Asset Management Plan 2023

Counties Energy

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1.1 Executive Summary

Counties Energy is leading the adaptation of the transformation taking place in the electricity industry as well as the changing expectations of our stakeholders. We are focused on partnering strongly with our regulators and customers over the long term to meet these challenges and to continue to provide a response and sound business for the benefit of our community.

In response to the changes and opportunities of a new energy world, we are purpose led as we transition from a Distribution Network Operator (DNO) to a Distribution System Operator (DSO). We are “reimagining energy” to prepare for a future of rapid change which includes increased vehicle electrification, DERs (distributed energy resources) and new technologies that allow us to provide aggregator services and manage a smart network.

Our vision is an ambitious one - to unlock our energy potential through the power of our people, communities, and country as we shape New Zealand's energy future. To do this, we have refreshed our corporate strategy to focus on critical programmes of work in the short, medium and longer terms across the business.

At the centre of our refreshed corporate strategy is a strong resilient network, innovation and customer centricity - we’re here to support our customers’ changing journey with energy. We’re proud to be a community owned business that is focused on doing good for a fast growing 46,925 homes and businesses that rely on us.

Counties Energy is also committed to playing our part in New Zealand’s decarbonisation journey where we are making progress towards our emissions targets. We are also cognisant of the important role we play in managing the impact of climate change for our customers given extreme weather events in recent years such as Cyclone Gabrielle. Our focus remains on continuous improvement to operational and technological efficiency in large scale power restoration that is well supported by timely and relevant customer communications.

Any changes to our plan or expenditure relating to network resilience triggered by the learnings from cyclone Gabrielle will be addressed in the next Asset Management Plan.

The following sections in this Executive Summary outline how we’re managing our assets optimally to deal with rapid growth as well as how we will use technology to help us operate more efficiently and in a smarter way.

Network Reliability

Our reliability strategy takes the approach of a "whole-of-life costs" where we focus on longer term initiatives to maximise asset performance and to minimise cost to our customers.

We continue to measure our results with SAIDI and SAIFI targets that will lift our performance year-on-year. However, such targets will be balanced against a 'needs must' basis as planned SAIDI & SAIFI is necessary for renewal, growth, and customer-initiated works. In line with our value of being customer obsessed, our expanded performance measures monitor elements of the customer experience such as giving notice to customers, starting, and finishing planned work on time, and communicating changes to customers in a timely manner.

For unplanned outages, our strategy is to address the root cause rather than just the symptoms. This means that we will drive reliability improvements through cost-efficient long-term initiatives rather than shorter-term improvements (e.g. adding more automatic reclosers) which would drive costs up for our customers in the longer term – even if they improve reliability faster in the short term.

Digital & Technology

The overarching objective of our digital and technology strategy is to enable a reliable network and service, not just to keep the lights on but also to provide a sustainable integration of EV and DER uptake. With customers' needs evolving over time, the ability to manage demand for smarter network services will be paramount.

A big part of this strategy comprises the transition from a DNO (distribution network operator) to a DSO (distribution systems operator) which will provide the foundation for the network to flex to a changing role within the electricity sector. Our role won't just be about the reliability of supply; we will also play an aggregator role to support demand management in a way that meets customers' needs regardless of where they are in their energy journey.

At the core of our digital and technology strategy is the fostering of a culture that creates new value or solves problems. We recognise that 'good' innovation comes from constraints and rigour, a proven approach to validating problems and solutions, and a disciplined framework with stage gates, intervention, and a low cost/low risk approach.

Finally, our digital and technology strategy also includes improving data quality for greater network performance granularity together with increased data security and network protection.

Asset Renewal & Maintenance

We take a pragmatic approach to keeping our assets in good working order by weighing up the respective costs, risks, and benefits. We balance our assets' whole-of-life-cost with the probability and likelihood of failure, contributing factors, the consequence of risk, and public safety assessments in our renewal and maintenance strategy.

Whole-of-life-cost for assets is maximised by optimising maintenance and inspection regimes to maintain and assess condition, allocate appropriate corrective works and eventually replace when the asset is at the end of its economic life.

Counties Energy has increased its focus on alignment to ISO55001 principles for asset management practices. In addition, we utilise new technology, data, and modelling to inform investment decisions and optimise replacement programmes. We continue to improve our standards, systems, and processes to ensure we operate and manage a robust, cost-effective network.

Network development for growth and future proofing

As in previous years, our network development strategy is designed to flex with the rapid growth that we're experiencing across our region, and which has been forecast by local councils. In Auckland for example, the council estimated in 2019 that there would be 22,000 new dwellings in the Drury-Opaheke area and 12,500 dwellings in the Pukekohe-Paerata area over the next 30 years.

In the Drury area, there are several significant developments which have the potential to add new demand to the network including Drury South Crossing, the Auranga subdivision west of SH1, Kiwi Property Trust and Oyster Capital developments south of the existing Drury area. Based on these developments, we have brought forward the Quarry Road Substation to meet anticipated demand.

The timeline of the proposed new Pukekohe North/Karaka South zone substation in the Karaka South and Drury West areas has been pushed out to accommodate bringing forward the Quarry Road Substation. We have however, identified a suitable location for the substation and expect to be in a position to secure this location in FY24.

With energy flow now bi-directional, we are investigating several initiatives to improve our Low Voltage (LV) capability that will enable customers to leverage DERs for participation in flexibility services. With smart meters across 96% of ICPs on our network, a key initiative is to investigate DER (Distributed Energy Resources) visualisation tools that will identify DERs and EVs on the LV network in the longer term.

1.2 Period Covered

This Asset Management Plan (AMP) covers the period from 1 April 2023 to 31 March 2032 (the planning period). As with any long-term planning document, there is greater certainty and more details available for works planned for the immediate future, generally, up to five years out. Long-term projects are more indicative of our expectations based on known trends and projections impacting the network.

1.3 Approval Date

This AMP was reviewed and approved by the Counties Energy Limited Board of Directors on 29th March 2023.

1.4 Purpose of this Document

The purpose and objective of our Asset Management Plan and its practices are to assist us in managing our assets throughout their lifecycle in an efficient, effective and sustainable manner to provide the type and level of services that our customers expect. This AMP is a vital planning document as it focuses our decisions and activities so that our assets provide lasting value to our customers, stakeholders and ourselves. It illustrates how our asset management objectives align with our corporate vision, values and objectives.

We apply a disciplined and consistent approach to the management of our assets so that we can accomplish our corporate vision of being a successful community-owned electricity distribution company that delivers a safe, reliable and cost-effective network to our customers. Our approach transforms our corporate objectives of managing a safe network, meeting customer needs and maximising shareholder returns into technical and financial decisions, plans and activities. This AMP connects with our other documented plans that are part of our business processes; these documents are our Statement of Corporate Intent, our Strategic Plan, and our annual budget.

1.5 Intended Audience

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

1.6 Document Structure

Chapter	Document Structure
Chapter 2 – Overview of Counties Energy	This chapter provides an overview of Counties Energy, our organisation, vision, values, stakeholders, operation environment and a general network overview.
Chapter 3 – Our Assets	This chapter provides an overview of our asset fleet, quantities and health.
Chapter 4 – Service Levels	This chapter provides an overview of the service levels we expect to provide to our stakeholders, which inform our asset management decision-making.
Chapter 5 – Approach to Asset Management	This chapter outlines our objectives and strategies to ensure we make the best investment decisions, including our approach to risk management.
Chapter 6 – Network Reliability	This chapter outlines the philosophy and strategy with detailed analysis to show events and trends, and the works occurring to maintain or improve.
Chapter 7 – Innovation & New Technology	This chapter outlines our core system implementation and improvements, our DSO strategy, and how we are adopting new clean energy technologies.
Chapter 8 – Renewal and Maintenance	This chapter provides a more detailed overview of our assets by category and includes our plans for inspecting, maintaining and replacing them.
Chapter 9 – Network Development	This chapter provides our planning approach and how we forecast our network demand, the capacity of our network to manage the demand and constraints identified.
Chapter 10 – Other Non-Network Investment	This chapter outlines the non-network investments we will make, land, IT equipment, tools, vehicles and machinery.
Chapter 11 – Expenditure Summary	This chapter summarises all the operational and capital expenditures identified in Chapters 7, 8 and 9 of the 10 years covered by this plan.

Chapter	Document Structure
Chapter 12 – Evaluation of Performance	This chapter assesses performance against previous plans as part of our continual improvement in asset management and overall business performance.
Chapter 13 – Appendices	This chapter provides a glossary of terms, a performance summary against previous plans, the information disclosure schedules and director certification.

1.7 Plan Assumptions

Assumptions relating to individual aspects of the plan are considered in their respective chapter. The overall assumptions relating to the plan are:

- Counties Energy is an ongoing business;
- No significant legislative changes affecting the industry structure or operating environment;
- No step changes in customer expectations or willingness to pay;
- Nominal dollars reflect future cost increases of 3% per annum; and
- The plan assumes continual ICP growth at 2.5% per annum, in line with current and historical growth of the region. System Growth capital expenditure is reflective of this to meet forecast future energy demand over the 10 year planning period.

2.0 Overview of Counties Energy


Counties
Energy

2.0 Overview of Counties Energy

2.1 Our Company

Counties Energy owns, manages and operates an electricity distribution network in South Auckland, North Waikato and Hauraki District areas with a system length of 3,462m, covering an area of approximately 2,250 km. The Auckland Council area covers 830 km (37%) of the Counties Energy network, the Waikato District covers 1,340 km (60%), and the Hauraki District covers the remaining 80 km (3%). We receive power from the national grid at the Bombay and Glenbrook Grid Exit Points (GXPs) and then transport it to our customers via nine zone substations and our extensive network of lines, cables, transformers and other equipment.

2.2 Ownership and Governance

Wholly owned by our customers, Counties Energy is 100% for our customers. All shares in the company are held by the Trustees of the Counties Energy Trust (Trust) on behalf of all local power customers. The Trust has five Trustees, of whom two are required to be elected every two years. The Trust oversees the performance of Counties Energy through the appointment of a Board of Directors (Board). The Board and Management of Counties Energy engage the Trust on our strategic direction, business plans, and asset management measures and targets. Information about the Trust can be obtained from countiesenergytrust.org.nz.

2.3 A New Strategic Direction

Our vision is to unlock our energy potential through the power of our people, our communities and country as we shape New Zealand's energy future.

To achieve our vision, our strategic direction accounts for changes not just within our industry but in our goals and ambitions for the future. More importantly, our refreshed corporate strategy was developed to respond to the changing environment and aligns with our vision and values.

It reflects how we're reimagining energy for our customers, our peers and the industry in an aspirational, bold and inspiring way. Our corporate strategy positions us as a leader that is thinking beyond our transition from a Distribution Network Operator (DNO) to a Distribution System Operator (DSO).

There are three strategic focus areas which are the pillars to our corporate strategy, with programmes of work under each to cover the short, medium and long-term horizons.

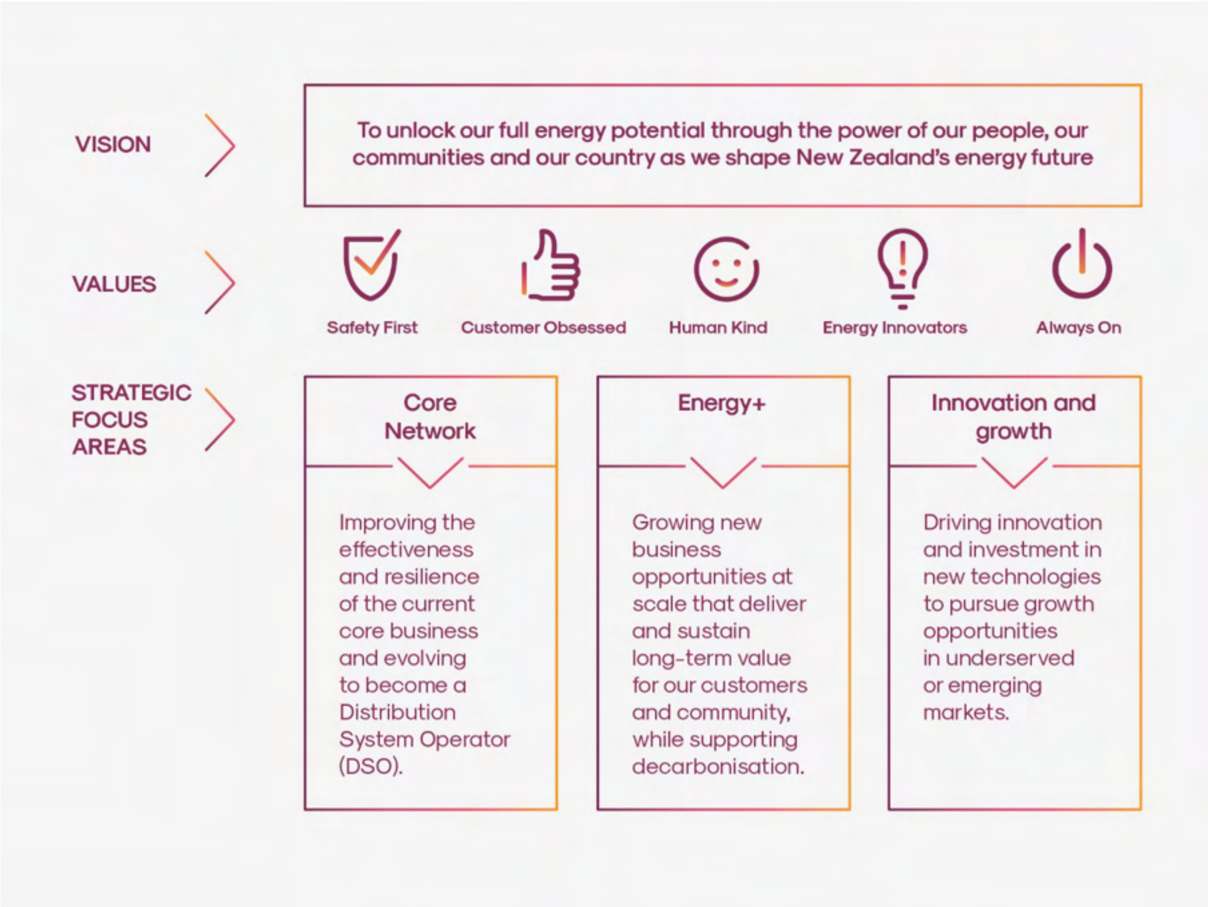


Figure 2-1 Corporate Vision, Values and Strategy

Core Network (robust, reliable, here to serve)

At the core of Counties Energy is the electricity network supplying electricity to a fast growing 46,925 homes and businesses. The central premise is to protect the value of the network by improving network performance and our operations. We intend to achieve this by continually improving the efficiency and effectiveness of our business, balancing the needs of our customers, whilst also maintaining the value and performance of the network. We are evolving the capabilities of the business to be a DSO and provide the foundations to unlock value from Distributed Energy Resources (DER) and create new energy experiences for customers.

Energy Plus (unlocking new energy experiences)

Energy Plus is an exploration of growth opportunities for Counties Energy. This includes growing and scaling areas that build on the foundations of the core network business or pursuing new opportunities that leverage current capabilities to deliver new products and services in adjacent markets at scale.

Growing new business opportunities at scale will deliver and sustain long-term value for our customers and community while supporting decarbonisation.

Innovation and Growth (shaping New Zealand's energy future)

Developing an innovation and growth culture and governance framework is important for Counties Energy as it enables us to explore new growth opportunities, be a catalyst and investor in energy sector innovation and be a competitive force in a more diverse energy marketplace.

Critical to this is enabling a framework and a culture for innovative ideas to flourish and be investigated.

2.4 Counties Energy's Values

Underpinning Counties Energy's strategy are our values that guide everything we do. They embody the qualities of our people and the way we do business to deliver forward-thinking energy today and tomorrow.

Safety First	The safety of our people, our communities and our customers comes first, and we never underestimate the power of energy or how we need to work to stay safe.
Customer Obsessed	From the smallest gestures to major fixes, we aim to surprise, delight and serve our customers above and beyond expectations, giving them an unforgettable experience every time.
Human Kind	Being human-centred in everything we do means being kind in our approach, proactive in our help, and showing empathy when it counts; we do the right thing for our people and our customers.
Energy Innovators	To reimagine our energy future, we innovate by challenging the status quo, staying curious, thinking differently and looking at old problems in new ways.
Always On	Reliability is important as it builds confidence and trust within our community. We are proactive through adapting and changing our skills and service opportunities for today and the future.

2.4.1 Corporate and Organisation Structure

The Counties Energy Board is responsible for the overall governance of the business, including approval of the company strategy, business plans and annual budgets. The Counties Energy Trust appoints the Directors. The Board reports to the Trust every quarter.

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 below.

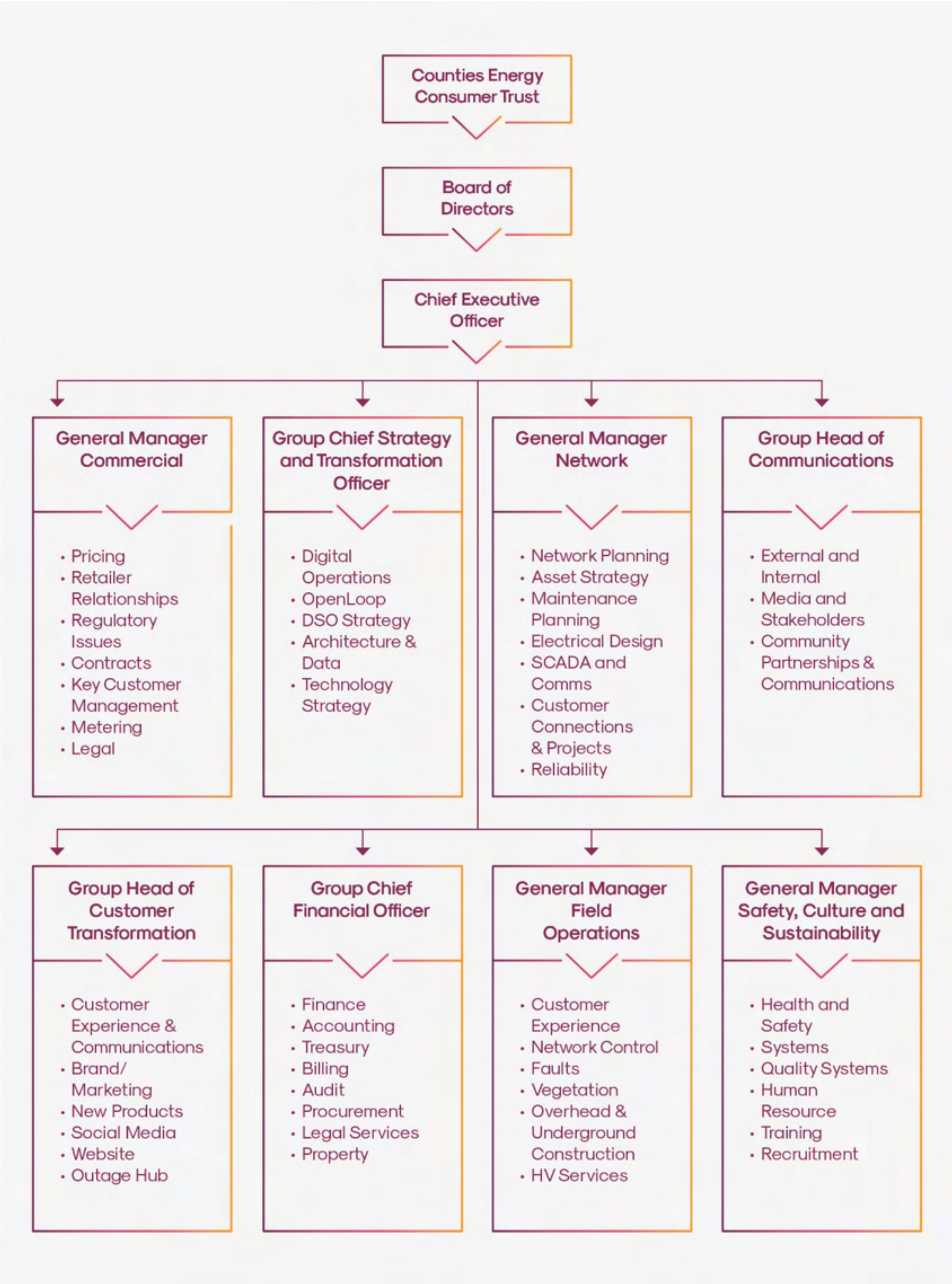


Figure 2-2 Corporate and Organisation Structure

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.

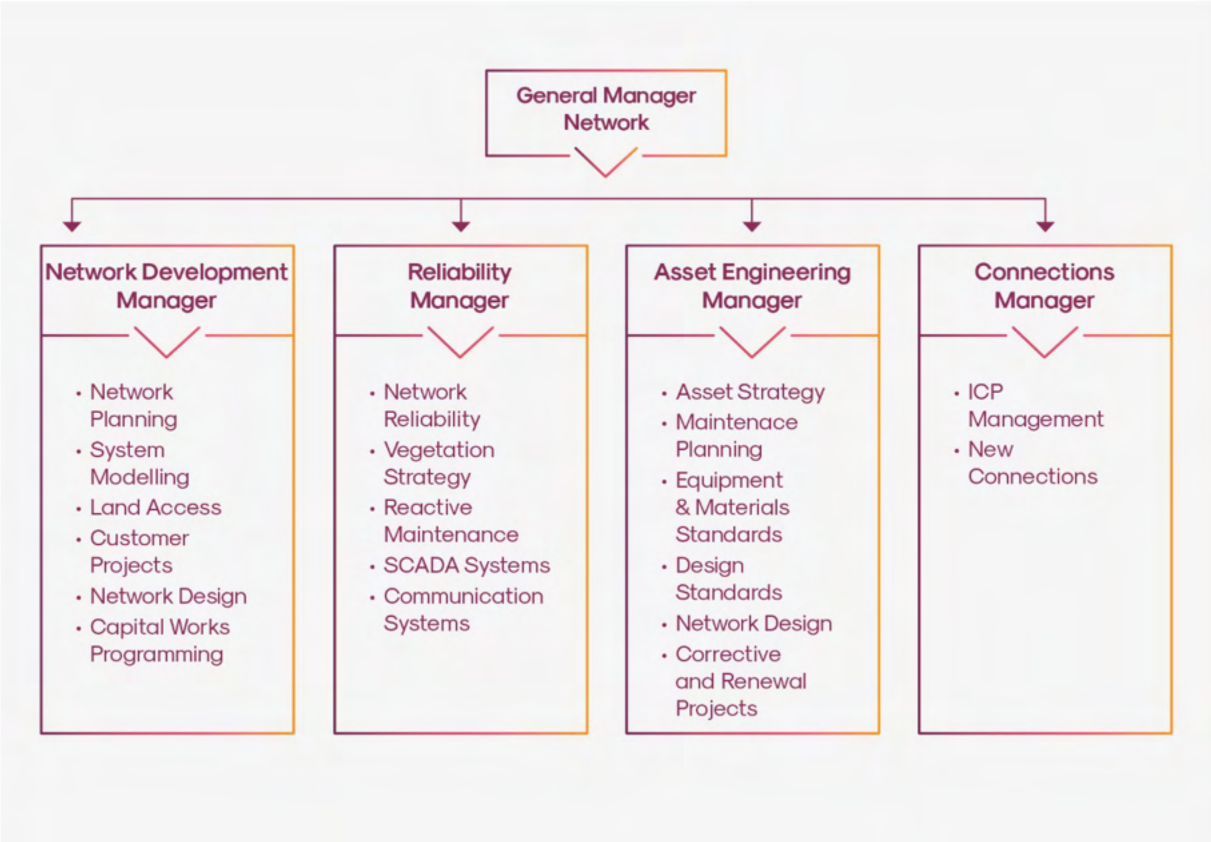


Figure 2-3 General Manager Network

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

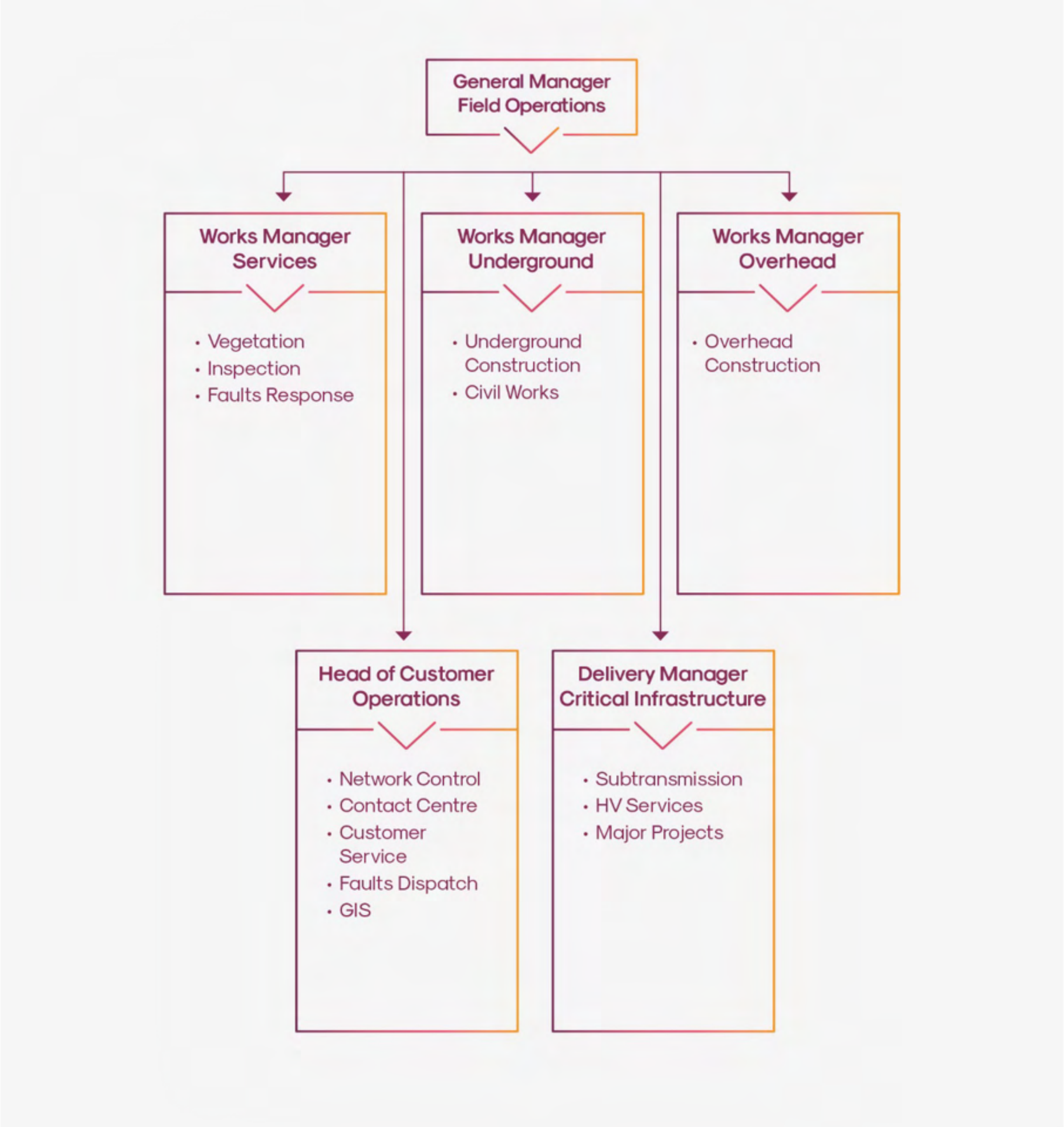


Figure 2-4 General Manager Field Operations

2.4.2 Asset Management Governance

Board Governance

The Leadership team reports to the Counties Energy 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.

Expenditure Approvals

Through this Asset Management Plan, the Board of Directors is informed of the expected levels of expenditure required over the next 10 years, but no expenditure is directly approved through the AMP process; rather, annual budgets and business cases are prepared for their consideration.

The Board of Directors approves the annual budgets for the 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 expenditures in line with the requirements of the position and responsibilities.

All network capital projects require business justification and appropriate delegated financial approval. Significant projects have a more in-depth business case approval process which the Leadership Team approves. Major capital projects are put to the Board for overall approval. All major projects over $5.0m are reported to the Board monthly and can be 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

To deliver this plan, Counties Energy must ensure that appropriate skills and capabilities are available within the business.

Counties Energy undertakes most routine asset management activities in-house. This is shown in the organisation structure diagrams located in section 2.4.1. The network and operations teams develop and deliver this plan with the support of the wider 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 employees is critical to the success of the business and identifying areas where new skills requirements or development pathways exist.

2.5 Network Operating Environment

2.5.1 Network Overview

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

We are in a transformational time for the electricity industry. Our network, designed based on a centralised uni-directional power flow model, is evolving to a bi-directional model where customers will have more control and choice. New technology advancements and New Zealand's net-zero greenhouse gas emission target by 2050 will introduce a new level of electricity demand. Counties Energy are committed to supporting the decarbonisation transition and understands the key role we play in the future of climate change.

We recognise the potential for changes in demand characteristics influenced by changing customer behaviour and anticipate our customers will expect services that enable them to leverage Distributed Energy Resources (DER) and participate in flexibility services.

Today, 59% of our network is rural overhead by length. However, the urban networks supplying Pukekohe, Waiuku, Tuakau, Pokeno, Drury and parts of Papakura comprise a split of overhead and underground assets. Whilst the majority of our network is rural, the ICP split is 30% Rural and 70% Urban.

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 state highway corridors. The western side 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 (SHA) and other subdivisions are creating pockets of high growth requiring network reinforcement, especially where they are some distance from existing substations.

The Counties Energy network is exposed to climatic variation, including temperature, wind and rain variances. 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 rugged terrain which brings access and maintenance challenges.

Vegetation management is another area of serious concern to Counties Energy. Areas such as Ararimu, Glen Murray, Onewhero and Hunua are heavily vegetated. Counties Energy and our vegetation management contractors liaise with the relevant local authorities and landowners concerning tree trimming in accordance with the Electricity (Hazards from Trees) Regulations 2003. Further details on vegetation management can be found in section 5.12.6

A rural view of Patumahoe

2.5.2 Statutory Planning Framework

Resource Management Reforms

The Government announced in February 2021 that the Resource Management Act (RMA) would be repealed and replaced with three new Acts: the Spatial Planning Act (SPA), the Natural and Built Environment Act (NBA) and the Climate Adaptation Act (CAA).

The proposed reforms are intended to create a resource management system that's more certain and efficient – a system that supports development within environmental limits and is required to give effect to the principles of Te Tiriti o Waitangi (the Treaty of Waitangi). Embedded in the bill is Te Taiao an intergenerational ethic that speaks to the health and wellbeing of the natural environment, and the essential relationship between a healthy environment and its capacity to sustain all life.

Environmental outcomes, limits and targets are key to the natural and built environment (NBE) Bill rather than managing adverse effects. They set clear expectations on development and environmental performance.

The existing regional and district plans across New Zealand will be consolidated to around 14 NBE Plans. The Bill introduces a regional, collaborative approach through the establishment of joint planning committees, including representatives of regional and district councils, mana whenua and the Minister for Conservation. These committees will oversee the development of NBE Plans along with Regional Spatial Strategies (RSS) which identify the housing and infrastructure needed in a region over at least 30 years.

A new National Planning Framework will draw together more than 20 existing pieces of national direction and will include an infrastructure chapter that is being developed by the New Zealand Infrastructure Commission (Te Waihanga). The new legislation will permit a greater number of permitted activities in plans and require fewer resource consents to be obtained.

In addition, the fast-track consenting process will continue for some infrastructure, along with a more flexible designations process available to more infrastructure providers that more clearly differentiates between the 'route protection' and 'design and build' stages.

National Policy Statement on Urban Development 2020

The National Policy Statement on Urban Development 2020 (NPS-UD) requires councils to plan well for growth and ensure a well-functioning urban environment for all people, communities and future generations. The NPS-UD contains objectives and policies that councils must give effect to in their resource management decisions.

To give councils further direction and support to implement the NPS-UD, the Resource Management (Enabling Housing Supply and Other Matters) Amendment Act (RMA-EHS) was passed into law on 20 December 2021. The RMA-EHS requires councils in New Zealand's largest urban areas to increase the housing supply and allow a wider variety of homes to be built. The RMA-EHS required territorial authorities to notify plan changes by 20 August 2022.

Medium Density Residential Standards

The RMA-EHS also introduced new Medium Density Residential Standards (MDRS), which require high-growth councils across New Zealand to introduce new standards into their district plans that will ease planning rules for what can be built without resource consent. The standards mean that up to three dwellings of up to three storeys can be developed on each site without needing to apply for resource consent as long as development rules and standards have been met. Territorial authorities can modify the Medium Density Residential Standards if a qualifying matter applies to an area that would make higher density inappropriate. For example, areas with natural hazards, special heritage character or a site in a 'new residential zone', i.e. a site in a greenfield area that is proposed to be rezoned to a relevant residential zone.

Territorial Authorities

The Counties Energy network operates in an area split between three territorial authorities, Auckland Council (40%), Waikato District Council (54%) and the balance is 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.

Auckland Unitary Plan

Within the area of Counties Energy that Auckland Council administers, 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 several 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 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 in the AUP(OP) but does not reflect changes in the development sequence resulting from the approval of Private Plan Changes 48, 49 and 50. These three plan changes will collectively provide up to 6,000 new dwellings and a new town centre in Drury. These plan changes are part of a wider development in the area, which is expected to bring a new city, the size of Napier, centred around a new state-owned railway station and new interchange on State Highway One. The Environment Court approved all three plan changes, with modifications, by consent order on 1 November 2022 following the resolution of all appeals.

The AUP(OP) came into effect in 2016 and replaced the former Regional Policy Statements and twelve District and Regional Plans. Whilst there are plan changes either in progress or in effect, we utilise the AUP(OP) in our network's design, construction and maintenance.

Auckland Council has prepared the Proposed Plan Change 78 Intensification (the Proposal) to the AUP(OP), the Council's intensification planning instrument. The proposal seeks to include provisions in the AUP(OP) that incorporate the MDRS in relevant residential zones and to give effect to Policies 3 and 4 of the National Policy Statement on Urban Development (NPS-UD).

The MDRS sees additional capacity in many peripheral areas where Residential – Single House and Residential – Mixed Housing Suburban zoned land is rezoned to Residential – Mixed Housing Urban, allowing for three dwellings per site. The effect of the MDRS, in particular, is likely to see a more widespread pattern to urban development and redevelopment, rather than in specific areas, as the AUP(OP) promoted.

Waikato District Plan

In the southern part of the Counties Energy area, the rules of the Waikato Regional Plan determine how we undertake work that might impact the use, development or protection of natural resources. At the same time, the Proposed Waikato District Plan (PWDP) provides the district plan rules. Change 1 of the PWDP, publicly notified in July 2018, combines the Franklin and Waikato sections into a single plan for the Waikato district. The PWDP will guide and set the rules that will shape growth and development in the southern section of the Counties Energy area for the next 10 years. We note their intention to concentrate development in existing developed areas such as Tuakau and Pokeno.

In January 2022, the Council adopted the recommendations made by the Hearings Panel as the Council's decisions on the proposed plan change. As of November 2022, parts of the PWDP, including the Infrastructure Chapter, are still under appeal, requiring us to utilise both the PWDP – Decision Version and PWDP – Appeals Version in our network's design, construction and maintenance.

Waikato District Council has also prepared Proposed Variation 3 to the PWDP. The proposal seeks to include provisions in the PWDP that incorporate the MDRS as contained in Schedule 3A of the RMA in relevant residential zones and to give effect to Policies 3 and 4 of the National Policy Statement on Urban Development 2020. While the decisions on the PWDP included areas zoned for medium density residential, the variation will enable more houses and higher density housing to be built in the Medium Residential Zones in developed areas such as Pokeno and Tuakau. The Hearings for Proposed Variation 3 begin in early 2023, and a final decision is expected in late 2023 or early 2024.

Hauraki District Plan

In the Hauraki District Council area, the requirements for Counties Energy'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 Energy activities.

Growth – Present and Future

The Counties Energy network is one of the fastest growing electricity networks in New Zealand, with connection growth in the order of 2 to 3% per annum, driven primarily by the growth of Auckland and our proximity to the 'golden triangle' between Tauranga, Hamilton and Auckland.

Population growth trends within the Counties Energy area are monitored in terms of building consent applications and new connections. The most significant contributor to demand growth in the medium term continues to be industrial and residential developments around Tuakau, Pokeno, 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 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 using the Rural Urban Boundary (RUB).

The RUB contains sufficient appropriately zoned land within its boundary to accommodate a minimum of seven years of projected residential, commercial and industrial growth. Land development beyond the RUB, such as that proposed at Clarks Beach and Glenbrook Beach, can only be achieved through a formal plan change process.

This plan change process allows utility operators to comment on the ability to supply the new developments and identify required upgrades.

Maps outlining the RUB impact are provided in Chapter 9.0 Network Development. A similar change notification process also applies to land zones 'Future' within the urban boundary.

The supply and delivery of development-ready land for housing and industrial growth is an important planning issue for Auckland. The operative plans identify the anticipated dwelling capacity in future urban areas and provide a basis for calculating the scale and location of likely demand increases on the network. While the timing of these developments may move, the scale and location information forms the basis of our network development planning.

Special Housing Areas

The Special Housing Areas initiated to help maintain a ready supply of housing land during the preparation and development of the AUP(OP) have been progressively disestablished since the Unitary Plan became operative (in part) in September 2016. These also feature in the FULSS and are part of the transition to longer-term proactive planning.

Construction has already commenced on many of these sites within the Counties Energy service area, including Belmont, Pukekohe and Hingaia, McLarin Road, Glenbrook, Clarks Beach, Paerata Rise and Bremner Road, and Drury. The final SHA was disestablished in May 2017.

Regulation

Counties Energy, 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 consumers are the beneficial owners through the Counties Energy Trust. However, it is still required to comply with the Information Disclosure Requirements, of which this AMP is one requisite.

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

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 regulations, Counties Energy has a range of legislative requirements to comply with, including the Electricity Act 1992, the Electricity (Safety) Regulations 2010, the Health and Safety at Work Act 2015, and the Electricity (Hazards from Trees) Regulations 2003, amongst others.

2.6 Stakeholders

Our stakeholders are people or organisations that affect or can be affected by or recognise themselves to be affected by Counties Energy's decisions or activities. There is great importance placed on stakeholder requirements, and we constantly focus on identifying them to meet stakeholders' expectations. Our stakeholders are outlined below, along with their requirements, how those requirements are identified and how they are incorporated into our asset management practices.

Stakeholder	Requirement	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Customers	Safety Reliable supply of electricity at an acceptable quality and price Effective communications Protecting the environment Climate change leadership / initiatives / responsiveness Lifelines preparedness	Meetings Customer focus groups Annual surveys Feedback	Public safety initiatives Service level targets and investment in the network Customer engagement process Network development projects for subdivision and network extensions Asset fleet management
Public, Community, Iwi and Landowners	Safety Lifelines preparedness Care of the environment Mana whenua values and engagement Protection of property and amenity values Reconciling land development opportunities with infrastructure routes Effective communication regarding access and maintenance Responsible climate change action.	Meetings Feedback Consultations	Public safety initiatives Network development planning Service level targets Emergency preparedness planning
Local Authorities	Alignment with district and regional planning requirements Accommodation of population and industrial growth	Meetings Consultation on appropriate infrastructure development and regional and district plans	Network development planning to ensure planned growth can be accommodated within the identified zones Emergency preparedness planning
Energy Retailer	Fair contractual arrangements Transparent, clear billing; suitable tariff structures Effective delivery of business-to-business services	Industry forums, conferences and seminars Regular consultations Electricity industry participation code Use of System Agreements	Service level targets Network development planning
Regulators and Governmental Agencies	Statutory and regulatory compliance Ensure customers receive a reliable supply of electricity at an acceptable quality and price	Legislation and regulations Consultations Industry forums, conferences and seminars	Network development planning Service level targets

Stakeholder	Requirement	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Working Groups – Industry and Customer	Electricity Authority Quarterly Forum for EDB discussions Counties Energy (CE) Customer Panel Northern Energy Group (NEG)	Meetings Sharing of information between CE and representatives of community groups to include businesses, rural community and local council. Feedback from customer representatives.	Customer engagement process Customer centrism ensure CE is aware of community and customer issues. Industry best practice learnings.
Transpower (as Grid and System Operator)	Security of supply New grid investment and planning provision Effective and timely communication Legislative and regulatory compliance Sustainable earnings from connected and interconnected assets	Operational standards and procedures Regular meetings	Network development planning
Board of Directors	Governance Risk -management Business direction and sustainability Performance of Chief Executive and Leadership Team	KPIs Regular Board meetings and directives	Risk management is integrated into all business processes Monthly reporting
Employees	Safe and enjoyable work and work environment Job satisfaction Work/life balance Development opportunities Fair remuneration Effective support	Employee surveys Meetings Regular employee briefings and communications	Forward planning of work Safety initiatives and reporting Integration of risk management into all processes Training
Contractors	Safety Commercial treatment and access Assurance of work continuity Visibility of forward workload requirements Risk management	Contractual arrangements Regular meetings	Forward planning of work Safety initiatives and reporting Integration of risk management into all processes
Suppliers	Fair, transparent, unbiased selection Forecast requirements to optimise the supply chain Commercial sustainability Risk management	Contractual arrangements Regular meetings	Forward planning of work Network standards
Counties Energy Trust	A fair and reasonable rate of return on equity Incentives to invest and innovate Good governance, risk management Business sustainability Good reputation with the community Good asset management	Trustee meetings KPIs	Network development planning Organisation and governance structures Integration of risk management Half-yearly and annual reporting

Table 2-1 Counties Energy's Stakeholders

2.6.1 Balancing Stakeholder Requirements

Counties Energy has a wide range of stakeholders, and we must be aware of all stakeholder requirements, including those that conflict. Safety is a company-wide priority that takes precedence in resolving any conflicting requirements. Balancing differing requirements is managed in the following order:

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

2.7 Our Customers

As a consumer-owned EDB, our customers are our owners. While we own a predominantly rural network, the majority of our customers are in urban areas. However, our network territory is one of the fastest growing areas in New Zealand because of Auckland's southward urban growth. Consequently, our customer numbers, recorded as ICPs, have increased significantly over recent years, and this growth is expected to continue over the AMP planning period.

2.7.1 Customer Profiles

As of 30 September 2022, there were 46,925 ICPs connected to Counties Energy's network. In the 12 months to 31 March 2022, Counties Energy's maximum network demand was 129 MW, and annual delivered energy was 659 GWh. In the recent 2022 winter peaks, peak demand increased to approximately 134 MW. Both the Company's ICP and peak demand numbers are continuously increasing, with new residential, commercial and industrial customers being connected. At the same time, Counties Energy's customer mix is changing from predominantly rural with small towns to having large residential urban areas and an increasing industrial base.

A breakdown of the ICP type is shown in table below:

Customer Group	ICPs	Delivered GWh
Direct supply	9	112.31
Time of use	180	116.87
Commercial	7,231	119.97
Domestic	39,505	310.26
Total	**46,925**	**659.41**

Table 2-2 Customer Profiles

2.7.2 Major Customers

Counties Energy has four large direct supply customers: Watercare Services Limited, New Zealand Steel Limited, Yashili New Zealand Dairy Company Limited and Synlait Milk Limited. The four large direct supply customers comprise 15.7% of Counties Energy's total electricity volume. This percentage is expected to increase because of Watercare's expansion of its Waikato Water Treatment Plant. Counties Energy works closely with its direct supply customers to meet their electricity demand and power quality requirements and to understand their future expansion plans.

Power demand from Counties Energy'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 as small companies expand and new companies are attracted to the region. Counties Energy'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 Energy's top 11 customers account for 23% of Counties Energy'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.

2.7.3 Distributed Generation

Counties Energy has 64 embedded generators greater than 10 kW and 1,337 embedded generators under 10 kW. The 10 larger embedded generators (100 kW or greater) consist of the following:

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

The remainder of the greater than 10 kW systems are all photovoltaic installations, generally on industrial or commercial sites.

The remaining 1,337 embedded generators under 10 kW are nearly all small residential and business photovoltaic installations. There has been noticeable, significant growth in the number of photovoltaic installations of all sizes in recent years.

2.7.4 Energy Delivered and Demand

Counties Energy's total delivered electricity in the year to 31 March 2022 was 659 GWh and peak demand was 130 MW. The network load profile is winter peaking, with typical morning and evening peaks for residential loads, and commercial loads generally having a constant daytime load.

Delivered energy has increased 3.3% YOY, whereas the peak demand has decreased 6.5% YOY. This is primarily due to improvements in load control, which has resulted in reduced network peaks despite a higher volume of total delivered electricity. The graph below shows the growth split over our main customer groups and the peak demand.

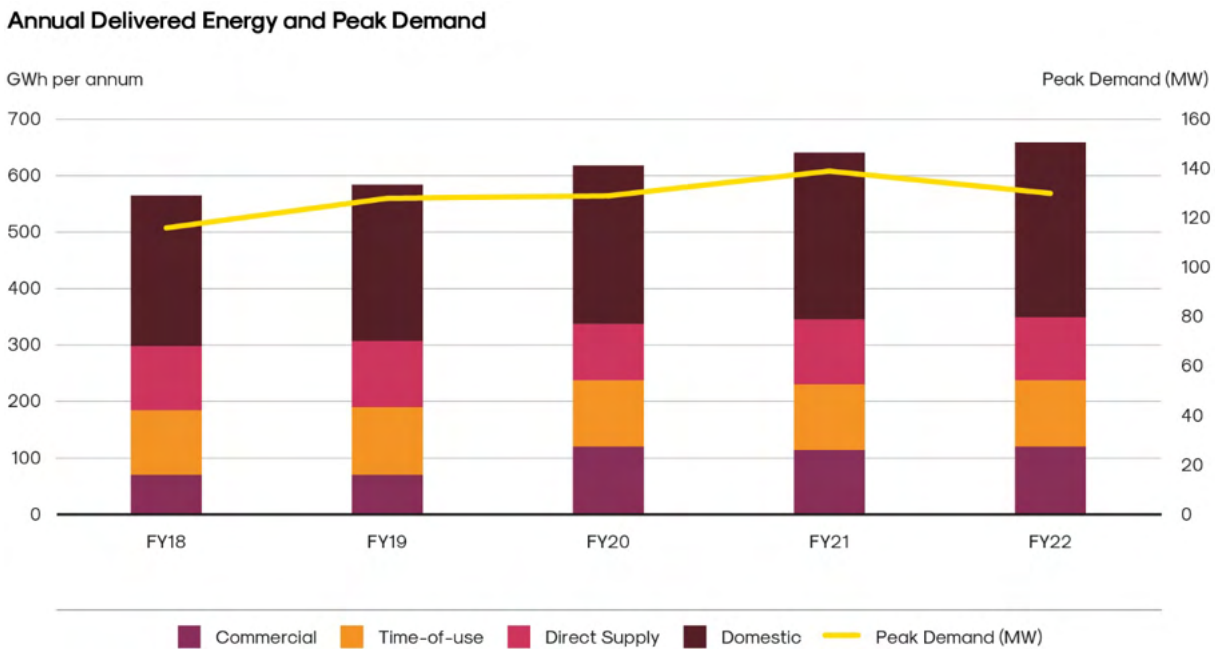


Figure 2-5 Energy Volumes and Network Demand

2.8 Our Network

2.8.1 Overview and Customer Distribution

Counties Energy has two points of supply from Transpower's National Grid via Grid Exit Points (GXPs) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33 kV, while the Bombay GXP supplies the eastern substations at 110 kV and 33 kV.

The number of active installations and the installed distribution capacity controlled by each GXP are shown in Table 2-3. 73% of ICPs are supplied from the Bombay GXP at 110 kV and 33 kV, and the remaining 27% from Glenbrook GXP.

Other details are included in the following sections.

Zone Substation	No. of Distribution Substations	Distribution Capacity (kVA)	Active ICPs				
			Total	Residential	Commercial	Industrial	% of total ICPs
BOMBAY 110 KV GXP							
Opaheke	504	88,170	9,217	8,238	932	47	20
Tuakau	708	51,325	5,249	4,182	1,041	26	11
Pokeno	45	14,840	1,824	1,664	154	6	4
Pukekohe	668	103,315	13,950	11,770	2,109	71	30
BOMBAY 33 KV GXP							
Mangatawhiri	422	25,730	2,309	1,756	541	12	5
Ramarama	346	22,195	2,401	1,924	472	5	5
GLENBROOK 33 KV GXP							
Waiuku	649	49,305	7,541	6,372	1,155	14	16
Karaka	456	31,615	3,888	3,229	655	4	8
Maioro	113	19,905	546	370	172	4	1

Table 2-3 Overview of Network Substation and Customer Information

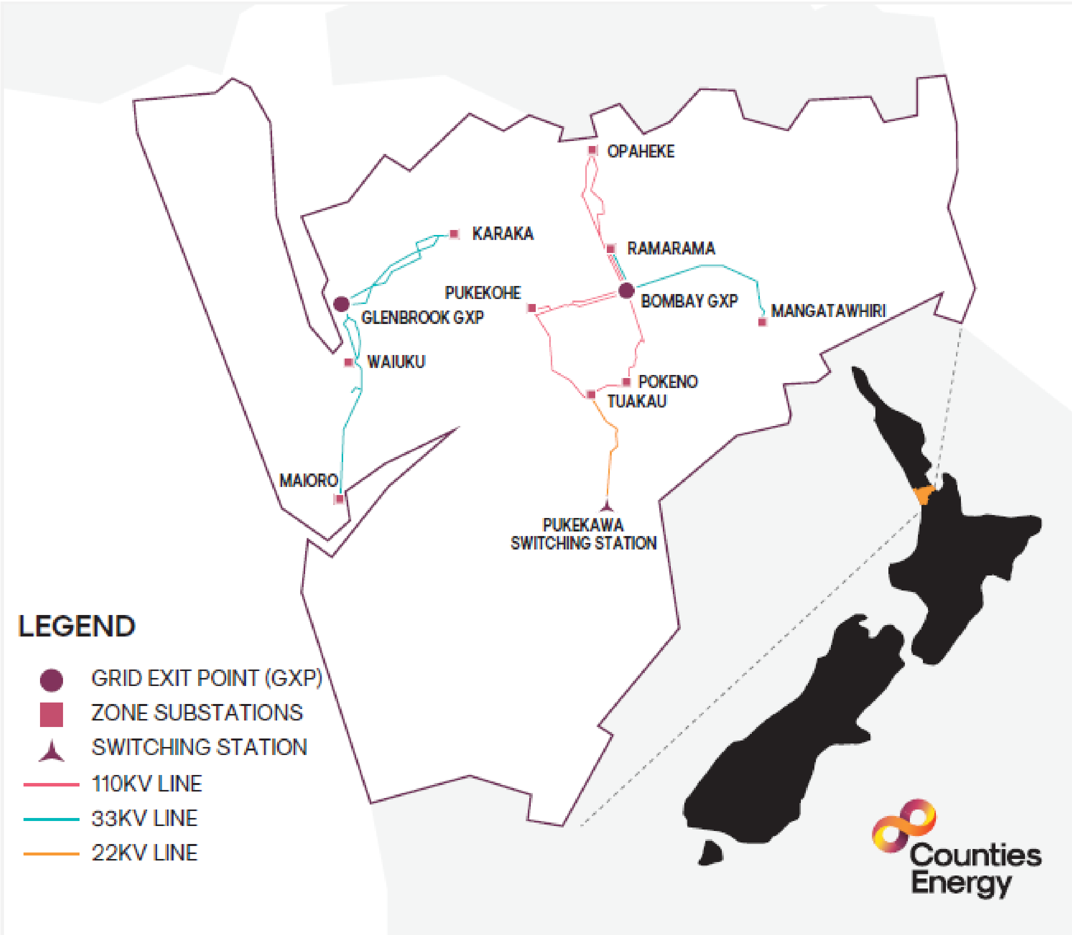


Figure 2-6 Overview of Counties Energy Subtransmission Network

2.8.2 Overview of Network Substations and Customer information

Subtransmission

Our subtransmission network consists of 110 kV and 33 kV subtransmission lines from Bombay and Glenbrook GXPs. The architecture of the network is typically radial subtransmission circuits connecting to 33 kV buses or configured as transformer-feeders where no bus is installed.

- The Pukekohe Substation is supplied via two 110 kV lines from Bombay, with a 110 kV bus;
- The Opaheke Substation is supplied via two 110 kV lines from Bombay configured as transformer-feeders; and
- The Tuakau and the new Pokeno Substations are supplied on a ring circuit via two 110 kV lines – one from Bombay and one from Pukekohe.
- The remaining five zone substations are supplied via the 33 kV subtransmission network, with distribution supply operating at 11 kV, with some feeders stepped up to 22 kV using autotransformers.

The subtransmission system schematics, capacity and demand information are provided in Chapter 9.0 Network Development. A summary of the loading and other characteristics of the subtransmission system and zone substations are illustrated in Table 2-4.

Aerial view of Waiuku substation

Zone Substation	No. GXP Circuits	Description	Installed Capacity	N-1 Capacity (MVA)	Load 2022 (MVA)	No. Customers	Average Forecast Growth Trend (%)
BOMBAY 110 KV GXP							
Opaheke	2	Single 110 kV tower & pole lines	2x 20/40	40	28.3	9,217	5.5
Tuakau	2	Single 110 kV pole line	2x 20/40	40	12.8	5,209	0.2
Pokeno	2	Single 110 kV pole line	2x 30/40	40	10.2	1,824	13.8
Pukekohe	2	Single 110 kV pole line	2x 30/60	60	38.8	13,950	3.3
BOMBAY 33 KV GXP							
Mangatawhiri	1	Single 33 kV pole line	1x 7.5/9.4	N/A	7.6	2,309	1.0
Ramarama	2	Single 33 kV tower & pole lines	1x 5 + 5/6.25	5	6.7	2,401	1.0
GLENBROOK 33 KV GXP							
Waiuku	2	Single 33 kV pole line	2x 10/20	20	16.4	7,541	2.7
Karaka	2	Single 33 kV pole line	2x 10/20	20	12.6	3,888	4.9
Maioro	1	Single 33 kV pole line	2x 7.5/9.4	9.4	8.5	546	0.5

Table 2-4 Summary of Subtransmission and Zone Substation Characteristics

Distribution

Our zone substations supply 62 distribution feeders (operating at 22 kV or 11 kV) via 4,189 distribution substations. These substations connect over 46,925 customers to the Counties Energy network.

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

A total of 45 22 kV/11 kV transformers, the earliest of which were installed in 1994, are also used on the network to provide interconnection between circuits operating at each voltage. Table 2-5 shows the ratio of overhead to underground networks.

Type of Network	Percentage
HV NETWORK (11 KV AND 22 KV)	
Overhead	82%
Underground	18%
LV NETWORK	
Overhead	45%
Underground	55%
TOTAL NETWORK (HV AND LV)	
Overhead	**65%**
Underground	**35%**

Table 2-5 Network Overview – Overhead and Underground

Voltage	Length (km)
UNDERGROUND	
22 kV	236.5
11 kV	93.2
LV	893.7
OVERHEAD	
22 kV	574
11 kV	897
LV	700

Table 2-6 Network Overview – Operating Voltage Quantities

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

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

In addition to our distribution network, there are overhead lines owned by private landowners which connect to our network, and third-party poles, such as those owned by Chorus, are used to support overhead lines.

Further details about the distribution network, including quantities and age profiles, are included in Chapter 3.0.

3.0 Our Assets

3.0 Our Assets

This chapter outlines the population profiles 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; and
- Other network assets.

The maintenance and renewal of these assets are discussed further in Chapter 8.0.

3.1 Age-Based Condition

Condition profiles are displayed for each asset group, currently based on their age. The Asset Health Indicator (AHI) scores and age parameters used are based on the Electricity Engineers' Association (EEA) AHI grades. As we develop our Asset Risk Management Model, these scores will be revised accordingly.

