an interruption to electricity supply
Overcurrent	Current in excess of the rated current of a conductor.
Overhead	Above ground, pole mounted conductor
Pillar (LV)	A plastic ground mounted enclosure, usually found on a properties boundary containing the fuses for a service supply.
PSMS	Public Safety Management System
PV	Photo-Voltaic - the conversion of light into electricity
QMS	Quality Management System
RCPD	Regional Coincident Peak Demand
Recloser	A piece of equipment on the distribution network work which automatically trips when a fault is detected (typically a tree touching the line) and recloses after a set time (minutes).
Reliability	The ability of an item to perform a required function under stated conditions for a stated period of time.
Residual Risk	The remaining level of risk after risk treatment measures has been taken.
Retailer	An electrical energy supplier who has a User Supply Agreement with Counties Power.
Risk	Probability (likelihood) and consequences, positive or negative, of an event. In some situations, risk is a deviation from the expected.

Term	Description
Risk Management	AS/NZS 4360 defines risk management as a term applied to a logical and systematic method of identifying, analysing, evaluating, treating, monitoring and communicating risk associated with any activity, function or process in a way that enables maximisation of benefits or minimisation of losses or detrimental effects.
RMU	Ring Main Unit
RTU	Remote Terminal Unit – Communications device used for relaying data from the field.
SAIDI	System Average Interruption Duration Index is the average total duration of interruption per connected customer.
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers.
SCADA	Counties Power’s computerised Supervisory Control and Data Acquisition System being the primary tool for monitoring and controlling access, and switching operations for Counties Power’s Network
SHA	Special Housing Area
Smallworld	GIS-based system for mapping of the network
Stakeholder	People and organisations who may affect, be affected by, or perceive themselves to be affected by a decision or activity.
Standard	The document that prescribes the requirements with which the product or service has to conform. The criteria for acceptable levels of safety performance/behaviours set by Counties Power, industry codes or relevant legislation.
Substation	Electrical facility where the voltage of incoming and outgoing circuits is changed and controlled.
Supplier	Organisation that provides a service or product to the customer.
SF ₆	Sulphur hexafluoride - a gas used as an insulator in some switchgear
TOU	Time of Use pricing structure
Transpower	The national grid operator.
TRIFR	Total Recordable Injury Frequency Rate
UHF	Ultra-High Frequency.
UNI	Upper North Island
User	Any person or organisation using the Distribution System but excluding Transpower. It includes all Customers, embedded generators, and where appropriate, Electricity Retailers acting on behalf of their customers.
Vegetation	Any trees or other plants threatening the Counties Power Networks overhead lines.
Voltage Regulators	A voltage regulator is an electrical regulator device designed to automatically maintain a constant voltage level.
VT	Voltage Transformer
XLPE	Type of cable insulation – Cross-linked Polyethylene
Zone Substation	Includes HV substations, switching stations, voltage regulators, ground mounted HV switchgear, large industrial/commercial distribution substations, ripple control plant, and associated protection and controls.



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