AHI Score	Description	Probability of Failure
H1	End-of-life (EOL)	Very High
H2	EOL drivers present	High
H3	Onset of reliability	Medium
H4	Normal in-service deterioration	Low
H5	As new	Unusual

Table 3-1 Asset Condition – AHI Scores

3.2 Subtransmission

3.2.1 Subtransmission Lines and Poles

We have a total of 137.5 km of subtransmission line on the network, consisting of the following types:

- All Aluminium Conductor (AAC);
- Aluminium Conductor Steel-Reinforced (ACSR); and
- Copper (Cu).

Older parts of the network are made up of ACSR and Copper, with AAC being installed from the 1990s.

The lines are supported by the following:

- Concrete Poles;
- Wood Poles;
- Steel Poles; and
- Steel Lattice Towers.

The steel lattice towers and copper conductor are undergoing refurbishment and replacement as part of the Barber Road substation works. Further detail can be found in section 8.2.

Type	Quantity	Life Expectancy	Average Age
SUBTRANSMISSION STRUCTURES			
Concrete Poles	1,352	80 Years	24 Years
Wood Poles	5	45 Years	18 Years
Steel Poles	184	55 Years	9 Years
Other	4	55 Years	4 Years
Steel Lattice Towers	10	80 Years	93 Years
33 KV CONDUCTOR			
AAC	53.57 km	80 Years	38 Years
ACSR	14.60 km	60 Years	46 Years
CU	3.38 km	80 Years	93 Years
110 KV CONDUCTOR			
AAC	62.46 km	80 Years	19 Years
CU	3.46 km	80 Years	93 Years
CROSSARMS			
Wood	729	45 Years	42 Years
Steel	804	80 Years	12 Years
Unknown	163		24 Years

Table 3-2 Asset Summary – Subtransmission Lines

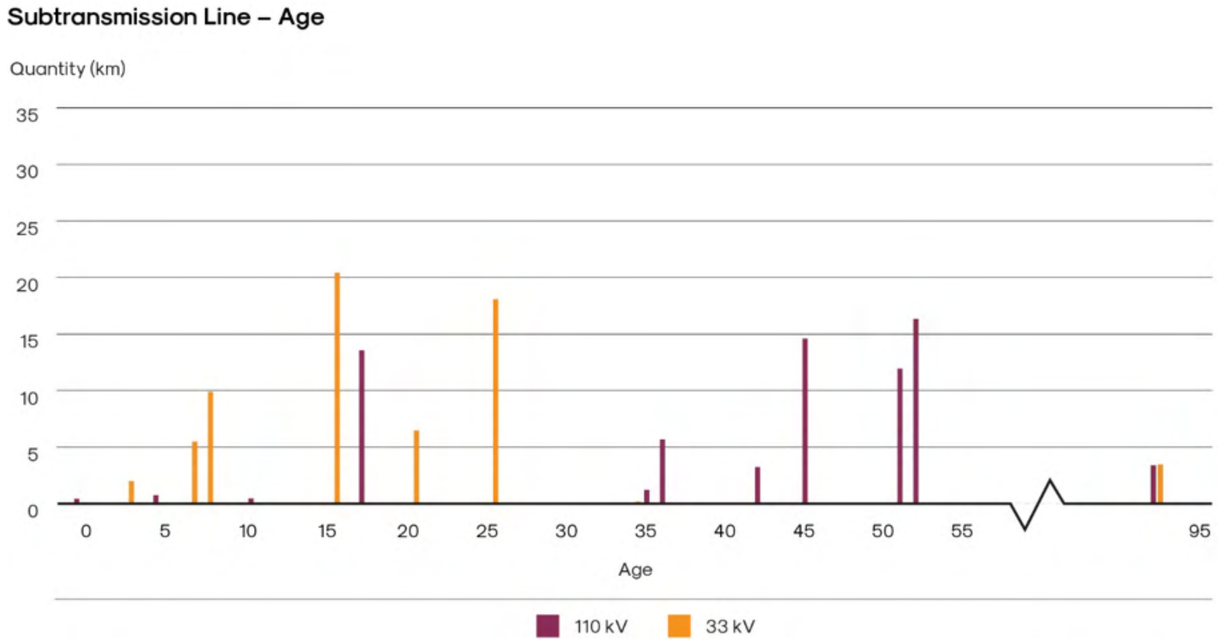


Figure 3-1 Age Profile – Subtransmission Line

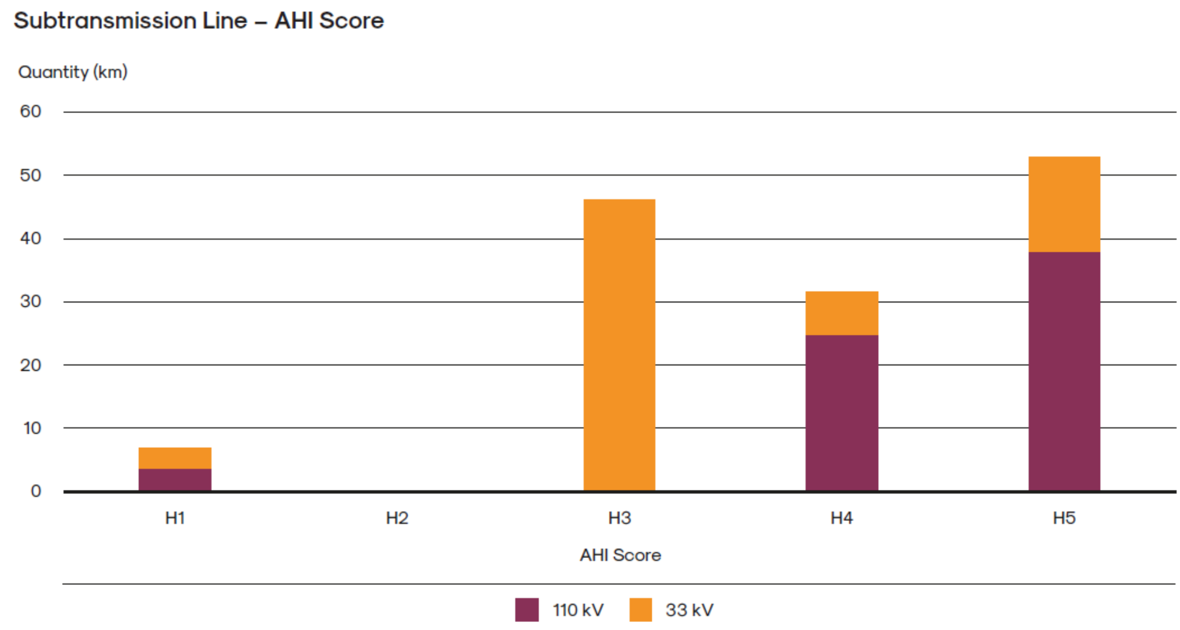


Figure 3-2 Condition Profile – Subtransmission Line

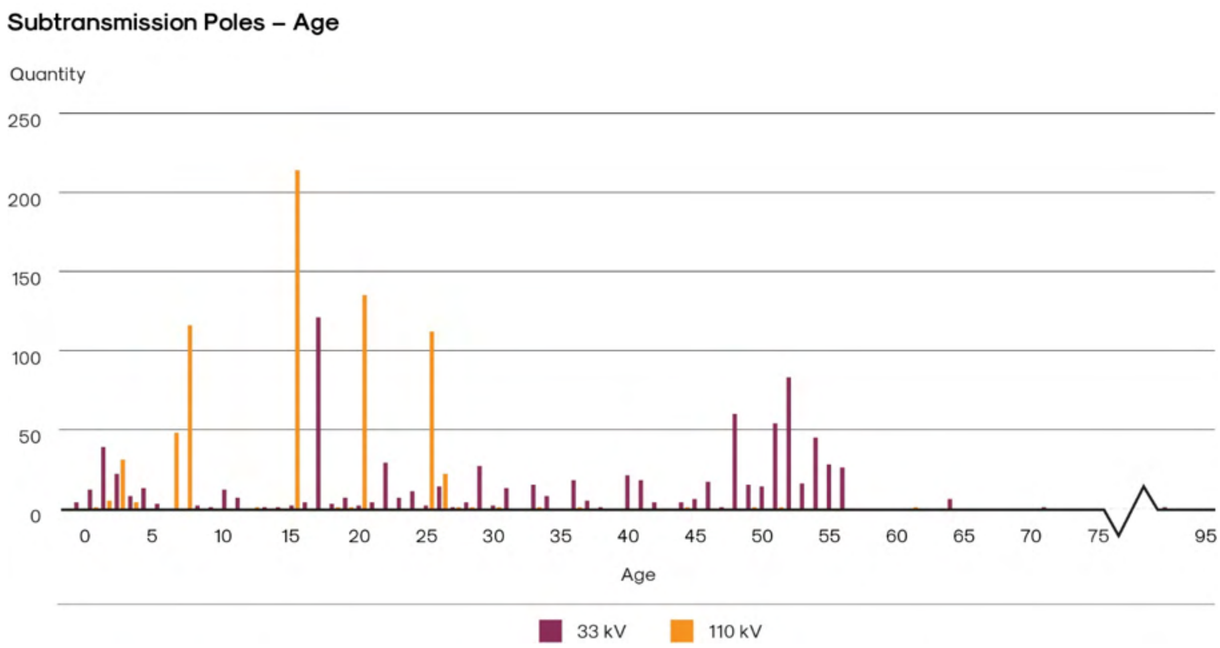


Figure 3-3 Age Profile – Subtransmission Pole

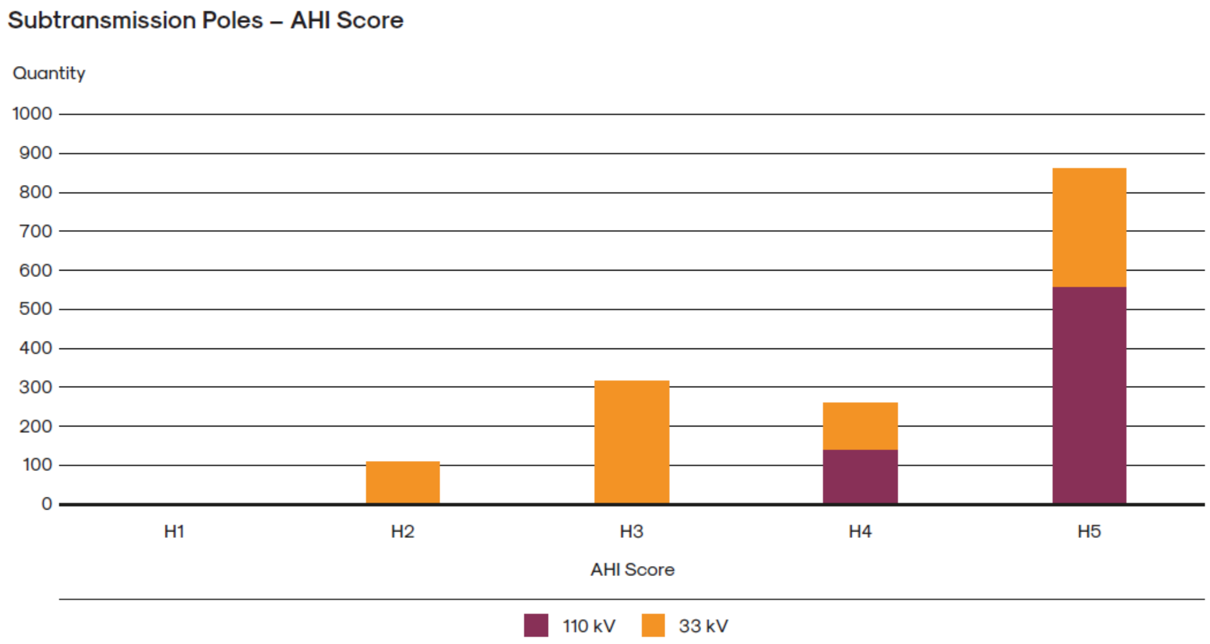


Figure 3-4 Condition Profile – Subtransmission Pole

3.2.2 Subtransmission Cables

We have a total of 2 km of subtransmission cable on the network consisting of the following types:

- 33 kV [1] Cross-linked polyethene (XLPE); and
- 110 kV [2] Cross-linked polyethene (XLPE).

Type	Quantity (km)	Life Expectancy	Average Age
SUBTRANSMISSION CABLE			
33 kV XLPE	1.96	55 Years	13 Years
110 kV XLPE	0.05	55 Years	3 Years

Table 3-3 Asset Summary – Subtransmission Cable

[1] Operating voltage
[2] Operating voltage

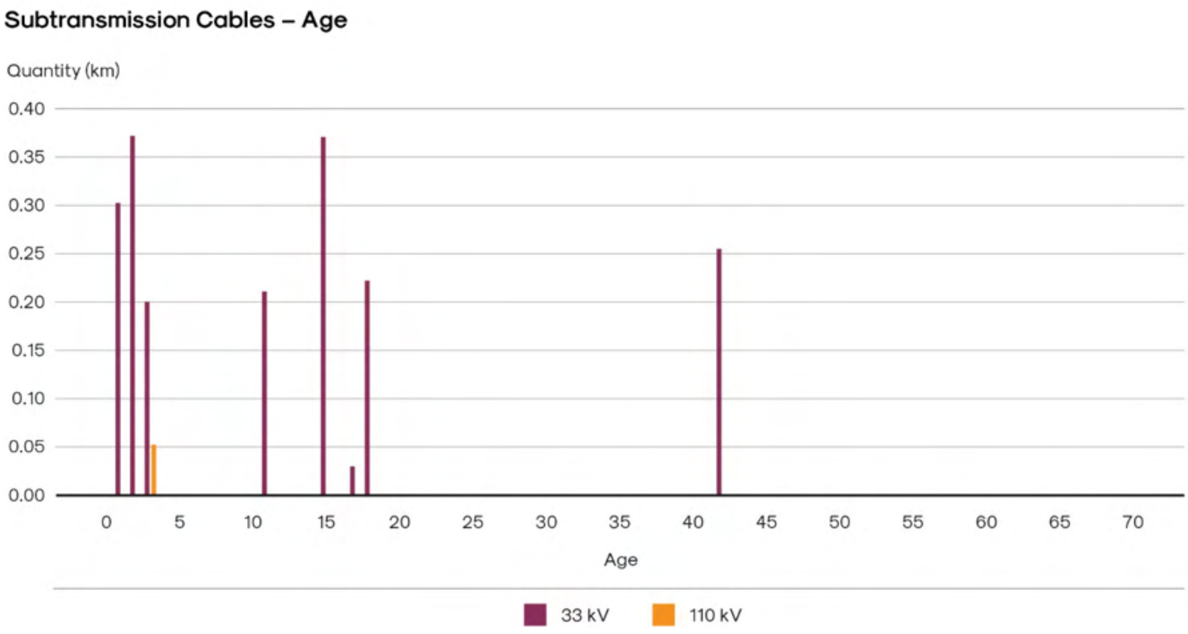


Figure 3-5 Age Profile – Subtransmission Cable

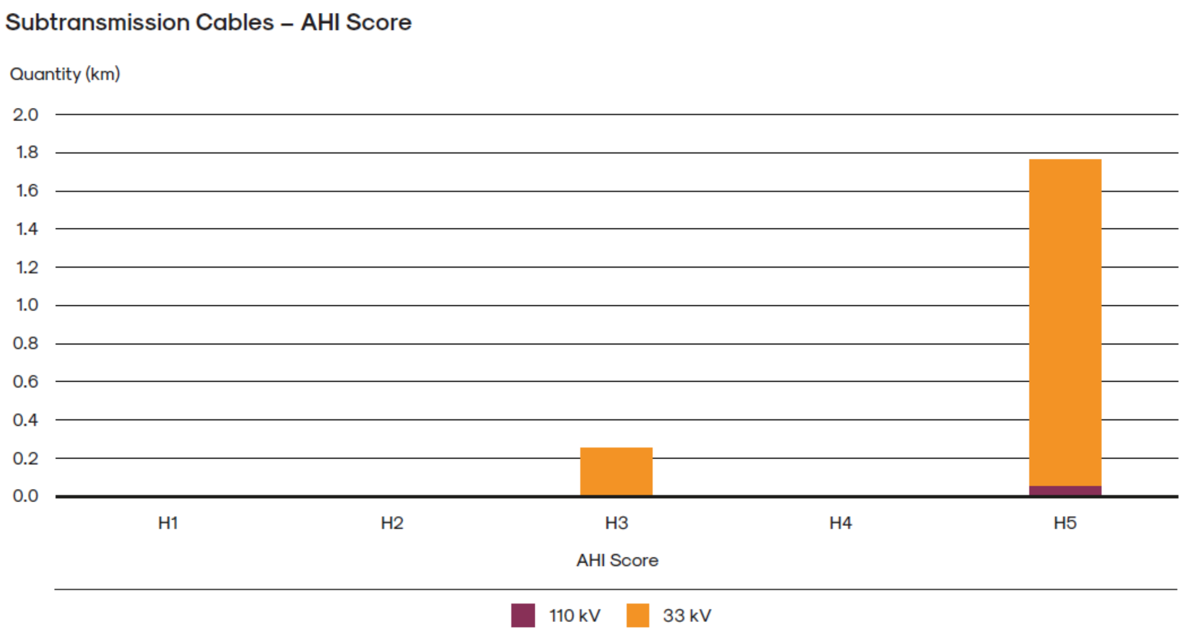


Figure 3-6 Condition Profile – Subtransmission Cable

3.3 Zone Substations

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

Type	Quantity	Life Expectancy	Average Life
NETWORK BUILDINGS			
	10	50 Years	35 Years
POWER TRANSFORMERS			
110/22 kV	8	50 Years	13 Years
33/11 kV	10	60 Years	40Years
CIRCUIT BREAKERS			
110 kV CBs	20	45 Years	7 Years
33 kV CBs	12	45 Years	14 Years
22 kV CBs	58	45 Years	12 Years
11 kV CBs	38	45 Years	30 Years
STATION DISCONNECTORS			
110 kV	2	45 Years	16 Years
33 kV	27	45 Years	33 Years

Table 3-4 Asset Summary – Zone Substations

3.3.1 Zone Substation Buildings

We operate nine substations, with the Eastern Network at 110 kV/22 kV and 33 kV/11 kV, and the Western network at 33 kV/11 kV.

Eastern Network 110 kV/22 kV

- Opaheke;
- Tuakau;
- Pokeno; and
- Pukekohe.

Eastern Network 33 kV/11 kV

- Mangatawhiri; and
- Ramarama.

Western Network 33 kV/11 kV

- Waiuku;
- Maioro; and
- Karaka.

Additionally, we operate a switching station at Pukekawa.

Barber Road Substation

In FY20, we commenced the establishment of the new 110 kV/22 kV Barber Road substation to replace the end-of-life Ramarama and Mangatawhiri substations. We are progressively migrating feeders onto the new substation. This will continue into the next regulatory period, with final decommissioning of the Ramarama and Mangatawhiri substations scheduled for FY25.

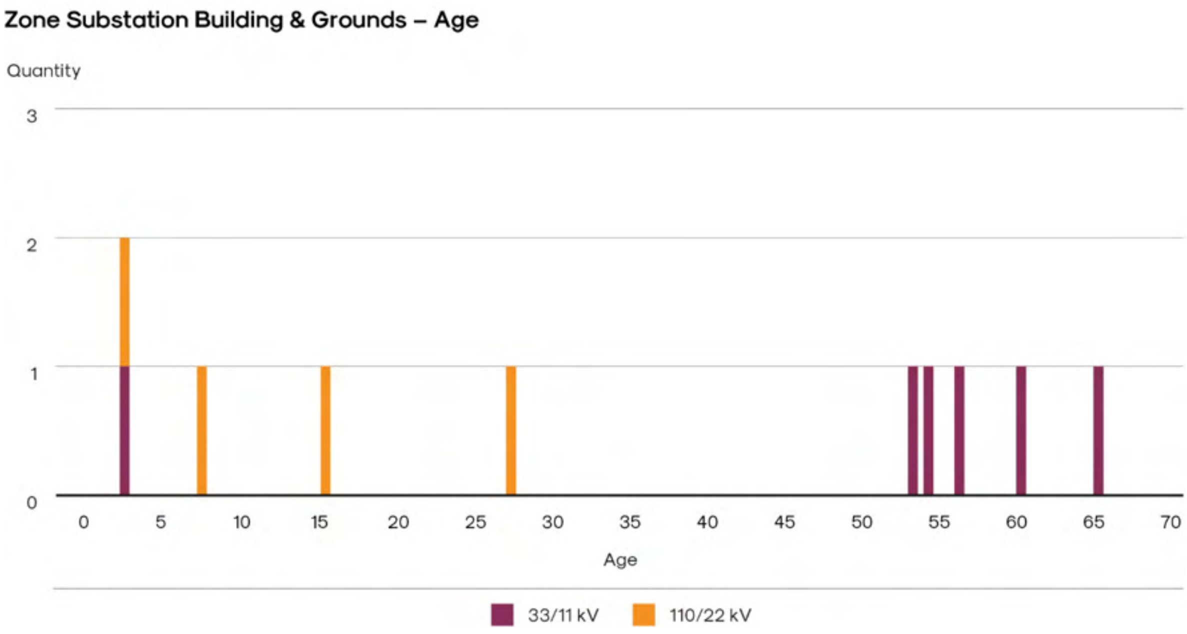


Figure 3-7 Age Profile – Zone Substation and Grounds

3.3.2 Power Transformers

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

We have 18 power transformers at our zone substations, operating at 22/110 kV and 33/11 kV. Power transformers installed prior to 1990 were 33/11 kV. One of the 11/33 kV transformers is installed at Waiuku substation as a strategic spare, and is a refurbished unit, original installed in 1986.

Since 1996, eight 110/22 kV transformers have been installed in line with our plans to convert the eastern region of our network to 110 kV subtransmission and 22 kV distribution voltage.

The transformers showing end-of-life (H1 and H2) are:

- Maioro T1 and T2 – They are operating over their rating during peaks. Further details can be found in Section 8.3;
- Ramarama T1 and T2 – To be decommissioned with the commissioning of Barber Road substation;
- Mangatawhiri T1 – To be decommissioned with the commissioning of Barber Road substation; and
- Karaka T2 – Two 33/11 kV 10/20 MVA transformers installed at the Karaka substation provide an n-1 capacity of 20 MVA and will be replaced in FY32/33.

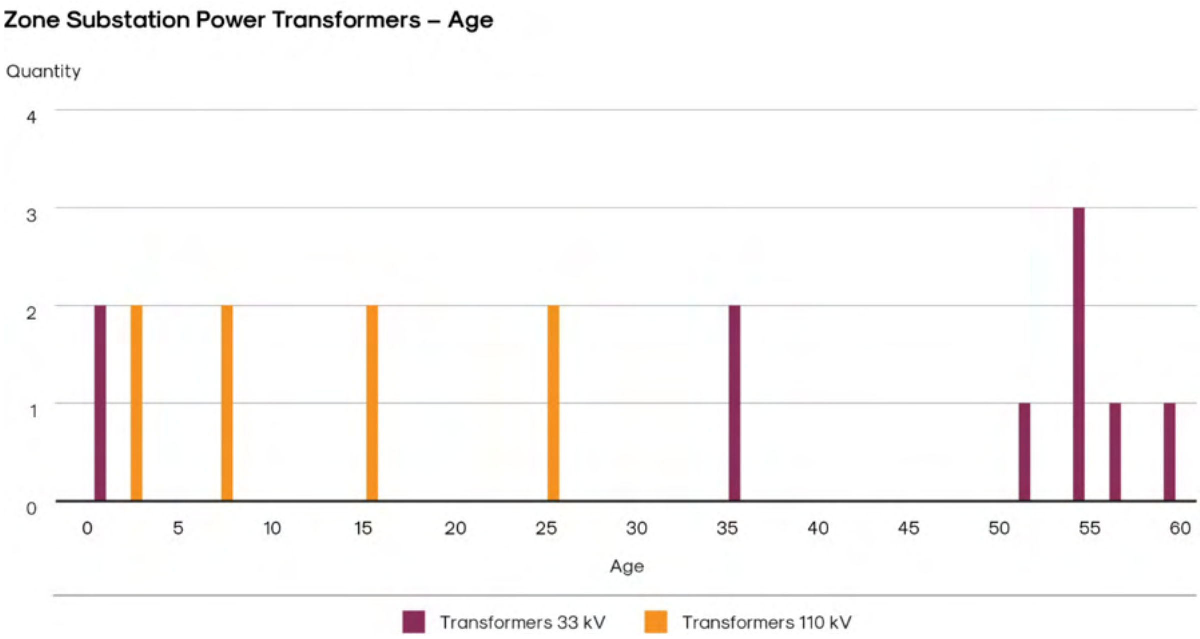


Figure 3-8 Age Profile – Power Transformers

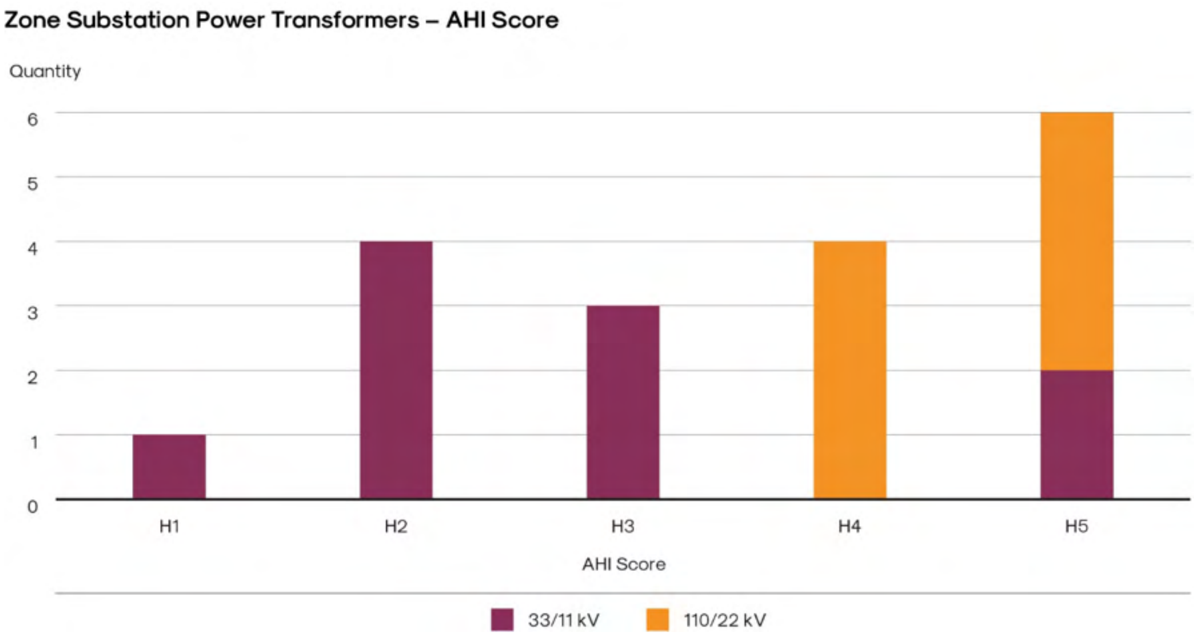


Figure 3-9 Condition Profile – Power Transformers

Aerial view of Pukekohe Substation

3.3.3 Zone Substation Switchgear

Zone substation switchgear provides control, isolates electrical circuits and protects the network. They contain circuit breakers and isolation switches and are associated with current and voltage transformers.

The majority of subtransmission switchgear is outdoor switchgear.

Over the past few years, we have replaced all outdoor oil circuit breakers with SF_6 gas circuit breakers. These oil circuit breakers had exceeded their expected service life, required intensive maintenance and were no longer available for replacement parts. We recently installed an indoor 110 kV gas-insulated switchgear at the Pokeno substation.

Indoor switchgear has been used for all 11/22 kV applications. Indoor switchgear has a smaller footprint, is contained within an appropriate building, and is generally more reliable than outdoor switchgear. The new switchboards commissioned at the Waiuku substation in 2019 and Pokeno substation in 2020 feature arc flash venting and arc flash dedication to quickly isolate arc faults and significantly reduce the operation safety risk to our field employees from an internal switchboard failure.

The switchgear showing end-of-life (H1 and H2) are:

- Mangatawhiri T1 – To be decommissioned with the commissioning of Barber Road substation; and
- Maioro – To be replaced in FY25 – see Chapter 8.0. for detail.

Substation Circuit Breakers and Switches – Age

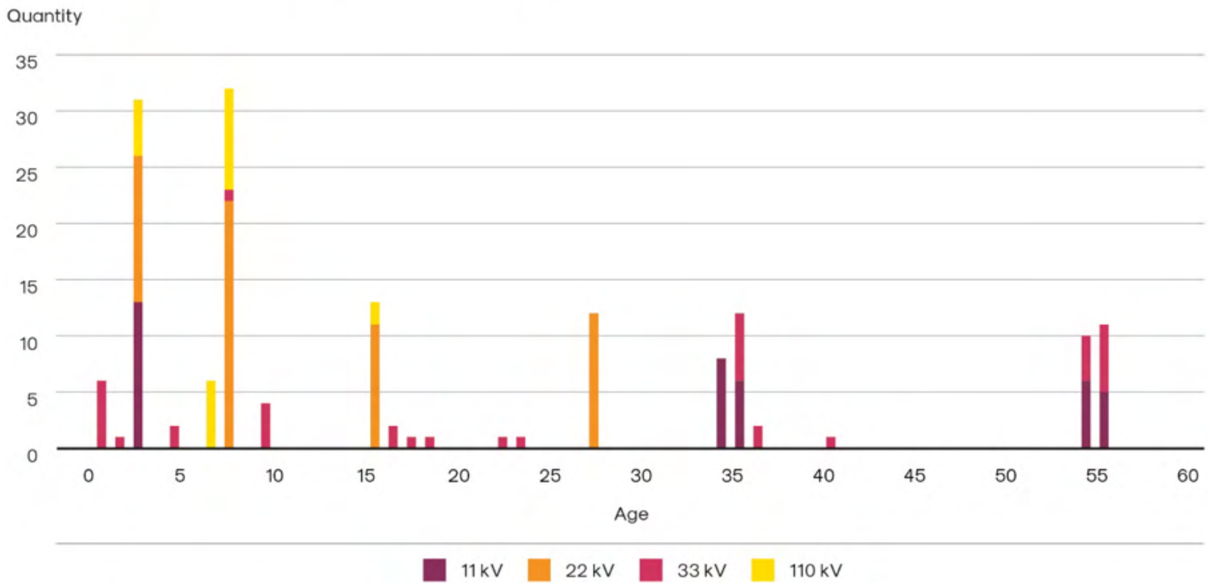


Figure 3-10 Age Profile – Circuit Breakers and Switches

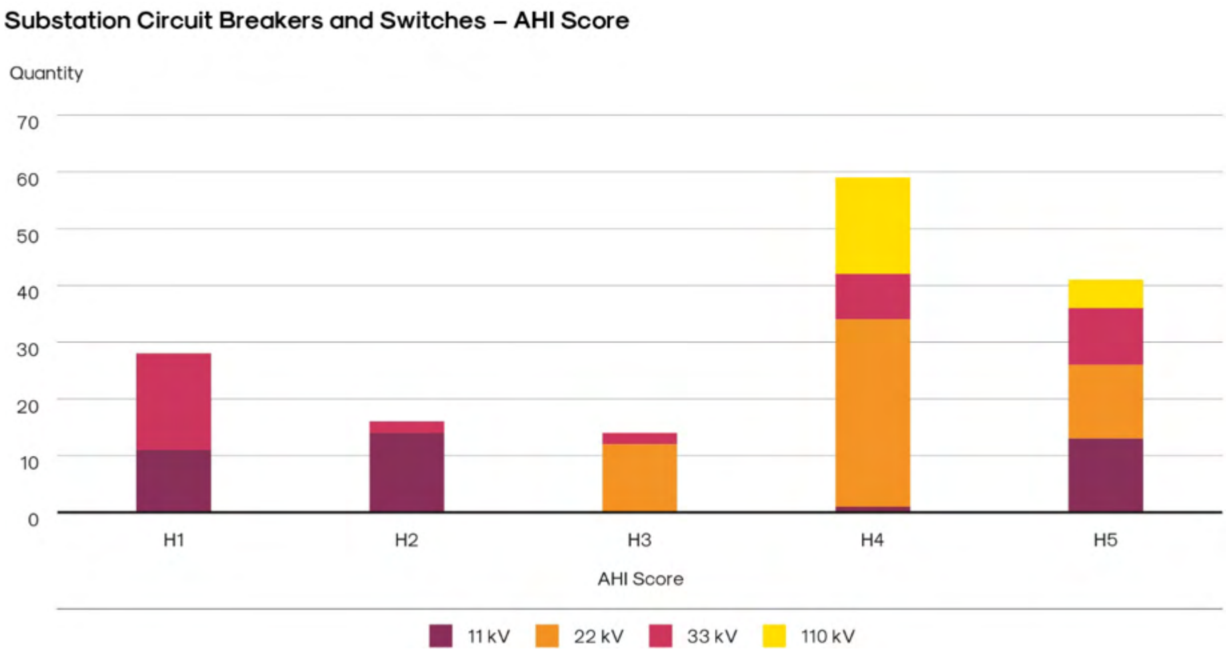


Figure 3-11 Condition Profile – Circuit Breakers and Switches

3.4 Distribution and LV Lines

We transfer electricity from our zone substations to our customers through our 22 kV or 11 kV distribution network and our 400 V Low-Voltage (LV) network, which consists of both overhead lines and underground cables.

Type	Quantity	Life Expectancy	Average Life
POLES			
Concrete/Steel	24,547	80 Years	29 Years
Wood	1,811	45 Years	18 Years
Other	76	45 Years	30 Years
CROSSARMS			
Wood	32,705	45 Years	31 Years
Steel	9,072	80 Years	13 Years
Other	282	80 Years	21 Years
Unknown	154	80 Years	28 Years
22 KV CONDUCTORS			
AAC	307.23 km	80 Years	32 Years
AAAC	67.33 km	80 Years	24 Years
ACSR	149.43 km	80 Years	41 Years
Copper	50.39 km	65 Years	54 Years
11 KV CONDUCTORS			
AAC	281.17 km	80 Years	30 Years
AAAC	121.28 km	80 Years	23 Years
ACSR	351.85 km	80 Years	43 Years
Copper	142.28 km	65 Years	49 Years
LV CONDUCTOR			
	700.03 km	80 Years	24 Years

Table 3-5 Asset Summary – Distribution and LV Lines

3.4.1 Distribution Lines – 11 kV and 22 kV

The Counties Energy distribution network consists of around 574 km of 22 kV conductor and 896 km of 11 kV conductor consisting of the following types:

- All Aluminium Conductor (AAC);
- All Aluminium Alloy Conductor (AAAC);
- Aluminium Conductor Steel-Reinforced (ACSR); and
- Copper (Cu).

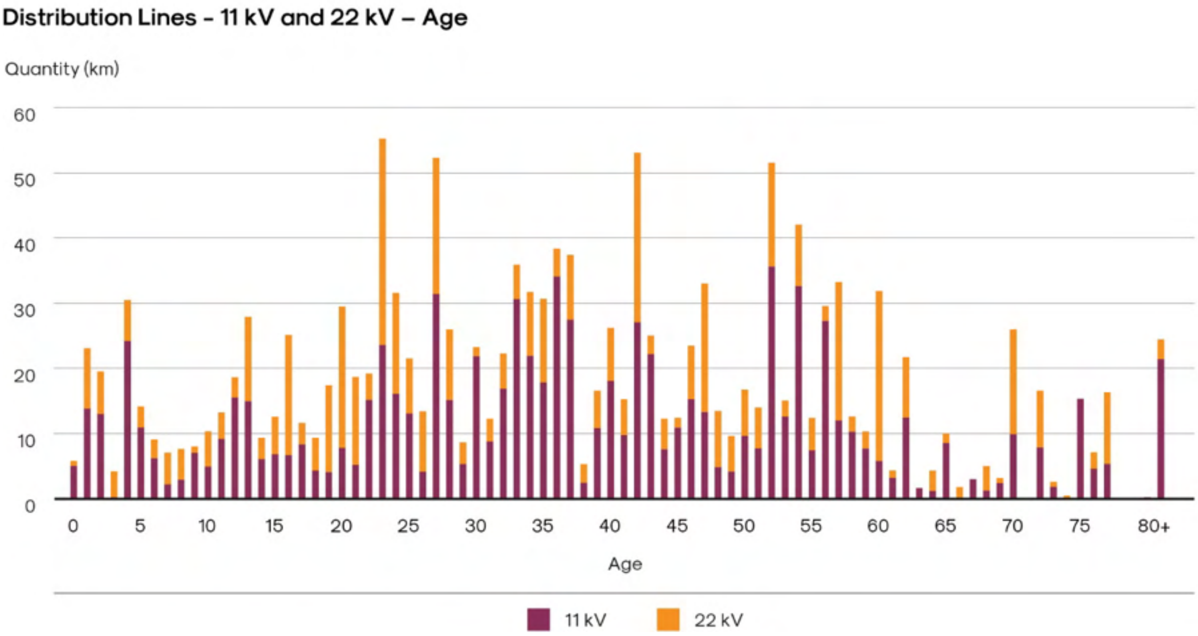


Figure 3-12 Age Profile – Distribution Lines

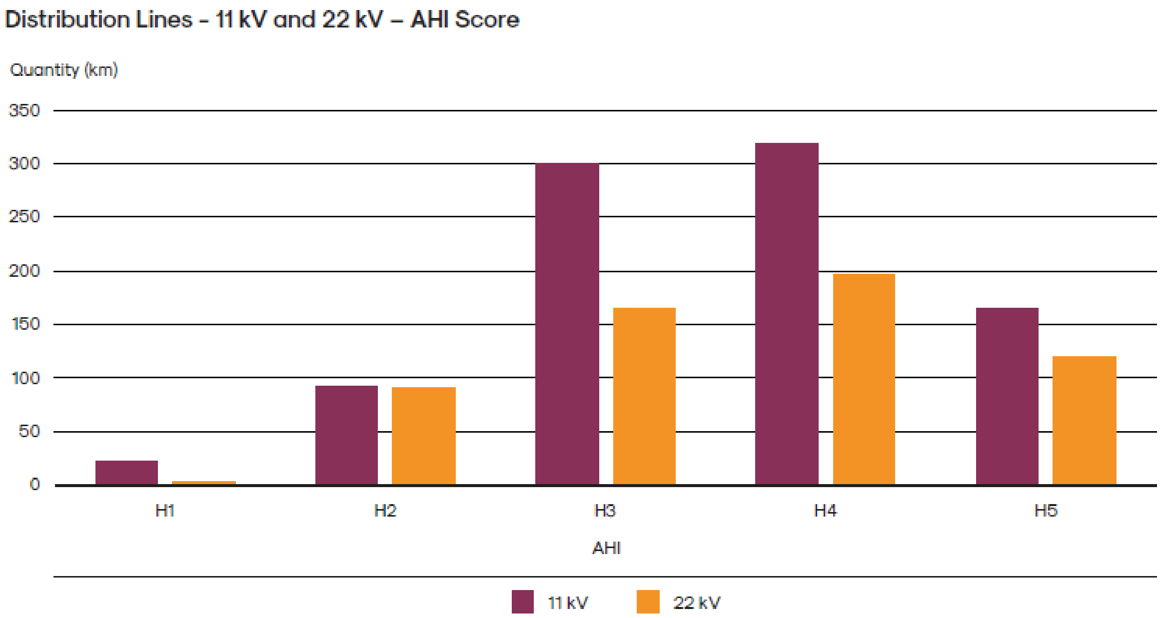


Figure 3-13 Condition Profile – Distribution Lines

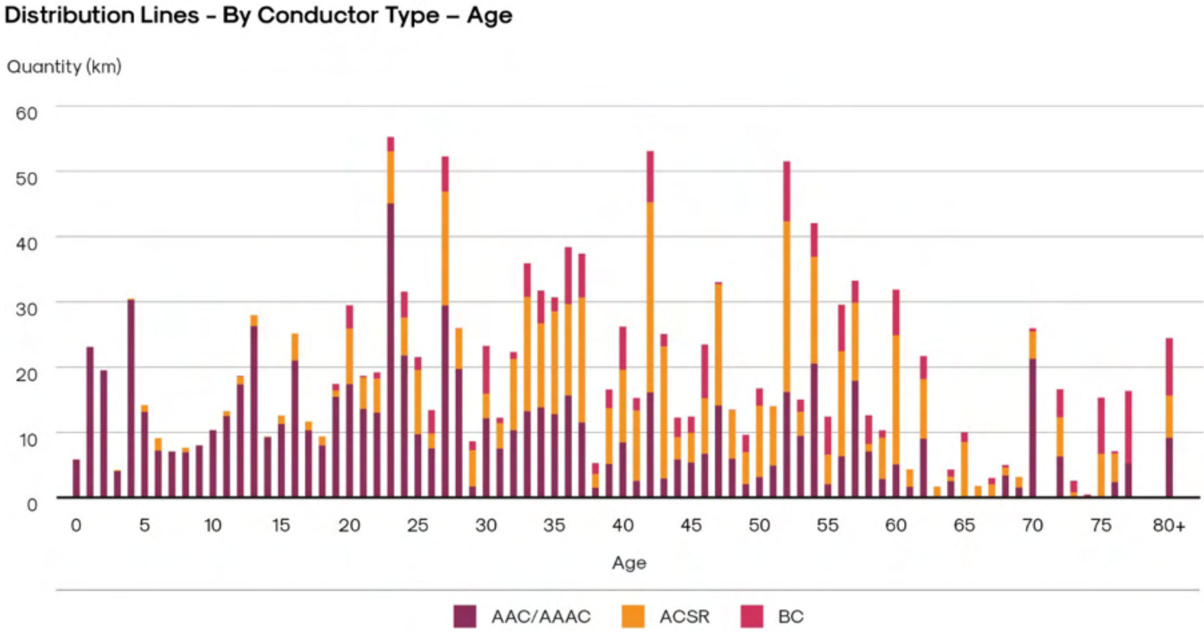


Figure 3-14 Age Profile – Distribution Lines by Conductor Type

3.4.2 Distribution Lines – Low Voltage [3]

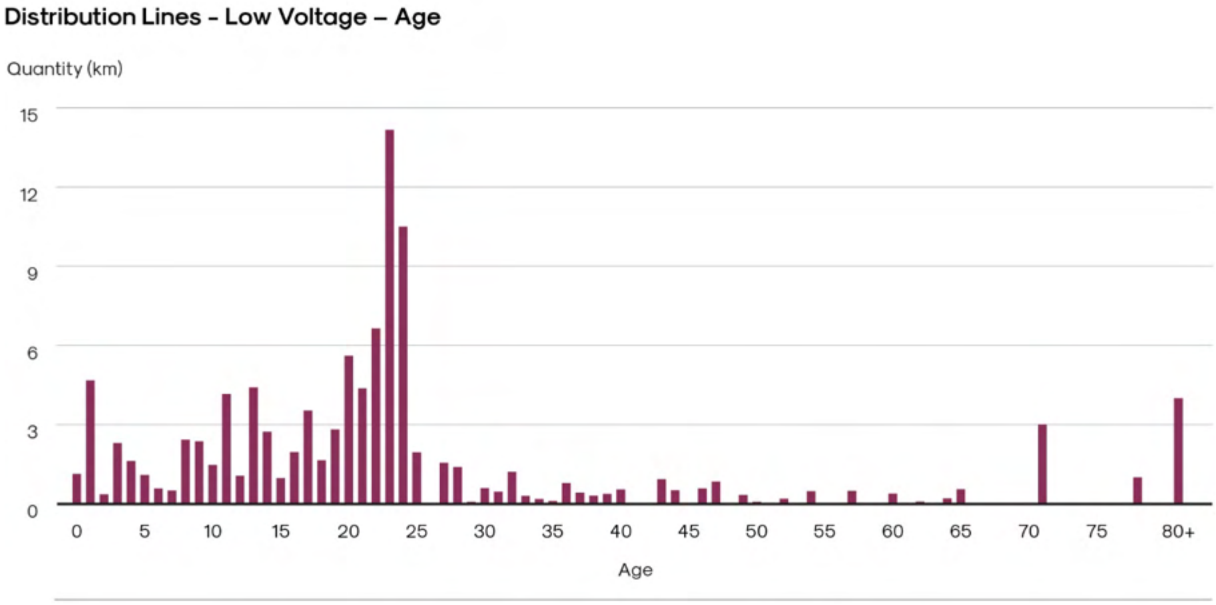


Figure 3-15 Age Profile – LV Lines

[3] Unknown LV age – 599 km

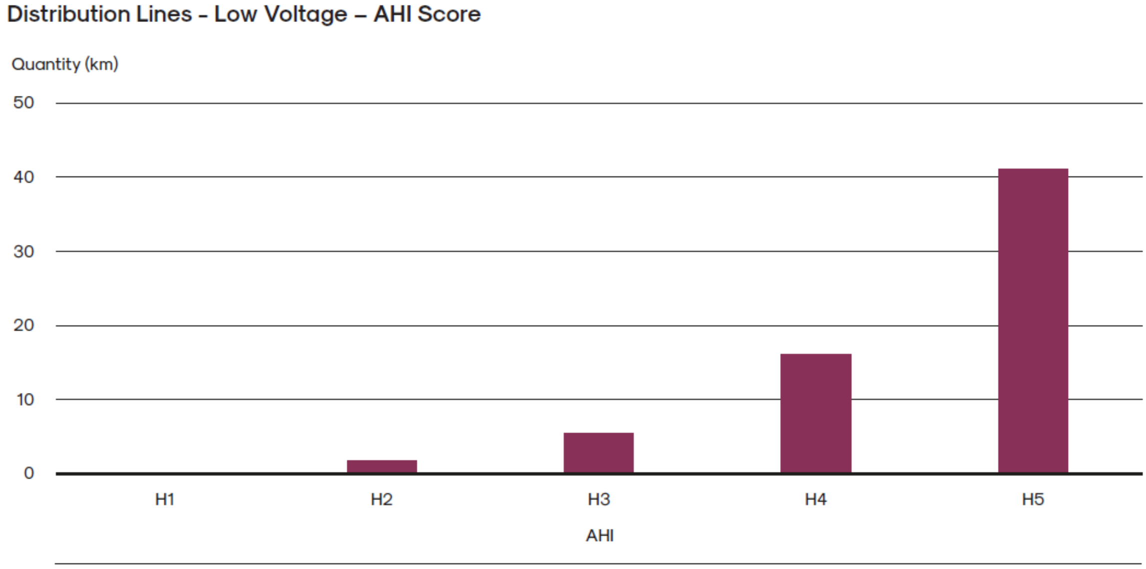


Figure 3-16 Condition Profile – LV Lines

3.4.3 Distribution Poles and Crossarms

We have 26,434 poles in our distribution system. The majority are concrete poles (93%), 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. Distribution crossarms are typically wood and steel, with a small fleet of fibreglass. The standard since 2020 installs steel crossarms for the 11 kV and 22 kV network and wood on the low voltage.

In 2020 Counties Energy standardised the 2.4m delta steel crossarm with polymer insulators for the 11 kV and 22 kV network and porcelain insulators for copper conductors if the conductor is not being replaced. This standard is to provide an increased clearance to minimise faults as a result of clashing and debris.

The age profile portrays a network undergoing significant expansion over the last 25 years and replacement over the last eight years.

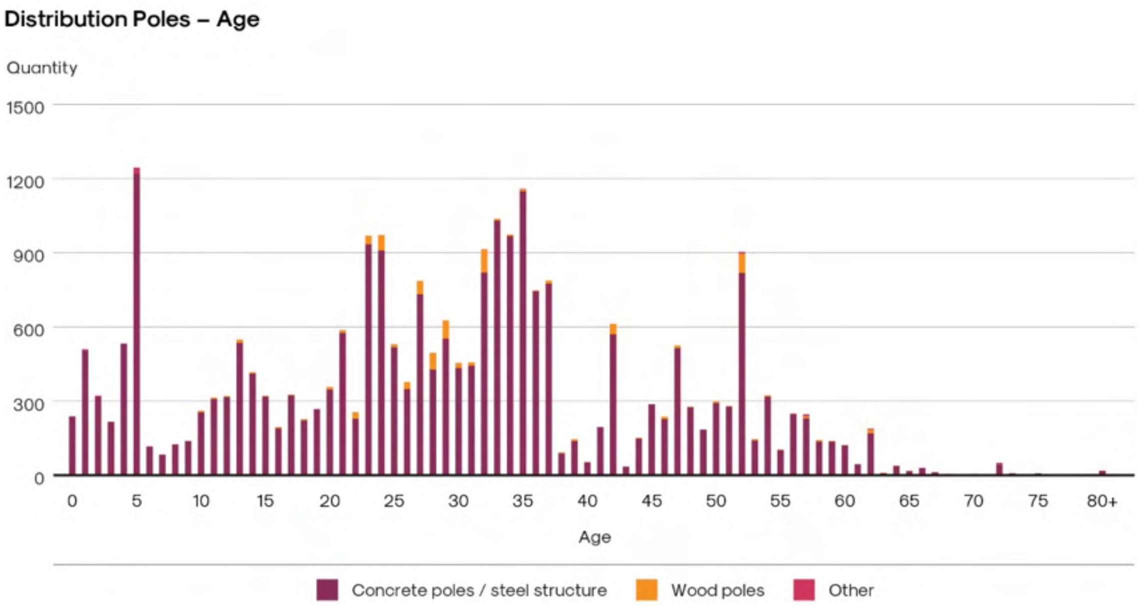


Figure 3-17 Age Profile – Distribution Poles

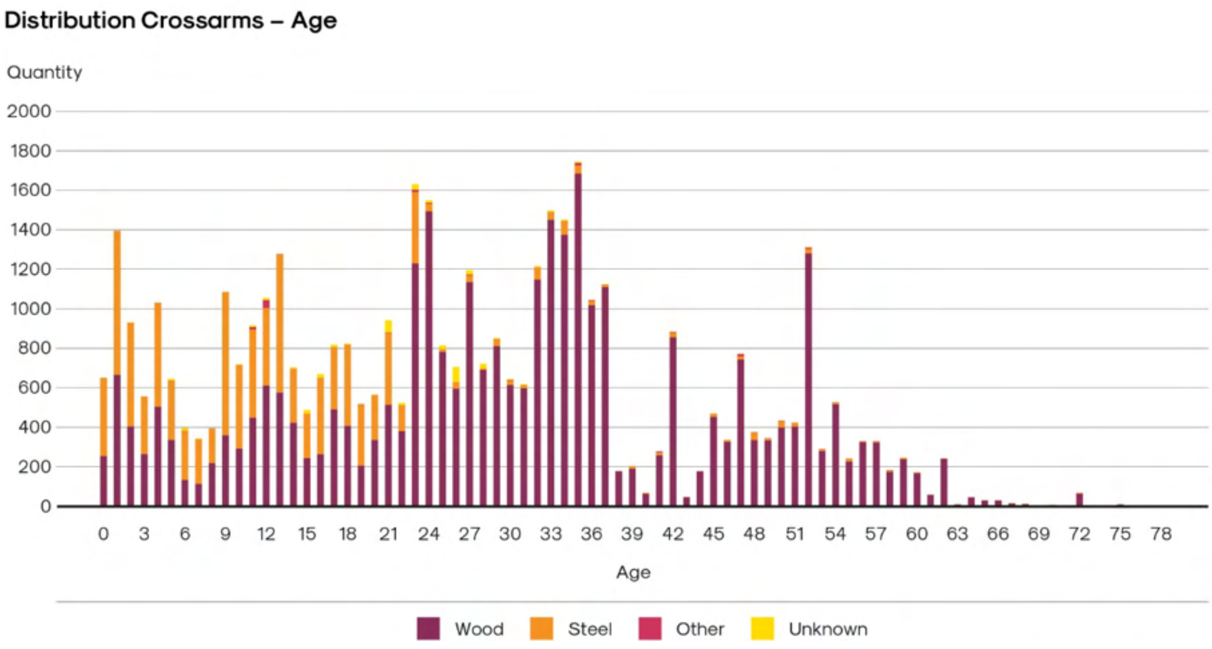


Figure 3-18 Age Profile – Distribution Crossarms

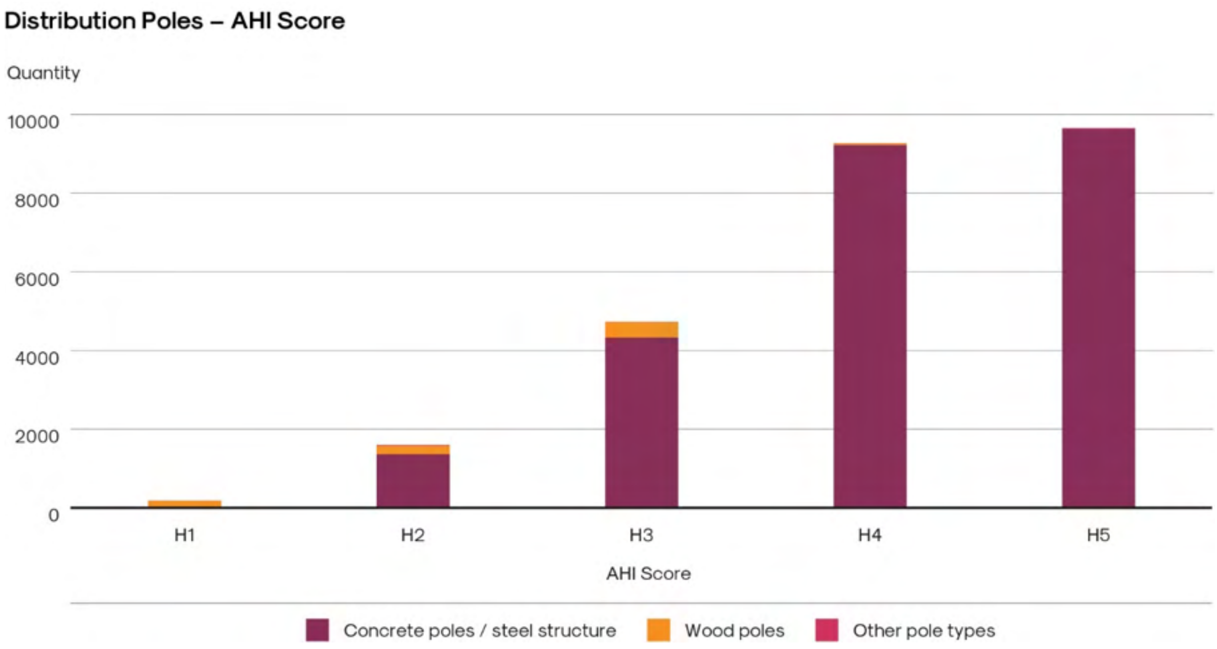


Figure 3-19 Condition Profile – Distribution Poles

3.5 Distribution and LV cables

Our distribution cables (22 kV and 11 kV) are:

- Cross-linked polyethylene (XLPE); or
- Paper insulated, lead covered (PILC).

Our 400 V cables are:

- XLPE;
- Polyvinyl Chloride (PVC); and
- PILC.

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. Most land developers require electricity to be supplied underground for new subdivisions.

Type	Quantity	Life Expectancy	Average Life
DISTRIBUTION CABLE 11 KV			
PILC	6.8 km	80 Years	33 Years
XLPE	80.68 km	55 Years	33 Years
Other	5.5 km	55 Years	33 Years
DISTRIBUTION CABLE 22 KV			
PILC	1.1 km	70 Years	19 Years
XLPE	212.3 km	55 Years	26 Years
Other	23.2 km	55 Years	26 Years
LV CABLE			
LV Cable	863.91 km	55 Years	16 Years
Street Light Cable	50.10 km	55 Years	8 Years

Table 3-6 Asset Summary – Distribution and LV Cables

3.5.1 Distribution Cable – 11 kV and 22 kV

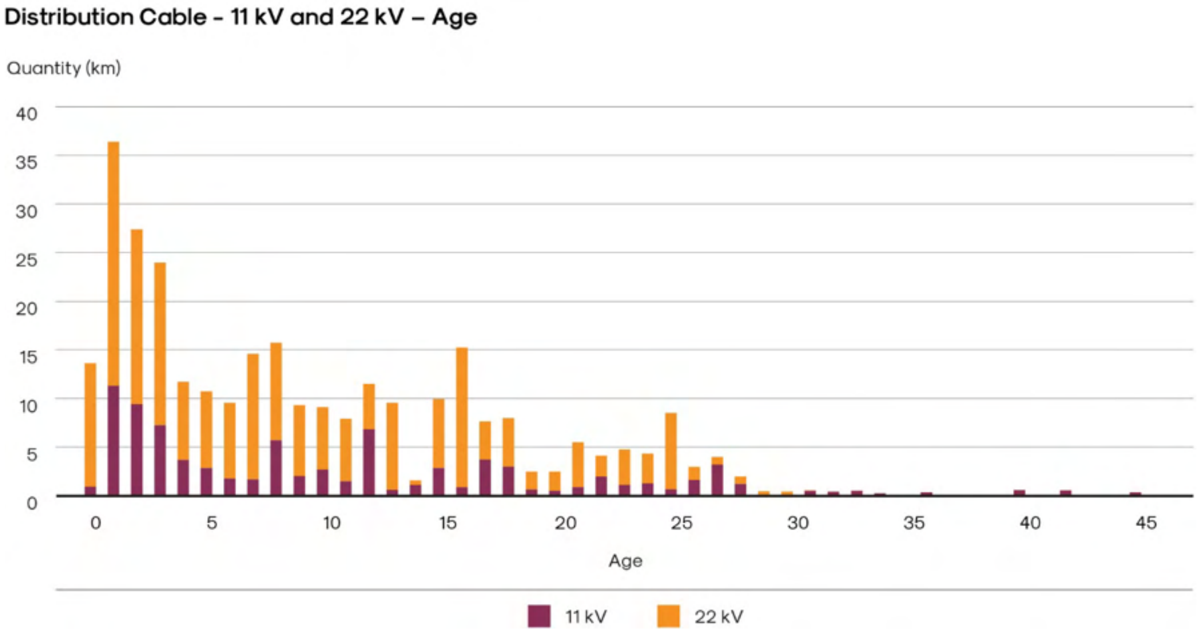


Figure 3-20 Age Profile – Distribution 11 kV and 22 kV Cable

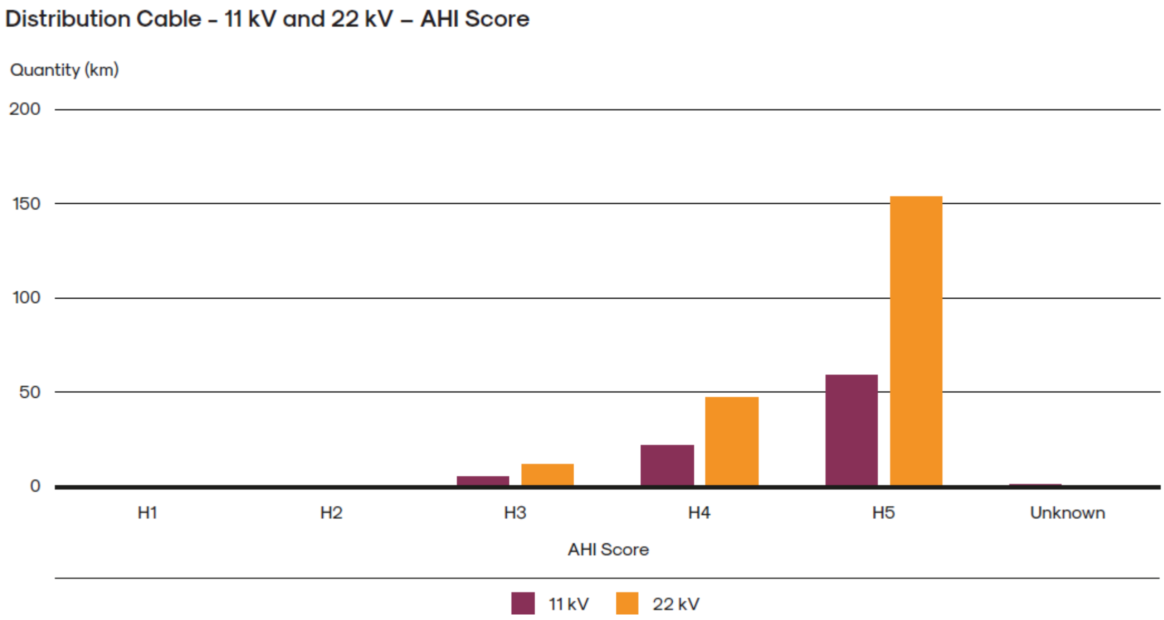


Figure 3-21 Condition Profile – Distribution 11 kV and 22 kV Cable

3.5.2 Distribution Cable – LV [4]

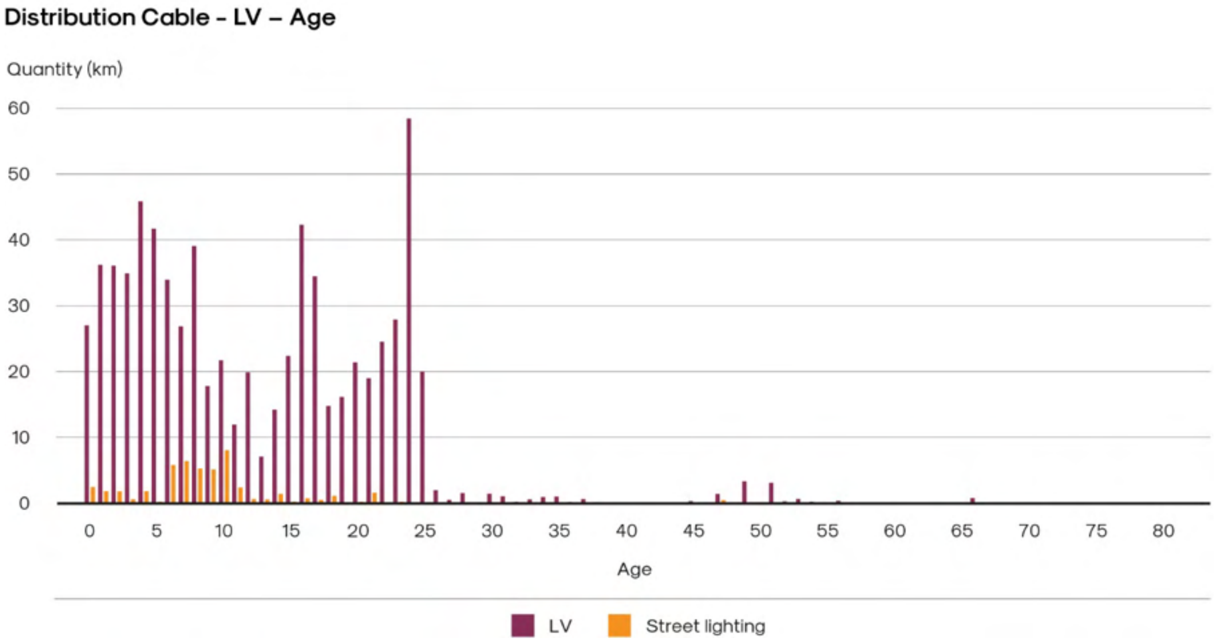


Figure 3-22 Age Profile – LV Cable

[4] Unknown LV age – 112 km

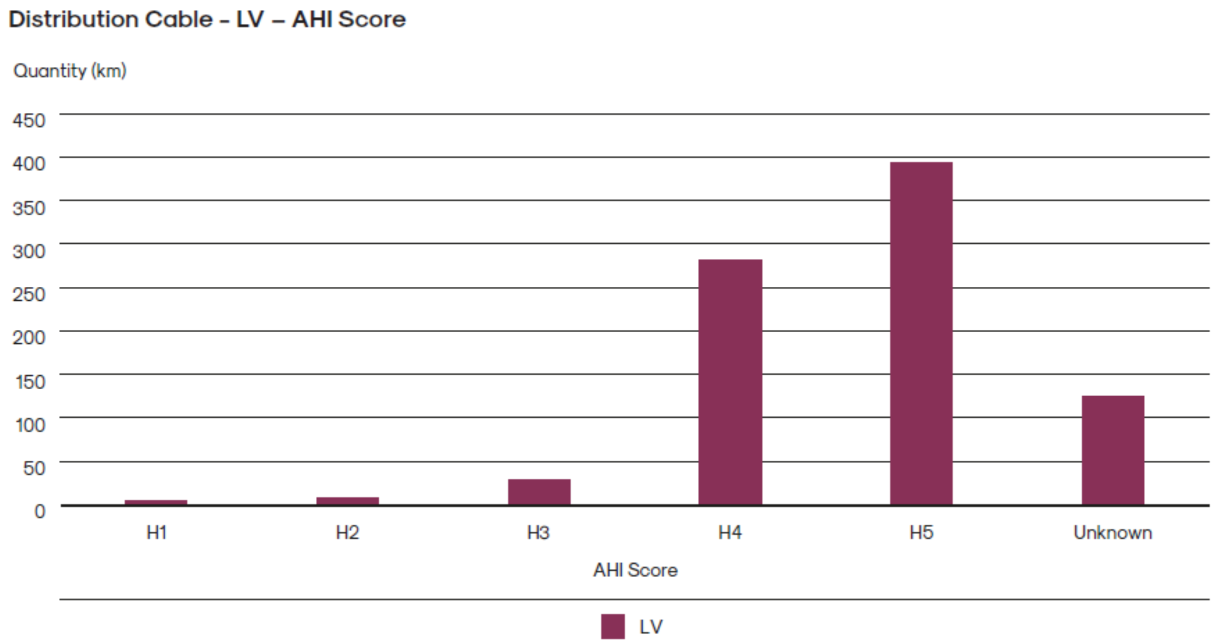


Figure 3-23 Condition Profile – LV Cable

3.5.3 LV Pillars and Pits [5]

Pillars and Pits 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 are avoided where possible in new-build situations.

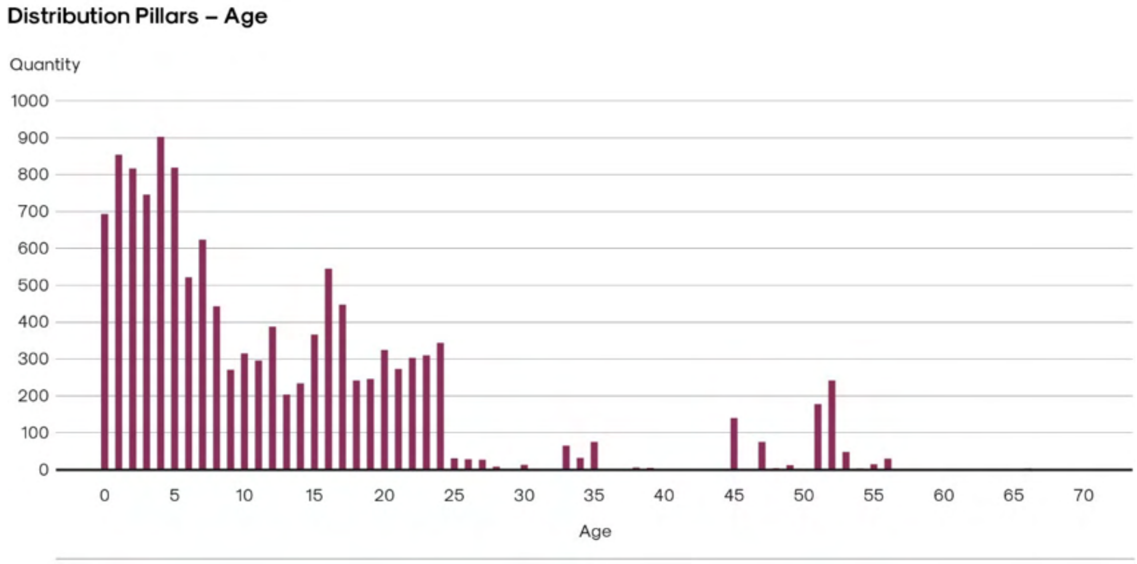


Figure 3-24 Age Profile – Distribution Pillars

[5] Unknown pillar age – 3,436

3.6 Distribution Substations and Transformers

Distribution substations accommodate transformers which step down higher distribution voltages (22 kV or 11 kV) to low voltage (400 V/230 V) 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 control and isolate the network by switching sections of distribution feeders and supply and protect transformers. This enables a network section to be de-energised for maintenance work or to isolate faulted sections of the network to minimise the impact of faults.

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

Type	Quantity	Life Expectancy	Average Life
DISTRIBUTION TRANSFORMERS			
Pole Mounted	3,159	45 Years	17 Years
Ground Mounted	985	45 Years	12 Years
22/11 KV TRANSFORMERS			
Auto Transformers	45	45 Years	11 Years

Table 3-7 Asset Summary – Distribution Substations and Transformers

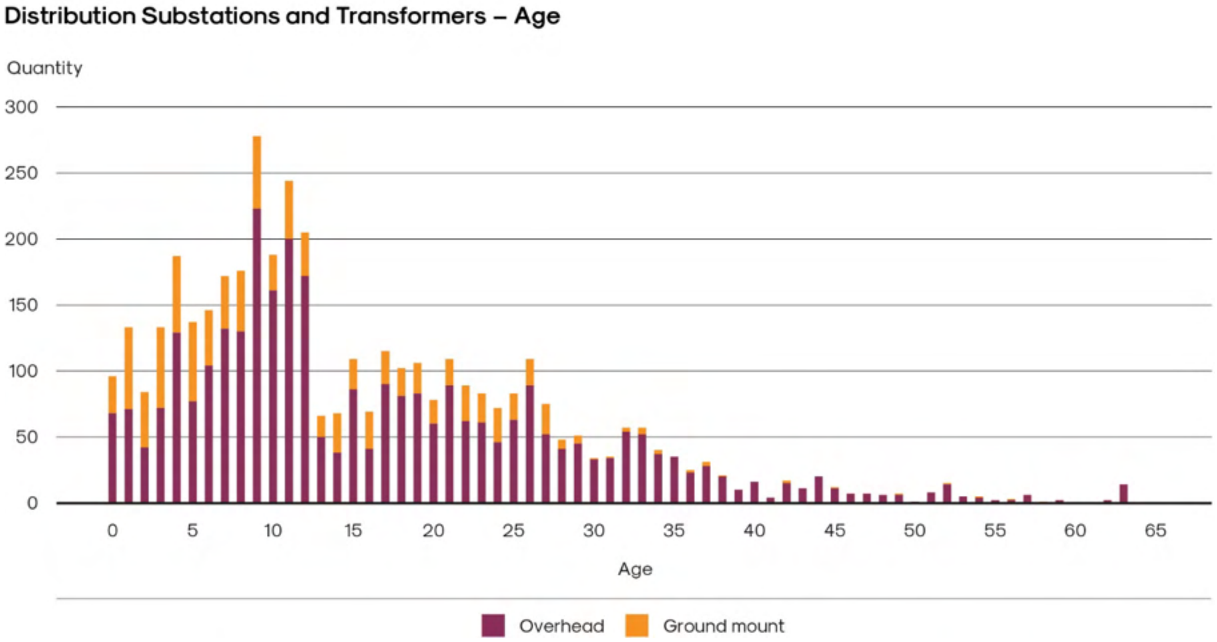


Figure 3-25 Age Profile – Distribution Transformers

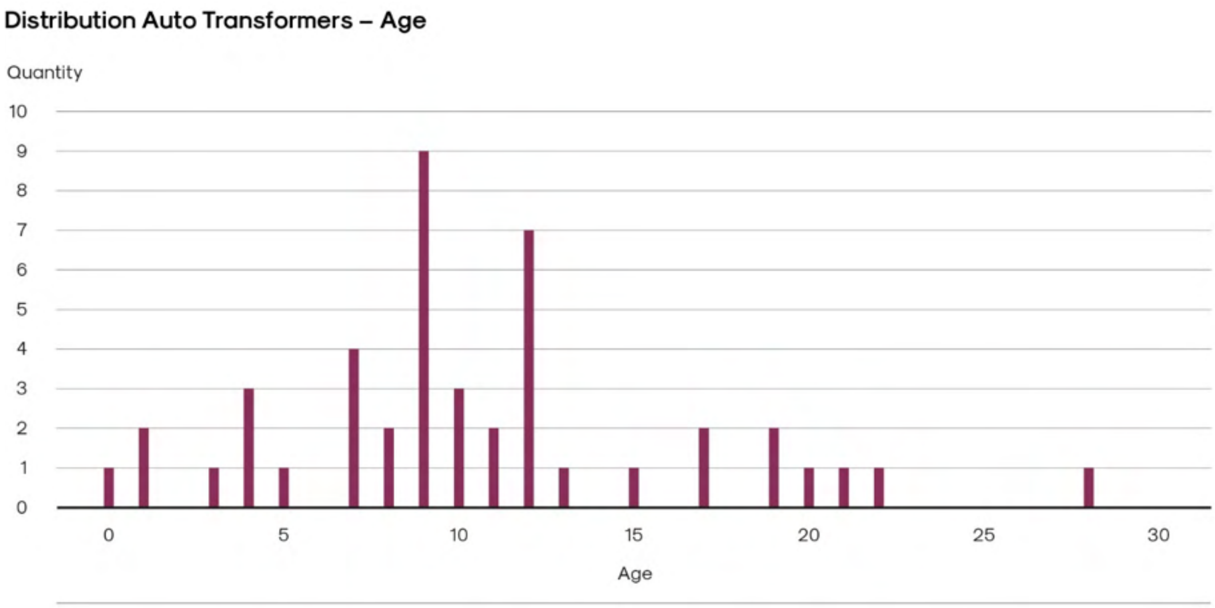


Figure 3-26 Age Profile – Auto Transformer

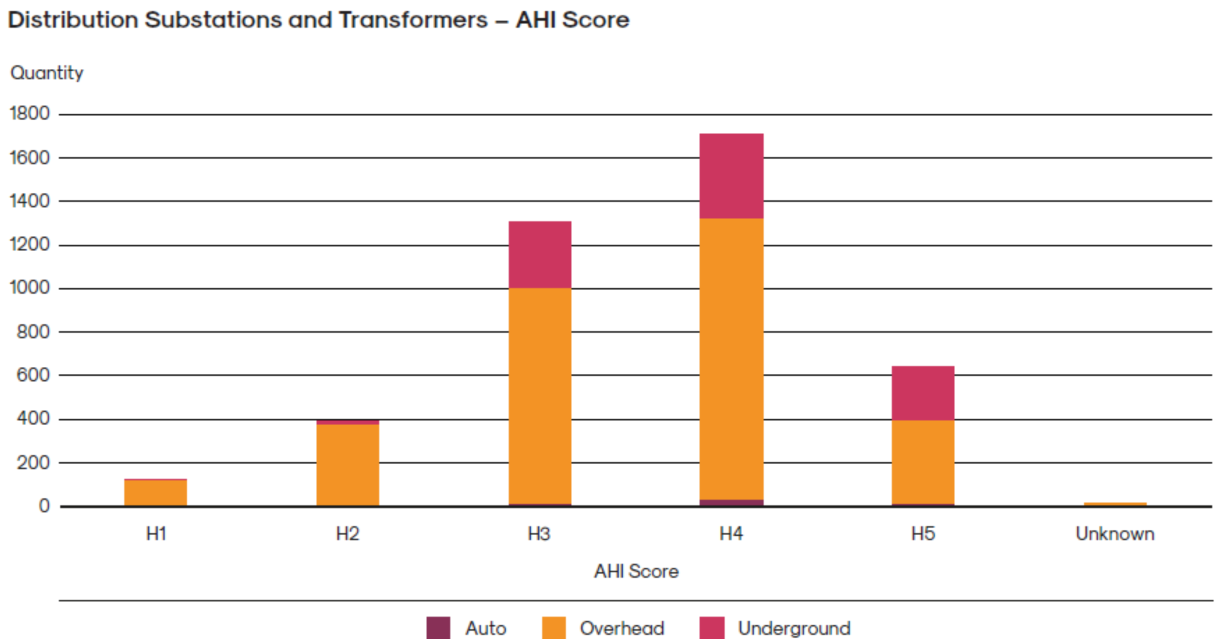


Figure 3-27 Condition Profile – Distribution Transformers

3.7 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.

We use air break switches (ABS), gas-insulated switches (GIS), reclosers and drop-out links and fuses on the overhead network.

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.

Type	Quantity	Life Expectancy	Average Life
GROUND MOUNT SWITCHGEAR			
Ring Main Units	382	40 Years	6 Years
POLE MOUNT SWITCHGEAR			
Air Break Switch (ABS)	151	35 Years	24 Years
Gas Insulated Switch	190	35 Years	7 Years
Spur Line Isolator	1566	35 Years	23 Years
Recloser	37	40 Years	11 Years

Table 3-8 Asset Summary – Distribution Switchgear

3.7.1 Distribution Ground Mount Switchgear

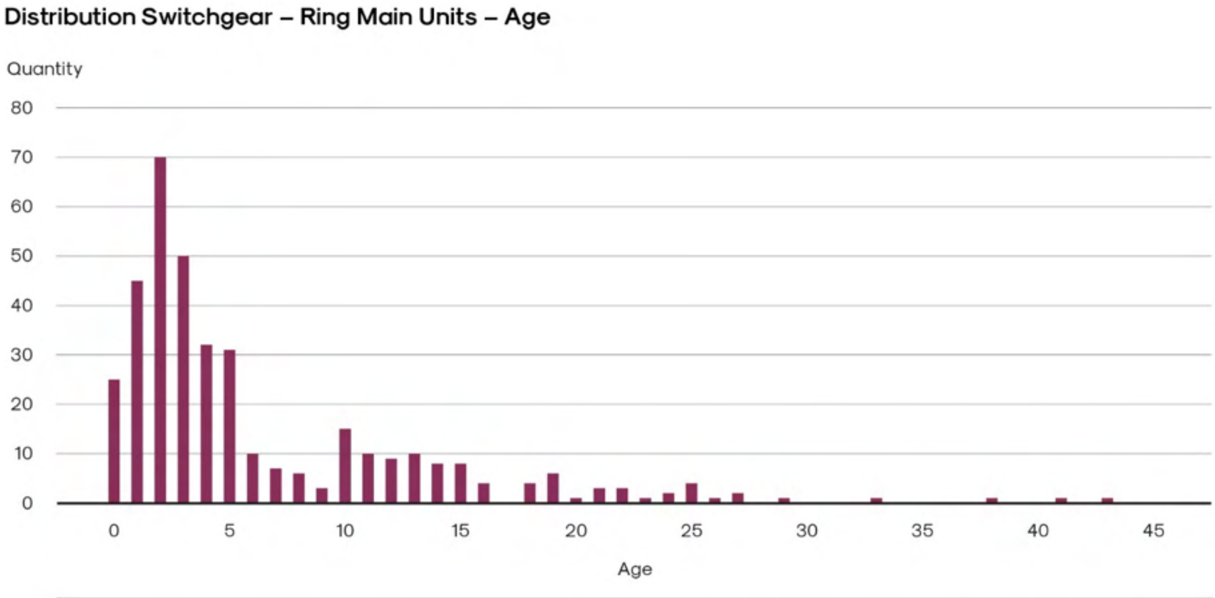


Figure 3-28 Age Profile – Ring Main Units

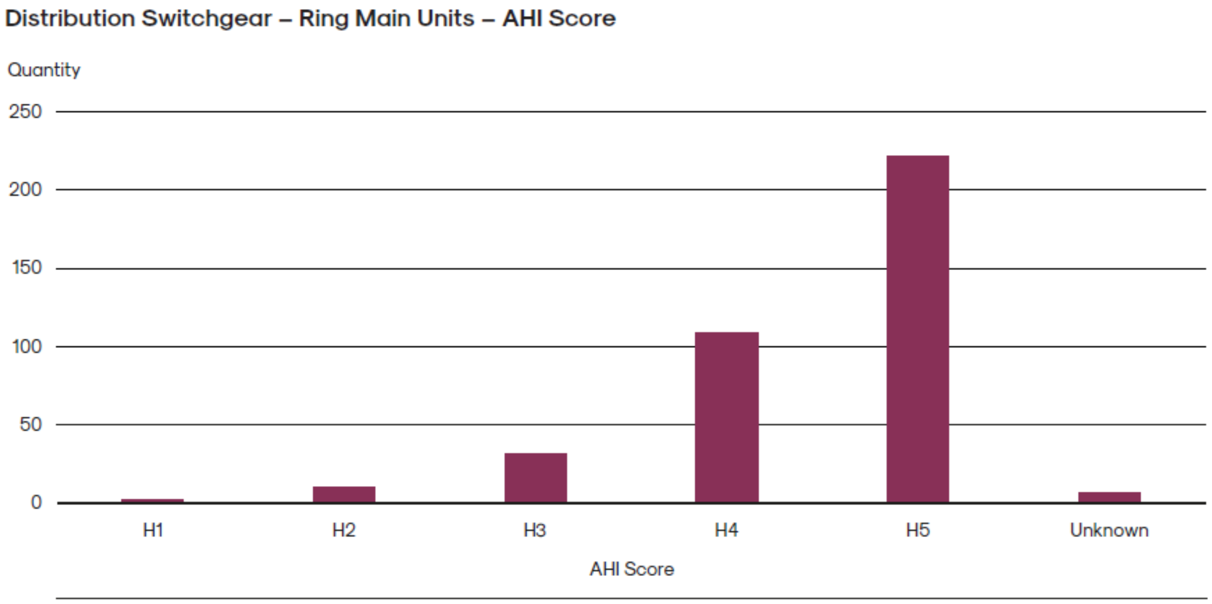


Figure 3-29 Condition Profile – Ring Main Units

3.7.2 Distribution Overhead Switchgear

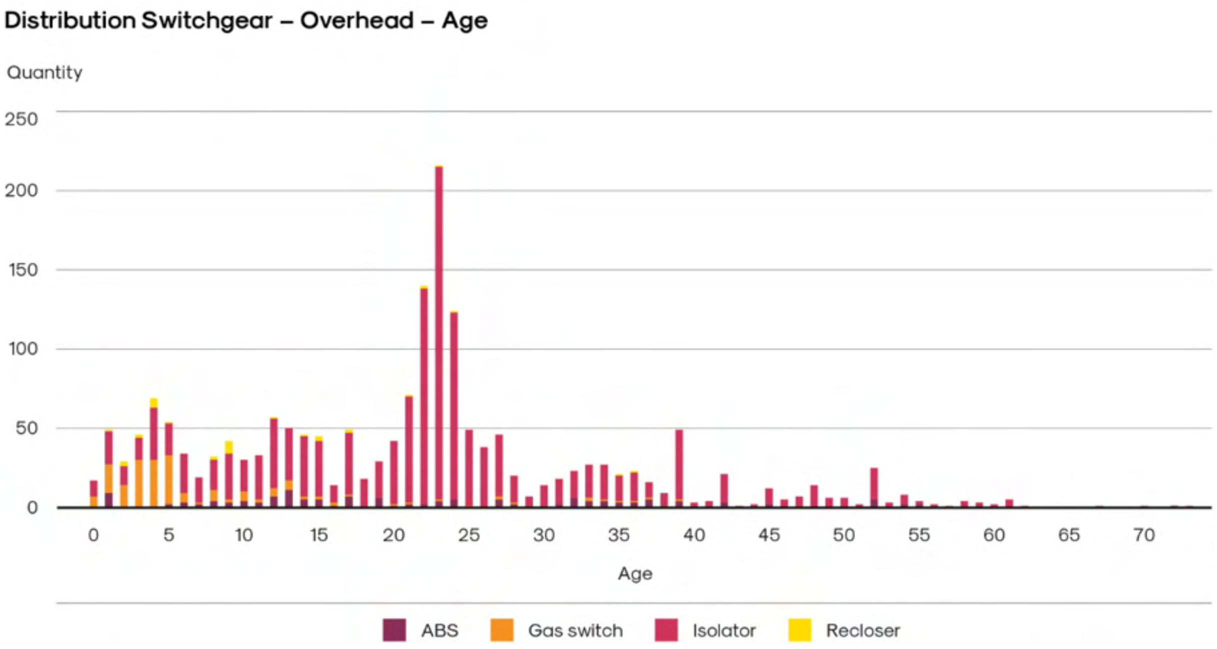


Figure 3-30 Age Profile – Overhead Switchgear

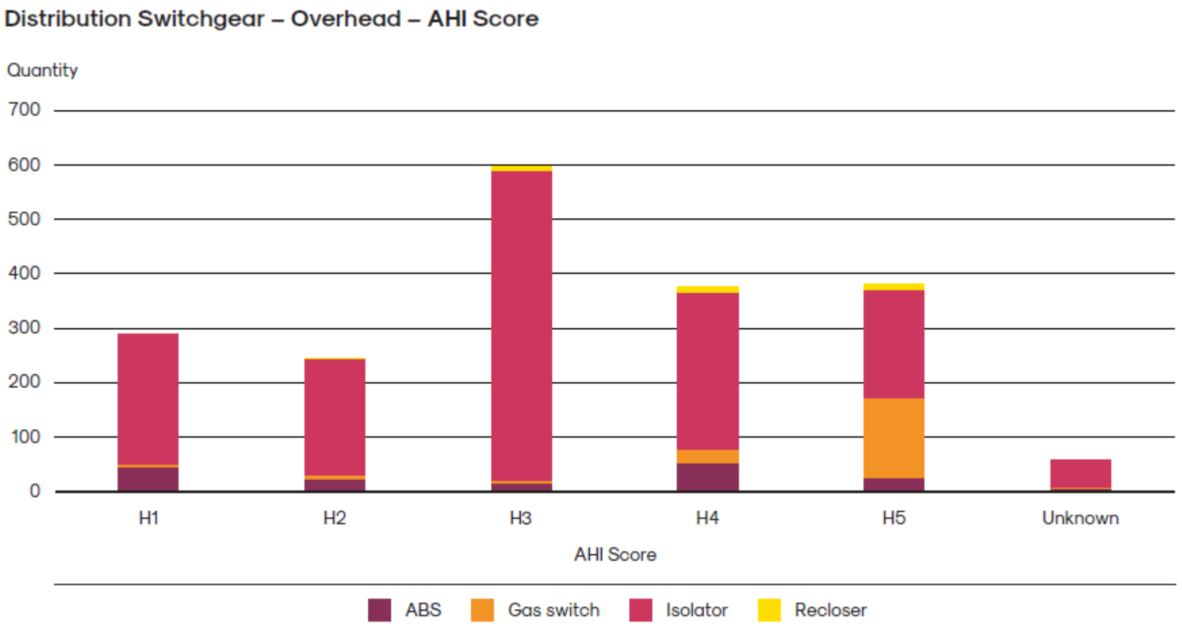


Figure 3-31 Condition Profile – Overhead Switchgear

3.8 Other Network Assets

Asset	Quantity	Life Expectancy
Capacitor Banks	19	55 Years
Voltage Regulator	15	55 Years
Protection Relays	186	40 Years
Load Control Relays	3,087	20 Years
Ripple Injection Plant	6	20 Years
Auxiliary Battery Banks	35	8 Years
Remote Terminal Units	279	15 Years

Table 3-9 Asset Summary – Other Assets

3.8.1 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 a 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 closed delta configuration and three sites of two units operating in an open delta configuration.

Voltage Regulators – Age

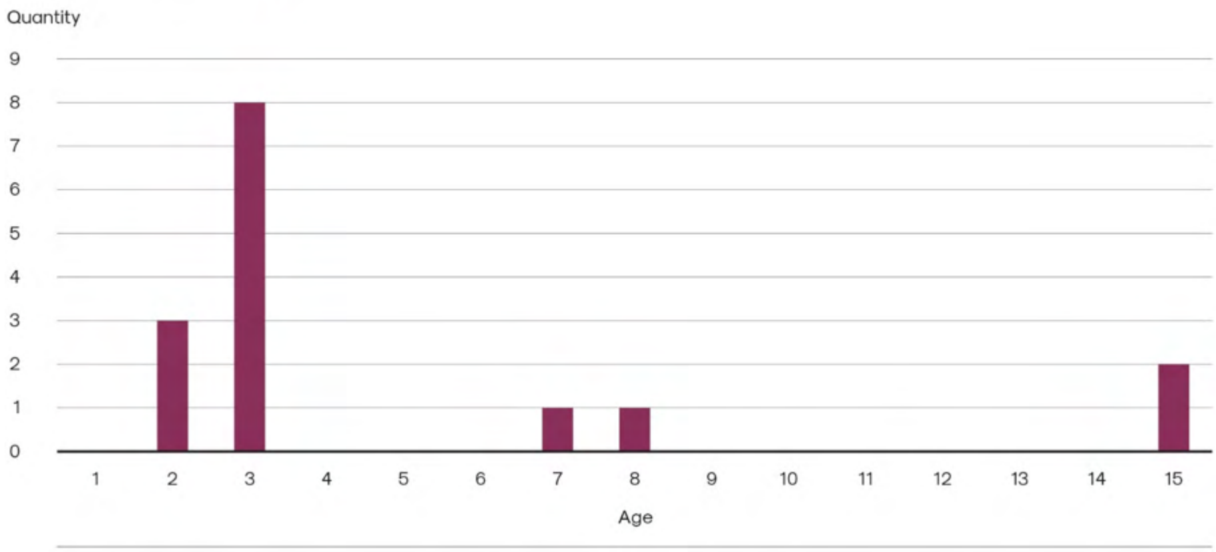


Figure 3-32 Age Profile – Voltage Regulators

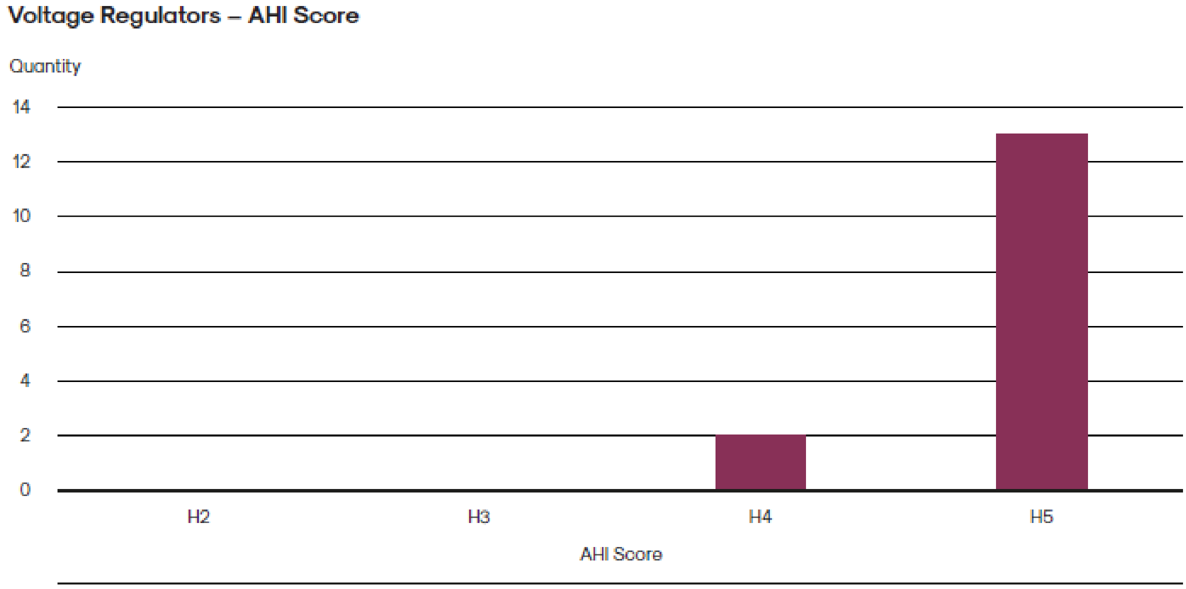


Figure 3-33 Condition Profile – Voltage Regulators

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.

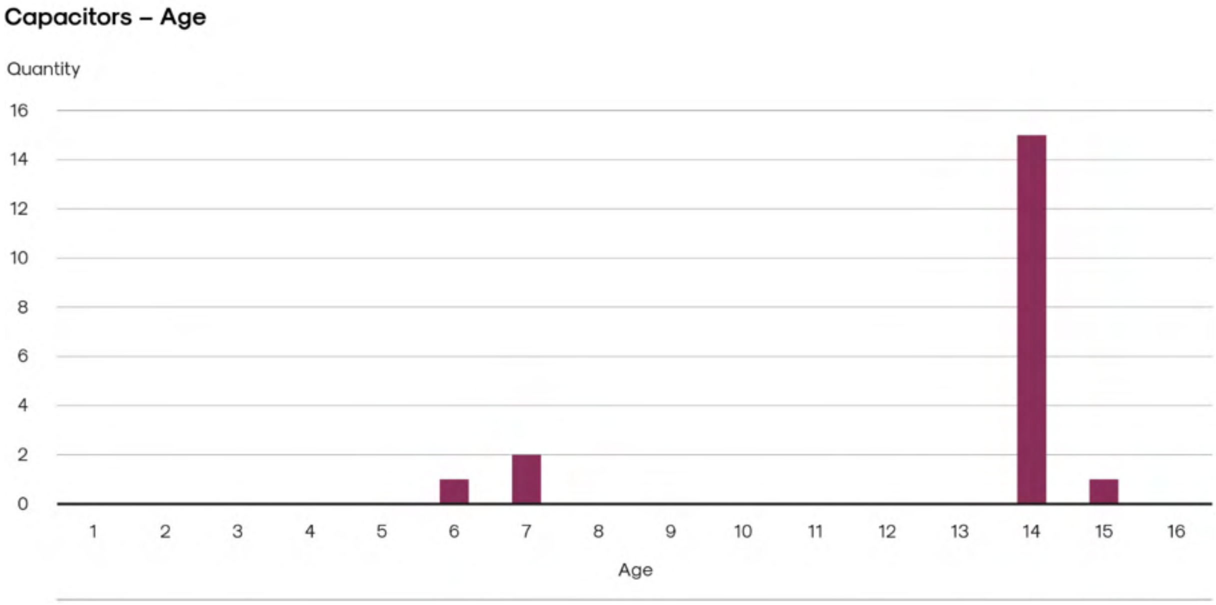


Figure 3-34 Age Profile – Capacitor Banks

3.8.2 Protection Relays

Protection relays rapidly detect and initiate the operation of circuit breakers to isolate electrical faults to ensure the safety of our employees and the public and to protect equipment from short circuits and overloads.

We have 144 protection relays installed at our zone substations and Transpower's Bombay and Glenbrook GXPs.

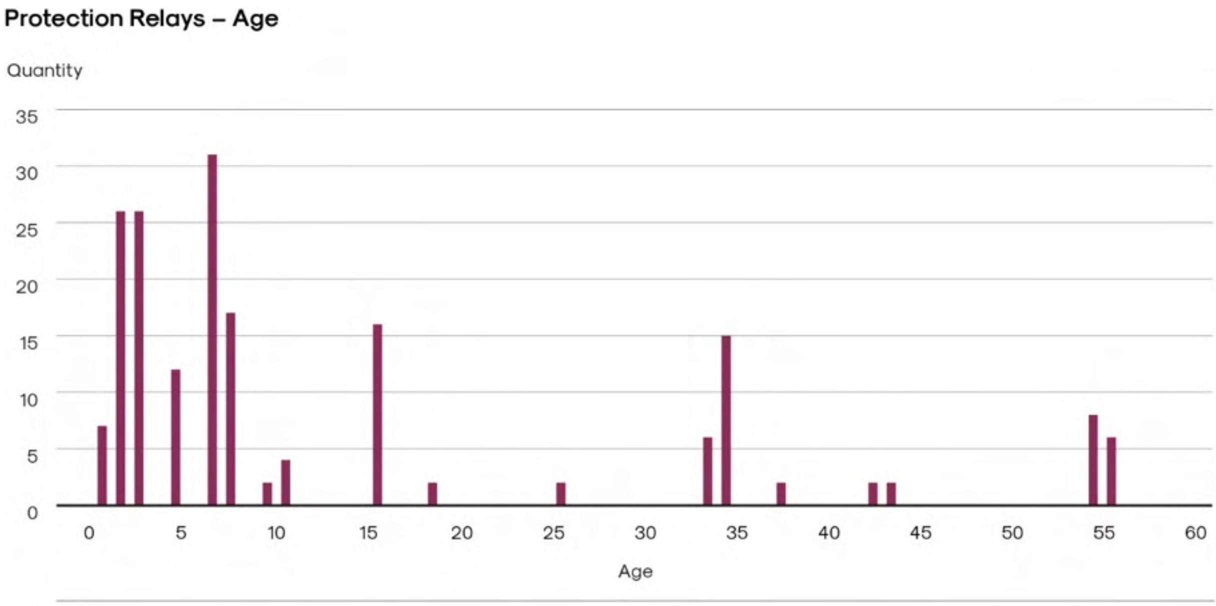


Figure 3-35 Age Profile – Protection Relays

3.8.3 Load Control Relays

We have over 3,217 load control relays associated with legacy meter installations on our network. We have reduced the number of individual load control relays by introducing smart meters on our network, which have the ripple receiver inbuilt.

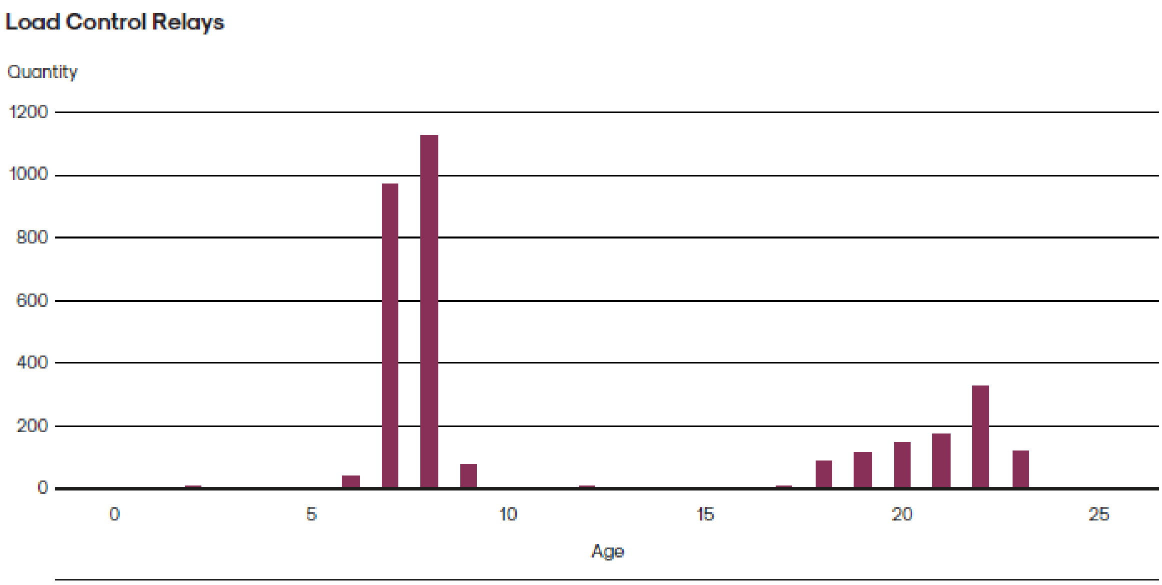


Figure 3-36 Age Profile – Load Control Relays

3.8.4 Ripple Injection Plant

Load control equipment consists of a 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 (Supervisory Control and Data Acquisition) master station to the relevant ripple injection plant(s), which sends 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. The operating frequency of our load control system is 317 Hz.

3.8.5 Auxiliary Battery Banks

110 V and 24 V 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 12 units of 110 V battery banks and 23 units of 24 V battery banks.

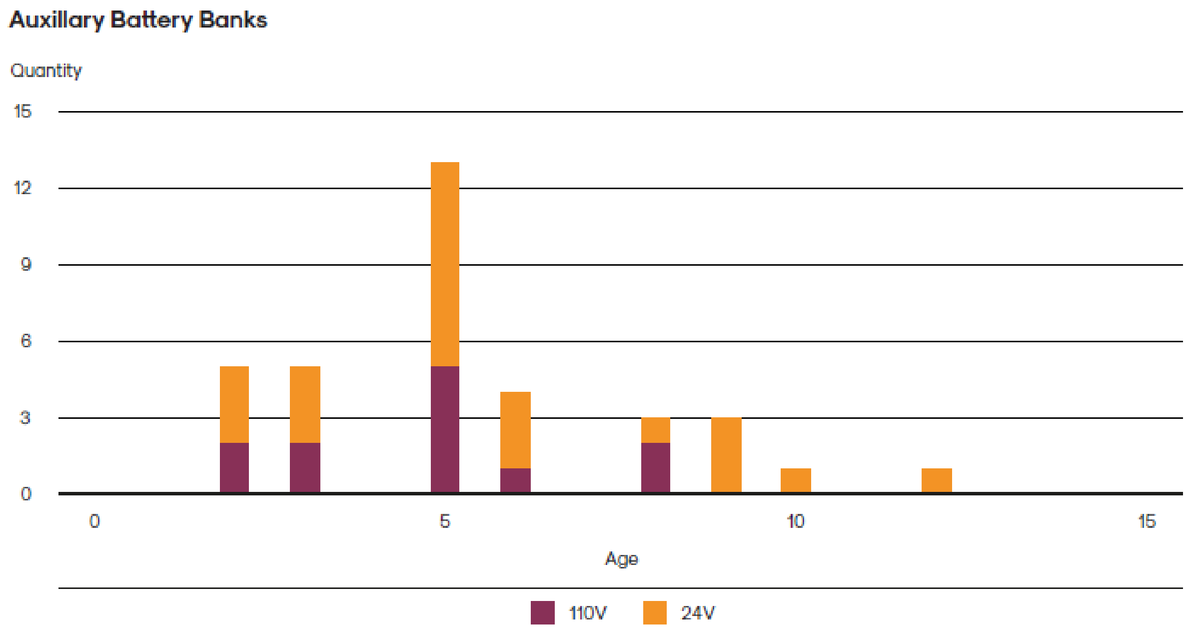


Figure 3-37 Age Profile – Auxiliary Banks

3.8.6 Remote Terminal Units

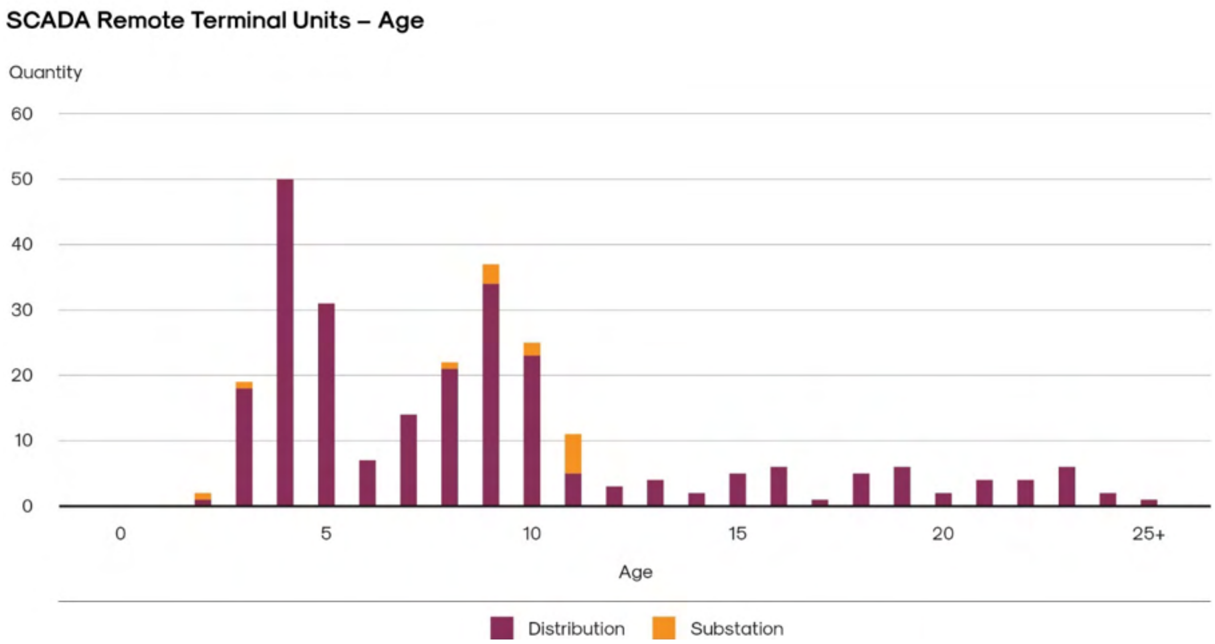


Figure 3-38 Age Profile – SCADA RTUs

3.9 Asset Summary

Type	Quantity	Life Expectancy
SUBTRANSMISSION STRUCTURES		
Concrete Poles	1352	80 Years
Wood Poles	5	45 Years
Steel Poles	184	55 Years
Other	4	55 Years
Steel Lattice Towers	10	80 Years
33 KV CONDUCTOR		
AAC	53.57 km	80 Years
ACSR	14.60 km	
CU	3.38 km	80 Years
110 KV CONDUCTOR		
AAC	62.46 km	80 Years
CU	3.46 km	80 Years
SUBTRANSMISSION CABLE		
33 kV XLPE	1.96 km	55 Years
110 kV XLPE	0.05 km	55 Years
NETWORK BUILDINGS		
Network Buildings	10	50 Years
POWER TRANSFORMERS		
110/22 kV	8	50 Years
33/11 kV	6	60 Years
CIRCUIT BREAKERS		
110 kV CBs	22	45 Years
33 kV CBs	39	45 Years
22 kV CBs	58	45 Years
11 kV CBs	38	45 Years
STATION DISCONNECTORS		
110 kV	2	45 Years
33 kV	27	45 Years
POLES		
Concrete/Steel	24,547	80 Years
Wood	1811	45 Years
Other	76	45 Years
CROSSARMS		
Wood	32,705	45 Years
Steel	9,072	80 Years
Other	282	80 Years
22 KV CONDUCTORS		
AAC	307.23 km	80 Years
AAAC	67.33 km	80 Years
ACSR	149.43 km	65 Years
Copper	50.39 km	80 Years

Type	Quantity	Life Expectancy
11 KV CONDUCTORS		
AAC	281.17 km	80 Years
AAAC	121.28 km	80 Years
ACSR	351.85 km	65 Years
Copper	142.28 km	80 Years
LV CONDUCTOR		
LV Conductor	700.03 km	80 Years
DISTRIBUTION CABLE 11 KV		
PILC	6.77 km	80 Years
XLPE	80.68 km	55 Years
Other Types	5.75 km	55 Years
DISTRIBUTION CABLE 22 KV		
PILC	1.06 km	70 Years
XLPE	212.31 km	55 Years
Other Types	23.6 km	55 Years
LV CABLE		
LV Cable	863.91 km	55 Years
Street Light Cable	50.10 km	55 Years
DISTRIBUTION TRANSFORMERS		
Pole Mounted	3,159	45 Years
Ground Mounted	985	45 Years
22/11 KV TRANSFORMERS		
Auto Transformers	45	45 Years
GROUND MOUNT SWITCHGEAR		
Ring Main Units	382	40 Years
POLE MOUNT SWITCHGEAR		
Air Break Switch (ABS)	151	35 Years
Gas Insulated Switch	190	35 Years
Spur Line Isolator	1566	35 Years
Recloser	37	40 Years
OTHER		
Capacitor Banks	19	55 Years
Voltage Regulator	15	55 Years
Protection relays	184	40 Years
Load Control relays	3,087	20 Years
Ripple injection plant	6	20 Years
Auxiliary Battery Banks	35	8 Years
Remote Terminal Units	279	15 Years

Table 3-10 Asset Summary

4.0 Service Levels

4.0 Service Levels

4.1 Stakeholder and Customer Engagement

We continue to focus on stakeholders and customers through our Customer Strategy, the purpose of which is to reimagine energy in ways that improve and simplify our customers' lives today while quietly and ambitiously preparing for a future of rapid change.

We make things better by simplifying how our community interacts with us, providing choice and focusing on what's important to them.

A key part of our customer strategy is gaining valuable customer insights through customer research, referred to below as **'Get to know me'** – one of six pillars in our customer strategy.

Figure 4-1 Customer Strategy Summary

4.1.1 Customer Engagement

This section outlines the different surveys we have used in the last 12 months to keep in close contact with our customers and the insights we have gained to improve our service to the community we serve.

4.1.2 Annual Quantitative Survey

This is managed by a specialist market research firm that surveyed over 400 customers by phone. The annual survey monitors customer experience and satisfaction with services provided by Counties Energy. Key topic areas include the reliability of supply, image and reputation, value for money and communication.

The latest survey was carried out in March 2022, soon after Cyclone Dovi hit in February. Besides the usual satisfaction questions, we used this opportunity to ask customers how we could do better in a storm situation. Key insights included an omnichannel approach to customer communications, more regular updates, and a preference for updates via SMS.

For the first time in this annual survey, we asked customers what they thought we should focus on for Counties Energy's sustainability programme. Most customers (76%) want us to focus on health and safety, while 64% see our people's wellbeing as another focus area. Not surprisingly, waste management (64%) and reducing emissions (64%) were also rated highly.

4.1.3 Targeted Customer Interviews

We conducted individual interviews with customers online in March and April 2022 to delve deeper into their Cyclone Dovi experience. This was the first time we had commissioned qualitative research into a storm response, and the detailed feedback has shaped our priorities and list of improvements.

Despite Counties Energy managing the storm response well overall, there were pockets of customers with less-than-ideal experiences – mainly those who were without power the longest. These were the customers we surveyed to identify what we need to do to lift our game.

Compared to qualitative outage research carried out in August 2021, the Cyclone Dovi research showed us that customer expectations had changed drastically – people were less tolerant, and levels of uncertainty, stress and vulnerability were higher. With life lived mainly online during multiple lockdowns, their expectation of an essential utility is now on par with what they expect from all top-performing companies: excellent service and timely communication enabled by smart technology.

We've made several technological and communication changes because of the Cyclone Dovi research. To further improve the customer experience, we are currently scoping two projects that will kick off in 2023 that aim to minimise customer disruption caused by storms and outages.

4.1.4 Monthly Surveys with Customers who Have Engaged with Our Customer Services Team

A sample of customers who contact us about a service (e.g. new connections, faults, electrical inspections or disconnections, locating a cable) are surveyed monthly. Results are tracked on the following KPIs:

- Efficiency lodging an issue;
- Satisfaction with the time taken to deal with the issue and with the final outcome;
- Our employees understands the query;
- Satisfaction with the arrangements made; and
- Communication with people on the job.

These surveys complement the extensive annual survey and act as an early warning system for any potential operational issues that require improvement.

4.2 Customer Service

This section outlines our core customer services objectives, initiatives and targets.

4.2.1 Objectives

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

4.2.2 Initiatives

- Ensure that 100% of customer feedback is captured within our customer management system, both positive and negative;
- 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 an updated self-service web application;
- Measuring the actual time to deliver our services against customer satisfaction levels, relating to time to complete;
- Regular pulse surveys of customers, seeking feedback on all facets of our service;
- Achieve 100% compliance with Utilities Disputes performance measures (formerly the Electricity and Gas Complaints Commission – EGCC) scheme;
- Engage with electricity retailers to ensure that customer contact details are provided through the Electricity Information Exchange Protocols to allow for efficient notification of planned and unplanned outages; and
- Pursue all opportunities to update customer contact information so that our customers can benefit from notifications of planned and unplanned outages via the most efficient communication methods.

4.2.3 Planned and Unplanned Communication Process

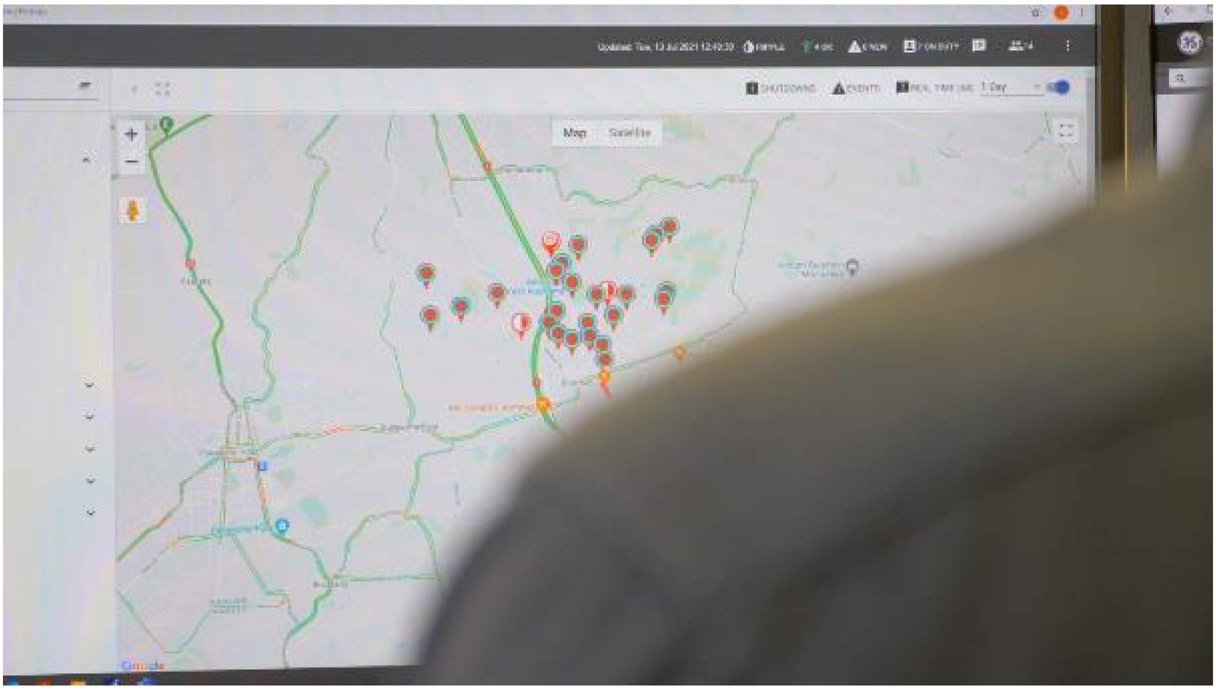
Planned Outages

We engage directly with connected consumers for all communication relating to planned outages, rather than this being an electricity retailer activity. All outage planning, notification, and other customer interactions relating to outage planning activities are tracked and managed within our customer management system, Salesforce.

We recognise that email is the preferred method of contact for most customers, and this is our primary communication method. Where requested, we also have the facility to provide notification via conventional mail. In rare cases where the electricity retailer has not provided an email address, and we do not hold an email address for the connected party, the conventional mail service is used.

Our minimum notification requirements are as follows:

- Standard planned outages: Email or post sent no less than 10 business days from the outage date; and
- Reactive planned outages (urgent repairs): Email or post sent no less than four business days from the outage date.



A view of INDI, our outage management system

For customers that utilise email, a reminder notification is sent one business day prior to the planned outage date. We also use email to communicate with customers relating to any changes, such as confirmation of a shift to the alternative date, cancellations, and any ad-hoc changes leading up to, and during, any planned outages. Our web app “Outage Hub” also displays all current information relating to any advertised planned outage.

Due to the increased impact of planned outages on some medically dependent customers, schools, childcare centres, and some major customers, for these customers an additional pre-engagement step is made during the planning stages, prior to formal notification of any planned outage.

Unplanned Outages (faults)

We are fortunate to be the majority Metering Equipment Provider (MEP) within our network area, and almost all our meters are smart meters. This provides us with real-time monitoring of 95% of all meter stations on our network, where the data connects with our in-house outage management system, known as INDI or "Infrastructure and Network Data Interface".

Our web app "Outage Hub" connects with INDI, and summary real-time outage detail and response information is displayed to users. Outage Hub users have the option to subscribe to change notifications relating to any unplanned outage that affects their property. Our app also allows customers to report an outage or other issues with their power supply.

4.2.4 Targets

Description	Target
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.
Service Feedback	95% of service feedback is resolved within 10 business days of submission; 100% within 20 business days.
Quality of Supply Complaint	Advise outcome of investigations, nature of issue and timing of intended remedial action (if required) within 10 business days after receipt of the complaint.
Service Response	Answer an average of 80% of calls within 20 seconds (major weather events excluded) and acknowledge or resolve customer-driven service requests via email by the next working day.
Planned Outages	95% of planned outages are advertised at least 10 business days before the outage occurs. 100% of planned outages are advertised at least four business days before the outage occurs.
Unplanned Outages	Resolve 95% of unplanned outages: Urban = 4 hours Rural = 6 hours

Table 4-1 Targets

4.3 Workplace Safety

Counties Energy Limited (CEL) is committed to reaching Zero Harm across every aspect of our business by conducting our operations in a manner that enables the safety and wellbeing of everyone every day.

At CEL, we believe that our long-term success depends on our ability to keep our workforce, business partners, suppliers, subcontractors, community and the environment safe. Nothing we do is so vital that it cannot be done safely.

For us, Zero Harm means no injury, ill health or incident caused by our work activities.

4.3.1 Leading Indicators

With cross-team collaboration, there has been an upskilling and emphasis on on-site and contractor auditing, with both active site and office-based audits. This increased auditing regime has helped to identify and promote focused safety improvements and engagement.

Additionally, Network Operations have been using a 'Living and Breathing the Basics' series of safety-related topics to dive into high-risk areas. Topics are all aligned with their associated critical risk category, and with the Counties Energy Limited and Electrical Engineers Association definitions of critical risk.

The 11 Critical Risks are all subjected to the Bow tie hazard analysis. The controls identified that need improving are fed out from this process to the Network Operations and Network teams.

Leading Indicators

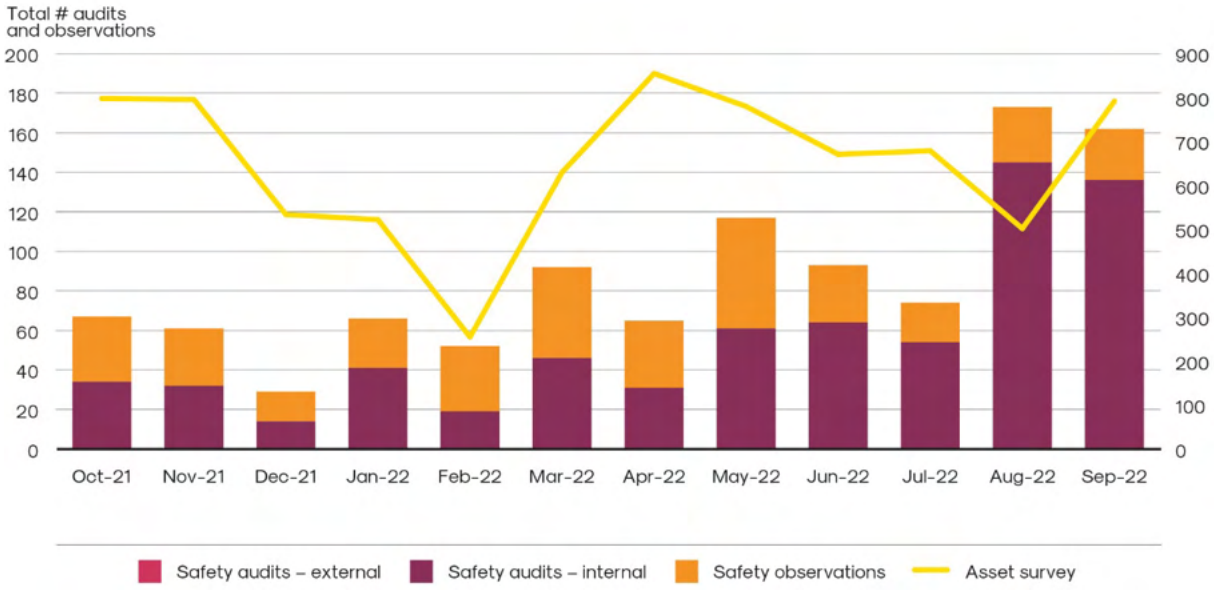


Figure 4-2 Leading Indicators

4.3.2 Lagging Indicators

We continue to review and implement learnings from incident trends and data analysis.

Our **Lost Time Injury Frequency Rate (LTIFR)** and **Total Recordable Injury Frequency Rate (TRIFR)** reflect lost time incidents over the past 12 months. Incidents were investigated, improvements were implemented with changes, and learnings were notified to the business. While essentially the LTIs were of a minor nature, Covid restrictions limited CEL's ability to redeploy employees to alternative duties as access to offices, warehousing and yard areas was not possible. We continue to grow and stretch in the safety space by constantly considering what we can improve and do differently.

Lost Time Injury Frequency Rate – Low Impact
(12 Month Rolling Average (per million hours worked)

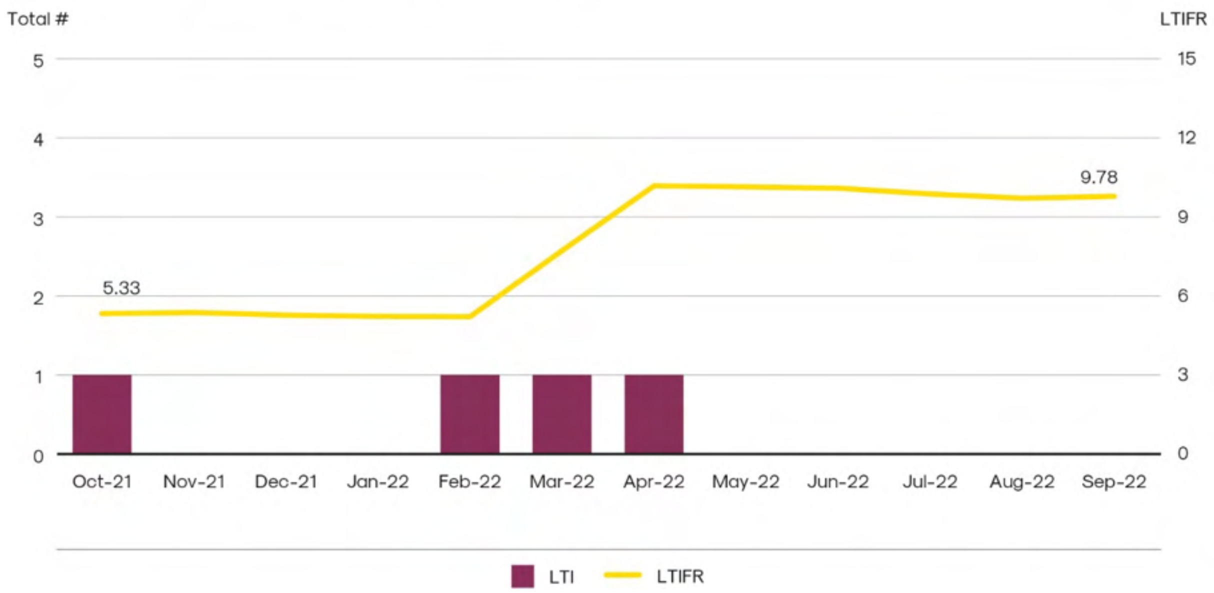


Figure 4-3 Lost Time Injury Frequency Rate (LTIFR) 12 Month Rolling Average (per million hours worked)

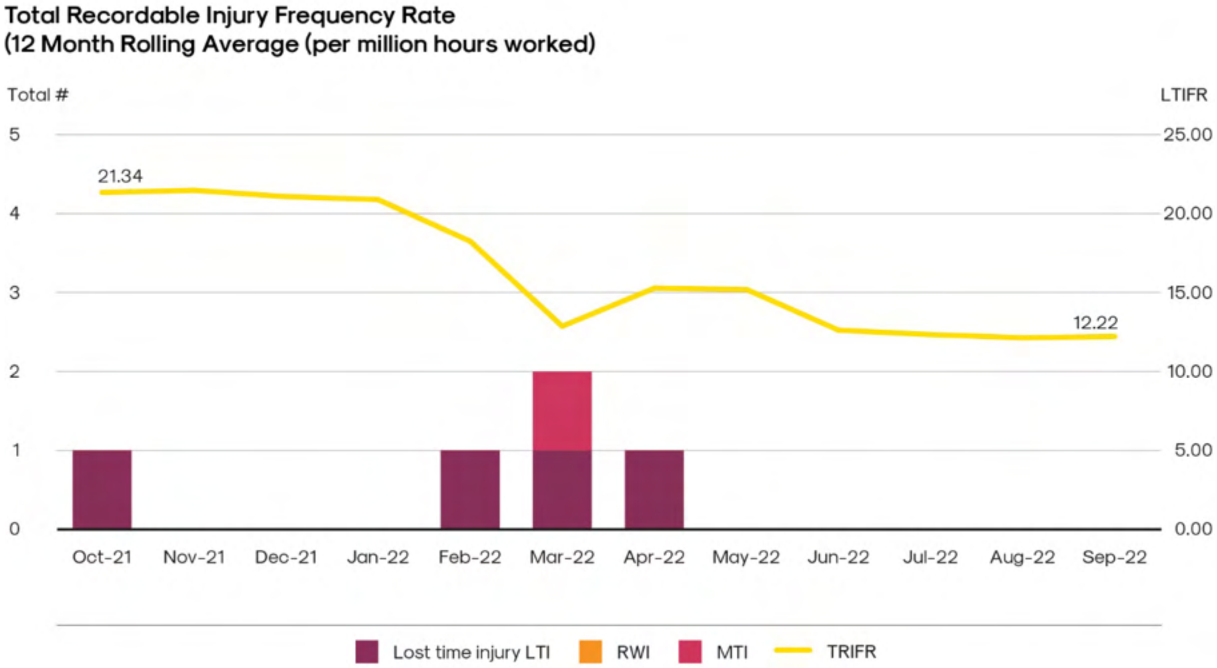


Figure 4-4 Total Recordable Injury Frequency Rate (TRIFR) 12 Month Rolling Average (per million hours worked

4.4 Public Safety Measures and Targets

Our objective is to ensure that our network assets harm no member of the public and that hazards introduced by our network assets are controlled to minimise the risk to be as low as reasonably practicable.

4.4.1 Leading Indicators

Categories for leading public safety indicators include:

- The number of asset inspections and tests undertaken on:
  - High-risk asset categories in the public domain – pillars, transformers, high-voltage switchgear, poles, and zone substations;
  - Safety-critical assets – earthing and protection systems; and
  - Assets in unique locations – those located around schools, public recreation spaces, commercial and shopping areas.
- The time taken to repair high-risk defects on the network (percentage completed within required timeframes); and
- The number of external stakeholder engagement activities.

4.4.2 Lagging Indicators

Lagging indicators include:

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

The actual performance for FY22 to FY23 is shown in the table below.

Details	FY21	FY22	FY23 to Sept
Damage to Network or Customer Assets	193	232	65
Reported Public Injuries from Network Assets	1	0	0

Table 4-2 PSMS Lagging Indicators

4.5 Reliability

4.5.1 Objectives

We are committed to continuously improving our network reliability and have made substantial improvements. We also recognise there are still more improvements to be made. For full details of our Reliability Strategy, refer to section 6.2.

4.5.2 Targets

SAIFI and SAIDI targets have been set based on the following:

- Recent performance of the network;
- Research presented to the Counties Energy Board on network reliability; and
- A forecast of planned outage requirements, which is based on investment programmes (outlined in the Asset Management Plan), and the expected reliability improvements from these investments.

Unplanned Outages

The below tables outline our service level targets from FY23 to FY28.

For unplanned SAIFI/SAIDI, we use the DPP3 normalisation methodology (for full details, please refer to our Reliability Philosophy in section 6.1).

Unplanned	FY23	FY24	FY25	FY26	FY27	FY28
Average number of interruptions per Customer (SAIFI)	1.921	1.861	1.788	1.721	1.678	1.636
Average minutes without electricity per Customer (SAIDI)	100.11	101.31	97.52	94.33	91.94	89.61

Table 4-3 Unplanned SAIFI/SAIDI Service Levels FY23–FY28

Our service levels for SAIFI and SAIDI relate to outages originating on the Counties Energy network and do not include outages originating from networks owned by other parties such as Transpower, other EDBs or privately owned service lines. The service levels are also exclusive of the full impact of major events such as extreme weather events.

The table below shows the recent performance against our unplanned outage service levels for FY22 and the first half of FY23 (to the end of September 2023). For FY23, the service levels used are year-to-date linear of those set out in Table 4-3 above.

Unplanned	Average number of interruptions per Customer (SAIFI)		Average minutes without electricity per Customer (SAIDI)	
	FY22 (full year)	FY23 (to end Sep)	FY22 (full year)	FY23 (to end Sep)
Service Level	1.919	0.963	104.29	50.19
Actual	2.705	1.254	147.89	65.78
Variance	+0.786 (+41%)	+0.291 (+30.2%)	+43.6 (+41.8%)	+15.59 (+31.1%)

Table 4-4 Unplanned SAIFI/SAIDI Service Levels Performance FY22 and FY23

A full analysis of unplanned outages can be found in Chapter 6.0.

Our recent performance from FY17–FY22 and forward targets to FY28 are shown below, in Figure 4-5 for SAIFI and Figure 4-6 for SAIDI. This is shown using the DPP3 method across all years to provide a consistent comparison.

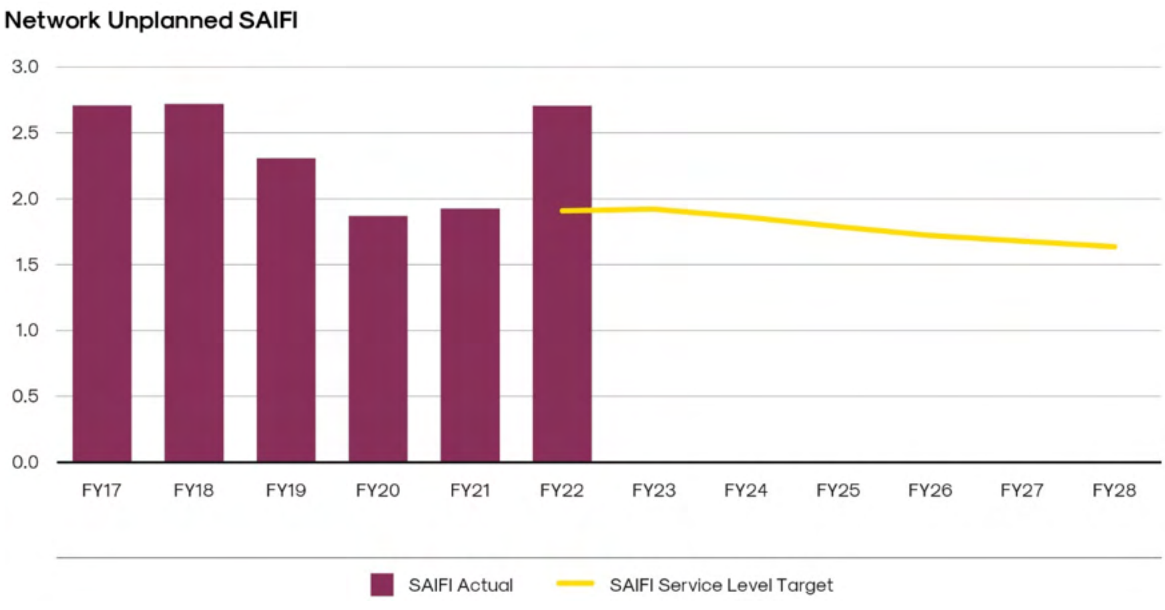


Figure 4-5 Unplanned SAIFI Service Levels Actuals FY17–FY22 and FY23–FY28 Targets

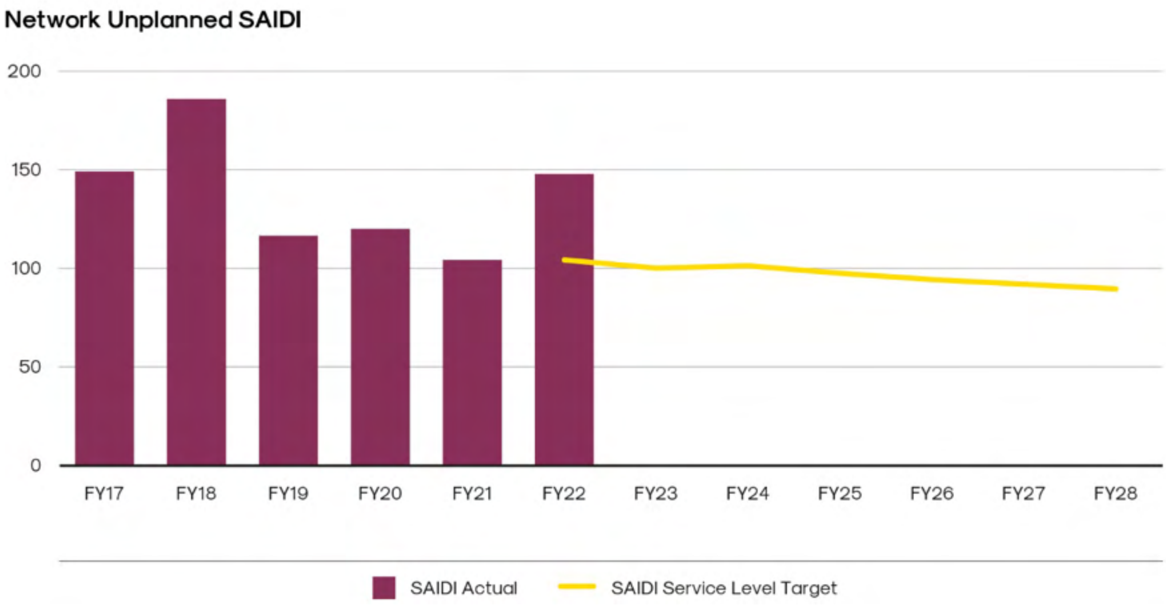


Figure 4-6 Unplanned SAIDI Service Levels Actuals FY17–FY22 and FY23–FY28 Targets

Planned Outages

The below tables outline our service level targets from FY23 to FY28.

For Planned SAIFI/SAIDI, we use the ID methodology (for full details please refer to our Reliability Philosophy in section 6.1).

Planned	FY23	FY24	FY25	FY26	FY27	FY28
Average number of interruptions per Customer (SAIFI)	0.543	0.719	0.656	0.738	0.790	0.754
Average minutes without electricity per Customer (SAIDI)	176.15	188.49	168.04	194.89	216.20	203.03

Table 4-5 Planned SAIFI/SAIDI Service Levels FY23–FY28

As with unplanned, our service levels for SAIFI and SAIDI relate to outages originating on the Counties Energy network and do not include outages originating from networks owned by other parties such as Transpower, other EDBs or privately owned service lines.

The table below shows the recent performance against our planned outage service levels for FY22 and the first half of FY23 (to the end of September 2023). For FY23, the service levels used are year-to-date linear of those set out in Table 4-5 above.

Planned	Average number of interruptions per Customer (SAIFI)		Average minutes without electricity per Customer (SAIDI)	
	FY22 (full year)	FY23 (to end Sep)	FY22 (full year)	FY23 (to end Sep)
Service Level	0.600	0.272	180.00	88.32
Actual	0.475	0.390	150.37	121.30
Variance	-0.125 (-20.8%)	+0.118 (+43.4%)	-29.63 (-16.4%)	+32.98 (+37.3%)

Table 4-6 Planned SAIFI/SAIDI Service Levels Performance FY22 and FY23

Planned outages were lower than expected in FY22 during the long periods of COVID-19 alert level restrictions, which reduced our ability to complete work. Some of this work flowed over into FY23, which is reflected in the YTD result.

Our recent performance from FY17–FY22 and forward targets to FY28 are shown below, in Figure 4-7 for SAIFI and Figure 4-8 for SAIDI. This is shown using the ID method across all years to provide a consistent comparison.

Our forward planned SAIFI/SAIDI targets set out in this section are based on a long-range forecast of future planned outages we believe we will need in order to deliver our 10-year investment programmes set out in this Asset Management Plan. These programmes have in turn been determined to be in the long-term interests of our customers – enabling renewal, growth, reliability improvement or customer-initiated connection or relocation works.

To derive these forecasts, we have analysed the last 18 months of actual planned SAIFI/SAIDI performance, comparing against the actual investment spend delivered. It is noted that this varies by investment type, recognising that works on our overhead network typically require a greater volume of planned outages than works on underground networks, and that substation or control systems projects may require almost zero planned outages. Additionally, future years have reductions applied based on our approach to continuously look for ways to reduce the impact of planned outages to our customers – through better works programme coordination, work scheduling and outage management.

Further detail on our Planned Outages Philosophy can be found in section 6.1.6, and further detail on our Planned Outage strategy can be found in section 6.2.2).

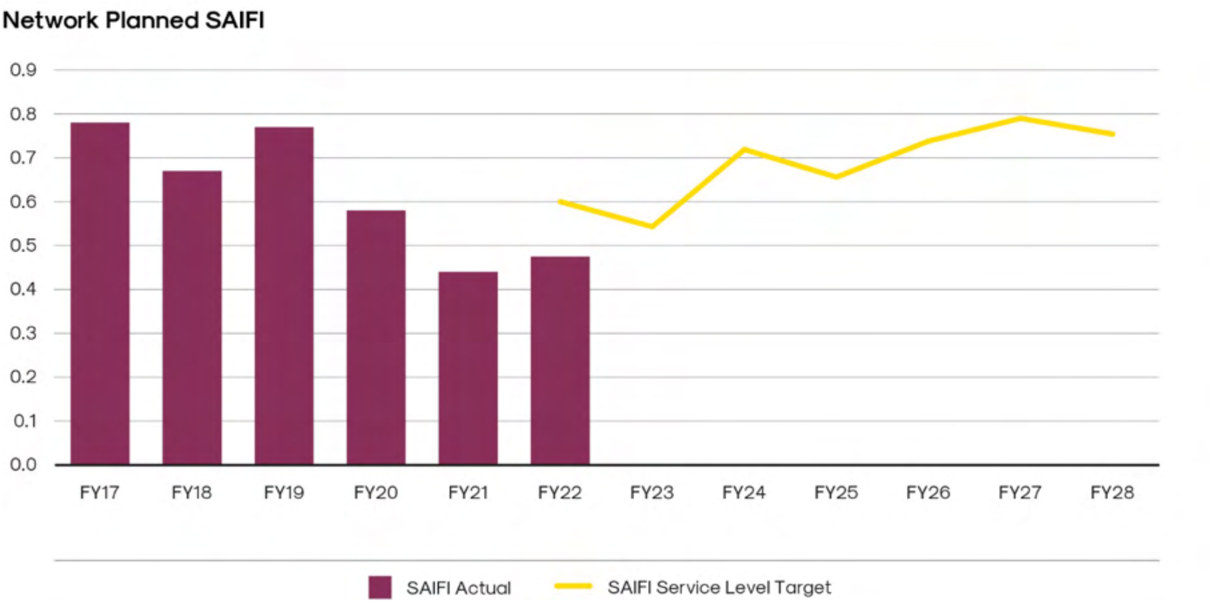


Figure 4-7 Planned SAIFI Service Levels Actuals FY17–FY22 and FY23–FY28 Targets

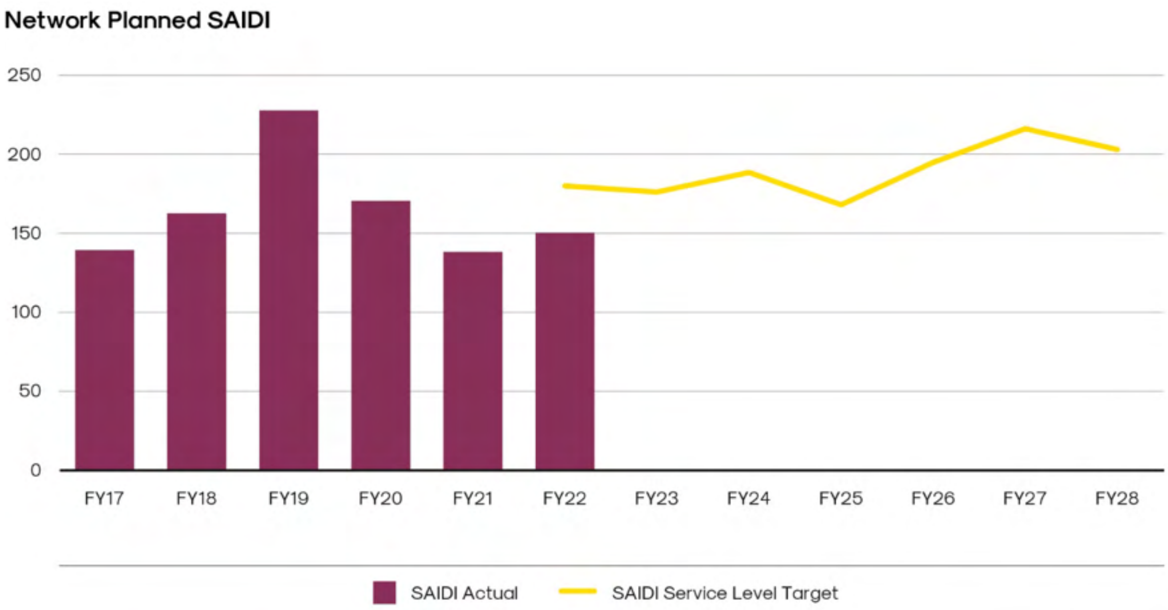


Figure 4-8 Planned SAIDI Service Levels Actuals FY17–FY22 and FY23–FY28 Targets

4.6 Economic Efficiency

4.6.1 Objectives

- Effectively and efficiently manage the network to have a low cost to serve;
- Reduce losses on the network; and
- Reduce capital expenditure by deferring investments through increased utilisation of assets (load factor).

4.6.2 Initiatives

- Continuous improvement in works delivery model and processes to reduce costs;
- Investigate new technology options for reduced whole-life costs;
- Investigating the option of a Distributed System Operator to actively manage capacity and asset utilisation; and
- Identify non-technical network losses, including theft and faulty customer power meters.

4.6.3 Targets

Cost to Serve – Operating Expenditure

To deliver on our vision of having cost-effective supply of electricity to our consumers, it is important that we have efficient operating costs. We measure operating costs per consumer and system length. We aim to be at or below the industry average for our peer group and to ensure that our asset management and business operating decisions do not drive unnecessary costs into the business. The cost has increased in recent years as a result of inflationary pressures, wages and IT related cost such as cyber security.

Our performance and targets are shown in the table below.

	2020	2021	2022	2023+ Target
Operating Cost per ICP	$362	$399	$415	$513

Table 4-7 Operating Cost per ICP

	2020	2021	2022	2023+ Target
Operating Cost per km	$4,672	$5,181	$5,429	$6,884

Table 4-8 Operating Cost per km

Network Losses

We aim to keep our losses at or below the industry average. Our traditional network was predominantly rural, with small urban areas of moderate consumer density; thus, our electricity losses tended to be higher than average. However, losses have been kept close to the industry average by gradually upgrading the primary distribution voltage to 22 kV and the subtransmission voltage to 110 kV. Using these higher operating voltages, together with the network architecture we have implemented, has contributed to reducing losses. Our deployment of smart meters and consequential installation audits have reduced non-technical unaccounted for energy losses due to the replacement of faulty legacy meters and better identification of power theft.

Our performance and targets are shown in the table below.

	2020	2021	2022	2023+ Target
Loss Ratios	4.8%	5.4%	4.9%	less than 5.0%

Table 4-9 Loss Ratios

Network Utilisation

Network Utilisation is another crucial aspect of operating an economically efficient electricity network and ensuring that our distribution network has been constructed to meet consumer demand but does not have too much excess capacity built-in. Load Factor is an important measure of utilisation as it compares the installed transformer capacity to the demand at peak times. Improving the Network Utilisation (Load Factor) allows Counties Energy to defer capital expenditure through accommodating growth using existing assets.

Our performance and targets are shown in the table below.

	2020	2021	2022	2023+ Target
Network Utilisation	57%	54%	61%	60%

Table 4-10 Network Utilisation

High levels of growth have been experienced from both industrial/commercial developments and new multi-stage residential subdivisions. Thus, significant works have been carried out, which have created a headroom of installed distribution capacity ahead of the uptake in demand driven by new customer connections. This customer-driven demand growth is expected to be compounded because of decarbonisation, particularly in transport and industrial process heating.

Counties Energy is investigating distribution system operator functionality to better utilise the network capacity. This is through monitoring the network's infrastructure capacity in real-time load and utilisation of flexible loads to reduce peak demand in real-time when any aspect of the network reaches capacity. Flexible loads include Counties Energy's existing controlled household hot water cylinders and load aggregators like OpenLoop that can control electric vehicle chargers.

5.0 Approach to Asset Management


H.V. INSULATED
WITH LINER FITTED
Max. Wind Speed 12.5m/s

5.0 Approach to Asset Management

Counties Energy has adopted an approach to Asset Management following the principles of the ISO 55000 framework, specifically adopting the process of seeking continual improvement. The corporate strategy and objectives are derived from our stakeholder and include legal requirements, influencing how we manage our assets and deliver safe, reliable energy to our customers.

Figure 5-1 Asset Management Framework below shows the high-level Asset Management framework for Counties Energy.

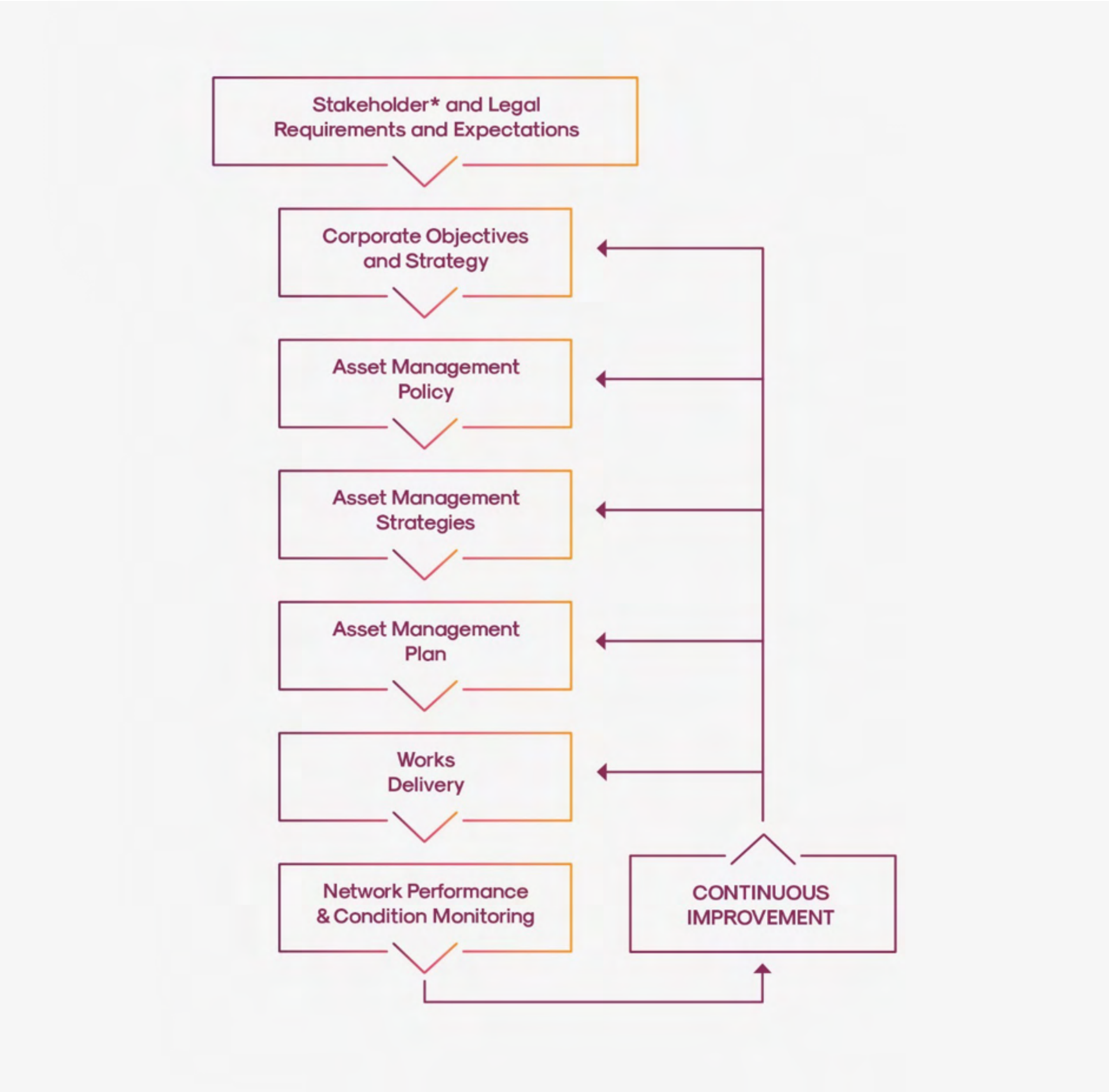


Figure 5-1 Asset Management Framework

*Refer to section 2.6 for details of our stakeholder

5.1 Asset Management Objectives

5.1.1 Asset Management Objectives

Our Asset Management Policy links our Asset Management approach to our corporate objectives and details the objectives, the accountabilities, and the implementation considerations.

The Asset Management Policy states our objective to be:

> **Optimise the whole-life costs and the performance of the distribution assets to deliver safe, cost-effective, high-quality services to our customers.**

Our objective will be achieved through the following strategic objectives:

- Safety First in everything we do – No business objective will take priority over health and safety;
- Safe, empowered, skilled workforce making Counties Energy a preferred employer;
- Improve our network performance, including through a targeted reliability programme, meeting our stakeholder expectations;
- Improve our Asset Management System through defined alignment to ISO 55000;
- Improve our low-voltage capabilities to enable DER and EV integration;
- Improve asset management information systems to support the asset management decision-making processes;
- All new developments, projects, plant and equipment include environmental considerations in procurement and design; and
- Focus on the Human Experience by simplifying how our community interact with us, providing choice and implementing what's important to them.

5.2 Asset Management Strategies

The asset management strategies have been developed to deliver the requirements of the Asset Management Policy and inform this Asset Management Plan and proposed operational and capital expenditure programmes.

5.2.1 Reliability Strategy

Counties Energy recognises the direct effect network reliability has on the experience of our customers connected to the network and it is a core business priority reflected in our value of 'Always On'. Network reliability for us includes unplanned outages, planned outages, weak power (part-phase) outages, auto-reclose interruptions and power quality.

We aim to continuously improve our reliability performance, as set out in our reliability service levels (refer section 4.5). We have a slightly different approach for each aspect of reliability - full details of our Reliability Strategy can be found in section 6.2.

5.2.2 Maintenance Strategy

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

Our maintenance programme consists of three categories of maintenance activity.

Preventative maintenance

- Routine inspection (including defect and hazard identification);
- Condition assessments;
- Testing and servicing; and
- Vegetation management

We undertake or review targeted inspections or maintenance where:

- Network performance is poor, or the consequence of failure is extreme;
- High-value assets are identified as deteriorating but serviceable to ensure the maximum life is obtained but minimise the likelihood of failure in service; and
- Recurring or common failure modes have been identified with revised inspection criteria.

Corrective maintenance

- Scheduled repairs to assets following inspection or testing to address known defects based on the risk they present.

Reactive maintenance

- Unplanned repairs or replacement of assets if a defect presents an immediate risk to safety or the network; and
- Unplanned repairs or replacement of assets upon failure.

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 replacement cost 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.

5.2.3 Vegetation Strategy

We undertake vegetation management to ensure safety around our network and that network performance meets expectations. Our vegetation management is approached in accordance with the Electricity (Hazards from Trees) Regulations 2003, although there are significant components of our vegetation programme which have to operate outside the scope of these regulations as they currently offer limited protection. Our approach focuses on vegetation management as a preventative rather than a reactive activity.

Our vegetation management is proactive and reliability-focused whilst supporting public safety where trees contacting lines have become a hazard. The completion of the Light Detection and Ranging (LiDAR) surveys on a three-yearly basis, and subsequent analytics, have enabled a proactive, risk-based approach.

This approach balances:

- Encroachment severity;
- Fault history;
- Customer impact; and
- Network criticality.

Our 33 kV and 110 kV subtransmission circuits are targeted due to the criticality of these lines.

A detailed description of our vegetation investment programmes is covered in section 6.7.

5.2.4 Renewal and Replacement Strategy

The existing network consists of assets of varying ages, which are replaced based on their age, condition and, in some cases, specific fail modes relating to those assets; for example, targeted conductor types or identified components.

Across our major asset classes, we have preventative and corrective maintenance programmes to ensure these assets perform as expected and to understand their condition to allow us to plan repair and replacement activities. There is an ongoing strategy of using and improving data collected from the asset during operation and maintenance to optimise the replacement strategies for each asset class and optimise whole-life costs for those assets before replacement.

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

Where an asset is at the end of its life, no longer required, or has been superseded, it may be retired from service without replacement.

A detailed description of our replacement programmes are covered in Chapter 8.0 Renewal and Maintenance.

Substation Plant Renewal and Replacement Strategy

Major substation plant is of high value, has significant consequences associated with failure, and can present a serious risk to safety, the network and the environment if poorly managed.

To optimise the asset life, we assess the substation plant for:

- Whole-life cost assessments;
- Condition;
- Failure mode risk (FMEA);
- Performance;
- Asset health modelling; and
- Capacity requirements.

Distribution Renewal and Replacement Strategy

Distribution assets are generally in the public domain and can present a public safety risk. Our objective is to replace these assets based on condition before they fail or present an unacceptable risk.

To get improved condition, defect and geospatial data, we now utilise unmanned ariel vehicles (UAV) and LiDAR surveys to collect and analyse imagery.

The following activities are undertaken to forecast optimal replacement timeframes:

- Whole-life cost assessments;
- Defect identification;
- Condition assessments;
- Asset health modelling; and
- Analysis of failure rates and causes.

5.2.5 Network Development Strategy

As demand on our network grows, we must ensure it can meet our consumers' capacity, security and reliability requirements.

We have developed security and planning criteria and assess the network against these for a 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 overinvestment, premature investment, or 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 improve our network performance as defined by SAIDI and SAIFI to reflect the customer and broader service delivery expectations identified in our network performance trends analysis.

We are in a transformational time for the electricity industry. New technology advancements and New Zealand's net-zero greenhouse gas emission target by 2050 will introduce a new level of electricity demand management. We recognise the potential for changes in demand characteristics influenced by changing customer behaviour and anticipate our customers will expect services that enable them to leverage Distributed Energy Resources (DERs) and participate in flexibility services. Counties Energy is evolving from a Distribution Network Operator to a Distribution System Operator (DSO).

Further information on this transformation is in Section 7.2 Becoming Distribution System Operator (DSO) Ready.

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; conversely, if demand growth is faster than forecast, we may bring forward investment.

These network development plans are covered in Chapter 9.0 Network Development.

5.2.6 Connections Strategy

Small residential developments continue to occur as landowners are subdividing pieces of urban or rural land. Therefore, we continue to see a high demand for small connections within these areas.

We have set processes in place to ensure all relevant checks are done to be able to provide these customers with the capacity they require without causing undue strain on the existing network. Our strategy is to ensure that the connections we install are to our standards and to ensure any maintenance work required within the area of work is completed at the same time. Further information can be found in Section 9.0

5.2.7 Underground Asset Strategy

Unless otherwise allowable under structure plans, subdivisions are designed and installed as underground circuits. New rural networks may be built as overhead circuits and new lines installed underground through urban areas, per the respective council plans applicable to the Auckland, Waikato and Hauraki areas.

Overhead to underground conversions of an existing line are reviewed as part of project scoping and optionality. To proceed, it must meet set criteria for public safety or network reliability, such as vehicle versus asset risk (refer to section 5.3.3), proximity to high-risk areas (i.e. schools) and future development plans.

5.2.8 Low-Voltage Strategy

We recognise the LV network is becoming increasingly important and will become the key interface between our traditional activities as an EDB and the future network of electric vehicles and other connected DERs.

In 2022 we started to refresh our strategy for managing these assets. This includes a number of workstreams which we will take into considering our approach into the following:

Grouping	Considerations
Operations	Management of LV network normally open points Works management Operational control SCADA/ADMS (Advanced Distribution Management System) visibility Dynamic rating
Network Naming	Circuit naming Switch numbering/labelling
Network Planning	Refining load and voltage planning standards Security of supply, including contingency standards LV network architecture
Asset Information	Location, rating, fuse sizes Installation dates, condition Connectivity/switch status Population of information for existing in-service assets
Service Connections	Phasing Privately owned service cable/line asset information Population of information for existing in-service assets
Visibility	Load flow sensing/monitoring Understanding hosting capacity Real-time capacity versus load balancing Distributed generation visibility and compliance with connection standards
Reliability Reporting	Low-voltage SAIFI/SAIDI measurement and reporting
Power Quality	Improving voltage management processes Dynamic voltage management

Table 5-1 Low-Voltage Strategy

These will be progressed throughout the upcoming year. There is a strong overlap with our DSO work in this space; refer to section 7.2.

5.2.9 Integration of Strategies

The above strategies identify actions and are not considered in isolation. To ensure maximum value is obtained from all expenditures, proposals from each are examined across the other drivers to ensure integration of works and compliance against our asset management objectives.

Each proposal is checked against the following:

- The Reliability Strategy – to ensure the configuration of the works meets automation and switching requirements;
- The Development Strategy– to clarify whether reinforcement is planned for the near future in this vicinity; and
- The Renewal and Replacement Strategy – to ensure that any asset which is of a condition requiring replacement within the work area is identified and included in the scope.

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

5.3 Investment Planning

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

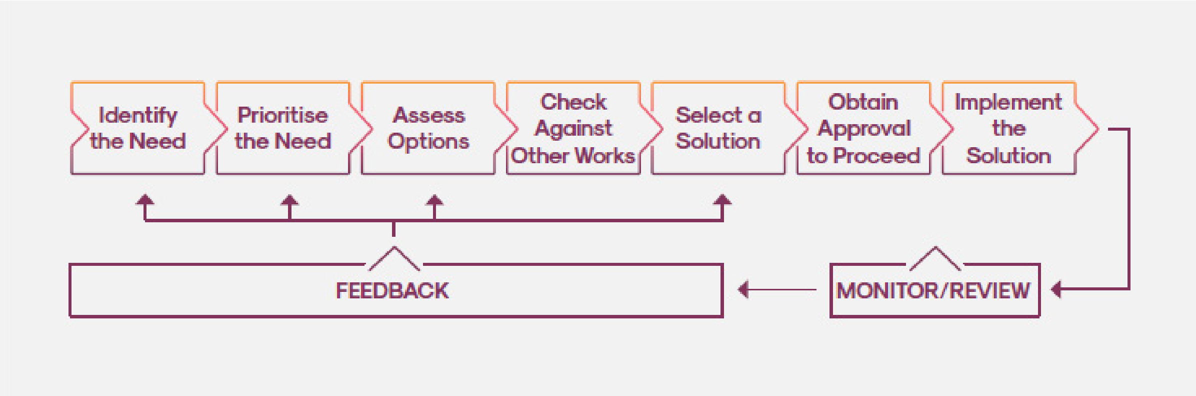


Figure 5-2 Investment Planning Process Overview

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:
   - Network planning process identifying constraints on the system;
   - Maintenance process, including asset condition surveys; and
   - Network fault and performance data, including the network performance trend analysis.

These processes produce outputs of a list of issues which may require investment.

1. **Prioritisation of the Need** – Prioritised by risk (including safety, security, reliability, environmental and regulatory), timings and criticality.
2. **Assess Options** – Optionality is developed with risks, benefits and high-level costs. Benefits will include all aspects, including those directly seen by our customers (such as improved SAIDI and SAIFI performance) and wider benefits from improved network resilience. From this, a preferred option is recommended.
3. **Coordination Assessment** – Projects are assessed for overlap between drivers.
4. **Select a Solution** – The solution is selected based on providing the highest benefit to risk.
5. **Approvals to Proceed** – The business case outlining the preferred solution is presented for the appropriate level of management approval.
6. Implementation of the Solution – Design and delivery.
7. **Review/Feedback** – After completion, the project implementation and results are reviewed, and feedback is provided to inform and improve the steps in the process for future projects.

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

Figure 5-3 demonstrates how the planning activities within each strategy are coordinated and aligned, and co-ordinated for delivery into the 10 year, and annual works plan.

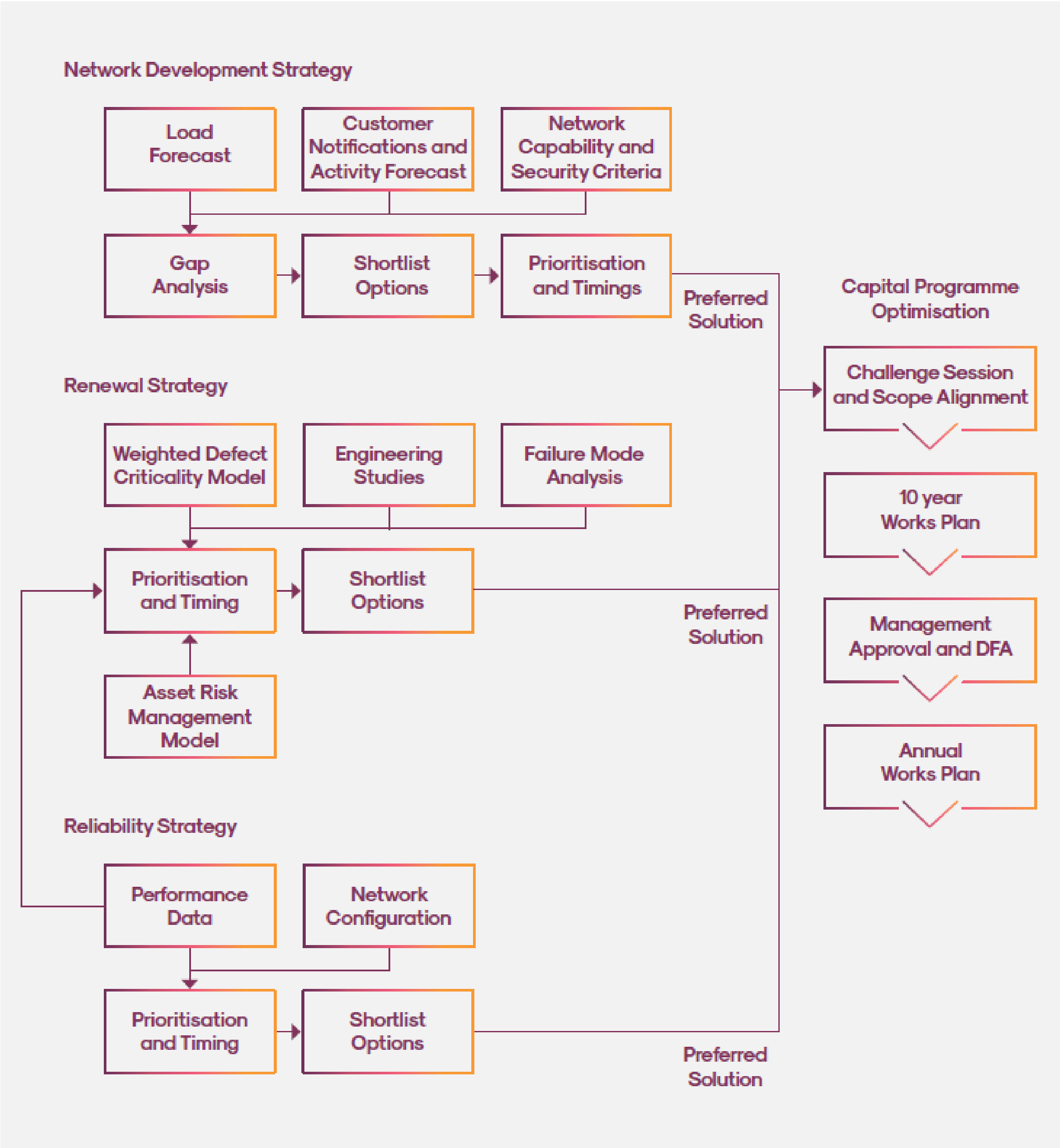


Figure 5-3 Integration of Planning Activities

5.3.1 Investment Planning Process – Renewal, Replacement and Reliability

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 employee safety, network security and reliability, regulatory requirements and environmental effects.

Figure 5-4 Renewal Investment Process

The condition monitoring input is derived from multiple sources:

- Asset inspection outputs and defect reports;
- Weighted criticality and defect model (refer section 5.3.3);
- Asset risk management model (refer section 5.3.3); and
- Failure mode analysis (refer section 5.3.3).

5.3.2 Investment Planning Process – Network Development

Our process for network development investments is shown in the diagram below.

Full details of this process are provided in Chapter 9.0.

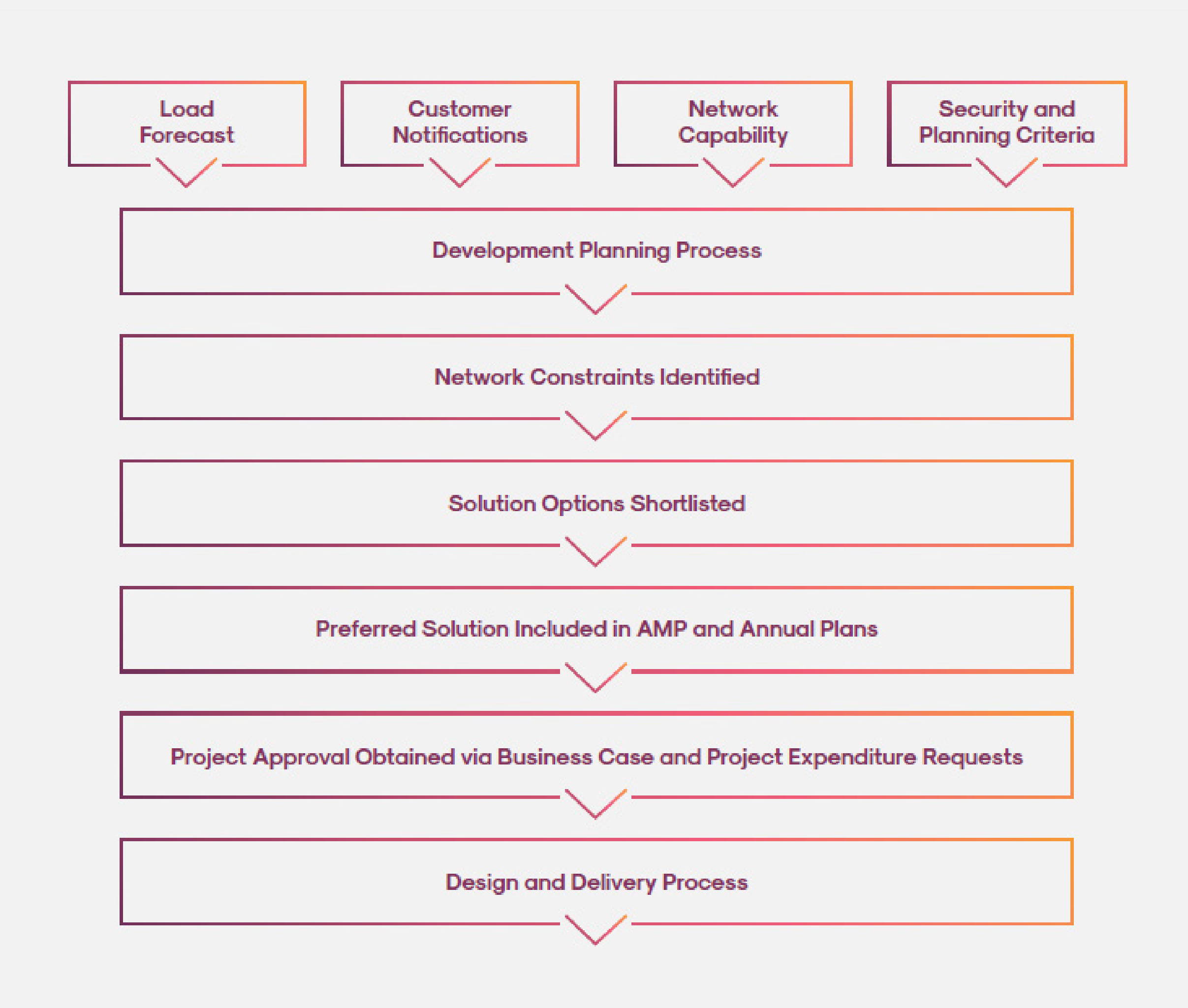


Figure 5-5 Network Development Investment Process

5.3.3 Data and Investment Planning

Counties Energy has initiated a series of data models to help inform investment planning decisions and assist in an improvement asset management strategy. These models include;

- Weighted criticality and defect model;
- Asset vulnerability model (vehicle vs asset risk);
- Failure mode and effect analysis;
- Asset risk management model;
- Network criticality model; and
- Smart meters.

Weighted Criticality and Defect Model

A weighted defect model has been developed to support asset replacement and corrective maintenance investment decisions. The model assists in the prioritisation of identified asset defects and hazards by considering the following:

- Defect type and hazard score;
- Defect clustering;
- Light Detection and Ranging (LiDAR) defects (low lines and pole lean);
- Asset criticality;

- Public safety impact; and
- Fault history.

The use of the defect model informs the prioritisation of corrective maintenance works, coordination of activities and defect identification with wider network projects.

Asset Vulnerability Model (Vehicle vs Asset Risk)

An asset vulnerability report has been developed as part of the safety in design activities. It collates crash data from Waka Kotahi (NZ Transport Agency) and overlays it with our geospatial data to provide insights into areas where assets may be vulnerable to vehicle collision.

This model is referred to during both scope and design phases to proactively establish areas of risk regarding vehicle collision and ensure asset placement is appropriate when considering historical crash data.

Remedies may include relocation of individual assets, relocation of a collection of assets, such as an overhead line, or undergrounding. This dataset provides information used in the undergrounding strategy.

Failure Mode & Effect Analysis (FMEA)

Failure mode and effect analysis studies are underway for the major asset groups, starting with the major substation assets.

The outputs of these studies will inform:

- Maintenance requirements;
- Critical spares requirements;
- Asset information requirements; and
- Whole-life cost analysis.

This information will be required to form our asset class strategies, which determine appropriate maintenance frequencies, management techniques and performance indicators.

Asset Risk Management Model

Asset risk management models (ARMM) are being created for all major asset groups and forecast current and future risk, health indices and criticality.

These models assess against various asset health, other influencing factors and contextual factors which may affect the probability or the consequences of failure and determine current and future risks relating to safety, environmental impact, outage duration/network performance and cost.

The influencing factors are typically asset information (age, type, location), observed condition data and measured condition data from inspections and maintenance.

The output allows us to assess the fleet of assets for investment requirements and optimise replacement timescales and investment requirements related to projected risk values.

Network Criticality Model

In 2021, Counties Energy developed a network criticality model which leverages the existing data in company systems to form an understanding of the criticality for each and every part of the 11 kV and 22 kV networks in terms of customers impacted. This is achieved by using algorithms that interrogate the recorded asset locations and connectivity captured in our geospatial information system (GIS) to form a model made up of sections – with separate cases considered for the three main stages of a typical unplanned event.

Analysing these sections against typical average restoration times can provide an indication of the expected SAIFI/SAIDI impact of an unplanned event in a particular location on the network, i.e. the network criticality. This information feeds into our asset risk management models, as well as driving our vegetation management and reliability investment programmes.

Smart Meters

For details on how smart meters are used for investment planning through the Infrastructure and Network Data Interface (INDI) system, refer to section 5.4.1.

5.3.4 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.

Network alternatives may also be considered for customer connections where traditional distribution options are uneconomic relative to the available alternative.

We then consider if network alternatives are feasible, such as demand-side management, localised storage or generation, remote area power supplies, flexibility solutions and other assets. These can be installed to defer the need for investment by reducing the peak demand or supporting the voltage along a feeder.

A network alternative is not typically suitable when the investment need is driven by the poor condition of assets and public safety. Where investment for the replacement of network components is required, consideration is given to the size and configuration to determine if the network can be optimised.

Further details around our assessment and selection of Network Alternatives is covered Section 9.0 and the section 7.2 Becoming Distribution System Operator (DSO) Ready.

5.3.5 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 IEC and AS standards 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.

A line mechanic inspects equipment inside the Pokeno Substation

5.4 Asset Management Information and Systems

5.4.1 Asset Management Systems

Several key systems are used in the asset management process and are part of our wider business operation. The key systems are listed below with a brief description of their role.

Some minor systems have not been detailed here.

Geographic Information System (GIS) – Smallworld Electric Office

We have previously upgraded to 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
- Use Geospatial Analysis (GSA) tool to deliver analysis and reporting.

GIS (Geographic Information System) data quality improvements will continue to be an area of focus in the coming years.

Infrastructure and Network Data Interface (INDI)

INDI is a simple, cloud-based outage and dispatch system that is core to Counties Energy's outage management and reactive works. Data is pulled together from a range of inputs, and supports workflows, information updates, and visibility to our customers through three web-based applications.

A key input to INDI is the data available from the population of smart meters on our network, which is available for more than 95% of connected ICPs. These are provided as the retailer revenue meters by Counties Energy as a metering equipment provider (MEP), although they also offer us invaluable network information to manage our network more efficiently.

We use INDI for a number of key functions:

Operations

- Outage management, dispatch and geospatial visualisation;
- Use of smart meters to automatically raise work orders for 'No Power', often long before a customer is aware that their power is affected; and
- The ability to check in real-time the status of a meter. This reduces the need to respond to call-outs for issues internal to the property. The same function also enables us to check that outages have been fully restored after an event, preventing extended outages for our customers that we would otherwise be unaware of, and the need for a follow-up response.

Planning

- Visibility of historical consumption data, enabling more accurate transformer and low-voltage network planning based on real information, rather than purely based on average consumption models.

Power Quality

- Event recording and reporting for voltages at the meter outside of standards;
- Avoids the need to always deploy monitoring equipment at both the customer's premises and on the reticulation in the street; and
- Proactive reporting of power quality (voltage), without the need for a customer to complain first.

IQGeo

The IQGeo platform is a foundation product for transforming the ability for Counties Energy to manage its complex and constantly evolving network assets. It provides a digital twin of the network to its users, and its core functions are currently:

- Provide asset information to field employees; and
- Provide updated asset information to Smallworld Electric Office.

Roames World

The Roames World platform displays the digital twin of the network, showing the following asset data:

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

Enterprise Asset Management (EAM) System – Maximo

Maximo was introduced in 2020 as the enterprise asset management system; however, it is currently under design and process review. It is intended 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 EAM system will be expanded to include capital and reactive works management.

Further detail on the design review of the EAM can be found in section 5.12.

Supervisory Control and Data Acquisition (SCADA) – iPower

Our GE iPower SCADA system is used for real-time operations of the high-voltage network. It provides telemetry and remote control of substations 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.

AutoCAD and Meridian Drawing Management

All our design work is undertaken in AutoCAD, including substation 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.

All standard, as-built and construction drawings are now held in the Meridian drawing management system and integrated with SharePoint for user access.

Microsoft Dynamics NAV

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

This system has been customised to provide several 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 various in-house field tools based on the Google Android platform. These are used as part of our dispatch process and for recording job information in the field and capturing the results of asset surveys. This system has linkages to GIS and 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 the main network planning tool for power flow analysis and network simulation. It is used to undertake systems studies for large-scale new connections, assess network loads, identify network constraints, and assess network performance and operational scenarios. We have a complete network model represented within Powerfactory.

5.4.2 Asset Management Information

To support our asset management processes, we use the following information, some of which is held electronically and some in hard copy. With the ongoing development of asset management systems, it is intended 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. These standards are used in all capital and customer designs to ensure consistency across the network and improve cost efficiencies through standard constructions.

  Standard designs are used for all distribution overhead and underground constructions including (but not restricted to):
  - Subtransmission, Distribution and LV Pole, crossarms and attachments;
  - Transformer installations and easement areas;
  - Switchgear installations;
  - Cable installations; and
  - Ground mount distribution asset installations;
- **Standard Equipment -** All new assets and equipment installed on the network are subject to a network equipment approval process to ensure it is fit for purpose, controlled and integration of change is managed. The approval process ensures that technical requirements, constructability concerns, environmental impact and procurement processes are considered and seeks endorsement from the impacted stakeholders.

  New substation and subtransmission equipment are also standardised to allow for compatibility and strategic spares management across the network. Approval documentation is retained, and details recorded in the Approved Asset Register.
- **Network Diagrams** – This information is contained in AutoCAD drawings as well as in the GIS and SCADA systems. These are used to plan and operate the network;
- **Test and Inspection Records** – Outcomes of these activities are stored for future reference and 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 the duration, cause and number of customers affected. These are used for calculating our SAIDI and SAIFI figures for regulatory reporting and analysis of network performance trends; and
- **Legacy Information** – We have a range of information in hard copy format, particularly older test and inspection records, equipment manuals and technical documentation. Some information has been digitised; however, much 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. Where necessary, we 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 such as email.

We have identified opportunities for improvement on how we maintain our geospatial data; as such, our as-built and data-capturing processes are being updated to reflect the new system's requirements. Details can be found in section 5.12.

Asset Management Information - Completeness

We recognise that there are currently gaps in our asset condition information due to poor data capture capabilities through historical maintenance and inspection methods. This is being continually improved through the maintenance and Maximo improvement project (Refer to section 5.12) as well as the use of LiDAR and UAV surveys to establish baseline conditions of our overhead assets. Additionally, historical errors in data are routinely identified and corrected through the asset inspection processes.

Data completeness dashboards and governance is being introduced through FY24 as part of the ISO55001 framework alignments. These dashboards align the business requirements of asset information through the asset management system and monitors gaps and trends improvements in data completeness.

Asset Management Information - Quality Control

Core asset information is mastered in our GIS system (EO Smallworld), which undergoes regular automated quality assurance management. All data undergoes quality checks before it is published into the production environment via "Quality Manager" software processes.

Quality Manager is the framework for performing quality checks on Smallworld data, providing a streamlined user workflow for managing flags generated within a design. In addition, many checks are made as part of code-based business rules, and triggers in the GIS design as users make changes.

Automated quality routines run in a predefined order against one or more quality sources, such as a circuit or design changes. The availability of activities exposed to users in the Quality Manager is controlled by authorisation rights assigned to specific user groups. No asset changes can be made without running a full suite of quality manager routines.

Asset Management Information - Integrations

Counties Energy use the GIS Electric Office system as the master for physical assets and core attributes, including connectivity. This is due to a standard data model for assets and Electric Office has robust design processes and Quality Management.

All asset information changes are subjected to an as-built process; these can come through reactive, corrective, and capital works or customer-initiated works processes. The GIS administration team processes these asset information changes and posted into production following the quality control process described above. This as-built process is currently under review to streamline to support the ADMS introduction (refer to 7.1.1)

Integrations to other systems start with the generalisation of the Electric Office data model for consumption. Electric Office has multiple tables / joins for separate assets. These are generalised using FME (Safe – Feature Manipulation Engine) for general use. Once asset data is generalised, it is extracted to Counties Energy's consumption platform SQL Server. This is where further integrations to systems such as Salesforce, Maximo, INDI and BI Reports occur. This ensures that asset data remains consistent across all platforms at all reporting stages.

5.5 Works Delivery Processes

5.5.1 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 or programme justification. This section describes the key works processes in delivering the plan.

Network Projects

Network projects cover a range of work, including system growth and capacity projects, reliability, quality of supply, and asset replacement and renewal programmes.

The project management framework follows:

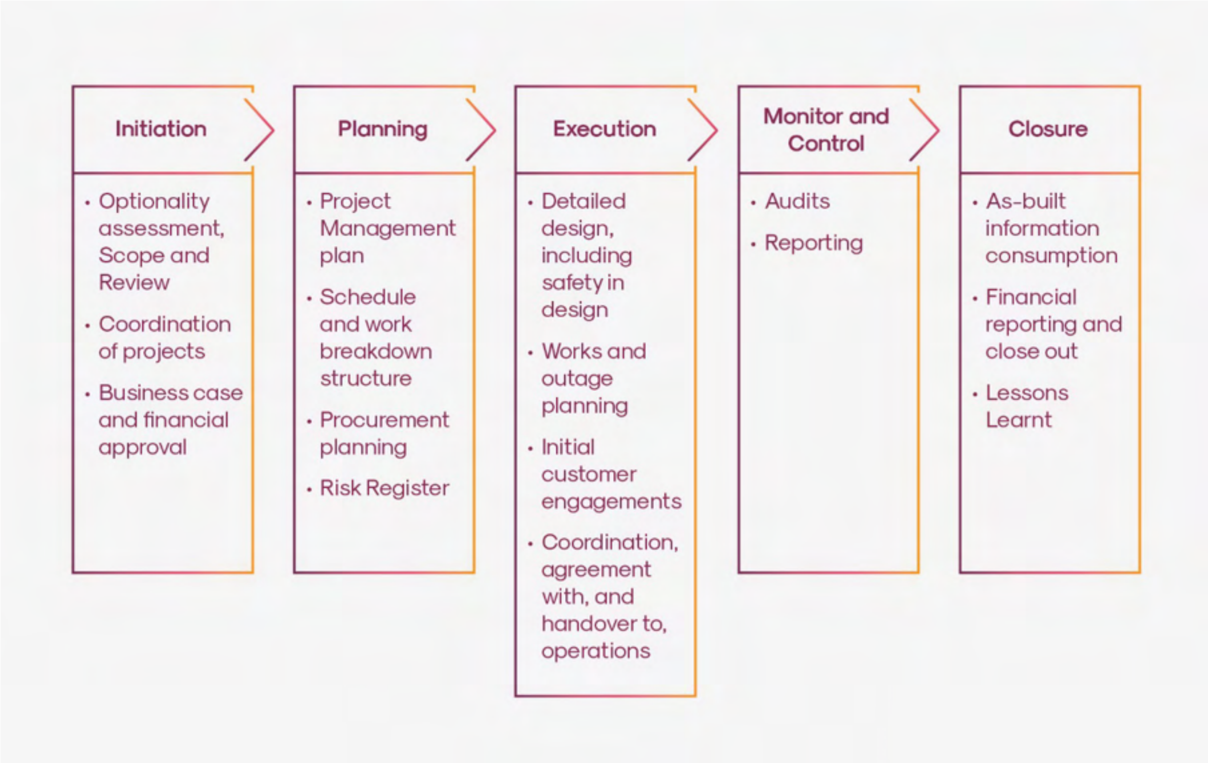


Figure 5-6 Capital Works Project Management Framework

The complexity of the project framework depends on the size and complexity of the project, from major projects (>$1m) to minor works (<$200k).

Customer Projects

Customer projects include new connections to the 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. The customer requirements are identified, and a concept and budget price are presented to the customer. Following acceptance of this, a detailed design is created and quoted, and an offer is made. When the customer accepts with payment, the work is passed to the Field Operations group in the same way a network project is.

Preventative Maintenance Planning

Preventative maintenance is the programme of routine inspections, testing and servicing of network assets to ensure they are performing as expected. The programme considers public and worker safety and network reliability.

The activity type and frequency are determined by regulatory requirements, known historical performance, manufacturer's recommendations, and good industry practice. We develop maintenance standards for each asset class to develop the overall Preventative Maintenance Plan.

The Network team develops the annual preventative maintenance plan in conjunction with Field Operations and, in some cases, contractors, who then deliver the programme over 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 other network requirements such as dismantling old assets or refurbishing equipment.

Corrective maintenance is prioritised based on the following criteria:

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

- Type and age of equipment.

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

Defect Management

Defects raised on the network are assessed using guidance provided as part of the inspection standards, which are being revised and updated using failure mode study outputs and maintenance standard requirements.

If the defect is deemed to be of immediate risk, then it is immediately isolated and rectified; otherwise, it is planned for remediation through the corrective maintenance process, reprioritised into that financial year if required or planned into the five-year remediation schedule.

Defects and hazards requiring corrective maintenance planning are identified via an analytics dashboard. The engineering team monitors the dashboard daily with weekly review meetings to react to corrective actions required. It is reviewed with the weighted defect model to prioritise non-urgent works.

Reactive Maintenance Process

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

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, our Network Control team will use remote control capable switchgear to restore as many customers as possible, whilst at the same time ensuring fault crews are dispatched to attend to the issue. There may then be further switching and isolation to restore customers before any required repairs are completed to the network.

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

In many cases, our Outage Management System, INDI (Infrastructure and Network Data Interface) will leverage smart meters and let us know of a supply outage long before a customer may even realise. This applies to events on the high- and low-voltage systems, where the smart meter will advise notification of a loss of power, enabling us to start to respond long before a customer has called us.

Immediate hazards can be identified by our employees 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 on outages, customers can access a map showing events on our website (https://app.countiesenergy.co.nz/) or by downloading our smartphone App. This map provides details of outages and the expected restoration time.

We also 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. This avoids delays to the restoration of supply to customers where we believe the issue is resolved, but another previously unidentified issue is still causing supply to be unavailable. This is a particular problem during weather events where the chance of multiple issues happening together is higher.

Vegetation Management Process

The majority of our vegetation plan is delivered by our utility arborist crews within our Field Operations team. The process is designed to meet the requirements of the tree regulations, adding the risk-based approach for vegetation out of scope of the regulations. Full details are available in section 6.7.3.

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** – For transport operators wishing to move oversized objects, typically houses, along routes with 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 Mark-outs** – We provide plans of our network and can undertake onsite locates or mark-outs to show where our buried services are; and

- **Safety Disconnections** – The disconnection of consumer 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 Energy. Our Customer Service team initially handles these requests, and the requests are fulfilled by the Network Control or Field Operations teams depending upon the nature of work required.

5.5.2 Field Delivery Capability

Counties Energy manages and delivers the majority of fieldwork internally through our Field Operations group.

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

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

- The tasks require a specialist skill that Counties Energy employees do not have, and the 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
- When the work type is not core business to Counties Energy, such as the 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.

5.6 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 2022, our certification continued after Telarc conducted a review audit against NZS 7901:2008. This follows recertification in 2020, 2018, 2015 and initial certification in 2012.

5.7 Organisation and People

5.7.1 Training

The Safety, Culture and Sustainability team work closely to implement initiatives related to the CEL employee's core skill sets and cater specifically to opportunities to improve from acute risk exposure and post-incident investigation. Notable, among many initiatives, is the 'First Person Up', working at height system, and improved capability to respond to environmental incidents.

The First Person Up device (FPU) is intended to eliminate the fall from height risk. If a fall occurs, the FPU prevents the fall through a controlled brake and rope system. The FPU also offers the ability to perform a rescue on an unconscious climber.

The Counties Energy Limited network has sizeable remote rural areas with poor communication methods such as radio and cell phones. To ensure teams, and lone workers, have a constant source of communication with emergency services, Personal Locator Beacons (PLB) were issued to workers. The combination of the PLB and the FPU has provided teams, and especially lone workers, with robust controls to mitigate various risks.

Our Physical Work Capacity programme is tailored to identify underlying physical conditions that could lead to injury if not addressed. Sessions with a Counties Energy Limited physiotherapist ensure a detailed physical assessment while delivering industry-specific manual handling and strengthening training.

5.7.2 Quality Improvement

Counties Energy has started on a journey of transformative improvement to reduce costs and improve delivery times for all processes. This multi-year initiative is set to investigate and improve interconnected processes across the business, assisting with the alignment of business objectives. Several key initiatives have been identified to accomplish these goals:

- Redefined Document Creation and Management System;
- Design a robust Change Management System; and
- Over-arching Quality Management System.

Together, these systems will become the foundation of the Total Quality Management System, ensuring that change, growth and service delivery are continually adapted and improved to achieve the most effective and innovative results possible. Once implemented, the collaboration between these three systems will ensure that we can more effectively manage change while continuously identifying opportunities for improvement to meet our business objectives.

The complexity of implementing a Quality Management System of this scope denotes that it will be implemented and adapted over the next 4 to 5 years. During this time, our process inputs and outputs will be analysed using 6 Sigma methodologies and international best-practice guidelines to ensure that our KPIs align with our business objectives.

Quality Improvement Strategy

The table below outlines the implementation's quality improvement timeline to achieve the desired integrated Total Quality Management System.

	2022	2023	2024	2025
Continual Improvement Study	Improvement Gap analysis study completed	—	—	—
Document Management System (DMS)	Investigate improvements to the current system	Implement and populate the DMS	Gap analysis of document system to further improve availability	Completion of document creation and KPI integration
Change Management System (CMS)	Investigate updates to the current process	Integration of the DMS and CMS	Full implementation of the CMS	—
Quality Improvement System	Study the requirements for a tailored system	DMS system to supply KPI for the QMS	Completion of the QMS reporting system	Quality Improvement report analysis – first cycle
Integrated Total Quality Management System	—	—	—	Full integration of the three systems completed

Table 5-2 Total Quality Management System Timeline

Once the Total Quality Management System has been implemented, it will generate comprehensive reporting on our performance, compliance and objective targets. This closed-loop system would ensure that we can quantify our performance, adapt to change and improve our services.

5.7.3 Environmental

Objectives

Counties Energy aspires to lead the way with best-practice environmental processes in our operations. We are looking to continuously improve our performance and capabilities in the environmental space and ensure we are going beyond compliance. We commit to understanding the relevant environmental risks while having plans in place to avoid, remedy or mitigate the effects, as well as providing training to our employees and contractors around these risks.

The focus of our environment and sustainability programme is:

Engaged Employees: We want our employees to be part of responsible environmental stewardship and use our environmental commitments to attract and retain exceptional employees. We want to foster an environment where employees feel empowered to speak up when there are opportunities for improvement in our environmental management.

Improved Systems and Governance: Ensuring we understand our business's environmental risks and opportunities. Ensuring that our processes and systems allow for the best environmental outcomes possible, as well as having employees with the required knowledge and skill sets.

Local Focus: We aim to support local communities with their own environmental goals by providing options for decarbonisation. We will assist the community through the annual Counties Energy Environmental and Sustainability Grant, which offers a total of $15,000 in grant funding for three organisations wanting to participate in projects that will have positive environmental impacts.

Sustainability: Ensuring we understand the sustainability aspects important to all our stakeholders and the global community. Ensuring we have adequate reporting and monitoring of impacts allows us to direct resources where they would make the most significant impact. We will be working on continuing to understand our asset risks from climate change as well as making progress towards our emissions targets and assisting our customers in their decarbonisation journey.

Emissions

Counties Energy is committed to reducing our impact on the environment. We will shortly complete our carbon inventory with Toitu and will be setting reduction targets in line with science-based targets.

Oil

Spill response training has been rolled out to all operational employees, including theoretical and practical sessions. This will continue to focus on our compliance training over the next twelve months to minimise the risks from spills.

5.8 Risk Management Framework

Our Risk Management System remains unchanged from previous years. Our current strategy has served us well, ensuring we can manage risks effectively. However, our recent growth has prompted us to refine this process further to ensure we take every opportunity to manage the complex arrangement of systems and projects more effectively.

To achieve this, we are currently working on creating a risk identification and management system capable of aligning our risks throughout the business. This will enable every team to effectively identify, score and manage risks in each business area. Once completed, the system could be dynamically updated to ensure that we are focused on addressing the risk where and when required.

Figure 5-7 Risk Objectives

Risk management and asset management are intricately linked. We recognise that risk management is integral to good management practice and corporate governance and 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, and industry and organisational standards and codes.

Our Risk Management Framework is aligned with the *ISO 31000:2009 Risk management – Principles and guidelines* standard. 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 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.

5.8.1 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.

5.8.2 Accountabilities and Responsibilities

The following table 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 the risk management process
Leadership Team (LT)	Ensure risk is 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, processes 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 risks within acceptable risk tolerance levels
Employees	Awareness of risk management and process
	Everyday identification and management of risks and improvement actions to minimise risk events and impacts

Table 5-3 Overview of Risk Management Accountabilities and Responsibilities

5.8.3 Risk Management Process

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

1. **Establish the Context**

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

2. **Risk Identification**

Our risks are identified through operational processes, including Hazard Identification by employees 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 employees 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 the health and safety of the public, employees or contractors of the organisation;
- **Operational** – Risks affecting the efficient operation of the company, including service delivery, continuity and recovery. 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.

3. **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.

Table 5-4,Table 5-5 and Table 5-6 below provide the ratings for probability, frequency and consequence.

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 to 10 years
0.5	Unlikely	1 event in 10 to 20 years, 10%	The event is unlikely to occur, possibly within 10 to 20 years
0.2	Rare	1 event in 100 years, < 1%	The event may occur only in exceptional circumstances

Table 5-4 Probability Rating

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

Table 5-5 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 employees, customers or the public
40	Major	Major unplanned service outage for up to seven days only
		Very serious, long-term environmental impairment to ecosystem functions
		Serious injuries to employees, customers or the public, requiring hospitalisation and or lost work days

Level	Description	Examples of Consequence
15	Moderate	Unplanned service outage for up to five days
		Serious medium-term environmental effects
		Serious injuries and/or disability to one or more employees, customers or members of the public
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 employee, customer or member of the 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

Table 5-6 Consequence Rating

4. **Risk evaluation**

Identified hazards and risk scores are verified and prioritised for rectification or treatment, network impact, and other additional public or worker safety factors.

5. **Risk treatment**

We treat a risk depending on the numeric score 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 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.
  Risk Register

Information from the risk management process is recorded, reported and monitored using our Risk Register. The Risk Register assists us in monitoring and reviewing risks in alignment with our business objectives.

5.8.4 Risk Reporting and Monitoring

All of our risks are periodically reviewed by our Leadership Team and are reported according to the residual risk score.

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 Employees
< 20	Insignificant	

Table 5-7 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 we face and the treatment applied to them. The Leadership Team and other senior managers meet periodically to review our risk management position.

5.8.5 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, and the approach to risk management includes the risk treatments and any relevant task Job Safety Analysis (JSAs) and work standards that apply to the project.

The design and implementation stages of each project's risk management plan consider our overall business objectives.

5.9 High Impact, Low Probability Events

We are exposed to several potential high impact, low probability (HILP) events, which could lead to a major unplanned service outage for an extended period. HILP events are defined as having a widespread impact but occurring rarely, and they are incredibly expensive to avoid if this can be achieved at all.

Accordingly, we have a responsibility to plan for and manage the risk of HILP events as best we economically and practically can. Within this context, our policy is to ensure the timely restoration of power supply, effective communication, a safe environment for employees, 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, customer service, security, reliability and supply quality. Events that could interrupt our critical business functions include natural disasters, such as floods, tropical cyclones and windstorms, electrical storms, volcanic eruptions, and earthquakes. Also included are airspace incidents, asset failures, communications failures, Information System security breaches or losses, and unplanned loss of supply from Transpower, including System Operator grid emergency events.

Note: System Operator supply shortage declarations (e.g. due to a 'dry year') leading to energy savings requirements are not included in the definition of HILP events, as advance notification can be provided to customers.

Studies have also been undertaken considering our subtransmission and zone substation system of lines, cables, switchgear and power transformers. A previous study identified the requirement for spare 110/22 kV and a 33/11 kV transformers that could be relocated in a HILP event should there be a total loss of power transformers at a zone substation. These two transformers are now installed and available for relocation, should they be required.

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

5.10 Emergency Response and Contingency Plans

We place emphasis on pre-event planning for HILP events to minimise the probability and impact of an event (where possible). 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 beyond that for which they are designed to withstand, which may result in outages or other supply issues.

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, operational contingency plans for the loss of SCADA and communications networks, switching schedules associated with the loss of zone substations and System Operator grid emergency plans.

When reviewing network development projects, the issue of resilience under abnormal conditions is considered during the selection process from the available options. During the delivery stage of any projects that impact our zone substation and subtransmission assets, our critical infrastructure outage standard must be followed to limit the probability and impact of any HILP event.

5.10.1 Lifeline Utility Groups

To ensure that New Zealand is 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 during and after an emergency, although this may be at a reduced level;
- Have a plan for functioning during and after an emergency;
- Participate in CDEM strategic planning;

- Provide technical advice on CDEM when required; and
- Provide reporting during and after events when required.

With our network spread over two major council areas, we are members of the Auckland Lifelines group and the Waikato Lifelines group. Lifelines groups are voluntary groups 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. However, during some major events, the Lifelines organisation monitors the impacts on participating utilities. Collaborating with other Lifeline 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.

5.10.2 Civil Defence Plan

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

5.10.3 Information System Security Breaches or Losses

We place emphasis on the security of information within all critical business systems, data acquisition systems and control systems.

As we are moving towards highly dynamic ADMS, DERMS (Distributed Energy Resource Management System), GIS, INDI, Substation Automation and other systems, we are steadily enhancing our proactive security, as well as reactive security measures.

Counties Energy has an already established defence-in-depth model for information security across our architecture, and we are further enhancing our maturity within this model.

We work with industrial cyber security experts and have deployed Threat Intelligence, Endpoint Detection and Response systems across our OT and IT networks. The threat intelligence platform is also integrated with the NZ GCSB National Cyber Security Centre for MFN (Malware Free Network) signature feed, which helps reduce our exposure further by enhancing our real-time monitoring solution. Our incident handling processes are based on industry best practices, which cover: identify, protect, detect, respond and recover – these include Incident Management, Incident Response Plans and Business Continuity Planning. These incident handling processes are tested annually through table-top exercises to ensure all parties within Counties Energy are aware of their responsibilities to facilitate the timely handling of security incidents.

We participate in SANS; CIGRE – Information Systems and Telecommunication; DERMS and Substations; and also the New Zealand Control Systems Security Information Exchange (NZ CCSIE). NZ CCSIE is an organisation 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.

Counties Energy has a strategic security roadmap that is focused on providing additional up-lift over the next two years and beyond, based on the above priorities. One primary driver for this work is the ADMS project, which has allowed Counties Energy to implement security-by-design from the ground up, ensuring that our data and our systems are protected from now and into the foreseeable future. This roadmap takes a structured approach towards security, with tangible milestones along the way (based on the aforementioned priorities), and ensures that cyber security is always front-of-mind across all workstreams. Some operational outcomes of the roadmap include the development of incident handling playbooks and Standard Operating Procedures, as well as implementing a cyber security awareness and education program across the organisation.

5.11 Asset Management Maturity

The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment process required by the Commerce Commission as part of the disclosure schedules included in Appendix A. It is a set of questions derived from the UK Standard PAS 55 (now superseded by ISO 55000), requiring 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.

Several areas of improvement have been identified through the ISO55000 alignment activities in the lifecycle management, communications and review section of the AMMAT assessment.

5.11.1 AMMAT Assessment

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

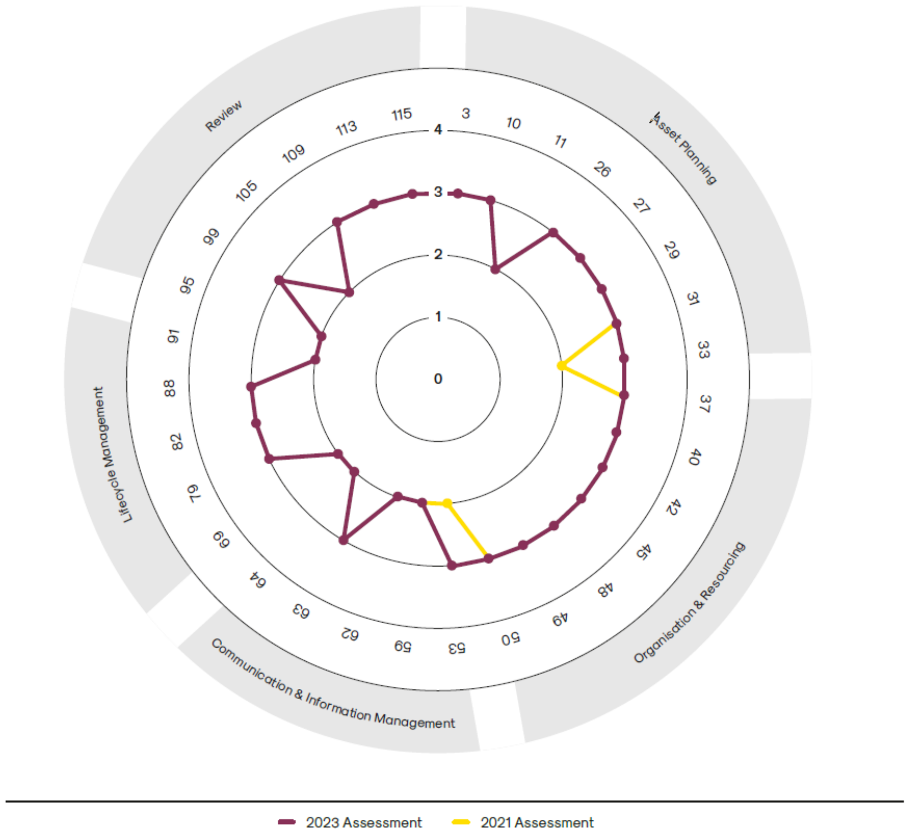


Figure 5-8 AMMAT Results

5.12 Improvement Initiatives/Continuous Improvement

We continue to revise our processes and systems to improve our asset management maturity. Some areas of focus are:

- Improvement of Asset Management Framework, ISO 55000:2014 alignment;
- Enterprise Asset Management System improvement;
- Quality Management System improvements;
- Change Management System development;
- Protection review; and
- As-Built Process review.

5.12.1 ISO 55000:2014 Alignment

Counties Energy is working towards alignment with ISO 55000 in its asset management practices, and we are now embarking on a programme of improvements to our asset management system.

ISO 55000 is widely accepted as a best-practice asset management framework and may become a requirement of the Commerce Commission in the future. In our programme, it will be used as a benchmark and a guide rather than certification as a goal. We'll propose improvement projects to our asset management system and processes starting now and lasting for several years.

A staged cyclic approach is recommended for this work. It is anticipated that a significant number of discreet improvement projects will be uncovered at various milestones as we progress through the discovery phase.

At a high level, these stages can be described as:

- Gap analysis of the ISO 55000 framework against current practices;

- Review of the ISO 55000 requirements and establish where alignment is required and desired;
- Identify and prioritise opportunities; and
- Develop and engage specific working groups to deliver identified opportunities.

Focus areas for the first cycle (FY23–24) are:

- Alignment of asset management objectives and corporate strategy;
- Definition of the asset management system framework, including an end-to-end process mapping;
- Establish a programme to form asset class strategies; and
- Establish performance measurement and monitoring framework.

The asset management objectives have been revised and endorsed by the Counties Energy Leadership Team, these can be seen in Section 1.4 Purpose of this Document, and will form the basis upon which the framework is developed.

The asset class strategies will detail and review the management processes and decision-making criteria for the major asset classes, and using FMEA studies, performance data and accepted industry standards the following will be determined for each:

- Appropriate asset hierarchy;
- Appropriate data requirements to meet business and regulatory requirements;
- Revised failure modes to be recorded as defects and prioritisation alignment; and
- Revised maintenance standards and procedures.

5.12.2 Enterprise Asset Management System

Accompanying the ISO 55000 alignment project, Counties Energy is reviewing the Maximo implementation to improve its ability to deliver against our asset management objectives. The project includes process reviews and system restructure, asset data and hierarchy review and rebuild and a review of the in-field delivery options.

This review will address the following components:

- Stakeholder requirement alignment;
- End-to-end process review;
- Asset hierarchy and data information assessment;
- KPI and reporting establishment; and
- Review of end-user interface.

Further detail can be found in Section 7.1.2.

5.12.3 Quality Management Systems

The Quality Management System is currently looking at how information is shared, stored and implemented in the business. To ensure that information is both available and suitable. It is required that processes and standards are available, clear and concise and that their related KPIs are quantifiable. To achieve this, we have employed a Quality Improvement Manager to redefine the Quality Management System and any supplementary systems required to ensure that quality results are attainable and measurable. The current focus is on:

- Documents Management System;
- Change Management System; and
- Risk Reporting System.

5.12.4 Change Management Systems

To align with international best practices, we are currently reconstructing the Change Management System to align with our document structure and the Quality Management System. Combining these three systems will enable us to adapt to change and grow sustainably. The change management system will look at the following:

- Identifying new and existing changes in the business;
- Analysis of and interpreting the effects of such changes; and
- Capturing and reporting on changes to ensure we are meeting our objectives.

5.12.5 As-Built Processes

We are currently undergoing a review of as-built processes to achieve the following improvements:

- Reduced timeframe of as-built data into asset information systems;
- Increase in data quality of asset information; and

- Asset information meets the requirements of core operation and planning systems.

This process review will support the ADMS and EAM system rollouts by ensuring accurate and timely asset information for maintenance and operational purposes.

5.12.6 Vegetation Management

We are working on a number of improvement initiatives relating to vegetation management:

- Enhanced fault cause reporting for vegetation events, considering if the species of tree can be recorded, as well as if the vegetation was inside the growth limit zone or not. It is hoped this additional information can be used to enhance our risk assessments undertaken when scoping our vegetation management programme;
- Replacing the existing information systems we use to manage vegetation with a Vegetation Management System (VMS). It is expected this will enable closer management of the vegetation programme and associated costs enabling us to refine our plans. It will also link to our customer management systems, to unlock better customer experiences; and
- Continued work towards agreeing vegetation management protocols with the local authorities within our network area.

In addition, we intend to repeat our LiDAR survey in 2023, which we originally undertook in 2020. As part of this, we intend to complete some analytics to establish the difference in observed vegetation encroachments between the two surveys. The insights gained from this will be used to further refine our vegetation strategy.

6.0 Network Reliability

6.0 Network Reliability

This chapter:

- Provides an overview of our approach to network reliability at Counties Energy;
- Provides analysis of how the network is performing, highlighting key themes/trends;
- Describes our future targets;
- Outlines our reliability investment within the planning period, and
- Sets out our improvement initiatives for the management of reliability.

6.1 Reliability Philosophy

6.1.1 Minimum Whole-Life Costs

We are continuously aware that our investment decisions will affect the prices our customers pay for electricity services long term. With this in mind, we are conscious to drive reliability improvements through cost-efficient long-term initiatives rather than short-term improvements which, although they may improve reliability faster, would incur overall higher costs for our customers long term. It is a primary focus of our asset management activities to ensure all expenditure is targeted to achieve the best overall network reliability, recognising that the asset is generally a long-term one and thus a minimum whole-life approach to costs is usually the most appropriate.

6.1.2 Regulatory Alignment

As a 100-percent consumer-owned EDB, we are obliged to meet Information Disclosure (ID) requirements, although we are exempt from the quality standards of non-exempt EDBs. Nonetheless, we recognise the regulatory regime as a widely consulted and agreed methodology in the industry. As a result, we aim to align closely with the regulatory methodology used by non-exempt EDBs as far as possible.

6.1.3 Change in Operating Environment from 2016

Comparing our operating environment before and after 2016, we recognise a number of changes which have significantly impacted reliability performance. The most notable changes being:

- **Weather Trends** – The period from 2007 to 2013 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 of 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 work, allowable only in exceptional justifying circumstances. Aside from a significantly increased number of planned outages required 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 with 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 improved traffic management safety. These changes impact both the financial cost and duration of planned and unplanned events.

As a result of these changes, we believe that attempting to extract useful trends using SAIDI data, and to a lesser extent SAIFI data, from before FY17 is unlikely to yield meaningful results. Therefore, for our trend analysis we have taken the approach that performance from FY17 is more indicative of the new typical network performance under the revised operating regime.

6.1.4 Unplanned Outages

Our reporting was updated for the start of FY22 (from 01 April 2021), so unplanned SAIFI/SAIDI (class C) is now measured using the latest ruleset used by non-exempt EDBs for the period 1 April 2020 to 31 March 2025, the third default price-quality path (DPP3). The main change is the methodology for determining major events (see section 6.1.5 below).

This means we now use the latest DPP3 methodology in all our reporting for unplanned (class C) SAIFI/SAIDI except where required to report using the Information Disclosure (ID) method.

6.1.5 Major Event Periods

The latest DPP3 methodology provides an industry-agreed method to distinguish regular day-to-day reliability from days where major events are occurring, such as significant storm events.

The normalisation method now uses a rolling 24-hour period to trigger the major event, with normalisation applied per 30-minute period rather than a calendar day approach as used in the previous regulatory rules. Boundary values have been defined from the 10-year (FY10–FY19) benchmark period.

In our reporting, we treat any event which falls within a SAIFI or SAIDI major event window as being part of, or being impacted by, the major event. Our reporting therefore has a separate category for 'Major Events'. We believe this leaves our reporting by cause to be a more accurate reflection of day-to-day network reliability. Events within major events are analysed separately (see section 6.5).

6.1.6 Planned Outages

Also aligned with the latest DPP3 methodology, we report separately on unplanned (class C) and planned (class B) SAIFI/SAIDI. This aligns with our understanding of our customer needs, where planned events are preferable to unplanned events. This is because planned events can be undertaken at a time ideally suited to, and with prior notice to, the customer, enabling them to prepare and, if necessary, make suitable alternative arrangements. This is in contrast to unplanned events, which have a much greater negative impact on customer experience.

With planned SAIFI/SAIDI being a necessity for renewal, growth, or customer-initiated works, we do not consider setting a target for planned SAIFI/SAIDI to be appropriate as this could drive the deferment or postponement of required works in order to meet such a target. Our approach to planned SAIFI/SAIDI could therefore be described as 'needs must', but instead moving the focus to customer experience.

We are aware of the latest DPP3 rules for planned SAIFI/SAIDI that have been updated to incentivise similar, better, outcomes for customers. However, this methodology utilises reasonably complex mathematical adjustments that result in a number suitable for regulation but would have lower meaningful value to our customers. Therefore, from FY23 (01 April 2022) we have reverted our reporting of planned SAIFI/SAIDI to align with the Information Disclosure (ID) method, removing any weighting factors as previously used, but introducing additional reporting metrics to measure and drive improved customer experience.

6.2 Reliability Strategy

Counties Energy recognises the direct effect network reliability has on the experience of our customers connected to the network and it is a core business priority reflected in our value of 'Always On'. Consistent with the approach outlined in previous versions of our Asset Management Plans, engagement with our customers has previously identified that, although improved service levels are desired, there is generally very limited support for increased line charges to undertake such improvements.

Our operating environment changed notably from 2016 (refer 6.1.3 above) which means for the last few years our customers have been experiencing a greater number of minutes per year of supply outages (SAIDI) than we would like. We are committed to continuously improving our network reliability, and have already made good improvements, but recognise there are still more improvements to be made.

6.2.1 Unplanned Outages

We aim to continuously improve our unplanned reliability performance, as set out in our reliability service levels (refer section 4.5). Within this, we manage our business-as-usual reliability through our reliability metrics (refer section 6.3). We report internally on these and have set targets for these going forward which align to our service levels.

Customer-Centric Reliability Reporting

It is recognised that measuring network reliability on SAIFI/SAIDI has the disadvantage that the metrics are averaged across all network-connected customers. There are likely to be extremes within this, where customers supplied from reliable urban networks may go years between interruptions. The converse is true for customers on long remote rural networks, where multiple interruptions can occur during a single year. Our previous 2022 AMP (update) outlined how an initiative to better report on this was more complex than expected and unlikely to proceed. However, in 2022 a potential interim solution was identified which, by adding some data linkages in our reporting systems between already available data sets, a customer-level view (by transformer) could be achieved. This is presently under development and expected to be implemented by early 2023. We hope to be able to report on areas of best-served and worst-served customers in future versions of this Asset Management Plan.

Major Events

The impact of major events is measured and reported on separately. These are approached as a resilience challenge. Increased network resilience through hardened asset solutions is a consideration in our asset planning, although our resilience planning also focuses on response readiness, aiming to restore the network as effectively as possible after the event has occurred.

6.2.2 Planned Outages

Rather than managing solely on the total frequency and duration of planned outages, we instead focus on:

- Whether sufficient advance notice has been given;
- Planned works started on time (but not early);
- Planned works finished on time;
- Cancellations kept to a minimum, and notified in advance wherever possible; and
- Repeat interruptions for planned works for the same customers within a 12-month period also kept to a minimum.

We are in the process of updating our internal reporting systems to report on these outcomes and hope to be able to disclose these as metrics in future versions of this Asset Management Plan. In the meantime, we have set monitoring targets for planned SAIFI/SAIDI going forward which align to our reliability service levels (refer to Section 4.5). These have been sized based on the volume of investment in our 10-year investment plan.

6.2.3 Weak Power (Part-Phase Outages)

'Weak power' events are events where only some of the high-voltage phases of a normally three-phase system have been affected by an outage. Depending on the local network arrangement, this can see a range of customer experiences from full voltage, to reduced voltage, to an outage. This is unusual for underground networks and is more commonly an issue for overhead networks, especially in rural areas. An improved structure for recording unplanned events was implemented in June 2021, which saw us bring the recording of weak power events into our core event recording systems. Although these are not included in the SAIFI/SAIDI reporting, it is recognised these types of outages impact customers too, and it is aimed to start reporting on these separately from FY24.

6.2.4 Auto-Reclose Interruptions

Auto-reclose events are events where circuit protection interrupts supply to a section of the network, but then attempts a number of automatic supply restorations ('recloses') a few seconds apart. If these are successful, customers connected to the network section may see up to three short interruptions within a period lasting less than a minute, with each interruption lasting only a few seconds. These schemes are designed to prevent temporary faults which have not caused permanent network damage, such as wildlife or glancing vegetation contact, from causing extended outages. With the duration lasting less than a minute these events are not counted in the SAIFI/SAIDI reporting, although they can be summarised into a metric known as Momentary Average Interruption Frequency Index (MAIFI), which is similar to SAIFI but for momentary (<1 min) interruptions.

The same improved structure for recording unplanned events mentioned above also saw us bring the recording of auto-reclose events into our core event recording systems. Although these are not included in the SAIFI/SAIDI reporting, it is recognised that these types of outages impact customers too, and it is also aimed to start reporting on these separately from FY24.

6.2.5 Power Quality

Our power quality strategy focuses on delivering voltage within the required thresholds, primarily focusing on our customers connected to low-voltage networks.

Voltage excursions are typically caused in three ways:

- Network Design/Configuration for Connected Load;
- Momentary fluctuations; and
- Weak Power Events.

Network Design/Configuration for Connected Load

Although each connection will have an agreed maximum capacity, the network is designed assuming that not every customer will draw their maximum capacity at the same time, a concept known as diversity. Our networks have, therefore, been built using after-diversity maximum demand (ADMD). The ADMD specific to a localised area can be affected by the amount, and timing, of customer consumption and can sometimes differ to the assumptions made during network design. This, in turn, can cause voltage excursions outside of requirements, usually aligning to periods of high localised consumption (or, increasingly, generation such as photo-voltaic/solar).

Additionally, a one-way power flow from grid to customer had historically been assumed. This, as well as our ADMD assumptions, is being challenged increasingly more often as our customers begin to take advantage of opportunities offered by electric vehicles and other DER. Further information on this topic can be found in section 9.1.3.

Prior to 2019, identification of voltage excursions usually relied on customers advising us. This then changed to take advantage of our access to smart meter information, accessible via our INDI platform (refer to section 5.4.1). We are now able to proactively monitor extended or regular voltage excursions (whether high or low), and initiate investigations long before customers advise us. We can also use the smart meter information, including site-specific consumption data, to begin investigations without always having to deploy monitoring equipment to site, and having to wait for the results.

The findings for each investigation can vary a lot from site to site; however, the causes of low voltages are often an increase in customer consumption due to new loads (increasingly electric vehicles). High voltages are increasingly caused by distributed generation, reversing power flow and challenging the historical one-way design assumptions of the network. Both issues are also often impacted by long customer-owned service lines, which often amplify the voltage excursion experienced at the customer's property. Many customers are not aware that they may own, or jointly own with their neighbours, the lines across private land that connect their property to the Counties Energy lines on the public road. If these lines are no longer suitable for the connected loads/distributed generation, the issue, unfortunately, resides with the private line owners to address. Sometimes the issue can be addressed by changing the settings on our transformers, or by minor network reconfiguration (refer programme in section 6.8.8).

During 2022, the occurrences of voltage excursions have increased compared to prior years. We have increased our resources to tackle these and are working on improving our process to better manage this increasing volume. We aim to leverage our smart meter access to keep this as proactive as we can, fixing the issues before our customers are noticeably impacted and feel the need to raise concerns with us.

Momentary Fluctuations

These are events where voltage will briefly fall below (also known as dip or sag) minimum requirements, or rise above (also known as swell) maximum requirements. These events usually correspond to fault events where network protection is operating and almost always last for less than a second. These fault events may be on the Counties Energy network, but fluctuations can also be driven by transmission grid events elsewhere in New Zealand.

Most customers will only ever notice these as a brief flicker in the lights, and most appliances will continue functioning. Some commercial or industrial customers may have more sensitive plant which may be impacted, although often this can be improved by looking at the ride-through capability of control systems or internal power supplies.

Short of preventing every fault on the network, these events cannot be entirely avoided. Our protection and control systems are designed with an objective to reduce the impact of momentary fluctuations to our customers, although there are public safety and reliability trade-offs that also have to be considered.

We have a fleet of permanent power quality monitors installed at our zone substations that, amongst other things, monitor for momentary fluctuations on our HV networks. We monitor and report on these internally.

Weak Power Events

Voltage excursions due to single-phase fuse operation on the HV network are treated as 'weak power' events. For further information, please refer to section6.2.3.

6.3 Reliability Metrics (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 Events and Customers Impacted, with SAIDI being the product of SAIFI and Duration (CAIDI [6]).

[6] CAIDI = Customer Average Interruption Duration Index

Figure 6-1 Component parts of SAIFI and SAIDI

The unplanned event categories used are:

Event Category	Description
Equipment – Overhead	Events caused by overhead network equipment
Third-Party Interference	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
No Cause Found	Events where the cause is not found and the network is restored, understood to be typically vegetation, wildlife or transient equipment issues
Wildlife	Events caused by birds, vermin or possums
Equipment UG/GM/ZS (Underground/Ground Mounted/Zone Substation)	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 Energy or our contractors
Major Events	Any event starting within the Major Event Window as defined by the DPP3 normalisation rules

Table 6-1 Unplanned Event Categories

This section presents our reliability metrics from FY17 to FY22, plus the latest FY23 result for the first six months of the year (to 30 September 2022). Further analysis of the results presented in this section can be found in the following section 6.4

6.3.1 Events

The following table shows the number of events by unplanned event category.

Category	FY17–FY21 Average	FY22	±% (from FY17–21)	FY23 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	120	114	– 5%	51
Third-Party Incident	35	29	– 17%	20
Vegetation	37	67	+ 81%	24
No Cause Found	39	53	+ 36%	29
Wildlife	14	16	+ 14%	3
TYPICALLY MINOR CONTRIBUTING CAUSES				
Equipment – UG/GM/ZS	4	4	0%	3
Adverse Conditions	4	2	– 50%	1
Network Incident	2	5	+ 150%	7
Total to all categories	**255**	**290**	**+ 14%**	**138**

Table 6-2 Events by Unplanned Category

6.3.2 Customers Impacted

The following table shows the average number of customers impacted by an unplanned event in each unplanned event category.

Category	FY17–FY21 Average	FY22	±% (from FY17–21)	FY23 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	186	173	– 7%	157
Third-Party Incident	329	334	+ 2%	378
Vegetation	377	383	+ 2%	343
No Cause Found	575	616	+ 7%	412
Wildlife	868	1220	+ 41%	485
TYPICALLY MINOR CONTRIBUTING CAUSES				
Equipment – UG/GM/ZS	787	1211	+ 54%	1419
Adverse Conditions	465	142	– 69%	248
Network Incident	1121	982	– 12%	993
Average to all categories	**352**	**405**	**+ 15%**	**353**

Table 6-3 Average Customer Impact by Unplanned Category

6.3.3 SAIFI

The following table shows SAIFI by each unplanned event category.

Category	FY17–FY21 Average	FY22	±% (from FY17–21)	FY23 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	0.527	0.430	– 18%	0.172
Third-Party Incident	0.276	0.212	– 23%	0.162
Vegetation	0.327	0.561	+ 72%	0.177
No Cause Found	0.534	0.715	+ 34%	0.257
Wildlife	0.295	0.425	+ 44%	0.031
TYPICALLY MINOR CAUSES				
Equipment – UG/GM/ZS	0.079	0.105	+ 34%	0.091
Adverse Conditions	0.046	0.006	– 87%	0.005
Network Incident	0.047	0.108	+ 130%	0.150
Total to all categories	**2.131**	**2.564**	**+ 20%**	**1.045**
Major Events	0.174	0.142	- 18%	0.209
Total	**2.305**	**2.705**	**+ 17%**	**1.254**

Table 6-4 SAIFI by Unplanned Category

6.3.4 Duration (CAIDI)

The following table shows the average duration (CAIDI) by each unplanned event category.

Category	FY17–FY21 Average	FY22	±% (from FY17–21)	FY23 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	78	103	+ 32%	83
Third-Party Incident	114	106	– 7%	105
Vegetation	54	62	+ 14%	78
No Cause Found	43	29	– 32%	46
Wildlife	27	31	+ 14%	54
TYPICALLY MINOR CAUSES				
Equipment – UG/GM/ZS	39	42	+ 6%	13
Adverse Conditions	46	61	+ 34%	30
Network Incident	20	20	0%	14
Average to all Categories	**60**	**55**	**– 7%**	**59**

Table 6-5 Duration (CAIDI) by Unplanned Category

6.3.5 SAIDI

The following table shows the SAIDI by each unplanned event category.

Category	FY17–FY21 Average	FY22	±% (from FY17–21)	FY23 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	41.26	44.36	+ 8%	14.24
Third-Party Incident	31.56	22.39	– 29%	17.08
Vegetation	17.68	34.66	+ 96%	13.77
No Cause Found	22.71	20.53	– 10%	11.87
Wildlife	7.97	13.09	+ 64%	1.70
TYPICALLY MINOR CAUSES				
Equipment – UG/GM/ZS	3.10	4.40	+ 42%	1.19
Adverse Conditions	2.11	0.38	– 82%	0.16
Network Incident	0.96	2.20	+ 129%	2.13
Total to all Categories	**127.35**	**142.01**	**+ 12%**	**62.14**
Major Events	7.84	5.89	– 25%	3.63
Total	**135.19**	**147.89**	**+ 9%**	**65.78**

Table 6-6 SAIDI by Unplanned Category

6.4 FY22 Analysis

An improved structure for recording unplanned events was implemented in June 2021, with events dating back to the start of FY22 (from 01 April 2021) reviewed and updated with the latest categorisation. The improved categorisation breaks each unplanned event category further into a cause and, in many cases, a sub-cause too.

Events are recorded by our Network Operations Centre (NOC), with a weekly event review meeting held between network operators, field teams, engineers and asset managers to review the events, validate the accuracy of captured events and capture any lessons learnt or required improvement actions.

The event data is used to produce a biannual 'Reliability Anatomy' report, which forms one of our continuous improvement feedback loops in our asset management system.

This section summarises the analysis for FY22, highlighting observations raised in the year.

6.4.1 Equipment – Overhead

The following table shows the breakdown of the Equipment – Overhead unplanned event category.

Cause	Event Count	Average Customer Impact	SAIFI	Average Duration (CAIDI)	SAIDI
Overhead Connector/Joint	32	75	0.052	111.6	5.85
Crossarm	13	206	0.058	69.3	4.04
Drop Out/Isolator	13	84	0.024	112.4	2.66
Insulator	11	359	0.086	74.3	6.37
Wire (Conductor)	10	240	0.052	104.7	5.46
Lightning Arrestor	8	279	0.049	49.1	2.39
Binder Wire	7	92	0.014	102.3	1.44
Enclosed Switchgear (Gas/Vacuum)	6	455	0.059	137.7	8.14
Pole-Mounted Transformer	6	27	0.004	212.0	0.75
LV Asset	4	11	0.001	248.7	0.24
Preform/Dead-end	1	1010	0.022	229	5.07
Pole/Structure	1	236	0.005	345.0	1.78
Foundation/ Stay Wire	1	11	0.000	22.0	0.01
Jumper	1	182	0.004	38.3	0.15
Equipment Overhead	**114**	**173**	**0.430**	**103.1**	**44.36**

Table 6-7 Equipment – Overhead Unplanned Event Category

Notable Observations Raised:

Overhead Connector/Joint

Of the 32 events, 29 have been due to historical work practice which saw aluminium conductors (jumpers), usually Swan, directly terminated into the tinned copper terminals of drop-out fuse assemblies, causing galvanic corrosion of the aluminium. Eventually this breaks the jumper, resulting in an open circuit failure on one HV phase. Although initially causing a 'weak power' event due to only one phase being impacted, the repair typically involves an emergency shutdown. This is typically a spur line problem, hence the small average customer impact, although the outage can extend to the upstream (sometimes backbone) side if the failure is on the incoming side, the incoming side has to be isolated for safety reasons, or the decision is taken (which it commonly is) to repair all six terminals whilst the construction crew has been mobilised.

On the discovery of this trend, it was confirmed the standard requiring the installation of bi-metallic connectors, therefore preventing the galvanic corrosion, has been in place for many years. Refer to section 8.4.2 for the actions being undertaken as a result of this identified trend.

Crossarms

Of the 13 events, three have been failures of kingbolts on wooden arms, one was an arm brace failure and the remaining nine have been mechanical failure/rot on wooden arms. Only four of these 13 actually failed, resulting in a trip, the others were deemed urgent enough to justify an unplanned shutdown to customers to repair. Refer to section 8.4.3 for the actions being undertaken as a result of this identified trend. In addition, our Emergency Shutdown procedure was reviewed in 2022 to ensure unplanned shutdowns for work deemed urgent are taken with customer experience in mind (refer 6.6.3).

Insulator

Of the 11 events, three were on our subtransmission network. Due to the network redundancy at these voltages, the repairs were achieved with minor impact to customers. The other eight events were recorded as failures of insulators with a 'pin' design, of which four were at 11 kV, and the other four at 22 kV. Refer to section 8.4.3 for the actions being undertaken as a result of this identified trend.

Conductor

Of the 10 events attributed to conductor, three were related to suspected line clash issues relating to the installation of the conductor rather than asset failure of the conductor itself.

Of the remaining eight events, two were on small ACSR [7] (Swan) and the rest are small (16mm^2) copper. Refer to section 8.4.2 for the actions being undertaken as a result of this identified trend.

Enclosed Switchgear (Gas/Vacuum)

Of the 8.14-minute SAIDI total, 6.3 minutes was caused by a single emergency shutdown to nearly 2,000 customers due to a safety low-SF_6 gas inhibit switch activating and preventing us from breaking a critical feeder tie after planned switching. This was not ideal but was deemed to be necessary with weather forecast indicating incoming high winds a few days later. Although a high SAIDI impact, the interruption was scheduled to happen overnight at a time deemed to have the lowest impact on our customers.

6.4.2 Third-Party Incident

The following table shows the breakdown of the Third-Party Interference unplanned event category.

Cause	Event Count	Average Customer Impact	SAIFI	Average Duration (CAIDI)	SAIDI
Vehicle vs Pole	21	278	0.128	136.5	17.47
OH Line Contact	5	544	0.059	28.8	1.71
Cable Strike	2	565	0.025	130.8	3.21
(Other)	1	0	0.000	0	0.00
Third-Party Interference	**29**	**334**	**0.212**	**106**	**22.39**

Table 6-8 Third-Party Interference Unplanned Event Category

This shows 73% of incidents are vehicle vs poles. Of the OH Line Contact, only one of the events was a true contact (by digger). The others were:

- A damaged high-pressure water main which required a subtransmission circuit to be de-energised for safety – with zero customer impact;
- Irrigation sprayer causing lines to clash;
- Metallic party balloon hitting lines; and
- Emergency shut due to irrigation hose hanging over lines.

In 2020 we developed an asset vulnerability model (refer 5.3.3). The model is used to identify network assets located near sections of road with high numbers of reported crashes. This is used as an input to our asset planning and, in some cases, will see assets protected, engineered differently or even relocated. We are currently exploring options to collaborate with our peers to utilise more advanced models to improve our management of car vs asset risk.

[7] ACSR = Aluminium Conductor Steel Reinforced

6.4.3 Vegetation

The following table shows the breakdown of the Vegetation unplanned event category.

Cause	Event Count	Average Customer Impact	SAIFI	Average Duration (CAIDI)	SAIDI
Debris	37	463	0.375	54.8	20.56
Tree Fallen	16	296	0.103	35.8	3.70
Tree Contact	14	271	0.083	125.2	10.41
Vegetation	**67**	**383**	**0.561**	**62**	**34.66**

Table 6-9 Vegetation Unplanned Event Category

The definitions used for these causes are below.

Event Category	Description
Debris	This is defined as 'part of tree (i.e. bark or branch) blown into or fallen onto line' and can range from a shred of gum bark or small twig, to an entire tree limb/branch. Depending on the size, there can be damage to the lines, requiring repair, which would increase the duration of the repair.
Tree Fallen	This is defined as the entire tree falling across the line. This almost always results in damage to the lines, requiring repair, which would increase the duration of the repair.
Tree Contact	This is defined as where a tree contacts the line whilst still attached (i.e. not debris or fallen).

Table 6-10 Vegetation Event Categories

Whether the tree was inside the Growth Limit Zone (GLZ) or not is not something which is recorded at present. However, if the broad assumption is made that Tree Contact arises from trees inside the GLZ, and Debris/Fallen trees are typically outside the GLZ, then 53 out of 67 (79%) of the recorded events are outside the GLZ and, therefore, the scope of the tree regulations. This number is 85% for SAIFI and 70% for SAIDI.

It is planned to enhance our fault cause reporting for vegetation events, considering if the species of tree can be recorded, as well as if the vegetation was inside the growth limit zone or not. It is hoped this additional information can be used to enhance our risk assessments undertaken when scoping our vegetation management programme.

Refer to section 5.2.3 for details of our Vegetation Management Strategy, and section 6.7 for details of our Vegetation Management Programme.

6.4.4 No Cause Found

The following table shows the breakdown of the No Cause Found unplanned event category.

Cause	Event Count	Average Customer Impact	SAIFI	Duration (CAIDI)	SAIDI
Reclosed After Patrol Complete	50	625	0.684	29	19.96
Reclosed Before Patrol Complete	3	471	0.031	18	0.56
Total No Cause Found	**53**	**616**	**0.715**	**29**	**20.53**

Table 6-11 No Cause Found Unplanned Event Category

Events are recorded as No Cause Found when no evidence of a likely cause is found. Our experience, however, indicates that these originate from an approximately 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 the 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, sometimes with additional equipment deterioration and then a subsequent wind.

Our operational procedures already include a mandatory patrol of any network that has tripped and locked out (i.e. not successfully auto-reclosed). This is an attempt to find the cause, even if the network was successfully restored before a full patrol was completed. A patrol is also completed for 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.

6.4.5 Wildlife

The following table shows the breakdown of the Wildlife unplanned event category.

Cause	Event Count	Average Customer Impact	SAIFI	Duration (CAIDI)	SAIDI
Bird	14	978	0.298	32	9.49
Possum	1	1171	0.025	72	1.82
Other Wildlife	1	4658	0.102	17	1.78
Total Wildlife	**16**	**1220**	**0.425**	**31**	**13.09**

Table 6-12 Wildlife Unplanned Event Category

Of the 16 events, 14 have been recorded as bird strikes, with one possum and one other (cat). The cat came into contact with the 33 kV buswork within one of our zone substation outdoor switchyards, causing a significant outage to 4658 customers. This event triggered a review of our substation perimeter fencing standard, involving some improvement work at the site where the incident happened.

Of the other events, 12 were on our 22 kV distribution networks at sites built to older standards using 2.0 m crossarms. This is a near-identical construction to that typically found on 11 kV networks, and although electrically safe and compliant, we now believe the similar clearances for double the voltage is leading to more transient events that would otherwise be experienced if the voltage remained at 11 kV. Many of these sites are also on urban feeders around the Pukekohe or Papakura areas and this is reflected in the high average customer impact of these events. We believe it is unlikely that these areas have a higher population of birds compared to the rest of the network, and it is more likely reflective of the higher susceptibility of the legacy 22 kV designs to bird strikes. Additionally, with these being urban areas they do not have the auto-reclose functionality which would prevent a bird strike from becoming an extended outage, which could explain why we don't have many bird strikes recorded on our rural networks.

In 2020 our construction standards were updated to a 2.4 m galvanised steel crossarm with polymer clamp top insulators in a delta configuration, where appropriate. This configuration should minimise the frequency of bird strikes on the sections of network which have been rebuilt.

Due to the length of our network currently built to legacy designs, which remain in good condition and within the operate stage of their lifecycle, it is not economically viable to rebuild the whole network to this revised standard. As such, we continue to monitor locations of events, and may look to undertake targeted localised replacements in the future if particular areas of repeat concern arise.

6.4.6 Typically Minor Contributing Causes

Events classified in here include:

- Equipment Failures at Zone Substations, on Underground, or on Ground Mounted Assets;
- Adverse Conditions – Weather conditions outside of design limits such as tornadoes, lightning, seismic events, landslip or flood; and
- Network Incidents – events caused by the actions of Counties Energy or our contractors that have resulted in an unplanned event.

These causes are treated as minor contributors, because historically they have contributed less than 5% of the annual SAIDI.

6.5 FY22 Major Event Periods

6.5.1 FY22 Major Event Summary

The following table shows the summary of periods identified in FY22 identified as Major Events.

Number	Major Event Window (Start Date/Time of First Event)	SAIFI Major Event?	SAIDI Major Event?
1	28/06/2021 23:25	Yes	Yes
2	02/08/2021 18:29	Yes	Yes
3	23/11/2021 12:17	Yes	Yes
4	11/02/2022 08:46	Yes	Yes

Table 6-13 FY22 Major Event Summary

6.5.2 FY22 Major Event One

- Major Event Original SAIFI: 0.135 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.018
- Major Event Original SAIDI: 7.45 (SAIDI trigger met)
- Major Event Normalised SAIDI: 0.865

The day of wet and windy weather saw a number of events on various feeders. The sum of these triggered the DPP3 major event window thresholds.

A notable event within this major event was a No Cause Found event on Bombay feeder. This was the largest event in customer impact although not the largest SAIDI,. A protection mal-operation caused the incoming 33 kV circuit breaker to operate for a fault on the Bombay feeder, causing a loss of supply to 2,316 customers on Ramarama zone substation.

A summary of events by fault type/cause can be found in the table below.

Cause	Event Count	Average Customer Impact	SAIFI	Average Duration (CAIDI)	SAIDI
Equipment – Overhead	3	853	0.056	65.6	3.70
Overhead Connector/ Joint	1	211	0.005	141.0	0.66
Wire (Conductor)	1	992	0.022	44.6	0.97
Pole-Mounted Transformer	1	1357	0.030	69.2	2.07
No Cause Found	3	857	0.057	38.2	2.17
Vegetation	2	504	0.022	71.8	1.59
Tree Fallen	1	455	0.010	137.1	1.37
Debris	1	552	0.012	17.9	0.22
Major Event One	**8**	**767**	**0.135**	**55.1**	**7.45**

Table 6-14 FY22 Major Event One by Cause

6.5.3 FY22 Major Event Two

- Major Event Original SAIFI: 0.164 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.021
- Major Event Original SAIDI: 17.95 (SAIDI trigger met)
- Major Event Normalised SAIDI: 1.27

The day of wet and windy weather saw a number of events on various feeders. The sum of these triggered the DPP3 major event window thresholds.

In terms of SAIFI, Vegetation made up the bulk of the major event, contributing 0.119/0.164 (73%). This represented 5,417 ICPs losing supply across nine events.

A summary of events by fault type/cause can be found in the table below.

Cause	Event Count	Average Customer Impact	SAIFI	Average Duration (CAIDI)	SAIDI
Equipment – Overhead	8	253	0.044	123.9	5.50
Binder Wire	3	329	0.022	143.4	3.10
Wire (Conductor)	3	158	0.010	157.1	1.63
Overhead Connector/ Joint	2	283	0.012	62.2	0.77
No Cause Found	1	51	0.001	207.0	0.23
Vegetation	9	602	0.119	102.6	12.17
Tree Contact	4	571	0.050	101.1	5.05
Debris	3	418	0.027	47.1	1.29
Tree Fallen	2	941	0.041	141.4	5.83
Equipment – Underground	1	13	0.000	149.9	0.04
LV Asset	1	13	0.000	149.9	0.04
Major Event two	**19**	**395**	**0.164**	**109.1**	**17.95**

Table 6-15 FY22 Major Event Two by Cause

6.5.4 FY22 Major Event Three

- Major Event Original SAIFI: 0.233 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.003
- Major Event Original SAIDI: 24.70 (SAIDI trigger met)
- Major Event Normalised SAIDI: 0.14

This was made up of one single event, being the loss of Opaheke zone substation. This was caused by Vegetation contacting the Bombay-Opaheke (West) 110 kV line whilst the Bombay-Opaheke (East) 110 kV line was out of service for planned work, affecting supply to 10,712 customers. This was progressively restored over 198 minutes, with an average customer outage duration (CAIDI) of 106 minutes. The restoration to some customers was also delayed due to a separate SCADA communications issue.

Following this incident, a full investigation was completed looking into the decisions taken leading up to the incident, as well as the restoration response. This uncovered a number of opportunities to do things better, which were taken as learnings for this event. A number have already been implemented, such as improvements to our critical infrastructure outage planning (refer section 5.10).

6.5.5 FY22 Major Event Four

- Major Event Original SAIFI: 0.344 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.100
- Major Event Original SAIDI: 76.64 (SAIDI trigger met)
- Major Event Normalised SAIDI: 3.61

The day of wet and windy weather saw a number of events on various feeders. The sum of these triggered the DPP3 major event window thresholds. This event is linked to the extratropical remnants of Cyclone Dovi a 'significant weather event' for New Zealand.

In terms of SAIFI, Vegetation made up the bulk of the major event, contributing 0.234/0.344 (68%). This represented 10,832 ICPs losing supply across 27 events.

A summary of events by fault type/cause can be found in the table below.

Cause	Event Count	Average Customer Impact	SAIFI	Average Duration (CAIDI)	SAIDI
Equipment – Overhead	9	222	0.043	241.8	10.45
Pole-Mounted Transformer	2	147	0.006	369.7	2.34
Wire (Conductor)	2	303	0.013	309.9	4.06
Overhead Connector/ Joint	2	307	0.013	34.2	0.45
Pole/Structure	1	55	0.001	379.0	0.45
Crossarm	1	21	0.000	1018.8	0.46
LV Asset	1	410	0.009	302.1	2.68
No Cause Found	5	619	0.067	64.8	4.34
Vegetation	27	401	0.234	264.0	61.86
Debris	6	456	0.059	147	8.72
Tree Fallen	7	293	0.044	382.5	16.97
Tree Contact	14	432	0.131	276.4	36.17
Major Event Four	**41**	**388**	**0.344**	**222.5**	**76.64**

Table 6-16 FY22 Major Event Four by Cause

6.6 FY23 SAIDI Improvement Initiatives

In early 2022, a list of SAIDI improvement initiatives were identified and prioritised by a cross-functional business team. These are being worked on throughout FY23 and are grouped into four areas.

6.6.1 Vegetation

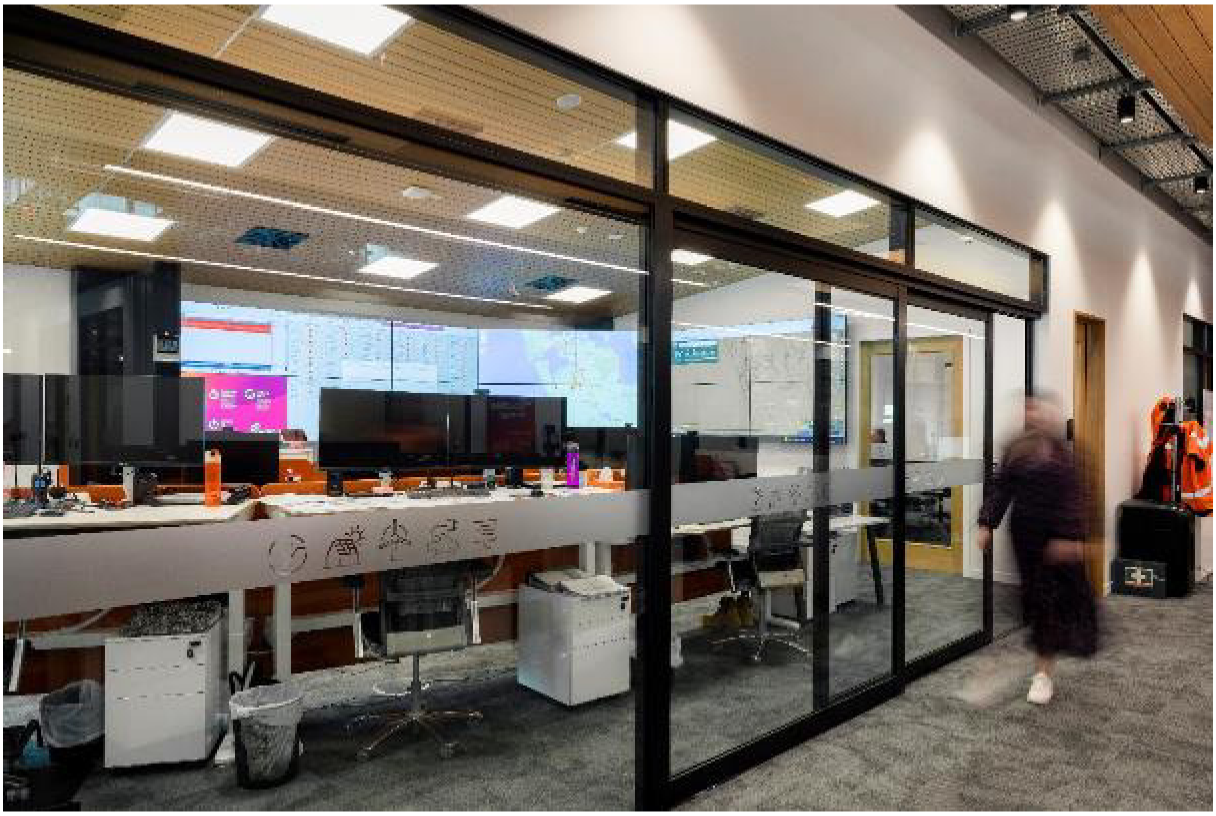
- Consider our vegetation management standard, looking to identify any further improvements that could be made to how out-of-zone vegetation is managed;
- Continue pushing for operational agreements with the two major councils in our network region, aiming to reduce the administration burden and approval time delays to deal with vegetation on public road corridors;
- Refresh the wording in our Cut and Trim Notices (CTN), which go to landowners, clarifying the requirements and emphasising the importance of swift action in terms of benefits to neighbours as well as the wider community;
- Proactive community messaging to all landowners in the community, emphasising the importance of effective vegetation management around power lines on their property and the benefits to the wider community; and
- Upskilling and providing tooling for our first response employees, enabling them to clear more vegetation under fault scenarios than they have traditionally been able to.

6.6.2 Fault Response

- Overhaul of our internal reporting metrics on response times to unplanned events;
- Reach out to industry peers and share learnings relating to response time improvement;
- Clarify standard procedures for reactive repair, aiming to improve consistency between reactive response teams;
- Increase focus on restoration, notably through temporary line breaks or low-voltage back-feeding where possible; and
- Clearer definition of roles with an unplanned event, including the flexibility available within these to ensure hold/wait points during unplanned events are kept to a minimum.

6.6.3 Network Operations Centre (NOC)

- Improved management of outages on critical infrastructure, such as subtransmission circuits, increasing the risk assessment and contingency planning required; and
- Update to the Emergency Shutdown Procedure, ensuring thorough risk justification for emergency shutdowns, and mitigation of customer impact where justified.



The Network Operations Control room at Counties Energy

6.6.4 Network Protection/Automation

- Refresh and update our Network Protection Philosophy and Electrical Protection Guidelines documents to capture learning from recent projects and substation builds. Focus on distribution protection, looking to address gaps highlighted by lessons learnt from events over the last two years;
- Conduct a network-wide review of all existing protection design and configuration against the philosophy/guidelines, and highlight gaps between what is implemented and what is asked for. Prioritise these gaps for any required remediation, with the highest priority to be addressed in FY24;
- Increase effectiveness of maintenance activities on existing automation devices, ensuring their continued availability for unplanned events;
- Consider introducing the ability for auto-reclosing on subtransmission circuits operating at reduced security levels, where the risk is tolerable; and
- Improve operational management of high-voltage distribution fusing.

6.7 Vegetation Management Programme

6.7.1 Vegetation Approach

Our vegetation management is undertaken primarily in accordance with the Electricity (Hazards from Trees) Regulations 2003 [the tree regulations]. These are prescriptive and transactional, focusing on addressing any vegetation growing close to conductors, but at present do not support us in addressing trees further away from lines (out of zone) that either present a risk of falling through or shedding debris into lines.

Our vegetation programme is risk-based. The likelihood is informed by the analysed results of our Light Detection and Ranging (LiDAR) survey (last completed in early 2020), identifying sections of line where vegetation has been detected near to lines as well as trees which could present a fall hazard, based on their height and distance from the line. Analysis of this against our network criticality model has produced a risk-based view of the zone's health in terms of vegetation, which was used to prioritise our plan.

As permanent removal of in-zone trees and remedial works on out-of-zone trees are outside the scope of the tree regulations, any remediation possible currently relies entirely on negotiation with the tree owner. This can consume a lot of administrative resources and lead to costs borne by Counties Energy, and therefore all network customers, rather than the tree owner which is otherwise generally the intent of the tree regulations. Out-of-zone vegetation continues to represent the majority of our known vegetation-related faults (refer to Section 6.4.3), rising even higher during stormy weather conditions. . These are industry-recognised problems. The Electricity Network Association (ENA) established a vegetation working group several years ago, formed of subject matter experts across many New Zealand EDBs. Counties Energy has been actively involved in this group. It is understood that the Ministry of Business, Innovation and Employment (MBIE) is still working on a full review of the tree regulations that initially commenced in 2018, on which progress updates are keenly anticipated.

6.7.2 Vegetation Plan

We are working to a five-year proactive vegetation plan, which commenced in FY21. A component of this approach also ensures our 33 kV and 110 kV subtransmission circuits are surveyed annually due to their high criticality. During the year, the programme may be reprioritised to address higher-risk sections identified on the network.

The warmer and wetter than average weather conditions throughout 2022 have seen faster vegetation growth rates than normally expected. This reflected in our reliability metrics for FY22 for Vegetation (refer section 6.4.3) and slowed down the delivery of our five-year plan due to the higher volumes of vegetation discovered during scoping. We have responded to this by increasing our vegetation management activities with the support of external contractors and have increased the budget available in the vegetation management programme for the first five years of the planning period. We intend to review this annually based on performance against our reliability metrics.

6.7.3 Vegetation Management Process

The majority of our vegetation plan is delivered by our utility arborist crews within our Field Operations team.

This includes:

- Undertaking tree surveys;
- Tree owner liaison; and
- Undertaking proactive and reactive cuts.

Our team is assisted by external contractors when workload requires, or specialist skills or equipment is needed.

A site scoping visit is first undertaken to validate the sites identified by LiDAR and any additional sites that have grown closer to the lines since the survey was undertaken. 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 us, 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, where it is advantageous for either the network or the tree owner to remove the tree, this can sometimes be facilitated by negotiation.

During the scoping, we also use the opportunity to survey sites with out-of-zone vegetation that poses a risk to the network, such as vegetation likely to shed debris into the lines or those flagged by LiDAR as potential sites where the tree could fall across the lines. For these out-of-zone sites, an arboricultural assessment is made based on tree species and health. This is used to inform the site's risk assessment, which informs the justification and prioritisation of any required remedial works. For these out-of-zone trees, we advise the owner and work with them to eliminate identified high-risk situations.

Information about trees near power lines is available on our website: https://www.countiesenergy.co.nz/articles/trees-near-powerlines.

6.7.4 Local Authority-Owned Vegetation

We estimate that approximately 75% of vegetation near lines in urban areas, and 25% in rural areas to be within the public road reserve and therefore owned by the relevant local authorities. If the intent of the tree regulations were followed, the full cost for ongoing management of this vegetation beyond the first trim would sit with these authorities as the tree owner. It is, however, our experience that funding is not available within these authorities to complete these works, and the processes to seek approval can take a long time and be admin heavy.

We have been working closely with the two main local authorities within our network area to agree on standard protocols on how this vegetation be better managed, focusing on guidance for works that can proceed without as many approval steps, although it is likely the cost will remain with the electricity lines customers. These discussions are ongoing.

6.8 Targeted Reliability Investment Programme

This section outlines our investment plan for the 10-year planning period, where the investment falls into the Reliability, Safety and Environment category. This includes:

- Quality of supply;
- Legislative and regulatory; and
- Other reliability, safety and environment.

It needs to be highlighted that nearly every project under Asset Replacement and Renewal (refer Chapter 8.0) as well as Network Development (refer Chapter 9.0) will have been scoped and designed with our Reliability Strategy and objectives considered. As such, the vast majority of investment aiming to meet reliability objectives sits outside of this targeted reliability investment programme. The project list in this section is not therefore an exhaustive list of projects with a network reliability benefit, but instead a programme of reliability targeted investment that supplements our more conventional investments in replacement, renewal and growth.

The specified projects in FY23–FY28, in conjunction with other network investments which also are expected to improve reliability, are expected to enable the achievement of our reliability objectives. For this reason, significant investment is not presently identified in the second half of the planning period. This may be revised in future versions of this Asset Management Plan as objectives or network reliability measures require.

6.8.1 Automation Re-build

The number of field devices such as overhead or ground-mounted switchgear with remote control and indication abilities, colloquially referred to as ‘automation’, has progressively grown on our network over many years. Initially begun as a strategic rollout, the policy later evolved. For the last several years, all newly installed field devices have been installed with automation functionality. As a result, beyond the initial deployment, the penetration of automation has not been even across the network, with areas of high investment from renewal or growth drivers seeing higher volumes of installed automation whilst other areas remained relatively lower.

When the existing SCADA radio network was identified in 2020 as approaching end-of-life, this presented an opportunity to consider whether our existing deployment of automation was fit for purpose. Analysis completed in 2021 indicated that instead of replacing just the radio communication equipment in all existing locations, a greater overall benefit to network reliability could be achieved by considering sites strategically network-wide. Our then recently developed Network Criticality Model enabled this analysis.

This approach would likely see the existing automation capability removed from some sites on feeders with an existing high penetration of automation, instead placing new additional sites on feeders that, at present, have less. Initial analysis completed on close to 90% of the network indicated that taking a strategic placement approach for the same investment could see the SAIDI saved annually increase by 10–15% compared to replacing all existing sites like-for-like, and the next stage of detailed modelling is still indicating these benefits.

Further analysis and scope determination has progressed throughout 2022, with estimated programme costs now built up based on the numbers of sites to be worked on. Equipment selection, scoping and site-specific design started in 2022, with the first sites programmed to be delivered in early FY24. The programme has been accelerated slightly compared to the previous Asset Management Plan, with the bulk of the work previously scheduled for FY26 now brought forward to FY24 and FY25 in order to deliver reliability benefits to customers sooner.

6.8.2 Network Isolation Point Improvement (NIPI)

Analysis completed in 2021, enabled by our then recently developed Network Criticality Model, compared the existing as-built network to our previously published security criteria requiring no more than 300 customers to be connected to a switching segment (i.e. between switching devices). A change to the previous approach, analysis was undertaken to consider the network lengths of each section. This showed that some sections could stretch for relatively long distances, in some cases up to 10 km, between switching devices, despite having less than 300 connected customers. With SAIFI (and therefore SAIDI) being a function of the number of faults as well as impacted customers, the model highlighted that focusing on customer numbers alone did not drive an outcome as optimal as considering customer numbers and network length.

Based on the modelled results, it was recommended to install new switching devices onto the network. Programme scoping completed in 2022 has identified approximately 60 locations network-wide, which collectively are expected to save around 9 SAIDI minutes per year based on present network design, fault rates and response times.

Installation started in FY23 after an opportunity to bring forward some expenditure to FY23 and deliver benefits to customers sooner was taken. The programme is expected to continue until FY27.

6.8.3 Fault Passage Indicator Deployment

Although Counties Energy has used overhead fault passage indicators for many years, they have traditionally been used as an operational tool, deployed to the network to chase down an intermittent fault, and then returned to the depot for future use elsewhere. As standard, all ring main units installed in the last few years have also been installed with fault passage indicators on all ring switches.

It is now considered that an effective deployment of permanently installed fault passage indicators can assist fault responders in locating the cause of unplanned events, thereby reducing restoration time and therefore SAIDI. This can be achieved by avoiding the need to patrol hard-to-access locations such as private property or restricted areas, or simply by adding fault passage indication ability to existing manual switchgear.

Although fault indication is made more difficult on the Counties Energy network due to our population of autotransformers, our initial research indicates devices are available on the market that overcome these challenges and meet our needs. An allowance has been included from FY24 to FY27 to source, trial and deploy fault passage indicators network-wide on both our overhead and underground networks.

6.8.4 Feeder Projects

A number of minor feeder projects are planned throughout the planning period. These projects each address individual site-specific reliability concerns, although they typically aim to either introduce secondary network feeds into an area or reduce the criticality of particular assets on the network. These projects will either therefore aim to provide alternative means of supply should the main feed to an area be out of service, or reduce the customer outage impact should a single asset be impacted, such as a car versus pole.

A subset of this programme will see four new reclosers installed on our Glen Murray, Onewhero, Red Hill and Hingaia feeders. These will reduce the number of customers impacted by faults in certain locations and enable rural sections of otherwise urban feeders to have auto-reclosing functionality.

6.8.5 Feeder Undergrounding

A small number of minor feeder undergrounding projects are also planned throughout the planning period. Although these areas would not normally be needing replacement yet, they have been identified as high SAIDI criticality, with high customer impact should a fault occur. They are also localised urban areas within our 22 kV overhead line network built to legacy 22 kV construction standards, which we now know to be susceptible to vegetation, debris and bird strikes. These projects will see the overhead lines replaced with underground cables, with ground-mounted switchgear too if required.

6.8.6 Legislative and Regulatory

For FY24, $300,000 has been budgeted to upgrade the HV metering equipment between the Counties Energy network and the Vector network in order to meet regulatory requirements.

6.8.7 Recloser Air Gap

Counties Energy has a fleet of reclosers in service across the network. Although these are a range of designs, almost all utilise vacuum interrupters for the circuit breaker with either solid or gas insulation. It has been identified that approximately half of these are currently installed ‘hard-tapped’, that is, there is no other device other than the vacuum interrupter if the recloser is called upon as a point of isolation. Engineering investigation undertaken in 2021 guided an operational decision to no longer rely solely on vacuum interrupters as a point of isolation. This programme has included an allowance to install additional solid links in-series with the existing reclosers that do not already have them, enabling these recloser sites to continue to be used as a point of isolation and avoid additional customer impact from needing to take wider outages.

6.8.8 Power Quality Compliance

An additional $304,721 has been added to FY24 to address known site-specific issues by installing additional distribution transformer capacity. This was originally planned for FY23 but was not able to be delivered due to site specific issues. Otherwise, a provision of $350,000 per year remains unchanged for years in the planning period.

6.8.9 Summary of Expenditure

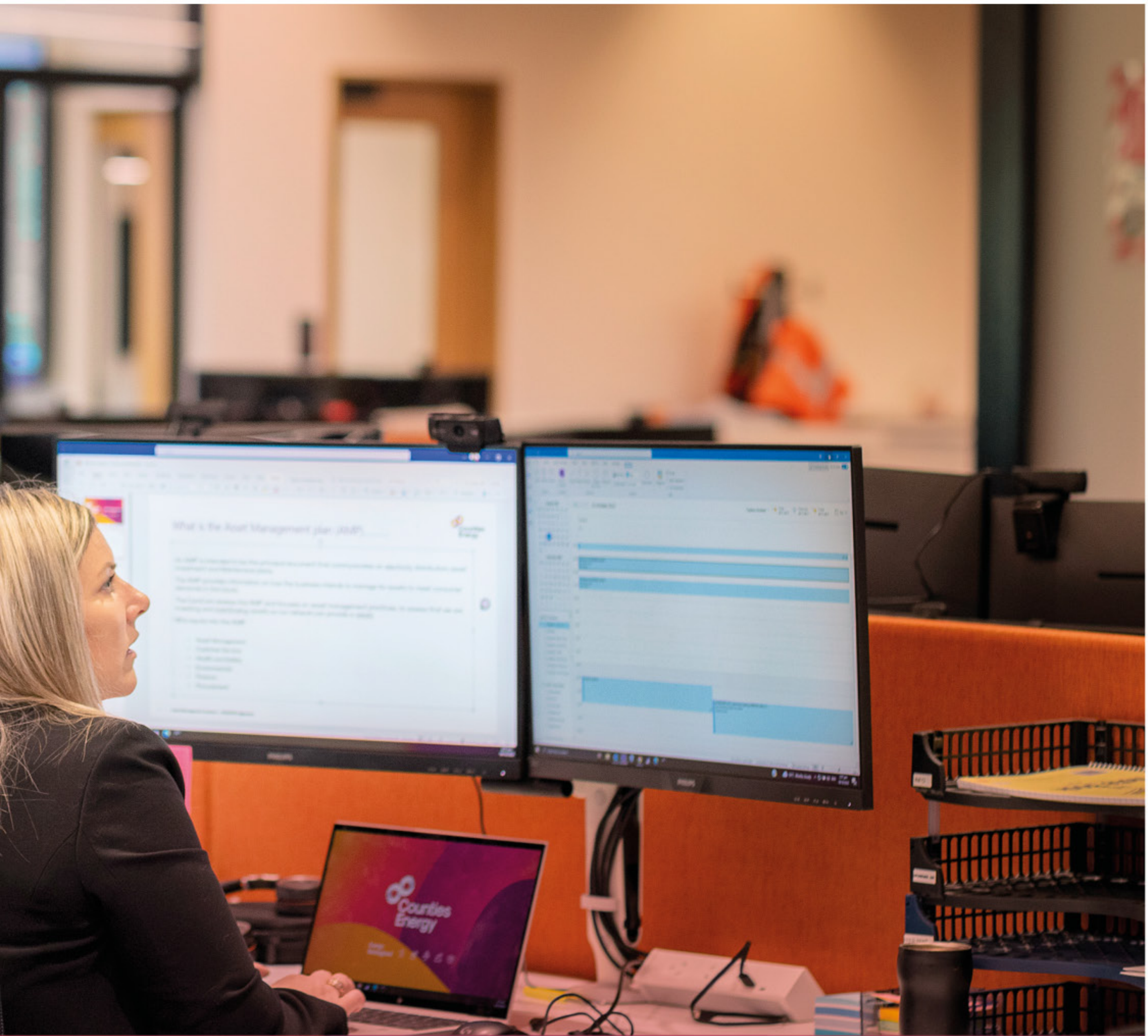
Project	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
QUALITY OF SUPPLY ($000S)										
Automation Re-Build	3,065	2,658	1,330	-	-	-	-	-	-	-
Network Isolation Point Improvement	1,138	374	374	299	-	-	-	-	-	-
Fault Passage Indicators	185	583	583	583	-	-	-	-	-	-
Feeder Projects	920	200	55	192	409	-	-	-	-	-
Feeder Undergrounding	620	1,195	-	-	990	-	431			
LEGISLATIVE AND REGULATORY ($000S)										
Legislative and Regulatory	300	-	-	-	-	-	-	-	-	-
OTHER RELIABILITY, SAFETY AND ENVIRONMENT ($000S)										
Recloser Air Gap	75	77	77	-	-	-	-	-	-	-
Power Quality Compliance	655	350	350	350	350	350	350	350	350	350

Table 6-17 Capital Expenditure Summary for Reliability, Safety and Environment

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
VEGETATION MANAGEMENT ($000S)										
Vegetation Management	2,500	2,500	2,500	2,500	2,500	2,100	2,100	2,100	2,100	2,100
SERVICE INTERRUPTIONS AND EMERGENCIES ($000S)										
Faults	2,838	2,876	2,901	2,927	2,954	2,980	2,994	3,007	3,021	3,034

Table 6-18 Operational Expenditure Summary for Vegetation Management & Service Interruptions and Emergencies

7.0 Innovation & New Technology



7.0 Innovation & New Technology

The Technology and Digital programme at Counties Energy is increasing at pace as the organisation digitises and embraces complex new technologies to deliver greater value to its customers and stakeholders and prepare for a low-carbon, electric future. This work programme reflects the organisation's growth as one of the fastest growing EDBs in New Zealand, with a trajectory towards transforming to be one of the smartest DSOs in New Zealand.

Counties Energy is investing in key areas of its core operations as part of its Digital Utility Strategy programme. This programme initially focuses on upgrades of key platforms such as Advanced Distributed Management System (ADMS), Maximo – Enterprise Asset Management System, Cloud Data and Integration platform, and OT/IT cyber security upliftment (part of the Cyber Security strategy). With some of the existing platforms and software tools coming to the end-of-life, Counties Energy is investing in the next phase of Technology and Digital capabilities that will prepare the business for a smarter energy future.

7.1 Core Systems Implementation & Improvement

The focus for Counties Energy's core systems is in ensuring the right capabilities and functions are being delivered or supported by the right tooling or system. The introduction of some new core systems and replacement/upgrade of others provides the opportunity to align functionality with the right data source, user experience and technology system.

7.1.1 Advanced Distribution Management System

Counties Energy is implementing GE Digital's PowerOn Advantage ADMS as part of its Digital Utility transformation programme. The ADMS solution, in combination with our existing implementation of GE Digital's Smallworld Electric Office, will drive greater reliability, resilience and flexibility for our assets through richer multi-source data. Combining the two platforms will enable smarter, sustainable and innovative energy services and solutions that deliver better customer experiences, operational efficiencies, and the ability to manage growth intelligently, ultimately shaping a future-proofed energy platform.

The ADMS solution combines Supervisory Control and Data Acquisition (SCADA), Distribution Management System (DMS) and Outage Management System (OMS) capabilities. By implementing this solution, Counties Energy will have a single platform to safely interact with its network, control work and share information in real-time and ultimately lead to providing low-voltage network visibility and control.

By integrating ADMS and Electric Office, Counties Energy will be able to provide network operators with an accurate connected single view of the end-to-end network of assets with a fully digital as-built process flowing from the field to Smallworld Electric Office and on to the ADMS. There are also plans to create a rich picture of its network by utilising its smart meter coverage to increase the accuracy of the traditional SCADA high- and medium-voltage view.

Counties Energy intends to leverage the improved knowledge of our physical assets in new and expansive ways. Advanced analytics can be used to simulate weather impacts, improve storm preparedness and outage response, and understand how the network will behave under different load and future Distribution Energy Resources (DER) growth scenarios.

7.1.2 Enterprise Asset Management (EAM) System Upgrade

Counties Energy intends to complete its alignment to the ISO 55001 standard, to improve asset management capability and maturity. A strong asset management approach and practice ensures a reliable network for our customers, optimised investment and expenditure, and forward-looking planning for ageing assets.

As such, Counties Energy has committed to undertake an upgrade to the EAM currently in place – IBM Maximo – to improve usability in the field and the underlying data model. 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 benefit all aspects of the asset management process including works management, resourcing, defects and equipment selection. In addition to this, the correct use of this platform will improve the quality, accuracy and timeliness of the data held on assets across the network, allowing for preventative and proactive decision-making and works.

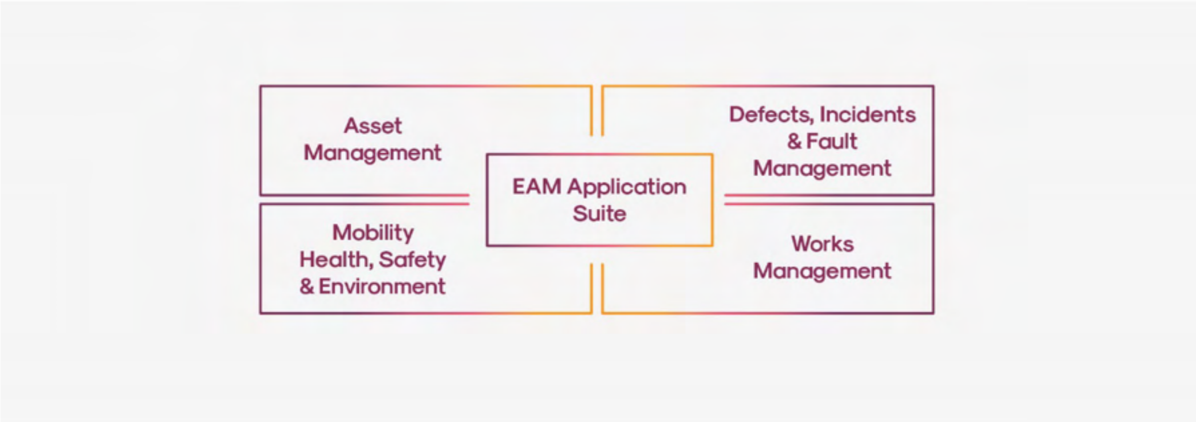


Figure 7-1 Foundational Areas of EAM Application Suite

7.1.3 Infrastructure and Network Data Interface (INDI) Improvements

Counties Energy continues to enhance and build out the functionality of its INDI platform and associated apps – the Field App, the Customer Outage Hub, and the Outage Management & Dispatch System. INDI is central to the smooth and responsive operations of our network, so upcoming investment will focus on:

- Improving controller experience in identifying, sizing and responding to unplanned outages – improving overall response, reaction and recovery time;
- Storm and adverse weather response, improving safety and response time;
- The user experience of the mobility tool (Field App) for Field Operations, allowing for better data collection and data use on-site; and
- Proactive customer communication on planned and unplanned outages, through a digitally enabled Omnichannel Strategy, ensuring Counties Energy builds trust with customers in providing a reliable and safe network.

In addition to this, opportunities to improve data quality, accuracy and frequency is crucial to INDI remaining a reliable and forefront tool for Field and Customer Operations.

7.1.4 GIS Upgrades

Counties Energy Spatial strategy incorporates the vision for Geographic Information System (GIS), and its major interactions with ADMS, ERP, EAM, DERMS and INDI. The GIS system is being improved to be:

- Highly dynamic;
- Intuitive; and
- Predictive.

The GIS system is being grown to support the power system functions, such as:

- Distributed generation: DER, Wind, and solar farms;
- Substation internals: Circuit breakers, busbars, etc.;
- T&D network modelling: All voltage levels, three-phase balanced/unbalanced, mesh and radial;
- Distributed energy resources: Rooftop solar, electric vehicle charging, battery storage; and
- LV network and structures: Poles, civils, streetlights, energy service points, meters and consumers.

This Leads to our short-term roadmap items connecting to emergency management and data quality model validations and boosting field mobility operations and boosting safety checks, boosting compliance capabilities, network mapping, boosting as-built processes, and business intelligence needs.

Looking at our Spatial Strategy and Data Management strategy, the business is spending on the spatial technologies to make sure we can predict optimally and early to manage our business and operational resources, reducing risks. This has led to investment in cognitive services, LiDAR data layers, digital twins, predictive simulation platform, AI platform and Integration platform.

7.1.5 Digital Customer Channels

The Technology & Digital team have initiated works to support the objectives of the Customer Strategy. In order to meet changing customer expectations, harness market forces, and deliver powerful customer engagement, Counties Energy is focused on ensuring there is a single view of the customer within our core Customer Relationship Management (CRM) system, Salesforce. The data we are able to collate on customers' history and interactions with Counties Energy fuels targeted communications about outages and events that affect them.

The next technology evolution for customers is about transitioning away from paper-based processes and building self-service digital capabilities through existing and new customer channels. Counties Energy aspires to ensure customers are able to initiate key product and service requests easily, via digital channels, and in a streamlined way. Aligning our digital channels to ensure there are a range of ways for customers to connect and receive timely, relevant information through an Omnichannel Strategy.

7.1.6 Capital Works Projects Management System

In line with the Digital strategy to reduce the burden of manual paper-based processes and increasing real-time, accurate information sharing between the office-based network design teams and in-field delivery teams, a works management platform is being deployed to capture all aspects of capital works project management and financial reporting into a single portal.

The overarching drivers relate to:

- Requiring a user friendly and visual experience that brings together all information relating to the project within easy reach of Project Managers and Field Operations employees;
- An easy and seamless flow of information between field and office;
- Clear and accurate reporting across multiple areas, that are easy to read, interpret and act upon, without manual interventions;
- Scaling up or down reporting capability to identify trends in wider or smaller datasets; and
- Uniform record keeping and documentation.

The outcome of this implementation is a digitised workflow for capital works project management, including the communication between Field Operations and office-based Project Managers. This is within a standardised and uniform approach that is centralised and easily repeatable, streamlining project works, and allowing for continuous improvement and optimisation.

7.1.7 Enterprise Resource Planning (ERP) System

The ERP system is set to undergo simplification and enhancement, to enable swifter upgrades of the core platform and leverage further functionality. Alongside providing operational efficiency in key business processes, this allows Counties Energy to take advantage of evolving platform and associated applications available. The roadmap for this work includes upgrading to a near-recent version of the platform, investigating cloud migration opportunities, and reducing custom-coded solutions to leverage marketplace add-ons and build out a set of cohesive and robust capabilities built on a reliable platform.

Billing is a core embedded function in the ERP that will continue to see support and enhancement moving forward. Efficient, clear and accurate billing has a direct impact on the relationship with retailers, and Counties Energy's core revenue stream, so the validity and accuracy of this foundational process is essential.

Additionally, there are several capabilities and functions that have been provisioned for in the ERP over the years, so there is a focus on critically reviewing what is best aligned with the ERP functionality and core data, versus better placed alongside another core system.

7.1.8 Vegetation Management System

Vegetation is a key target for Counties Energy to reduce unplanned outages and improve reliability, customer experience and safety. It is essential to proper asset management, but even more critical when assets include power lines that can be threatened by vegetation overgrowth. Possible in-market solutions could help the organisation integrate new and emerging technology to unlock efficiency, productivity, improve safety and transform how we manage vegetation management work.

Technology can enable better reliability outcomes through a sound and seamless vegetation management system (VMS) integrated with our core Customer Relationship Management platform and other Field Operations mobility solutions. The intention is to also leverage AI and advanced analytics to regularly assess the state of vegetation across the entire service area, allowing prioritisation of projects, decision making and cost efficiency. Scoping for a suitable VMS is within the next financial year, as the proposed benefits and outcomes will greatly benefit Counties Energy's overall network, as well as the customers affected by potential outages.

A specialist arborist from our vegetation team at work

7.1.9 Data Management

Counties Energy is actively looking at innovatively addressing new challenges, and data management is the key to unlocking our potential to the fullest.

The Enterprise Architecture team is executing the data management strategy, governance framework, and governance group to enable control of the areas such as: principles and polices, data stewardship and data management.

The data management strategy applies to all Counties Energy information systems. The directives and requirements are applicable to all systems, employees as well as contractors utilising its systems.

Counties Energy data management strategy has been drafted to utilise best practices from:

- DAMA – DMBOK: Data Management Book of Knowledge;
- ISO 9001:2015: Quality management systems – Requirements;
- ISO/IEC 20000-1:2011: Information technology – Service management – Part 1: Service management system requirements;
- ISO/IEC 27001:2013: Information technology – Security techniques – Information security management systems – Requirements; and
- IEC 62443: OT and IT system and information classification.

The data management strategy includes six assessments related to key aspects of the implementation of the strategy:

- Operational Metadata – Essential system data to ensure systems are effectively supported;
- Data Environment – Health of the data environment which is managed by the system;
- User Perspective – Usability, experience and fitness for purpose; how a system manages data to support the business use cases of present and future;
- System Data Architecture – ARB and peer review of the proposal which defines the system's data architecture;
- Data Governance – Assessment of how well the data that the system generates or utilises is managed; and
- Data Integration and Interoperability – How systems can work together to add value to the data.

The data management strategy has led to cutting-edge tooling for meeting the needs of today and the future. Counties Energy is looking at enhancing five capabilities that include the Data Fabric platform, the integration platform, AI platform, INDI and the IoT platform. For example, there are works in progress among the five capabilities above, which will enhance the secure OT-IT convergence via data patterns, data diode, graph search and analytics platform, and internal data lake platform.

Figure 7-2 Data Capabilities and Systems

7.1.10 Security

Counties Energy is working towards a cyber security program of work establishing strategies, patterns, templates, human procedures, standard operating procedures, coded policies, tooling, and configuring the tooling to make sure outcomes for Identifying, Protecting, Detecting, Responding and Recovering.

As Counties Energy supplies electricity to a large population, it utilises several automated technologies in its electricity supply, control and field operations – otherwise known as Operational Technology (OT). Operational Technology is the term used to differentiate Information Technology products and services when they are used for equipment or process control purposes. These functions are distinct from office automation or other traditional uses of IT systems, as they control physical assets directly and require a higher degree of predictability and availability. Counties Energy is ensuring that the OT security requirements are extended beyond the confidentiality, integrity and availability triad (CIA) to incorporate human safety.

Figure 7-3 OT Security Requirements

As we are moving towards highly dynamic ADMS, DERMS, GIS, INDI, Substation Automation and other systems, we have grouped the common services requirements. We are steadily enhancing our proactive security and reactive security measures to manage our terrain. We are enhancing our security maturity with the setup of a design ratification board for 'secure by design' evaluations, disaster day runbooks, Operational Support Guide, Business Continuity Plans and Standard Operating Procedures.

7.2 Becoming Distribution System Operator (DSO) Ready

Counties Energy's vision of a DSO is transforming the traditional electricity distribution utility to a 'smart energy orchestrator'.

This transformation requires building new capabilities that are focused on granular network visibility and intelligence, dynamic management of distribution capacity, aggregation, and management of Distributed Energy Resources (DERs). The broadening of the scope allows traditional Distribution Network Operators (DNOs) to enable customers with new energy-related opportunities, such as unlocking greater DER enablement, an alternative to traditional network investment and a highly visible, transparent cost-optimal service.

A DER can be any generation, storage or controllable load resource on the electricity distribution network. DERs include solar photovoltaic (PV), wind, batteries, electric hot water cylinders and EV chargers.

As a Distribution Network Operator (DNO) we're focused on reliability, safety, maintaining the existing network and facilitating new connections. As we transition to a DSO, the same emphasis will continue and expand beyond Counties Energy's existing role. As a DSO we aim to facilitate an open and inclusive distribution capacity market, create shared value and update existing practices with a DER lens.

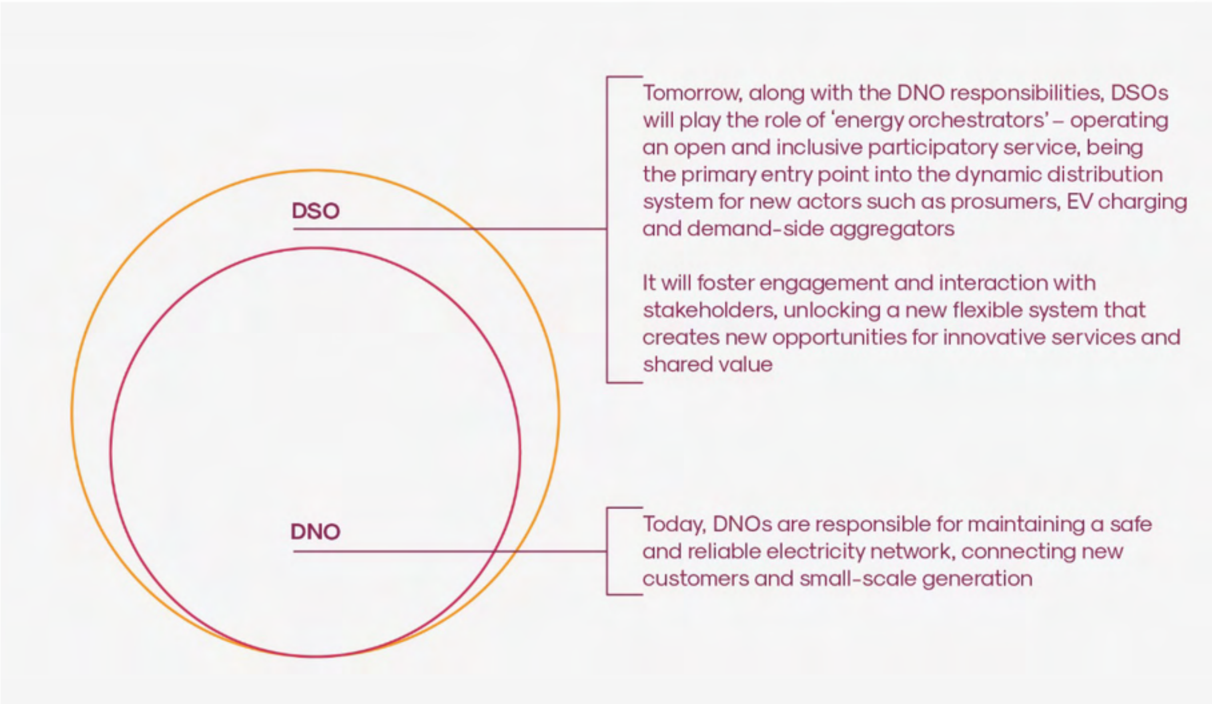


Figure 7-4 DNO to DSO Transition

As stewards of energy for our customers and communities, we believe we are uniquely placed to extend our role in a neutral manner. Our aim is to create a DSO service that is simple, consistent, and provides access to new value. As we start on our journey we will look to unlock and utilise inherent DER flexibility in our network to provide greater customer benefits.

Being Customer Obsessed is one of key company values at Counties Energy. The most critical part of this DSO strategy is to develop a view on the objectives that we wish to deliver for our customers, communities and the industry at large. Through our customer research we've developed an understanding of the customer personas that we service, with the top three personas clearly focused on generating economic value, being simple to use and actively seeking sustainable solutions. These areas of focus will be at the core of executing our DSO vision.

As a DSO, Counties Energy aims to:

- Provide a safe and reliable service in a dynamic energy system – Maintaining a safe and reliable service while optimising the supply and demand in every minute of every day;
- Give customers more options for how they use the network – As we look further into the future where customers want to do more with their energy, it becomes apparent that a one-size-fits-all energy distribution service will need to evolve;
- Get more out of the existing network – Using active orchestration and dynamic pricing will be a powerful tool for getting more out of the existing network; and

- Support the decarbonisation goals of customers and the overall system – With our customers increasingly decarbonising on the distribution networks, we will also be able to support the wider national electricity network.

These new capabilities will allow Counties Energy to continue providing a modern and cost-effective electricity lines service.

Counties Energy has recently started on its journey through the development of a strategy and framework to deliver DSO services. The guiding principles of Counties Energy's approach are explained by the diagram below.

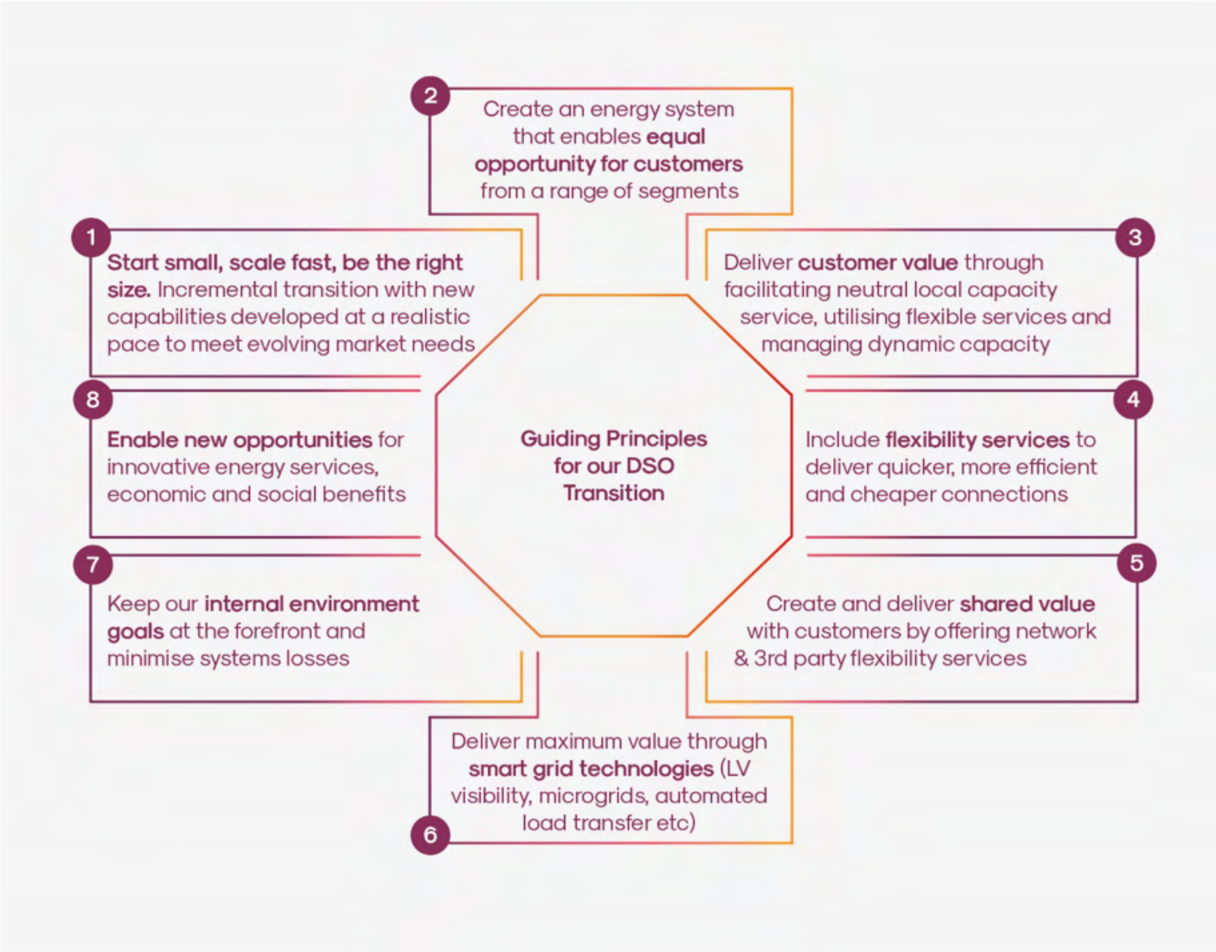


Figure 7-5 Guiding Principles for our DSO Transition

There are five core capability development areas of the DSO Strategy that will inform Counties Energy's investment as it transitions to a DSO future.

7.2.1 Whole System Orchestration

Whole System Orchestration workstream has the ambition to establish a new technology and software investment blueprint that allows for well-informed decisions on energy orchestration. Besides enabling DER integration on our network, Counties Energy will consider how best to integrate solutions such as community solar, battery and smart EV charging with its current operational technology stack. New technologies and software are a key contributor to enable smarter ways to manage demand and generation to ensure Counties Energy is at the forefront of a modern utility operations.

7.2.2 Capacity and Connections Management

EDBs are seen to play a key role in the transition to a low-carbon future, as they need to provide the infrastructure for the integration of DERs. EV charging is a DER that is front of mind for Counties Energy given it is likely to have the greatest impact on our network in the near-term. This new requirement can increase demand by 25–30% on the network, if unmanaged. The Capacity and Connections Management workstream will provide an opportunity for Counties Energy to review its existing network planning practices and connection contracts. Necessary adjustments are required to consider DERs and play an influential role in enabling our customers in their decarbonisation goals. We want to enable a deferral of traditional investment and increase utilisation of existing network infrastructure as we look to provide price stability for the community.

7.2.3 Asset and Operations Management

Today, Counties Energy's existing asset management and operations practices are well placed to address issues on the HV networks. As the uptake of DERs, such as batteries, EV chargers and solar, continues to grow, and these connections occur at an LV level, investment into the LV network is necessary to prevent impaired network performance. This requires real-time monitoring of changing consumer consumption (demand envelopes), DER injections (flexibility envelopes), and asset condition (capacity envelopes). Therefore, we recognise an LV strategy is required, expanding on existing practices that have been mainly focused on our HV networks until recently.

Development of this LV strategy commenced in 2022, working on a roadmap, and associated programme of works, covering several areas - such as:

- Operational management;
- Reliability reporting;
- Voltage quality management;
- Asset information requirements;
- Design philosophy review; and
- Demand, flexibility, and capacity monitoring/modelling.
- We also recognise our fortunate position of having access to the data available from our smart meters installed across most of our network. Work has already begun investigating the outputs our current data can deliver concerning identifying DERs and EVs on the LV network. We are also aware of many further opportunities the smart meter data may provide to enhance our network management processes - if not with our present data, certainly with enhanced, more granular data.

Many of these areas being worked on are critical to our DSO transition, with others driving improvement in operational or asset management practices around our LV networks. The intent is to ensure we have the right processes and digital tools to effectively manage the granular visibility of the LV network. While the focus in the near-medium term is LV, the overall aspiration is to ensure the reliable and safe supply of power in a future DER world.

7.2.4 Flexibility Services and Commercial Operations

Working together with DER aggregators, other market participants and our local community is key to providing this DSO service. Through our customer research we've found that our customers care most about a service that is reliable, makes economic sense, is easy to use and supports New Zealand's decarbonisation goals. This workstream will aim to provide guidance on our existing and new pricing and commercial frameworks to ensure they are attractive and meet our customers' needs for our developing DSO service. We want to make sure that the benefits of our DSO work are shared with our community whilst enabling the regulator's ambitions for a truly open and inclusive capacity marketplace.

7.2.5 Digital Operations

As the boundaries between the physical and digital worlds continue to blur in this new DSO world, Counties Energy will continue to invest in digital tools that provide the foundation for greater network granularity and control. This will enhance network reliability, worker safety and enable precision reinforcement. Key areas of investment will include OpenLoop EV charging platform, ADMS, GIS, Outage Management, Advanced Metering Data Intelligence, Artificial Intelligence, Machine Learning, Cyber Security, Data Privacy, Automation, Virtual/Augmented Reality, DERMS, etc. Balancing the demands of BAU and our newly developing DSO service is key to creating a Digital Operations roadmap that delivers value at the right time.

7.3 Adopting New Clean Energy Technologies

Advanced technologies provide a foundational step forward on Counties Energy's transformational journey to an innovation-led, low-carbon future. By keeping Counties Energy ahead of the digital curve, we will transform our service delivery to include diverse energy choices and offerings that customers are seeking.

7.3.1 Smart EV Charging with DER Aggregators

Transportation is the largest polluter worldwide, with many governments recognising that electrification of transportation (supplied by renewable energy sources) is key to meeting carbon reduction targets.

New Zealand's Climate Change Commission has submitted findings that shows homes with EVs on average spend up to 25% less on energy in comparison to those with petrol vehicles.

The limiting factor for many households and commercial businesses to transition to EVs is the upfront cost of an electric vehicle, which on average is 60% more expensive in comparison to an internal combustion vehicle. To encourage this transition, some governments have introduced subsidies to accelerate EV uptake. In New Zealand, for example, the Clean Car Discount (launched in July 2021) of up to $8,625 for a new Battery Electric Vehicle (BEV) has helped to make EVs a more attractive option.

Other influencing factors include:

- The surging price of petrol and diesel has reached record highs in 2021 and is expected to continue rising;
- The introduction of a carbon tax in Auckland, by Auckland Council; and
- The implementation of the Clean Car Standard where vehicle importers with a lower carbon footprint are rewarded with credit and those with a high carbon footprint are penalised.

These factors will contribute towards the uptake of EVs nationwide in the coming years.

Electricity distribution networks were not designed to take on this additional EV charging load if it were to all occur simultaneously. However, by using smart EV charging, we can manage peak demand while ensuring EVs are charged in a managed and dynamic way depending on the available capacity on the network within a given timeframe.

By pursuing smart charging and enrolling our customers' EV chargers onto our digital platforms, we will seek to avoid expenditure to reinforce the electricity network that may otherwise be required due to simultaneous EV charging. DER aggregators like OpenLoop will provide further benefits as we learn to better manage changing demand profiles on the network.

With the support of Energy Efficiency and Conservation Authority (EECA) co-funding, we are also researching new EV charging technologies such as Vehicle-to-Grid technology, which enables EV owners to discharge the energy from their EVs back to the grid during network peaks or emergencies.

7.3.2 Second-Life EV Battery Systems

With the large uptake of EVs worldwide, old EV batteries being stockpiled at the end of their life is becoming an issue.

At Counties Energy, we are exploring new ways of giving these batteries a new lease of life on our electricity network. We are currently trialling these batteries as network DERs to regulate power quality, shave energy peaks and as a buffer energy source for High Power EV charging to reduce the stress on the network.

These battery systems are typically cheaper and hold potentially up to 80% of their original charge – whilst not useful in an EV, they may be useful on our network as a substitute to traditional network solutions.

We are also investigating how these batteries can be used for large-scale community storage applications, such as backup energy sources for remote locations on our network, and to assist in the integration of distributed or centralised community PV. By utilising Second-Life EV Battery systems in this manner, we can potentially defer the need for infrastructure upgrades.

7.3.3 Virtual Power Plants (VPPs) and Microgrids

As greater distributed renewable generation and storage is hosted on the network, an area of opportunity arises to provide a greater level of energy service by being able to create Virtual Power Plants (VPPs) and Microgrids to serve key customer segments, such as customers in remote communities as well as new energy-efficient housing developments.

8.0 Renewal & Maintenance

8.0 Renewal and Maintenance

This chapter outlines 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 Energy at GXPs.

Delivering our performance objectives requires a balance of costs, risks and benefits. Using data and condition information, we look to balance our whole-life costs with the probability and likelihood of failure, contributing factors, the consequence of risk, and public safety assessments. Whole-life costs can be maximised by optimising maintenance and inspection regimes to maintain and assess condition, allocate appropriate corrective works and eventually replace when the asset is at the end of its economic life.

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

Details regarding the asset fleet can be found in Chapter 3.0 Our Assets.

Further detail on the frameworks and processes leading to investment decisions can be found in Chapter 5.0 Approach to Asset Management.

8.1 Renewal and Replacement Planning Approach

Asset replacement and maintenance activities are planned for by considering the asset health and condition profile of the asset fleet (refer to Chapter 3.0), and any known risks and issues from historical fault information, asset performance statistics and industry knowledge. These risks and issues or condition profiles are then monitored and managed through maintenance activities or through corrective works.

Through this section each asset class will identify:

- **Known risks and issues** – Identified risks and issues through maintenance activities, asset failure modes, known performance issues and contextual data;
- **Maintenance activities** – The maintenance and inspection activities are undertaken in order to proactively manage the identified risks and issues, manage the asset to the industry standard or manufacturer's recommendation, or identify defects for remedial action through routine inspection, as well as to assess and report on asset condition;
- **Planned capital works** – Capital expenditure projects to remedy condition, safety or performance issues identified in the 10-year plan. These planning decisions are informed by asset health and condition, asset risk modelling, defect prioritisation models and coordination with reliability and development workstreams. More information on data used in planning and investment decisions can be found in section 5.3.3; and
- **Corrective Works** – Corrective activities that are either operational expenditure or capitalised within a period that is appropriate to the hazard level, as detailed in the risk framework (section 5.6). This may include high-risk defects which need remediation within the financial year and have not been specifically identified within the plan.

8.1.1 Replacement and Maintenance Assumptions

The assumptions and inputs that inform our replacement and maintenance programme are:

Industry Standards

Maintenance standards and lifecycle assessments are informed by industry standards and operation manuals for specialist equipment. The Maintenance standards are currently under review as part of the ISO 55000 development and alignment activities, and EAM development and rollout.

Inspection Activities

Our assets are inspected regularly, at a frequency determined by industry standard, legislative requirement and specific asset health or condition information which may impact its risk to the network or public safety. When inspected, the inspection record is kept electronically with any defect information noted.

Condition Assessments

As we improve our inspection regimes, we assess assets for health score, which informs renewal decisions. The rating system assets are assessed against is detailed in Table 8-1.

AHI Score	Description	Probability of Failure
H1	End-of-Life (EOL)	Very High
H2	EOL drivers present	High
H3	Onset of reliability	Medium
H4	Normal in-service deterioration	Low
H5	As new	Unusual

Table 8-1 Asset Condition – AHI Scores

8.2 Subtransmission

The subtransmission network transports electricity from Transpower's Grid Exit Points to our zone substations.

8.2.1 Management Approach

Our subtransmission assets are critical to providing 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, and appropriate asset renewal programmes to ensure their reliability and availability. Defects are to be addressed with high priority, and investigations into failures are undertaken to identify underlying issues and avoid recurrence, given the importance of these circuits.

8.2.2 Subtransmission Lines and Poles

Known Risks and Issues

The primary risks and issues associated with subtransmission lines and poles are:

- Vehicle collisions, causing outages and public safety risks;
- Vegetation interruptions; and
- Contamination build-up on insulator causing tracking and flashover.

Maintenance Activities

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	Five yearly
Insulator Washing – Glenbrook and Maioro Area	Routine Servicing	Two yearly
Vegetation Survey	Inspection	Area Specific

Table 8-2 Inspection Cycles for Subtransmission Lines and Poles

We undertake subtransmission line rapid inspections annually to check key defects and vegetation encroachment.

Additionally, a five-yearly detailed pole and line condition assessment is undertaken to identify assets damaged or compromised by a third-party action, age, poor ground conditions, or land movement.

In areas subject to heavy pollution, particularly around the Glenbrook Steel Mill and Maioro iron sand mine, insulator washing is undertaken periodically to reduce contaminant build-up and the likelihood of tracking and flashover.

Corrective Maintenance

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

Renewal and Replacement

Western Area

The 33 kV line from Glenbrook to Waiuku has identified capacity constraints within the planning period. Any condition-based renewal will be undertaken as part of a larger capacity augmentation project detailed in Chapter 9.0 Network Development.

Eastern Area

The 110 kV lines in the eastern area supply Opaheke, Pukekohe, Tuakau and Pokeno, the majority supported by concrete and steel poles, and a section of line supported by steel lattice towers.

Since the mid-1990s, we have used AAC (All Aluminium Conductor) as the standard conductor type and composite insulator for our subtransmission network. These lines are in good condition as they have been constructed in the past 25 years and only require minor maintenance.

In this 10-year AMP period, the planned work is as follows:

1. Reinsulate the two 110 kV lines that supply Pukekohe in FY26 and FY27 as they approach the end of their 30-year life expectancy;
2. One section of line supplying Opaheke and Ramarama is constructed on steel towers and was part of a transmission line originally constructed by Transpower's predecessor but is now owned by Counties Energy. With Ramarama substation to be decommissioned in FY24, a conductor upgrade project is planned on this line to meet future requirements;
3. As part of the establishment at Barber Road substation, the beginning section of the Bombay to Opaheke 110 kV east line will be relocated in FY24;
4. The second 33 kV line from the Bombay to Ramarama substation is planned to be removed from service and dismantled in FY25 as part of decommissioning the Ramarama and Mangatawhiri substations. The line will continue to be maintained until then. Refer to Section 9.3 for further information; and
5. The single circuit 33 kV pole line from Bombay to Mangatawhiri is in below-average condition, with some components at the end of their lifecycle, requiring replacement within this planning period. These issues will be addressed as part of the feeder works to establish the Barber Road substation, and as such, no specific replacement project is included in this section of the plan. The refurbished Mangatawhiri line will operate at 22 kV and form the front end of the existing Kaiaua feeder detailed in Chapter 9.0 Network Development.

Out-of-Service Lines

As well as in-service subtransmission lines, we also own lines that are not currently in use; however, we may use these in the future. After a review of future needs, two unused lines have been removed in the past year, leaving one route only, which we continue 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 33 kV line. A detailed aerial drone condition assessment survey has been completed in FY23, and the identified issues will be addressed under corrective maintenance. This line will remain in place and will be repurposed as a 22 kV feeder out of the Opaheke substation, detailed in Chapter 9.0 Network Development.

8.2.3 Subtransmission Cables

Known Risks and Issues

The primary risks and issues associated with subtransmission cables are:

- Terminations and joints failures; and
- Third-party damage causing cable strikes and outages due to excavations or drillings.

Maintenance Activities

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

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

Renewal and Replacement

Our management strategy for 33 kV and 110 kV subtransmission cables is to replace them reactively due to premature failure or third-party interference, as there is currently no condition or age-based driver for replacement.

8.2.4 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
Barber Road – Subtransmission Rebuild	942		-	-	-	-	-	-	-	-
Barber Road – Tower 1 Refurbishment	900		-	-	-	-	-	-	-	-
Reinsulate Pukekohe Line	-	-	650	550	-	-	-	-	-	-
Subtransmission Renewal	20	20	20	20	20	20	20	20	20	20
OPERATIONAL EXPENDITURE ($000S)										
Subtransmission Lines	94	84	84	91	84	84	84	84	91	84
Subtransmission Cables	17	7	7	14	7	7	7	7	14	7

Table 8-3 Subtransmission Expenditure Summary

8.3 Zone Substations

Zone substations take supplies from Transpower's Grid Exit Points via the subtransmission network. They typically consist of:

- Substation building and grounds;
- Power transformers; and
- Indoor or outdoor switchgear.

The power transformers step-down subtransmission voltage (110 kV or 33 kV) to distribution voltage (22 kV or 11 kV), and the switchgear enables the network to be protected and operated safely.

8.3.1 Management Approach

Zone substations, like subtransmission assets, are a critical part of our network and have a high impact when they do not 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 the public.

Our zone substation objectives are to:

- Ensure they are safe and secure;
- Ensure they meet the network and environment performance standards (including seismic compliance, oil containment, discharge controls, noise levels, etc.); and
- 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.

8.3.2 Buildings and Grounds

Known Risks and Issues

The primary risks and issues associated with zone substation buildings and grounds are:

- Vandalism and graffiti;
- Humidity and condensation build-up causing damage to indoor equipment; and
- Pest or bird nesting, which may cause damage to equipment.

Maintenance Activities

Our inspection and maintenance cycle for zone substation buildings and grounds are as follows:

Activity	Type	Frequency
Routine Substation Inspection	Inspection	Monthly
Building Maintenance	Routine Maintenance	Monthly
Grounds Maintenance	Routine Maintenance	Monthly (Winter) / Fortnightly (Summer)
Substation Earth Grid Inspection	Inspection	Annual
Substation Earth Grid Test	Routine Test	Three yearly

Table 8-4 Inspection Cycles for Zone Substations

Renewal and Replacement

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

In FY24, we plan to undertake a network-wide zone substation buildings/structure seismic review against the latest New Zealand Society of Earthquake Engineering (NZSEE) seismic grades with a building importance level of 4 (IL4); this includes both indoor and outdoor structures. An allowance of $300,000 is included in expenditure forecasts in FY25 to strengthen the building/structure if structures are found to be earthquake-prone or earthquake risk below 67% of the new building standard (NBS).

Older substation 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.

Barber Road Substation

The end-of-life Ramarama and Mangatawhiri substations will be decommissioned in FY25 when the new 110 kV / 22 kV Barber Road substation works are completed in FY24.

Remaining works include feeder upgrades, subtransmission refurbishment and continuation of the substation build and commission.

8.3.3 Power Transformers

Known Risks and Issues

The primary risks and issues associated with zone substation power transformers are:

- Corrosion leading to the deterioration of the external transformer condition;
- Oil leaking through gasket/O-ring due to ageing and deterioration of sealing components;
- Insulation paper degradation, resulting in transformer failure; and
- Compromised insulation system (paper and oil) due to deterioration, resulting in transformer failure.

Maintenance Activities

Our inspection and maintenance cycle for the zone substation power transformers are as follows:

Activity	Type	Frequency
Routine Visual Inspection	Inspection	Monthly
Detailed Inspection and Condition Assessment	Inspection	Annual
Transformer Oil DGA Analysis	Routine Test	Annual
Transformer And OLTC Maintenance	Routine Servicing	Three yearly

Table 8-5 Inspection Cycle for Power Transformers

Renewal and Replacement

Our current practice is to carry out a 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 is available in service.

We are currently retrofitting two transformers (30/60 MVA) at the Pukekohe substation from normal conventional oil OLTC (online tap-changer) to vacuum OLTC, due for completion before the end of FY23. The vacuum OLTC will reduce our ongoing operational cost on the transformers as they have fewer maintenance requirements when compared to oil OLTC.

In this 10-year AMP period, the plan is as follows:

- The condition of the Maioro transformers will be assessed within the planning period, and a decision will be made dependent upon the condition and future capacity needs at the Maioro substation.
- Refurbish and retrofit vacuum OLTC on the Opaheke two transformers (20/40 MVA). This work is programmed to commence once the increased security level of the 110 kV outdoor bus has been commissioned. This project is driven by the Quarry Road substation establishment and is covered in more detail in in Chapter 9.0 Network Development.
- The Karaka two transformers (10/20 MVA) will be replaced in 2032/33 in conjunction with the substation rebuild. One of the existing transformers will be refurbished and ready for installation at the new Kingseat substation. For more detail in Chapter 9.0 Network Development.

8.3.4 Zone Substation Switchgear

Known Risks and Issues

The primary risks and issues associated with zone substation switchgear are:

- Contamination build-up on insulation, causing tracking and flashover;
- Arc flashover to employees and equipment, causing injury or damage;
- Partial discharge activity occurring on equipment indicates deteriorating condition;
- Gas/oil leak due to deterioration of sealing components;
- Orphan equipment resulting in non-availability of knowledge, skills, and spare parts. For detail on critical spares management, refer to Section 8.11; and
- Operational handling of SF_6 gas using external service provider due to hazard gas. For detail on SF_6, refer to Chapter 8.12.

Maintenance Activities

Our inspection and maintenance cycle for zone substation switchgear are as follows:

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

Table 8-6 Inspection Cycles for Zone Substations

Renewal and Replacement

Annual switchboard partial discharge testing and inspection is part of the ongoing condition monitoring across all zone substation switchboards. We have experienced partial discharge activity at Opaheke 22 kV bus section and feeder circuit breaker. While we have carried out additional maintenance in 2018 to address the partial discharge issue, we have identified one vacuum breaker that failed during three-yearly routine maintenance.

In this 10-year AMP period, the plan is as follows:

1. Continuation of the Barber Road substation build, due completion in FY24. Subsequent decommissioning of Ramarama and Mangatawhiri substations in FY25.
2. Due to the switchboard condition, orphan equipment, and capacity reasons, the Opaheke switchboard will be replaced in FY25. Issues relating to Opaheke include:
    - Identification of partial discharge activity on the 22 kV bus section and feeder circuit breaker, resulting in additional maintenance requirements (ongoing since 2018); and
    - One vacuum breaker failed during three-yearly routine maintenance.
3. Due to age and condition, the Maioro 11 kV switchboard will be replaced in FY26. Options considered have been:
    - Utilise the switchboard from the existing Ramarama substation when it is decommissioned; and
    - Replace it with a new switchboard, or ring main unit solution.

    Due to constructability and major industrial customer outage constraint, a new switchboard, or ring main unit solution, is likely.
4. The Karaka 11 kV switchboard is scheduled for replacement in FY32/33 in conjunction with the substation rebuild due to end-of-life at an estimated cost of $9.0m.

8.3.5 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
Barber Rd substation	500	-	-	-	-	-	-	-	-	-
Decommission Ramarama and Mangatawhiri	-	2,000	-	-	-	-	-	-	-	-
Karaka Substation Rebuild	-	-	-	-	-	-	-	-	3,000	6,450
Maioro Substation	-	100	1,400	-	-	-	-	-	-	-
Other zone sub renewal	50	50	50	50	50	50	50	50	50	50
Opaheke Programme	200	3,500	3,000	700	700	-	-	-	-	-
Seismic Study and Corrective actions	250	300	-	-	-	-	-	-	-	-

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
OPERATIONAL EXPENDITURE ($000S)										
Zone Substation Transformers	139	139	139	139	139	139	139	139	139	139
Zone Substation Switchgear	91	91	91	91	165	91	91	91	91	91
Zone Substation Other Equipment	56	56	56	56	56	56	56	56	56	56
Zone Substation Buildings and Grounds	87	87	87	87	87	87	87	87	87	87

Table 8-7 Expenditure Summary for Zone Substations

8.4 Distribution and LV Lines

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

This section will look at the following components of the overhead distribution network in terms of known risks, maintenance activities, and planned capital works:

- Distribution and LV lines;
- Poles and crossarms; and
- Private service lines.

8.4.1 Management Approach

In our management of overhead lines, our primary focus is on safety. Attention is paid to defects on lines in high-risk locations, such as around schools, commercial zones 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 the network or equipment with poor SAIDI and SAIFI performance are also investigated to identify and rectify systemic failure modes.

Common and frequent failure modes and known risks are monitored on an ongoing basis and considered in our maintenance regimes, inspection criteria and replacement decision-making processes.

In 2021, we commenced an additional inspection regime for our overhead lines, poles, crossarms and components using unmanned aerial vehicles (UAV). These surveys are prioritised based on performance and recommended work areas and inspect the assets for condition, including the conductor, identifying joints, crossarms, insulators, supporting structures and attached equipment. Any additional known issues and risks associated are also identified. Additional information about each component is detailed in the subsequent sections.

8.4.2 Distribution Conductor

Known Risks and Issues

- Vegetation encroachments – For details on vegetation management, refer to Section 5.12.6;
- Connection failures – Notably, this is related to dissimilar metals and greatly contributes to overhead equipment faults; and
- Conductor with high failure rates – Small-diameter copper ($16mm^2$ and $25mm^2$) and swan (ACSR) conductor. These conductors are also more susceptible to breaking when affected by vegetation, wildlife or clashing due to their deteriorated condition.

	11 kV	22 k V
Small-Diameter Copper Conductor	142 km	50 km
Swan (ACSR)	248 km	97 km

Table 8-8 High-Risk Conductors

Maintenance Activities

The inspections undertaken for distribution and LV conductors are as follows:

Activity	Type	Frequency
Overhead Line Feeder Patrol	Inspection	Five yearly
UAV Inspections	Inspection	Annual
LiDAR	Inspection	Three yearly

Table 8-9 Inspection Cycles for Overhead Lines

Unmanned aerial vehicles (UAV) are now used to enhance our traditional inspection surveys and provide additional data to determine conductor conditions. The inspection criteria assesses condition of the asset, identifies key defects with remediation priorities and identifies the location of connector types known to fail to enrich the defect and asset condition data used when prioritising and scoping works. More detail on the UAV surveys can be found under section 8.4.3 Distribution Poles and Crossarms.

LIDAR inspections are conducted on a three-yearly basis to check conductor clearances concerning NZECP 34:2001. It also provides vegetation encroachments to inform our vegetation management programme (refer to section 5.12.7).

Renewal and Replacement

Replacement of overhead conductor is usually to retain the existing configuration; however, there may be occasions when it is deemed more appropriate to re-route the line to avoid vegetation, increase access or convert to underground. During scoping and designing of our projects, the asset vulnerability model (refer to section 5.3.3) is used to aid in the justification of undergrounding overhead lines and ensuring our poles are in the best location to avoid vehicle vs assets. Where defects, equipment type or construction issues are identified, such as incorrect connector type, replacement is planned in the scope of works affecting the structure or work area.

Over the past two years, Counties Energy has built all HV overhead lines to a new standard, introduced in 2020, that provides greater clearances and reduced span lengths. The new standard aims to improve our overhead reliability from transient faults, such as line clashing, debris and wildlife. We suspect most of these transient faults contribute to unknown fault events.

Conductor replacement projects fall into the following categories, dependent on the driver:

- HV Rehabilitation – Replacement of aged, poor condition or poor performing overhead 11 kV or 22 kV conductor and associated assets;
- LV Rehabilitation – For aged, poor condition or poor performing overhead low-voltage conductor and associated assets;
- Copper Replacement programme – Replacement of prioritised 16mm^2 copper conductor; and
- Swan replacement programme – Replacement of prioritised swan ACSR conductor.

HV Rehabilitation

Replacement projects are also identified for network sections at end-of-life and in poor condition, contributing to customer outages or containing a high level of defects.

The identified projects for high-voltage line replacement in the next three years include the following:

Area	Financial Year	Length (km)	Cost ($000s)
Awhitu Road, Manukau Heads	FY24	1.1	512
Glenbrook-Opaheke Line	FY25	6	1,980
Lewis Road link, Black Bridge	FY26	1.5	408
Batty Road, Te Hihi	FY26	5	2,334
HWY 22, Glen Murray	FY26	3.3	1,309

Table 8-10 HV Rehabilitation Programme Summary FY24–26

LV Rehabilitation

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:

Area	Financial Year	Length (km)	Cost ($000s)
Prospect Terrace, Pukekohe	FY24	0.3	226
SH22, Paerata	FY25	1	903
Matatea Avenue, Pukekohe	FY25	0.2	181
Grierson Place, Pukekohe	FY26	0.1	108
Howden Street and Warriston Avenue, Waiuku	FY26	1.1	993
Philips Street, Pukekohe	FY26	0.2	190

Table 8-11 LV Rehabilitation Summary FY24–26

Copper Replacement Programme

A prioritised programme of replacing small-diameter copper conductor commenced in 2016/2017 in areas with elevated public risk, where there has been identified repeat failures or performance issues, and where there is no capacity or development need for replacement over the next three years.

The introduction of our Asset Risk Management Model has allowed us to improve our replacement strategy for copper replacement in line with the original criteria set out in 2016. The copper programme is expected to fluctuate as our use of the Asset Risk Management Model improves the priority of the projects. To improve our understanding of the condition, we may replace small sections and undertake tensile strength testing to verify the asset health model.

Area	Financial Year	Length (km)	Cost ($000s)
Glenbrook Station Road, Glenbrook	FY25	2.9	1,430
Findlay Road, Patumahoe	FY25	1.5	640
Tuhimata Road, Pukekohe East	FY25	1.6	574
Seagrove Road, Te Hihi	FY26	3.6	1,537

Table 8-12 Copper Replacement Programme Summary FY24–26

Swan Replacement Programme

As with copper conductor, there is a prioritised programme of replacing swan ACSR conductor. This programme commenced in 2017/18 in areas with an elevated public safety risk, where there have been identified repeat failures or performance issues, and where there is no capacity or development need for replacement over the next three years.

Introducing our Asset Risk Management Model has allowed us to improve our replacement strategy for swan replacement in line with the original criteria set out in 2017. The programme is expected to fluctuate as our use of the Asset Risk Management Model improves the priority of the projects.

Area	Financial Year	Length (km)	Cost ($000s)
Morley Road, Waiuku	FY24	2.0	1,106
Orua Bay-Grahams Beach Road, Te Toro	FY24	2.2	991
Pararekau Road, Hingaia	FY24	0.85	1,261
Wymer Road and Reid Road, Pakington	FY25	3	1,319
Fausett Road, Ararimu	FY26	1.2	550
Harkness Road, Black Bridge	FY26	0.6	236

Area	Financial Year	Length (km)	Cost ($000s)
Portsmouth Road, Bombay	FY26	2.8	1,388
Te Ahu Road, Churchill Road	FY26	0.2	104
Woodleigh Road, Glen Murray	FY26	3.35	1,229

Table 8-13 Swan Replacement Programme Summary FY24–26

Corrective Maintenance

Counties Energy is currently implementing an expulsion dropout (EDO) replacement programme, underway from FY24, to target our known connector issue. This programme aims to reduce the known failure point of connectors at EDOs and will form part of all capital and customer projects for the coming years, coordinating the works in planned outage areas.

LIDAR has highlighted areas of the network in breach of NZECP34:2001, and low line rectification is prioritised based on elevated public safety, such as road crossings and school areas. These are included in the capital plan; however, any line that is identified through inspections and deemed high risk is remediated in a reactive manner.

8.4.3 Distribution Poles and Crossarms

Known Risks and Issues

- Vehicle collisions, causing outages and public safety risks;
- Spalling concrete poles, identified during detailed pole inspections. These poles may be red or yellow-tagged, dependent on the severity of the damage;
- Ageing hardwood poles – rotting poles may fail and cause both network and public safety risks;
- Leaning poles due to unstable foundations may fall and cause both network and public safety risks;
- Ageing wooden crossarm fleet – outages due to damage or splits to the crossarm;
- Kingbolt failure on wooden crossarms – treated wooden crossarms cause premature failure of the kingbolt; and
- Insulator cracking due to type.

Maintenance Activities

Our inspection cycles for poles and crossarms are as follows:

Activity	Type	Frequency
UAV Inspections	Inspection	By criticality
Detailed Pole and Line Condition Assessment	Inspection	Five yearly
Acoustics Survey	Inspection	On repeated unknown cause fault

Table 8-14 Inspection Cycles for Distribution Poles and Crossarms

UAV survey areas are determined based on criticality. Areas are surveyed by drone where condition needs to be verified, network performance is lower than expected, or traditional inspections are not feasible due to access restrictions.

The UAV assessments identify and assess defects on the following components:

Data Improvement

- Geo-spatial accuracy;
- Structure Material;
- Crossarm Material; and
- Structure type.

Type Identification – Failure Mode analysis

- Insulator Type and Material;
- Connector type; and
- Number of Joints in conductor.

Condition and Defects

- Pole Structure;
- Crossarm structure;
- Guy/Stay;
- Insulators;
- Conductor;
- Conductor Hardware;
- Overhead Switchgear; and
- Vegetation.

The outputs of the above are prioritised and considered when identifying and delivering renewal scopes and defect remediation work.

Poles and associated fixtures are inspected on a five-yearly basis for damage and condition. Hardwood poles are also scanned during detailed pole inspections, and corrective work is prioritised based on remaining strength.

Ageing wooden crossarms are identified as part of UAV inspections and our detailed pole and line condition assessments; these crossarms are replaced based on risk profile, asset criticality and assumed remaining life. In addition to crossarm failure due to rot, a failure mode has been identified with kingbolt failures on wooden arms. These failures are hard to predict as the kingbolt fails inside the crossarm and is expected to be corrected as we replace our ageing wooden crossarms.

Where pole lean is identified through inspection, UAV or LiDAR surveys, severity is assessed and, where data is available, compared with previous datasets to establish movement and potential risk of failure.

When incidents of repeated outage events, including reclose events and an insulator fault, are suspected but not identified, acoustic surveys may be utilised to identify tracking and cracks. This method of surveying is specifically good for detecting small pin holes and cracks, which can be hard to pick up under UAV or ground inspection due to size or being hidden under binder wire.

Renewal and Replacement

Poles, crossarms and insulators are renewed with the conductor replacement projects as required by age, condition, forecasted risk, or where loading changes determine upgrade is needed. In all cases, these are replaced with the current network standard.

Our 11 kV and 22 kV standard is the installation of 2.4 m galvanised steel crossarms in a delta configuration where appropriate. This standard increases phase clearances and minimises interruption by debris, vegetation, wildlife, and clashing. Additionally, all HV insulators installed now are of a post type – either polymer or ceramic – due to known type issues regarding pin type insulators.

The five-yearly detailed pole inspections and UAV inspections identify defects and hazards on the overhead assets. Once identified, corrective work is prioritised based on possibility of failure, public safety risk, and network performance contribution. During the detailed pole inspections, poles are also checked to see if they can withstand service loads. Poles that cannot are tagged and replaced within the required replacement timeframes as outlined in the Electricity (Safety) Regulations 2010.

The weighted defect model (refer to section 5.3.3) provides insights into high-density defect areas to plan, scope and deliver replacement programmes on areas with the greatest network performance benefit (SAIDI impact if an outage were to occur). The model consolidates all defects within an isolation segment to enable as much remedial work as required within that area in a single work package.

There is an annual allowance of $4.0 m for overhead defect remediation; this allowance is established through anticipated defect volumes, low-line identification, remediation requirements, and EDO replacement requirements in the areas planned for defect remediation.

Corrective works

Any faults relating to poles, crossarms or associated hardware are remedied using the current standard. Additionally, any defects identified on these assets as ‘very high’ or ‘high’ are remediated on a short-term basis – either as an emergency shut, if the risk is significant to public or property, or as a planned activity.

If the defect is assessed and deemed to be below this level, it is scheduled into a larger project (either that year or planned within the five-year period as appropriate) in order to coordinate remediation activities in such a way to minimise customer impact.

8.4.4 Private Service Lines

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 over 238 km across 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 regularly increases the number of poles and our requirements for pole renewal and maintenance.

Known Risks and Issues

Private service lines share the same risks and issues as network-owned distribution and LV lines, poles and crossarms, with the additional risks below:

- Ownership of unmaintained, poor-condition lines;
- Adoption of known type issues and high failure rate; copper and swan conductor; and
- HV service lines serving multiple owners with unclear ownership.

Management Approach

The process has evolved throughout the project. Ownership transfer and defects rectification are driven by factors such as major capital work projects, identified high-risk defects, customer-initiated works, and a feeder-by-feeder approach.

HV service lines serving multiple owners with unclear ownership and unmaintained lines, or lines with identified safety risks or recurring faults, are considered high priority. Customer-initiated works involving HV service lines are dealt with on an as-required basis.

To date, we have transferred around 38 km (roughly 16%) of overhead HV line and 455 poles. The rate at which ownership transfers have been undertaken has been accelerated through FY22 and FY23 due to the conversion of 11 kV network to 22 kV in line with the Barber Road project (refer to Section8.3.2).

Non-network Solutions

Where rectification works of a line are undertaken, as with all capital projects, non-network solutions are considered during optionality, including using remote area power supplies.

8.4.5 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
Barber Road – Feeder Rebuild	1,400	-	-	-	-	-	-	-	-	-
Copper Programme	-	2,645	1,537	3,076	5,387	1,452	3,253	1,473	1,281	4,661
Swan Programme	3,358	1,319	3,507	1,964	4,815	4,369	6,746	6,105	4,269	6,746
HV Rehabilitation	1,512	1,980	4,051	1,081	-	-	-	-	-	-
LV Rehabilitation	226	1,083	1,291	542	361	361	361	361	-	-
Overhead Renewal	4,009	4,009	4,009	4,009	4,009	4,009	4,009	4,009	4,009	4,009
Private Service Line Remediation	500	500	500	500	500	500	500	500	500	500
Safety Compliance	100	100	100	100	100	100	100	100	100	100
OPERATIONAL EXPENDITURE ($000S)										
Distribution Poles and Crossarms	683	228	228	683	228	228	683	228	228	683
Distribution Conductor	345	645	345	345	345	345	345	345	345	345
Fault Indicators and Earthing	27	27	27	27	27	27	27	27	27	27

Table 8-15 Expenditure Summary – Overhead Lines

8.5 Distribution and LV Cables

8.5.1 Management Approach

Distribution and low-voltage cables are generally reliable and maintenance-free; therefore, the approach we take to manage these assets is to repair or replace them on failure. We do not 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.

8.5.2 Distribution Cables

Known Risks and Issues

The primary risks and issues associated with distribution cables are:

- Terminations and joints failures; and
- Third-party damage causing cable strike and outages due to excavations or drillings.

Maintenance Activities

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 the overhead line condition assessment surveys, and repair work is undertaken where defects are found. Cable terminations on ground-mounted transformers and ground-mounted switchgear are not easily inspected due to outage requirements on the equipment to access cable compartments; however, the use of thermal imaging and partial discharge location equipment assists in identifying deteriorating cable terminations in these locations.

Renewal and Replacement

Currently, there is no proactive renewal programme for this asset type as our management strategy is to replace upon failure or when the level of reliability becomes unacceptable. However, an allowance is made each year for the replacement of cable sections found to be faulty. We have made an allowance of $296,000 annually to address these replacements. We have also made an extra allowance of $50,000 in operational expenditure from 2029 for trialling cable testing technology by testing our critical cable routes with various cable diagnostic tools to allow us to use as a condition result for future replacement planning decisions as a response to an aging cable fleet.

In addition, we have made an allowance of $195,000 per year to replace the cables with 22 kV rated cables when we replace ground mount equipment for future network development needs.

8.5.3 LV Cables

Known Risks and Issues

The primary risks and issues associated with LV cables are:

- Terminations and joints failures;
- LV load exceeds cable rating; and
- Third-party damage causing cable strike and outage due to excavations or drillings.

Maintenance Activities

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 the overhead line condition assessment surveys, and repair work is undertaken where defects are found.

Renewal and Replacement

There is no proactive renewal programme for this asset type; however, an allowance is made each year for the replacement of cable sections found to be faulty.

8.5.4 LV Service Pillars and Pits

Known Risks and Issues

The primary risks and issues associated with LV service pillars and pits are:

- Vehicle collision causing outages and public safety risks;
- Overheating;
- Deteriorated connection causing failures; and
- Third-party damage causing cable strike and outage due to excavations or drillings.

Maintenance Activities

We conduct five-yearly inspections to determine the condition, surrounding vegetation and accessibility. We also carry thermographic scanning to ensure the components are not overheating, a common mode of failure.

Corrective Maintenance

Corrective maintenance addresses 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 the damage.

Renewal and Replacement

It has been identified that a number of asbestos 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 carried out on them. There is an allowance of $203,000 per year for pillar replacement.

8.5.5 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
HV Rehabilitation	195	195	195	195	195	195	195	195	195	195
Pillar Renewal	203	203	203	203	203	203	203	203	203	203
Cable Renewal	296	296	296	296	296	296	296	296	296	296
OPERATIONAL EXPENDITURE ($000S)										
Distribution and LV Cables	55	55	55	55	55	105	105	105	105	105
LV Pillars	106	110	115	120	125	131	136	142	148	155

Table 8-16 Expenditure Summary – Distribution and LV Cables

Aerial view of Barber Road Substation

8.6 Distribution Substations and Transformers

8.6.1 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 is a priority.

Some types of equipment, in particular early kiosk type substations, have restricted operating space and live parts, and these require outages to work safely in them. 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 10 km 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.

8.6.2 Distribution Transformers

Known Risks and Issues

The primary risks and issues associated with distribution Transformers are:

- Vandalism and graffiti on ground mount transformer;
- Vehicle collision to ground mount transformer, causing outage and public safety risks;
- Corrosion deteriorates external transformer condition;
- Oil leaking through gasket due to ageing and deterioration of sealing components; and
- Deteriorated connection causing failures.

Maintenance Activities

Our inspection and maintenance cycles for distribution substations and transformers are:

Activity	Type	Frequency
Transformer Inspection (Pole Mounted)	Inspection	Five yearly
Transformer Inspection (Ground Mounted)	Inspection	Annual
Transformer Earth Grid Test	Routine Test	Five yearly

Table 8-17 Inspection Cycles for Distribution Transformers

Corrective Maintenance

Corrective maintenance is undertaken on distribution substations and transformers when defects are identified as part of routine inspections. Examples include removing graffiti on ground mount transformers, minor corrosion treatment and replacing hot connections.

Renewal and Replacement

We generally replace our transformers when their condition is unacceptable for continued service or where growth requires a capacity upgrade. However, it has been identified that several older distribution substation kiosk buildings that contain both the transformer and the standalone LV panel, do not have the required seismic strength during a major seismic event. We plan to replace these kiosks buildings with pad-mount transformers to address the seismic risk and ongoing maintenance of the kiosk building itself. We have made an allowance of $4.1m in this AMP period for the renewal of transformers and associated equipment due to condition and seismic risk.

8.6.3 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
Distribution Transformers	475	475	475	535	475	475	341	281	281	281
OPERATIONAL EXPENDITURE ($000S)										
Distribution Transformers	453	472	492	513	536	559	583	608	634	661

Table 8-18 Expenditure Summary – Distribution Transformers

8.7 Distribution Switchgear

8.7.1 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 the necessary equipment isolation. These devices are generally located in the public domain, so safety is our main consideration concerning inspecting and maintaining these units.

The selection of low-maintenance Ring Main Units (RMUs) has positioned us well, with little ongoing maintenance needed apart from routine safety checks.

8.7.2 Overhead Switchgear

Known Risks and Issues

- Expulsion Drop Out (EDO) replacement; and
- Air Break Switch (ABS).

Maintenance Activities

Activity	Type	Frequency
UAV Inspections	Inspection	Trial
Air Break Switch Inspection	Inspection	Annual
Air Break Switch UAV And Thermal	Inspection	Five yearly
Air Break Switch Maintenance	Maintenance	Five yearly
Recloser/Vacuum Switch	Inspection	Five yearly
Gas Switch	Inspection	Five yearly
Overhead Switchgear Earth Bank Test	Routine Test	Five yearly

Table 8-19 Inspection Cycles for Overhead Switchgear

Renewal and Replacement

As part of the replacement programme for EDOs in section 8.4.2 Distribution Conductor, the lack of earthing spigot will also be addressed. Due to our network being primarily 22 kV, the phase-to-earth clearance needs to be improved to exceed NZECP34:2001: Minimum approach distance requirements. Adding the earthing spigot will aid in reducing outage areas, thus reducing planned and unplanned SAIDI.

Counties Energy is continuing to replace air break switches, which began in 2017/18, prioritising a specific manufacturer of ABS. Counties Energy had 267 ABS on the network in 2017; as of 2022, the network has 154. Those ABS are prioritised based on SAIDI criticality, condition, age and operability. There will be a significant overlap between air break switch replacement and the Automation Re-build project, details can be found in section 6.8.1.

All other switch types will be replaced as indicated by asset inspections and operating ability or as part of the Automation Re-build project, details can be found in section 6.8.1.

8.7.3 Ground Mount Switchgear

Known Risks and Issues

The primary risks and issues associated with ground mount switchgear are:

- Vehicle collision causing an outage and public safety risks;
- SF_6 gas leakage causing premature failure due to manufacturing quality; and
- End-of-life numerical protection relay.

Maintenance Activities

Our inspection and maintenance cycles for the ring main unit are as follows:

Activity	Type	Frequency
Ring Main Unit Maintenance	Routine Maintenance	Five yearly
Ring Main Unit Battery Renewal	Replacement	Five yearly

Table 8-20 Inspection Cycles for Ring Main Units

Renewal and Replacement

We have replaced all our air/resin-insulated and oil-filled RMUs in the last few years with modern gas-insulated RMUs, requiring very little maintenance. Some of these units have automation fitted, which requires battery replacement every five years.

It has been identified that several gas-insulated RMUs on the network have gas leakage issues due to manufacturing quality, we have made allowance in the early period of this AMP to address these issues. Alongside these replacements, we will be reviewing the technical specifications of our RMUs and enclosures.

The circuit breaker function within the RMU requires numerical protection relays with a life expectancy of 15 years. We have established a programme to replace these end-of-life numerical protection relays with an allowance of $1.3m in this AMP period from FY24.

8.7.4 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
Ring Main Units	565	555	673	428	488	593	1,262	691	916	210
Overhead Switchgear	309	309	309	309	309	309	309	309	309	309
OPERATIONAL EXPENDITURE ($000S)										
Ring Main Units	68	70	71	73	74	76	77	79	80	82
Overhead Switchgear	166	169	172	176	179	183	186	190	194	198

Table 8-21 Expenditure Summary – Distribution Switchgear

8.8 Grid-Scale Battery Energy Storage System

8.8.1 Management Approach

Our grid-scale battery energy storage system (BESS) was installed at the Tuakau zone substation. This system consists of the isolating transformer, power converters, battery cells, monitoring and control systems, cooling, and auxiliary supply systems. This system has been temporarily relocated to the Bollard Road storage yard due to the development of the Tuakau zone substation.

Known Risks and Issues

The primary risks and issues associated with the grid-scale battery energy storage system are:

- Corrosion deteriorates the external condition;
- Deteriorated energy storage capacity due to the nature of ageing battery; and
- Limited local technical support resources due to specialised equipment.

Maintenance Activities

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

Activity	Type	Frequency
Routine Battery Inspection	Inspection	Six monthly
Cooling and Auxiliary Systems	Routine Maintenance	Six monthly

Table 8-22 Inspection Cycles for Grid-Scale Battery Energy Storage System

Renewal and Replacement

There is no proactive renewal programme for this asset type. However, we are exploring the next suitable install location for the BESS. Details of redeployment expenditure will be included in the next AMP.

8.9 Other Network Assets

8.9.1 Capacitor Banks and Voltage Regulators

Known Risks and Issues

The primary risks and issues associated with capacitor banks and voltage regulators are:

- Corrosion deteriorates the external condition; and
- Long lead times on procurement.

Maintenance Activities

Our inspection and maintenance cycles for capacitor banks and voltage regulators are:

Activity	Type	Frequency
Capacitor Bank	Inspection	Annual
Voltage Regulator	Inspection	Annual
Voltage Regulator Maintenance	Routine Maintenance	Three yearly

Table 8-23 Inspection Cycles for Capacitor and Voltage Regulators

Renewal and Replacement

There is no proactive renewal programme for the capacitor banks or voltage regulators. We install, upgrade, relocate or remove capacitor banks depending on network development needs. Two new voltage regulator sites are planned to be established in the AMP period, one on Otaua feeder and one on Te Hihi feeder. This is covered in more detail in Chapter 9.0 Network Development.

8.9.2 Protection Relays

Known Risks and Issues

The primary risks and issues associated with protection relays are:

- Lack of electromechanical/static relays; and
- Performance and reliability issues related to one particular model of protection relays.

Maintenance Activities

Our inspection and maintenance cycle for protection relays is:

Activity	Type	Frequency
Protection Relay Testing	Routine Testing	Three yearly

Table 8-24 Inspection Cycle for Protection Relays

Renewal and Replacement

We typically replace protection relays when we replace the primary plant they are related to, for example, the replacement of feeder protection when we replace the corresponding circuit breakers. As a result, we include relay replacement in the cost of returning the major primary plant.

In some cases, we replace relays due to performance and reliability issues or end-of-life. Our replacement programme for protection relays is planned for:

- Replacement of protection relays at Pukekawa due to emerging performance and reliability issues; and
- Replacement of the Pukekohe – Bombay 110 kV protection relays due to performance and lack of local vendor support.

8.9.3 SCADA and Communication Devices

Known Risks and Issues

The primary risks and issues associated with SCADA and communication devices are:

- Weak/loss of communication signals causing loss of network visibility and control; and
- Cyber attack on SCADA system causing an unauthorised party to gain control of our network.

Maintenance Activities

Our inspection and maintenance cycles for SCADA and communication devices are:

Activity	Type	Frequency
SCADA Radio Repeater Station	Inspection	Six monthly
Remote Communication Equipment	Inspection	Annual

Table 8-25 Inspection Cycles for SCADA and Communications

Renewal and Replacement

The radio communication systems between Karaka substation and Glenbrook GXP will be upgraded to fibre optic communication systems.

We are currently replacing our analogue SCADA radio equipment with a digital radio network, including establishing new repeater sites and replacing remote terminal units as part of a three-year network performance and reliability automation improvement project. This is covered in more detail in Chapter 6.0 Network Reliability.

8.9.4 Load Control Equipment

Known Risks and Issues

The primary risk and issue associated with load control equipment is:

- Long lead times on procurement.

Maintenance Activities

Our inspection and maintenance cycles for load control ripple injection plants are:

Activity	Type	Frequency
Ripple Injection Plant Inspection	Inspection	Six monthly
Ripple Injection Plant Maintenance	Routine Maintenance	Annual

Table 8-26 Inspection Cycles for Ripple Injection Plant

Renewal and Replacement

The load control ripple signal injection module at Opaheke substation is planned to be replaced within this AMP period. This injection module will be replaced to align with the network standard module. As we upgrade legacy meter installations to smart meters, we will remove the standalone ripple receivers, so no future expenditure is expected on these.

8.9.5 DC Battery Bank Systems

Known Risks and Issues

The primary risks and issues associated with DC battery bank systems are:

- Deteriorated energy storage capacity due to the natural ageing of the batteries; and
- DC battery bank/charger system failure causing loss of substation visibility and control.

Maintenance Activities

Our inspection and maintenance cycles for DC battery bank systems plants are as follows:

Activity	Type	Frequency
DC System Inspection and Test – GXP	Routine Testing	Three monthly
DC System Inspection and Test – Zone Substation	Routine Testing	Monthly substation inspection
DC System Inspection and Test – Radio Site	Routine Testing	Annual

Renewal and Replacement

As 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. However, actual replacements, particularly as technology improves, may be favourable to this assumption. The trade-off between the relatively low replacement cost and the 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.

8.9.6 Backup Generators

We have 3 mobile generators, which do not form part of our regulated asset base, are used to maintain supply during planned and unplanned outages, and 1 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.

Inspection and maintenance Activities

These are maintained at 250 hours running time, and the fixed generator at our head office is checked every month and run every 6 months.

Our inspection and maintenance cycles for the backup generators are as follows:

Activity	Type	Frequency
General Maintenance	Routine Inspection	250 hours
Inspected and Run	Routine Testing	6monthly

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.

8.9.7 Summary of Expenditure

Asset Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPITAL EXPENDITURE ($000S)										
Communication Network	1,400	–	–	–	–	–	–	–	–	–
Karaka Fibre Upgrade	2,500	–	–	–	–	–	–	–	–	–
LCP Renewal	–	–	450	–	–	–	–	–	–	–
Relay Replacement	1,300	2,000	–	–	–	–	–	–	–	–
OPERATIONAL EXPENDITURE ($000S)										
Capacitors and Voltage Regulators	16	17	18	18	19	20	21	22	23	24
Protection	476	96	96	96	96	96	96	96	96	96
Load Control Equipment	45	47	49	51	53	56	58	61	63	66
Battery Banks	90	94	98	103	107	112	116	121	127	132
SCADA and Communications	343	343	335	335	335	335	335	335	335	335
Network Operations Control	300	300	300	300	300	300	300	300	300	300

Table 8-27 Expenditure Summary – Other Network Assets

8.10 Assets Owned by Counties Energy at GXPs

In addition to the assets we own at our 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 Counties Energy maintains.

Bombay GXP

Within the Transpower substation, we have the following equipment installed on site:

- Subtransmission line overcurrent and earth-fault protection relays;
- Subtransmission line differential protection relays;
- Subtransmission line inter-trip communication links;
- Metering equipment;
- SCADA RTU and associated equipment; and
- DC battery bank.

A 33 kV load control plant and an aerial mast are installed within the substation grounds, as well as a disaster recovery container with a backup SCADA control terminal.

The load control plant will be decommissioned as part of the Ramarama substation decommission project. And a new disaster recovery room has been set up in the new Barber substation to replace the disaster recovery container.

Glenbrook GXP

Within the Transpower substation, we have the following equipment installed on site:

- Subtransmission line differential protection relays;
- Metering equipment;
- SCADA RTU and associated equipment; and
- Fibre optic cables to the 33 kV Glenbrook load control plant.

The 33 kV Glenbrook load control plant is located near the Transpower Glenbrook substation on land owned by Counties Energy.

8.11 Critical Spares Management

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 crossarms. Some of these are new; others have been recovered from projects and are now held as spares. We have repurposed the old Tuakau 33 kV substation site to create an alternative storage site and are redeveloping space in our depot to store critical spares.

A refurbished 33/11 kV transformer at Waiuku is being repurposed as a critical spare. We have purchased a 110/22 kV 20/40 MVA transformer installed in Tuakau substation in 2022 and are using one existing transformer as a critical spare.

Inspection and Maintenance

During 2022, we have undertaken a review of our processes and updated our critical spares list and stock requirements. A critical spares management process, which looks at periodic inspection, refurbishment and maintenance of spares, is to be implemented as part of the new EAM system in 2023.

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.

8.12 SF_6 Management

Sulphur Hexafluoride (SF_6) is used in many of our modern switchgear assets as an insulating and arc-quenching medium. We are required by law to disclose our SF_6 quantities for in-service assets and equipment held on-site in storage.

When removed from service, it is taken and degassed by an authorised third-party contractor, and we report gas that is lost into the environment or removed by our contractor.

At the time of writing, we have the following in-service SF_6 quantities:

Type	Quantity (kg)
Substation Switchgear	808
Overhead Switchgear	191.5
Ground Mount Switchgear	695.4

Table 8-28 In-Service SF_6 Quantity Summary

9.0 Network Development

9.0 Network Development

In this section, we set out how we plan our network to prepare for the future. We discuss the changing demands on our infrastructure and responding to the changing needs of our region, along with the opportunities and challenges posed by evolving technology. We detail the proposed projects our planning process has identified to maintain our network's safety, reliability, resilience and sustainability over the 10 years.

New Zealand EDBs are increasingly seeing a limited but diverse range of drivers of increasing demand (and to an extent, increasing generation export capacity) on electricity distribution networks, caused by the decarbonisation and electrification of the economy, in service of the net-zero 2050 target.

Our capital expenditure maintains pace with the increasing demand on our network. This growth is both in terms of new connections and energy delivered. We continue to experience high residential development in the Pukekohe, Paerata, Drury, Karaka, Glenbrook and Pokeno areas; and industrial growth in the Drury and Waiuku areas.

We are also preparing our network for changes in energy consumption, and the impact of decarbonisation and Distributed Energy Resources (DER) such as electric vehicles, solar panels, wind turbines and battery storage. DER will result in bi-directional energy flows, which will place additional demand on our low-voltage networks, which were not designed for such operation. To manage this challenge, we are investigating upgrades to systems and initiatives to improve our low-voltage network data, and are aiming to integrate data from our smart meters to better monitor and manage the impact of emerging technologies.

Counties Energy has embarked on a journey to transition from a Distribution Network Operator (DNO) to a Distribution System Operator (DSO). Further details on this transition are in section 7.2. One key component of our DSO strategy focusses of Capacity and Connections Management, whereby we will evolve our planning practices and processes for DER enablement, whilst also influencing smarter investment decisions for bi-directional energy flows.

9.1 Planning Approach

Our long-range plan focuses on developing our network, including subtransmission, zone substations, distribution and 400 V networks, by taking into consideration the following:

- Plans for new areas of supply (e.g. new residential developments, industrial subdivisions) and anticipated demand growth in existing areas of supply;
- Adequacy of the 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, particularly feeder performance, and capacity to meet our operational objectives. Factors we consider in our short-range plan include:

- Network safety;
- Planning for an uncertain energy future;
- Security of supply;
- 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 consider the increasing lead times required to negotiate and agree on land-rights or new work for upgrades requiring land purchase, designations or easements.

9.1.1 Planning Drivers and Assumptions

The key drivers and assumptions for our investment plans include the following:

- The network must 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 9.1.4);
- We will invest to meet the demand forecast (see section 9.2); and
- We will make investment choices that minimise the risk of asset stranding.

When determining network investments, several 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.

9.1.2 Network Development Philosophy

Our network development philosophy consists of the following elements:

- We make sure any development option we consider has public and employee safety at the core;
- Where appropriate, we shall implement phased solutions to defer major subtransmission and distribution investment;
- Our network is primarily radial, with the ability to interlink various feeders;
- We continually reassess and reconfigure 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 reallocating load to adjacent zone substations;
- Where we identify a potential increase in demand (see section 9.2), we plan for significant line routes and substation sites to serve the demand and seek designations well in advance;
- The security of supply criteria recognises that it is not economical 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, automation and fault passage indicators.

9.1.3 Planning For an Uncertain Energy Future

Counties Energy, along with other EDBs across New Zealand, is aware that it has a key role to play to enable the decarbonisation and electrification of society, particularly in the transport and industrial sectors. As we confront this challenge, we recognise the importance of providing clear signals to our customers, communities, and other stakeholders, of the likely implications of this transition. It is important for stakeholders to understand that this is not 'just' an electric vehicle story –EDBs will experience increased demands for investment in their networks for a range of reasons.

The following paragraphs describe what Counties Energy anticipates being the most significant sources of this demand over the next three decades, out to 2050. While certain elements of the transition are well understood and reasonably well-fixed (e.g., the net zero by 2050 target), other elements which may have a significant impact (e.g., the impact of phasing out reticulated gas for heating and cooking, the extent of regulations and technology to manage distributed energy resources) are still uncertain.

Counties Energy has made an educated assessment of what we expect on our network, but there are significant uncertainties and assumptions built into this. The EDB sector will, via its association with the Electricity Networks Association (ENA), be developing a more rigorous and structured set of demand forecasts and scenarios out to 2050 in the coming months.

Counties Energy is also a member of the Northern Energy Group. This group formed in 2019 around a shared interest in delivering future-ready electricity services to communities and a common belief that consumer voices need to be stronger in industry and government decision-making. The group consists of Counties Energy, Northpower, The Lines Company, Top Energy, Waipa Networks and Vector.

Customer Behavioural Changes

Being Customer Obsessed is one of our key company values. Through our customer research, we've developed an understanding of the customer personas that we service. The top three personas are focused on generating economic value, being simple to use and actively seeking sustainable solutions. We anticipate behaviour changes within the planning period, including:

- Changes in consumption patterns, driven by the adoption of EVs and other low-carbon initiatives. This will create new challenges due to increased demands and unpredictable behaviour; and
- An increase in Distribution Energy Resources (DER), where we'll see electricity generated from renewable sources, like solar and wind, stored and supplied into grids by households and businesses. This could include battery storage and using EVs to provide energy (Vehicle to Home (V2H)/Vehicle to Grid (V2G)).

We anticipate our customers will expect services that enable them to leverage DERs and participate in flexibility services. To manage this evolution Counties Energy is evolving from a Distribution Network Operator to a Distribution System Operator (DSO). Further information on this transformation is in section 7.2.

Electrification of transport

Transportation is the largest polluter worldwide, with many governments recognising that electrification of transportation (supplied by renewable energy sources) is key to meeting carbon reduction targets. Electricity distribution networks were not designed to take on this additional EV charging load if it were to all occur simultaneously.

The impact of increasing number of EVs on electricity demand is uncertain. We are investigating the use of smart EV charging to manage this impact. Further information on this initiative is presented in section 7.3.1.

Research by others, and analysis using our data, indicates that distribution transformers are likely to be the weak point for loading scenarios where smart EV charging is not adopted on a larger scale. While the mode of management for EV chargers is still unclear, we have implemented the following changes to our design standards:

- Where new transformers are installed in residential areas, space will be reserved to upgrade the transformer one standard size higher in the future if required. Future work is required to determine the course of action with brownfield distribution transformers;
- For distribution transformer sizing and LV voltage drop calculations in residential areas, the after-diversity maximum demand (ADMD) has been increased from 3.5 kVA to 5.0 kVA.
- For distribution feeder (22 kV and 11 kV) forecasting in residential areas, the ADMD has been increased from 2.6 kVA to 3.5 kVA. This is slightly lower than the ADMD used for LV voltage drop calculations and distribution transformer sizing to reflect increased diversity at the distribution level.

Demands for decarbonisation

Decarbonisation of process heat is a key focus area for reducing New Zealand's carbon footprint. We anticipate some industrial processes on our network presently powered by gas and coal to migrate to electricity. Additional capacity will be required in constrained areas to facilitate this migration. We are also seeing major industries investigating the use of biomass as an alternative to electricity conversion.

9.1.4 Security of Supply Criteria

Security of supply is our network's ability to maintain electricity supply when electrical equipment fails. Our security of supply 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 engage with our customers annually and, through feedback received, have established that, although improved service levels are desired, there is generally minimal support for increased line charges to undertake such improvements. The service levels outlined in Chapter 4.0 are used to inform our security of supply criteria, and network reliability initiatives are discussed in detail in Chapter 6.0.

The Counties Energy 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. Our security of supply criteria is shown in Table 9-1 below.

Supply Class	GPD [MVA]	Examples	Reliability Criteria
C1	0 – 0.5	Urban LV distribution transformer	Repair time
C2	0 – 1.5	HV radial feeder (or spur from the main feeder)	Repair time
C3	0 – 12	Rural zone substations and feeders (11 kV and 22 kV)	50% GPD <3hrs; 100% GPD repair time
C4	12 – 40	Zone substations and Subtransmission feeders (33 kV or 110 kV)	100% GPD less 12 MVA immediately; Remaining 12 MVA <3hrs
C5	Large customers	Large industrial customers	As per supply agreement

Terms used in the table:
GPD – Group Peak Demand
Repair time – The total time from the start of the outage until the 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

Table 9-1 Counties Energy Security of Supply Criteria

We have historically adopted higher capacity substations (i.e. two 30/60 MVA or three 20/40 MVA transformers). These were primarily driven by the area load requirements and/or industrial loads. We plan to adopt a similar approach for industrial substations, where load requirements are less predictable. However, to limit the impact of unplanned substation outages on customers, we utilise a lower firm capacity substation size of 40 MVA (i.e. two 20/40 MVA transformers) for zones where the load is primarily residential. While outages of a substation are infrequent, this limits the number of customers affected by an event to less than 15,000 ICPs.

We have also adopted a network design with a higher overlap between substation zones. Operation at 22 kV enables us to spread our zone substations further and run fewer feeders. However, this has a negative impact on customer experience and network reliability during unplanned events due to limited interconnectivity. Having our substation zones overlap also improves our resilience under HILP events.

Criteria for Customers

For larger individual customers, we set the security criteria for their supply based on their load size, location, and special conditions agreed in their supply agreements. Such customers may make a price-quality trade-off and choose to pay a larger annual amount for higher service levels than the average customers supply agreements.

For most customers, who are fed by shared assets, it is not possible to set individual service levels, and thus our approach is to meet the targets developed above.

A further factor influencing network design is the adoption of monitoring network performance by SAIDI, SAIFI and CAIDI. These factors include both planned outages and unplanned (fault) outages.

We have historically used a 'desirable number of customers per feeder/switch segment' metric in our planning. We have replaced this metric and now utilise our Network Criticality Model, which factors in the network build type, ICP count per segment, and the ability for the segment to be backfed. We believe this approach delivers a more targeted approach toward reliability improvements. Further information on the Network Criticality Model is in Section 5.3.3.

Aerial view of Gellerts Nurseries in Drury

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 whilst 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 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 lower reliability than urban feeders due to their exposure to external factors such as trees, wildlife and weather.

Urban feeders also often have substantial underground cable sections, providing a more reliable service than overhead lines. As urban network boundaries 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 generally utilise existing switches to change network open points but may require conductor upgrades in some cases.

9.1.5 Design Standards

Our distribution network is predominantly rural, with earlier subtransmission built at 33 kV and distribution built at 11 kV. 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:

- 110 kV as a standard subtransmission voltage; and
- 22 kV as a standard distribution voltage.

Introducing these higher voltages has historically enabled us to build longer feeders, thus requiring fewer zone substations. However, an independent review of the significant impact of an outage on a very large zone substation on both SAIDI and SAIFI performance has resulted in a review of our network architecture. Very large zone substations with fewer but longer feeders reduce the interconnectivity between zone substations. This results in some parts of our distribution feeders becoming very critical for contingency scenarios and HILP events.

Our new architecture now focuses on running shorter distribution feeders with increased interconnection with neighbouring zone substations. This improves our ability to backfeed, limits the number of customers impacted by unplanned outages on these feeders (therefore improving SAIDI and SAIFI), and improves our resilience under HILP events. At 22 kV, this will result in spare capacity on most new feeders. This spare capacity enhances our ability to support further growth, is a head start for capacity challenges associated with an uncertain energy future and improves our capacity for DER hosting.

For our existing larger zone substations, the capacity is either already being utilised by industrial, commercial and residential growth, or in providing resilience to neighbouring zone substations by being able to support load through the network if a major event affects another adjacent substation.

The move to 110 kV/22 kV has progressed steadily for our eastern area (i.e. the area fed from the Bombay GXP). The remaining pockets of 33 kV/11 kV will be removed with the project to establish the new Barber Road 110/22 kV substation to allow the decommissioning of the old 33/11 kV substations at Mangatawhiri and Ramarama in FY24.

The western area of our network is supplied at 33 kV from the Glenbrook GXP with two circuits each to Karaka and Waiuku substations and a single 33 kV spur line from Waiuku to Maioro 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 in the long term. The Glenbrook GXP does not have 110 kV supplies available, which would be a significant expense for Transpower to provide. We have established that a 33 kV subtransmission system in this area is appropriate for the foreseeable future. Similarly, retaining 11 kV as the feeder voltage is suitable, noting that for very long rural feeders, 22 kV conversion of them (or parts of them) 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 the construction of overhead lines of up to 110 kV as a permitted activity in rural and formerly non-residential areas.

For compliance with our security of supply levels in Table 9-1, the subtransmission circuits (either at 110 kV or 33 kV) 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 12 MVA, can be supplied continuously, with the balance being restored within three hours. The preferred transformer size is 40 MVA for 110/22 kV substations, 60 MVA for industrial/commercial 110/22 kV substations and 20 MVA for 33/11 kV substations.

Transformer impedances are chosen to limit the maximum fault current to 16 kA (at 22 kV) and 13.1 kA (at 11 kV), with margins built in to accommodate source fault level and distributed generation increases. 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 rebuilt) follow good engineering practices adopting non-oil circuit breakers, bus section switches, unit protection, increased arc containment and multiple fire zones. Natural disaster resilience (e.g. floods, wildfires, earthquakes) is considered as part of the design process for all critical assets e.g. substations and Subtransmission lines.

To provide flexibility for future load developments, the switchboards are rated to be supplied with 60 MVA 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, while future substations will be designed for two transformers, and alternate engineering solutions will expand capacity as required. Smaller substations (class C3) may be fed on a spur line. However, a ring feeder approach will be adopted where possible to allow for future growth and provide greater security. A single transformer may be installed. However, provision for a backup (on-site or transported in) will be made to cater for a transformer failure HILP event.

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, with 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.

Table 9-2 below specifies our design ratings for network conductors and cables.

Cable	Rating	Design Rating	Notes	Overhead Conductor	Cross-section	Rating	Design Rating	Notes
630 mm^2 Al	590 A	590 A	1, 2	Cockroach	256 mm^2	560 A	560 A	3
240 mm^2 Al	360 A	240 A	1, 2	Cricket	160 mm^2	420 A	280 A	3
95 mm^2 Al	200 A	140 A	1, 2	Fluorine	40 mm^2	190 A		4

Table 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 maximum span lengths of 80–100 metres; and
4. Run spurs for volt drop considerations rather than capacity.

Table 9-2 Our Standard Distribution Network Conductor and Cable Ratings

Equipment Ratings

We design and operate our network to the following acceptable equipment load limits:

- 100% of zone substation power transformer nameplate ratings, with short duration overload to 120% under fault conditions; and
- 100% of the switchgear, line and cable ratings.

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.

The design criteria we utilise for our ground-mounted distribution switchgear (RMUs) is that they shall have the following:

- A fault rating of 16 kA;
- A bus rating of 630 A;
- Three-phase switching; and
- Remotely operable disconnectors on four function units.

We will consider using cyclic ratings of circuits as loading on them increases. This may provide an appropriate way of delaying further investment – particularly when loading only occurs for short durations, such as during plant outages (planned or unplanned).

9.1.6 Network Development Options

Subtransmission Development

When identifying subtransmission development options, we consider the following:

- Long-term load and usage forecasts in the area, considering consumer type and needs;
- The ability for the subtransmission system to 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 the following:

- 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 requirement 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 Network Boundaries

We share common boundaries with two electricity networks, Vector to the north and WEL Networks to the south. Although not immediately on our border, Powerco's 'Eastern' network is adjacent to the south-east of our network.

We will look to share investment with our neighbours when considering development options, including capacity and security projects, as the most economical solution may satisfy some mutual needs.

We share interconnection points with Vector in two locations and WEL Networks in one location.

Conversion to 22 kV

Conversion to 22 kV operation can increase our network capacity to meet load growth and service requirements effectively. This involves upgrading the 11 kV distribution network to 22 kV, where there are identified capacity and voltage constraints, and each area for conversion is assessed on its merits, including considering a range of alternatives. For all new work, we install insulators, cables, and switchgear to be capable of 22 kV operation. Where practical, we will convert the relevant distribution network to 22 kV when 11 kV capacity or voltage constraints occur, and there are no cost-effective solutions to improve 11 kV capability (e.g. the use of voltage regulators, reconductoring, network reconfiguration, new technology or non-network solutions).

Low-Voltage Reticulation

New subdivision developments drive the extent of underground LV reticulation augmentation. We liaise closely with local surveyors and property developers 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. Overhead LV augmentation is rare, as most area plans approved by local councils require underground reticulation.

Longer term, we anticipate emerging technologies to impact our LV network. Our network, which was designed based on a centralised uni-directional power flow model, is evolving to a bi-directional model where customers will have more control and choice. In addition to the initiatives discussed in section 9.1.3, we have moved to shorter runs for new low-voltage feeders and implemented the use of uniform cable sizes.

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 5.0 to ensure that any new equipment meets construction, technical and safety standards. Our teams identify potential new equipment as part of compliance and safety surveys, asset renewal policies for ageing assets and new customer requirements.

Load Control

Our load management system was previously based on minimising network peaks coincident with transmission peaks, which minimised transmission charges. Due to changes to the transmission pricing methodology, this incentive will no longer exist. Therefore, we intend to amend our load control methodology to target peak demand on specific feeders to defer the need for network reinforcement. We expect to implement this before winter 2023.

While the precise maximum load control capacity is measurable, the total 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 winter, where Counties Energy'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, which provides an after-diversity maximum demand controllable load of 38 MW via Bombay GXP and another 10 MW via Glenbrook GXP.

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

Distributed Generation

Several of our consumers own distributed generation systems that connect to our 11 kV or 22 kV distribution network. Generally, the network can support the connection of generation in a specific location:

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

We have recently connected a small number of photo-voltaic (PV) and wind systems of ratings less than 10 kW to our low-voltage network. We record the location of these but do not have control of these installations. 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 https://www.countiesenergy.co.nz/about/content/regulatory.

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. N-1 redundancy) 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 has a true firm capacity, 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 generator size 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). In remote rural areas, generators may be restricted to 0.5 MW for connection to 11 kV lines.

For load forecasting purposes, no specific provisions have been made for potential large-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 government subsidy provisions. At household levels, other generation options include wind turbines, micro-hydro systems, biomass and biogas engines and diesel or bio-diesel generators.

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

The impact of small-scale household generation depends on the provision of local storage (batteries). Without widespread battery storage, small-scale generation on our network (predominantly solar PV) is not expected to impact network demands (typically winter evenings). We anticipate localised LV constraints that will impact the ability of the network to accommodate small-scale generation; and we intend to better identify potential areas of congestion and ways to resolve this as part of becoming a DSO.

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

9.2 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 crucial to 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 monitor actual growth rates annually, and any change will be reflected in next year's development plan.

We have traditionally been a predominantly rural distribution network, with demand particularly sensitive to changes in industrial demand within our area.

This has changed in the last decade, whereby we're seeing unprecedented residential growth, primarily in urban areas but also in urban pockets within rural settings. Our ICP numbers are expected to double in the next 20 years.

Significant industrial/commercial load growth is already occurring in Pokeno and is expected in the Drury area over the next few years.

Greenfield development within our network

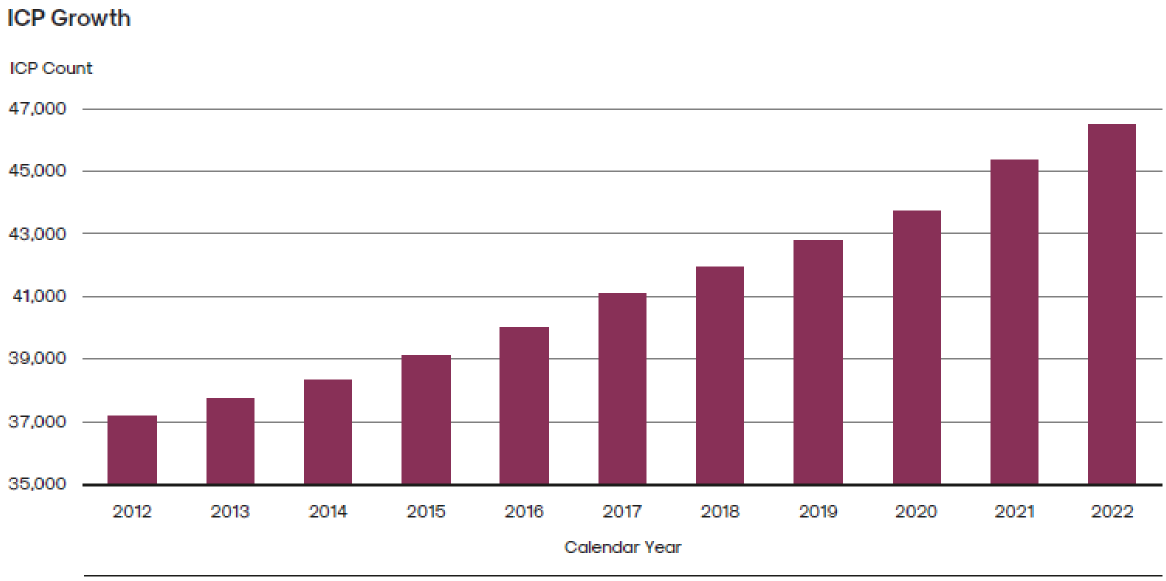


Figure 9-1 ICP Growth

This ongoing load growth introduces the need for us to invest in capacity augmentation infrastructure, e.g. new zone substations, associated subtransmission circuits, new feeders and existing network upgrades 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.

We recognise the potential for changes in demand characteristics where emerging technology will influence customer energy behaviour – the rise of the prosumer. While anticipated behaviour is difficult to predict, we need to consider the impact of EVs and charging behaviour, increased energy efficiency in new homes, future uptake of energy storage systems and utilisation of solar technology.

9.2.1 Demand Forecast Methodology

Our demand forecasting methodology follows the process shown Figure 9-2 below.

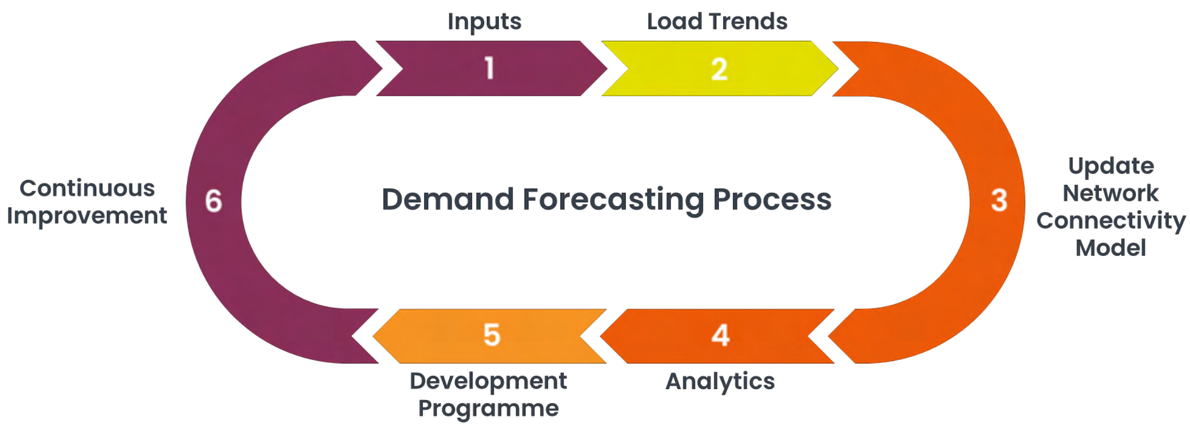


Figure 9-2 Demand Forecasting Process

We utilise our load forecasting model to forecast the future demand on our network for the planning period. The process is initiated by assessing network peak loading on all distribution feeders and zone substations. This provides an initial output for winter loading relative to previous forecasts.

Step 1 Inputs

We use the following inputs to develop our demand forecast:

- **Substation demand data**: We use 15-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**: We use half-hourly data for generators over 200 kW;
- **Coincident demands**: We extract the coincident maximum demand from the quarter-hourly data for our zone substations, feeders and embedded generation;
- **Key customer demand**: We review energy data for key customers using demand meters installed at various premises. We also consult with our major customers to identify any planned future expansion and changes in their 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 ADMDs of 5.0 kVA (for Low Voltage) and 3.5 kVA (for 11 kV and 22 kV) per lot for new domestic subdivisions. Demand estimates for industrial/commercial subdivisions are based on customer requests or known forecasted demand;
- **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 new connections to our substations. We use this data to verify our demand forecast.

Step 2 Load Trends

The inputs gathered in Step 1 are used to verify our previous forecasts and update any load trends. 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 GXPs supplying our network, Bombay and Glenbrook.

Step 3 Update Network Connectivity Model

The distribution network evolves through the year due to configuration changes resulting from load transfer between feeders, renewal-driven improvements, abnormal operating conditions, and new developments. We update our network connectivity model to include these changes.

This identifies any shortfalls and constraints appearing on the network.

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.

Step 4 Analytics

The outputs from the load trends and our network connectivity model (using DIgSILENT PowerFactory modelling software) identify issues or potential issues related to voltage breaches, thermal breaches, loading and configuration risks.

Once the constraints and their timing are identified, options are considered to determine the best solution. The selected option may include the following:

- Augmentation to increase capacity;
- Network reconfiguration to improve utilisation;
- Grid-scale battery solutions to provide voltage support or backup supply;
- Remote area power supplies instead of traditional network build;
- Load control to manage specific peaks; and
- Demand side management.

Step 5 Development Programme

The solutions identified in Step 4 above inform the investment proposals which form the network development programme over the period covered by this plan. While this process identifies these proposals, further detailed analysis is undertaken to inform the business case that is prepared before eventual investment. Where the timing of requirements aligns, we incorporate this programme with our asset replacement, maintenance and reliability programmes.

Step 6 Continuous Improvement

Counties Energy undertakes continuous monitoring of its network, investments and network performance to ensure the value identified in the above proposals is delivered. The review process ensures that we continually learn and improve our inputs into future demand forecasting.

9.2.2 Demand Forecasting Assumptions

The following assumptions are made whilst undertaking the demand forecasting process.

Impact of Demand Management

Ripple control is integral to 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 exclusive of controllable load. As discussed in section 9.1.6 above, this is likely to increase in areas as the use of ripple control is changing.

We incorporate power factor penalty charges in major supply agreements, which encourage our consumers 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 consumer has lowered their demand through power factor correction.

Impact of Distributed Generation

We consider the likelihood of a distributed generator being available on demand 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 several 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. Except for Hampton Downs, Awhitu Windfarm 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 several years. We usually assume uptake over a period of 18 months following the reticulation of the subdivision. However, a faster uptake is also considered for special housing areas (SHA).

Industrial subdivisions provide a high level of uncertainty, as the eventual load size and type are often unknown at the time of development. We provide a standard three-phase supply point unless more specific requirements are known. Often, dedicated transformers are installed for large consumers as development progresses.

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.

9.2.3 Maximum Demand and Forecast

Our maximum system demand forecast is shown below.

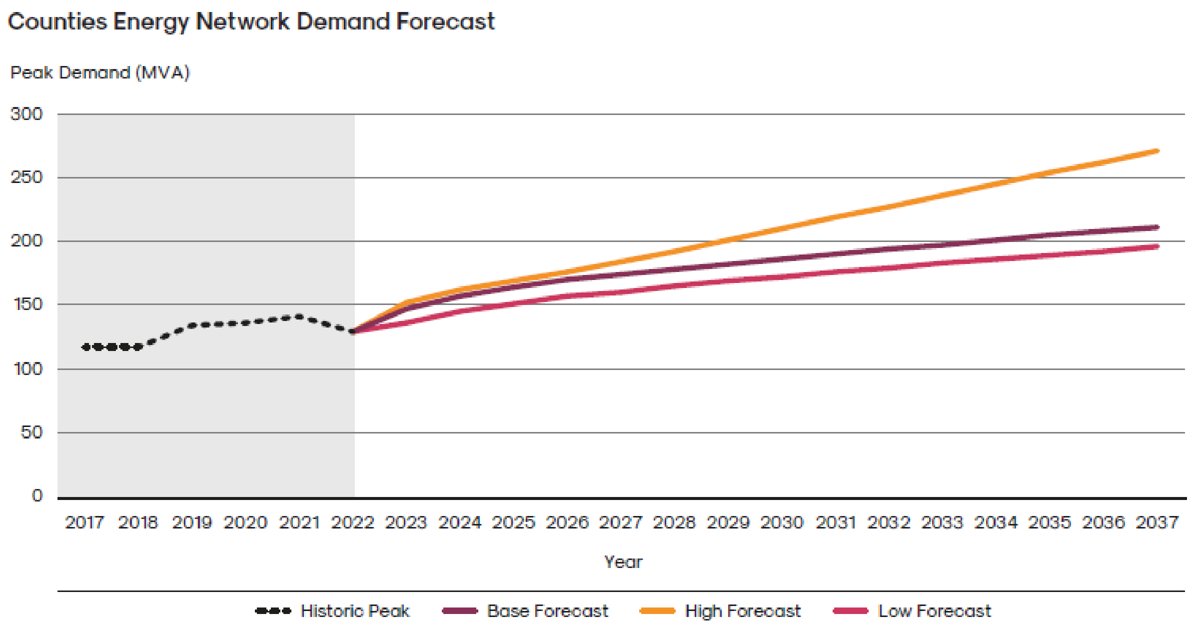


Figure 9-3 Overall Maximum System Demand Forecast

We have included scenario-based demand forecasting at the zone substation level and above. These scenarios are:

Base forecast

This is similar to the forecasting methodology used in previous years. It assumes future customer behaviour, with respect to electricity usage, matches historical behaviour, with an allowance for increased consumption due to EVs.

Low forecast

The low scenario represents a future which includes increased use of battery storage, improved consumer efficiency (e.g. heating efficiency from heatpumps and improved insulation levels), optimised demand control and widespread adoption of smart EV charging.

High forecast

The high scenario represents a future which includes EVs (along with the absence of smart charging), reduced use of load control and the impact of decarbonisation. It should be noted that this change would pose significant challenges to not only the Counties Energy network but also every other EDB, the Transpower grid and all generators.

For this AMP, the base forecast will be used to determine network development requirements. We will continue to monitor the impact of new technology and behaviour on network demand, which will be reflected in future demand forecasts.

The graph below shows the maximum demand for the eastern and western regions.

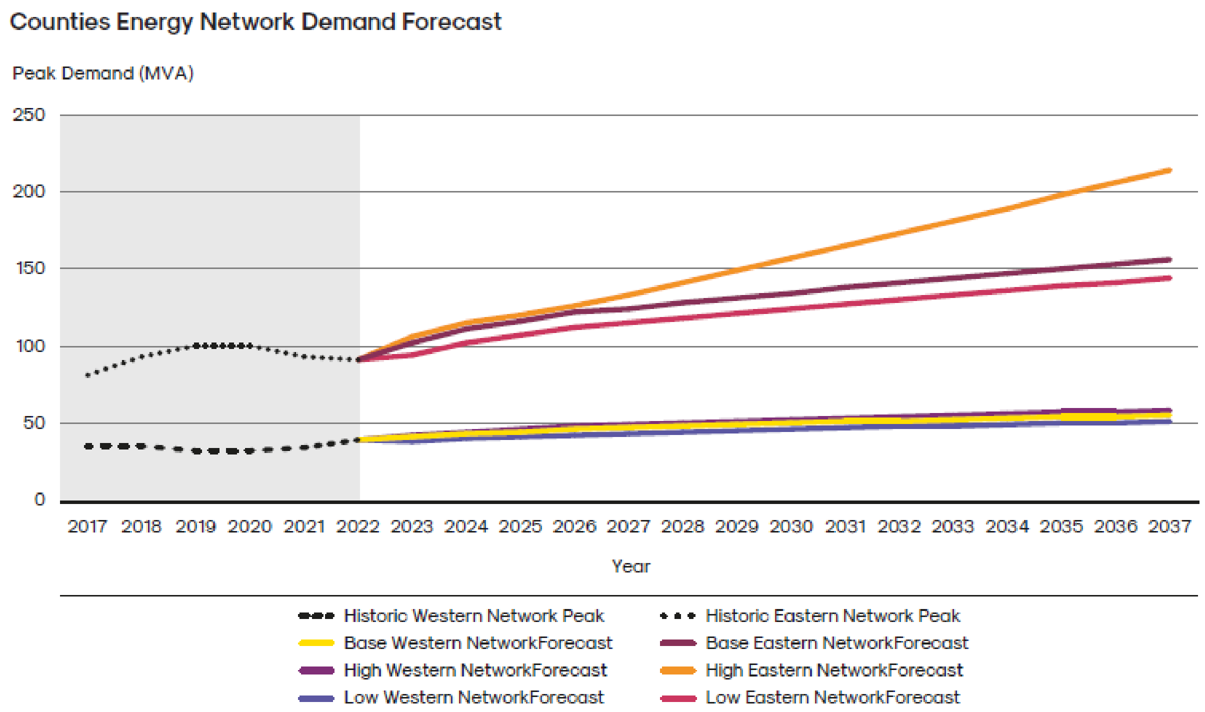


Figure 9-4 Maximum System Demand Forecast by Region

Area	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Eastern Area	91.3	101.9	110.6	116.1	121.6	124.0	127.5	131.1	134.4	137.6	140.7	143.8	146.8	149.9	152.8	155.7	4.7%
Western Area	39.1	40.9	42.9	44.4	45.9	46.9	47.9	48.8	49.8	50.6	51.4	52.1	52.8	53.5	54.1	54.7	2.6%
Generation	9.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	0.6%
Total (incl. generation)	134.0	146.6	156.8	163.5	170.2	173.5	177.9	182.2	186.3	190.2	193.8	197.5	201.1	204.8	208.1	211.4	3.8%

Table 9-3 Maximum System Demand Forecast Including Generation

9.2.4 Development Programme

The following sections provide an overview of current development programmes on our network. The development programme is split into two network regions, the eastern region, where most of the growth occurs, and the western region, which is dominated by rural and industrial consumers.

9.3 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 the following:

- A 110 kV ring from Bombay supplying Pokeno, Pukekohe and Tuakau;
- Two 110 kV lines from Bombay to Opaheke;
- Two 33 kV lines from Bombay to Ramarama; and
- One 33 kV line from Bombay to Mangatawhiri.

The figures below show the single-line schematics for the subtransmission network supplied from the Bombay grid exit point.

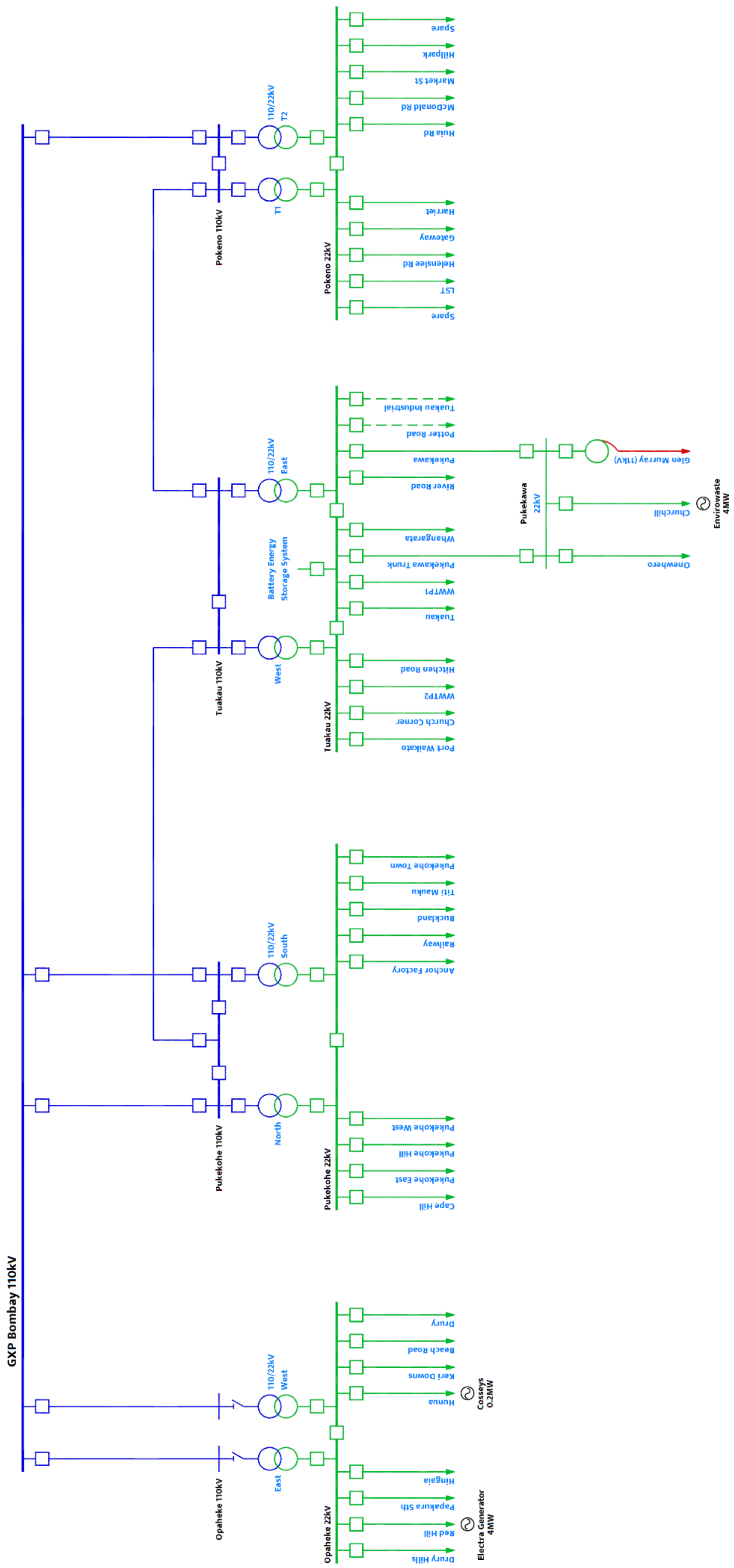


Figure 9-5 Single Line Schematic of the Eastern Region 110 kV Subtransmission Network

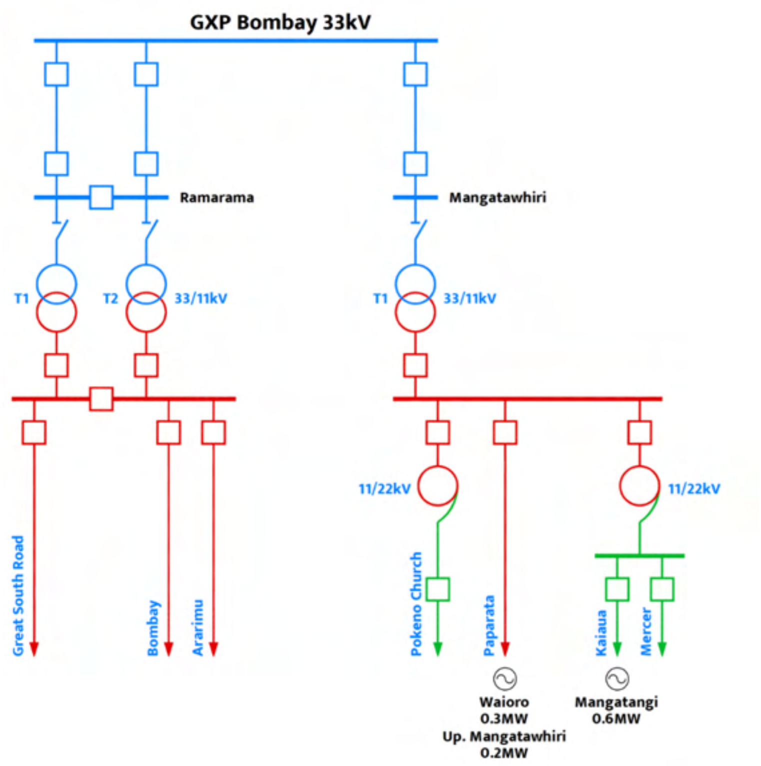


Figure 9-6 Single Line Schematic of the Eastern Region 33 kV Subtransmission Network

Figure 9-7 and Figure 9-7 Eastern Region Maximum Demand Forecast show the demand forecast for the Eastern Region and the Eastern Region zone substations.

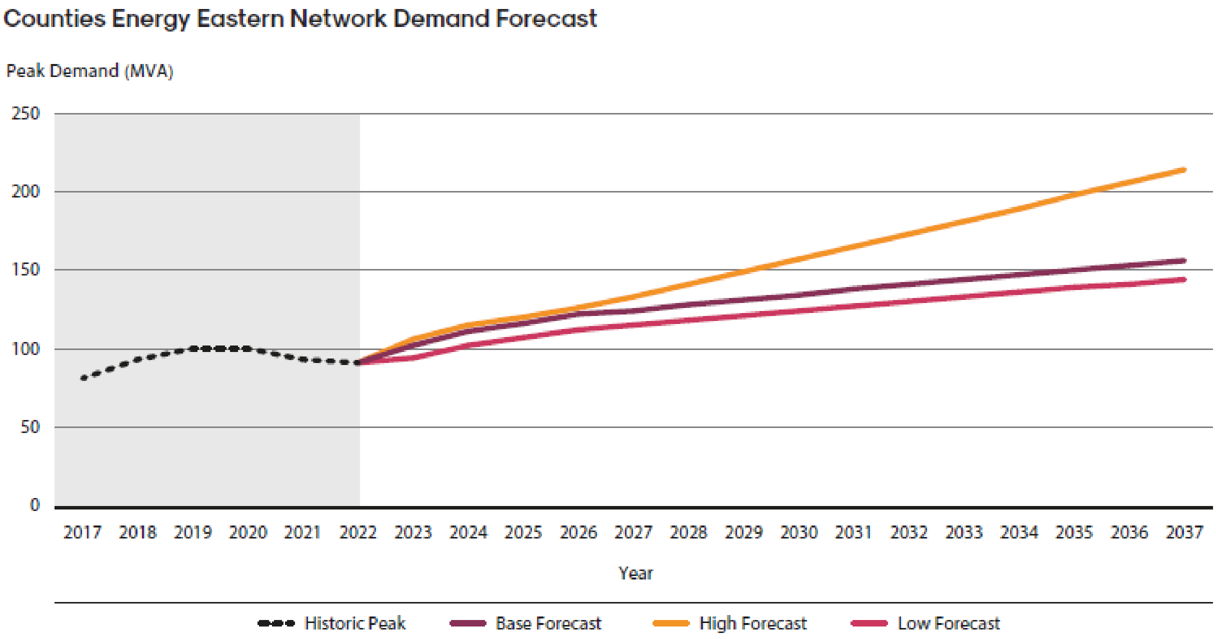


Figure 9-7 Eastern Region Maximum Demand Forecast

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Pukekohe	38.8	40.4	41.3	42.3	43.2	44.2	45.6	47.1	48.5	50.0	51.4	52.9	54.3	55.8	57.0	58.2	3.3%
Opaheke	28.3	30.4	32.8	35.2	37.6	38.3	39.8	41.3	42.8	44.2	45.5	46.7	48.0	49.3	50.5	51.8	5.5%
Tuakau	12.8	12.2	12.3	12.3	12.4	12.5	12.5	12.6	12.7	12.7	12.8	12.9	12.9	13.0	13.1	13.1	0.2%
Pokeno	10.2	15.9	21.5	23.8	26.0	26.6	27.1	27.6	28.1	28.6	29.0	29.5	30.0	30.5	30.9	31.4	3.5%
Ramarama	6.7	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	0.9%
Mangatawhiri	7.6	8.6	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	1.0%
Barber Road	0.0	0.0	16.0	16.3	16.7	17.1	17.4	17.8	17.9	18.1	18.2	18.4	18.5	18.7	18.8	18.9	0.7%
Eastern Region (Bombay GXP)	91.3	101.9	110.6	116.1	121.6	124.0	127.5	131.1	134.4	137.6	140.7	143.8	146.8	149.9	152.8	155.7	4.7%

Table 9-4 Eastern Region Maximum Demand Forecast Table

We 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. A further 4,000 dwellings are 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.

Pokeno continues to see significant residential and industrial expansion within the Waikato District Council area, with further rezoning of land from rural to residential likely if the Proposed Waikato District Plan is adopted.

In the Drury area, we are aware of several significant developments which have the potential to add new demand to the network. These include Drury South Crossing, the Auranga subdivision west of SH1, Kiwi Property Trust and Oyster Capital developments south of the existing Drury area.

Based on identified development in the Drury area, we have brought forward the Quarry Road Substation (see Section 9.3.2).

The following sections (9.3.1 to 9.3.6) describe the subtransmission and distribution issues and plans for each zone substation area within the eastern region.

9.3.1 GXP and Eastern Area Investment Requirements

Transpower's Bombay Substation has a transmission capacity limit [8] of:

- 170 MW for high north flow into the Bombay bus from the Waikato; and
- 120 MW for high south flow into the Bombay bus from the Auckland Region.

Based on current demand forecasts, the south power flow limit could be reached by 2026. To address this amidst other asset drivers for Transpower, they have installed two 150 MVA 220/110 kV transformers at their Bombay Substation in 2022. They have indicated that their existing 110 kV lines connecting to their Bombay Substation will eventually be decommissioned and so the substation transmission capacity limit will be based on the transformers.

Distributed generation within our network, approximately 23 MW, could defer the issue by one to two years. However, at present, 7 MW of this generation is connected to our network by a single rural distribution line; hence we haven't allowed for it as a reliable source for planning purposes.

KiwiRail previously approached Counties Energy about supplying their Papakura to Pukekohe (P2P) rail electrification project from Transpower's Drury Substation. KiwiRail has instructed Counties Energy to put this work on hold.

[8] There is no apparent seasonal pattern to the high north and south load flows.

9.3.2 Opaheke Zone Substation

We expect significant residential growth in the area through the planning period associated with continued development in Hingaia, Papakura and Drury areas.

The Opaheke 110/22 kV Zone Substation is supplied by two 110 kV circuits from Bombay GXP. Opaheke Zone Substation supplies 504 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 primarily industrial. Opaheke is classed as a zone substation (C4) and fully complies with our security criteria (Refer to Table 9-1). Major consumers in this area include Independent Liquor, Winstone Aggregates and van den Brink Poultry.

Figure 9-8 below shows the Rural-Urban Boundary (RUB) map for the Opaheke Zone Substation supply area (Papakura area), outlining the areas for future growth.

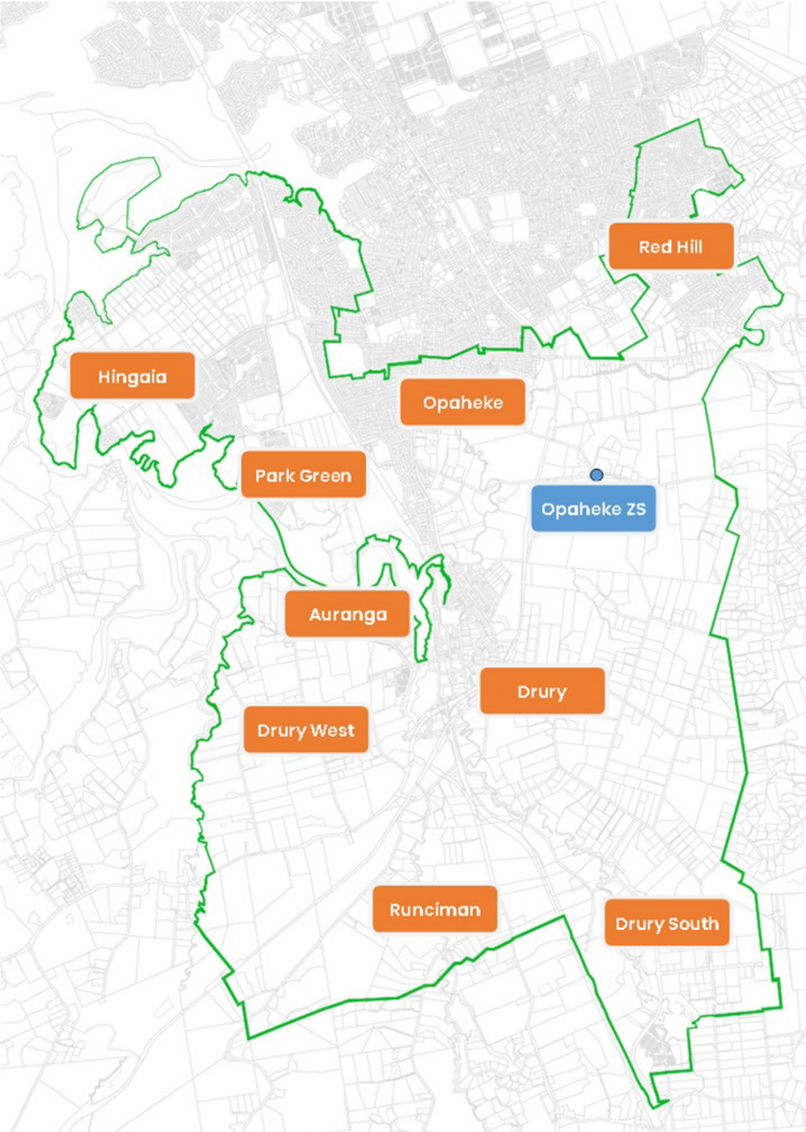


Figure 9-8 Opaheke Zone Substation Rural-Urban Boundary

The Opaheke load has a winter peak, and the forecast peak demand for Opaheke Zone Substation and associated distribution feeders is shown in Table 9-5.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Beach Road	4.0	4.0	4.3	4.5	4.8	5.0	5.3	5.5	5.8	6.0	6.3	6.5	6.8	7.0	7.3	7.5	5.9%
Drury	4.2	4.6	5.1	5.5	6.0	6.0	6.1	6.1	6.2	6.2	6.2	6.3	6.3	6.4	6.4	6.5	3.7%
Drury Hills	3.4	4.9	6.5	8.0	9.5	9.6	10.1	10.6	11.1	11.6	12.1	12.6	13.1	13.6	14.1	14.6	21.8%
Hingaia	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.4	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.9	3.7%
Hunua	4.4	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.0	5.1	1.0%
Keri Downs	3.4	3.4	3.4	3.5	3.5	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5	10.2%
Papakura South	5.3	5.4	5.6	5.8	6.0	6.2	6.3	6.5	6.7	6.9	6.9	7.0	7.1	7.1	7.2	7.2	2.5%
Opaheke Zone Substation	28.3	30.4	32.8	35.2	37.6	38.3	39.8	41.3	42.8	44.2	45.5	46.7	48.0	49.3	50.5	51.8	5.5%

Table 9-5 Opaheke Zone Substation Maximum Demand Forecast

Opaheke Zone Substation and Feeder Investment

The Opaheke Zone Substation demand forecast is shown in Figure 9-9.

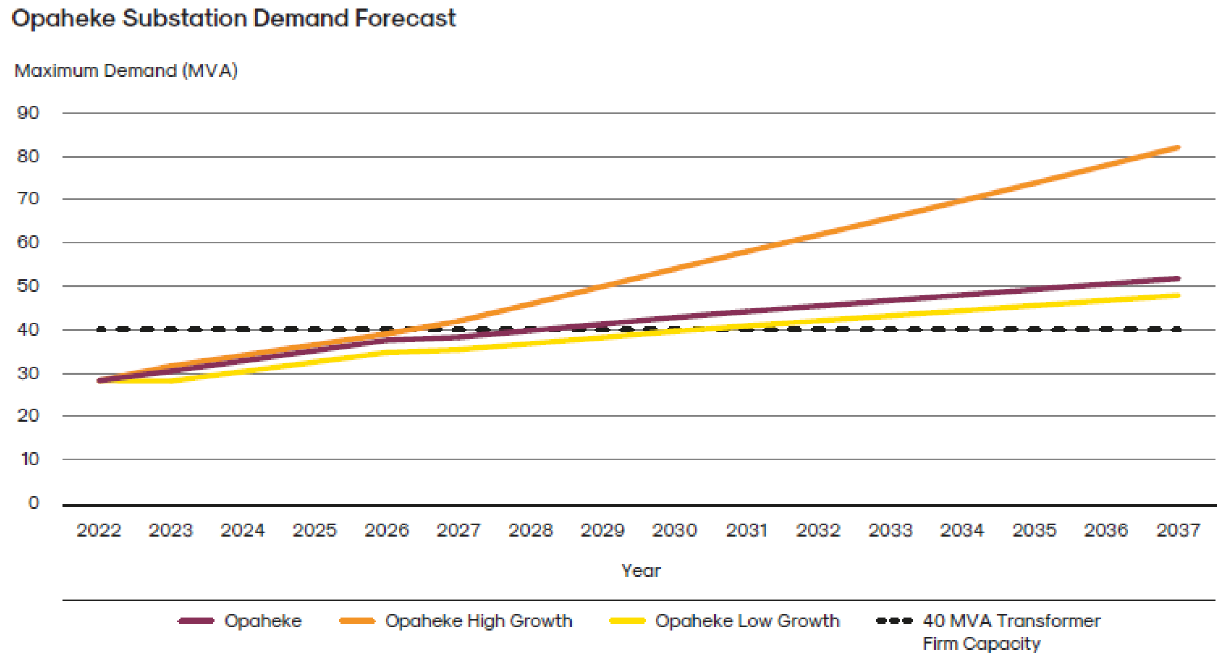


Figure 9-9 Opaheke Zone Substation Maximum Demand Forecast

Two 110/22 kV, 20/40 MVA transformers supply the load at Opaheke, providing an N-1 capacity of 40 MVA. The Opaheke maximum demand is forecast to exceed the N-1 capacity of the transformers from 2029. This includes the forecast load from Drury South Crossing.

Development in the Drury area continues to progress, and customers have approached us with requests to supply significant loads. Based on this, we will commence the Quarry Road substation design starting in FY24, with commissioning scheduled for FY28. The Quarry Road substation will be supplied at 110 kV by breaking into the existing Bombay GXP to Opaheke West 110 kV circuit. A 110 kV bus will also be created at the Opaheke substation, creating a 110 kV ring from Bombay GXP supplying the Opaheke and new Quarry Road substations.110 kV110 kV

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. This load will be shared between the existing Opaheke substation, the proposed Quarry Road substation, and a future substation situated in between Pukekohe and Drury.

We anticipate the Quarry Road substation to eventually be supplied from the proposed Transpower Drury GXP when load necessitates. Refer to Figure 9-15 for the proposed subtransmission single line for this proposed supply arrangement.

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 the rail corridors. Included in its area are the Hingaia Peninsula and Bremner Road just west of Drury, both of which have been designated as Special Housing Areas (SHA). As detailed earlier in this section, the supply area also includes the Drury South Crossing.

- The Hingaia Peninsula has already undergone significant subdivision. In the load forecast, we have assumed that over 500 lots will be developed over the next 10 years;
- The Auranga Subdivision continues to grow 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 for 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 the potential for 8,200 lots;
- The Hunua Views development, in the southern area of Drury South Crossing, has around 700 lots. These have been assumed to incur demand over the next 10 years;
- We are aware of significant potential development in the area between Drury and the Drury South Crossing area. This would include over 4,000 new dwellings plus businesses and other supporting amenities. The timing of this is uncertain; however, for load forecasting purposes, this is projected to commence after 2028; and
- Other smaller subdivisions could be developed around the North Opaheke area, with typical sizes between 50 and 300 lots. These have been allowed for in the demand forecast.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
QUARRY ROAD 110/22 KV SUBSTATION ESTABLISHMENT		FY23– FY28	38,513
Constraint	Capacity constraints on existing area zone substation and feeders.		
Solution	Establish a new 110/22 kV 60 MVA substation to supply load growth in the Drury, Karaka South and Paerata areas.		
Options considered	An upgrade of the existing Opaheke substation was considered. However, significant feeder infrastructure would deem this uneconomical relative to establishing a new zone substation. Non-network alternatives will not provide an economically viable solution based on current pricing and the industrial load requirement.		
HUNUA FEEDER – BROKEN BRIDGE ROAD LINK		FY32	655
Constraint	Spur load limit forecast to be exceeded.		
Solution	Create a new network link		
Options considered	Offloading customers to adjacent feeders is not a viable solution. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		
NEW FEEDER TO OFFLOAD RED HILL FEEDER		FY28	435
Constraint	High ICP numbers on feeder.		
Solution	Create a new feeder to split existing arrangement.		
Options considered	Offloading customers to adjacent feeders is not a viable solution. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-6 Summary of Opaheke Area Development Plan

9.3.3 Pokeno Zone Substation

Residential and industrial growth in the Pokeno area has continued. Several large industrial customers are now operating, some of whom have signalled their intention to expand their operations within the next five years. Approaches have been received about using electricity to replace processes powered by gas, although none have proceeded at this point. The Pokeno zone substation, commissioned in 2020, continues to provide these customers with the required capacity, security and supply quality. Pokeno supplies 45 distribution substations, is classed as a zone substation (C4), and fully complies with our security criteria (refer to Table 9-1).

The Pokeno load is primarily industrial, with winter peaking residential. The forecast peak demand for Pokeno zone substation and associated distribution feeders is shown in Table 9-7.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Gateway	3.5	6.0	8.5	8.7	9.0	9.2	9.5	9.7	10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	15.9%
Harriet	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3%
Helenslee Road	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.8	1.7%
Hillpark	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	1.0%
Huia 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	N/A
McDonald	3.5	5.5	7.5	7.7	8.0	8.2	8.5	8.7	9.0	9.2	9.5	9.7	10.0	10.2	10.5	10.7	14.0%
Market Street	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0%
WWTP 4 [9]	0.0	2.0	4.0	6.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	20.0%
Pokeno Zone Substation	10.2	15.9	21.5	23.8	26.0	26.6	27.1	27.6	28.1	28.6	29.0	29.5	30.0	30.5	30.9	31.4	13.8%

Table 9-7 Pokeno Zone Substation Maximum Demand Forecast

Pokeno Zone Substation and Feeder Investment

[9] New dedicated feeder established for Watercare's Waikato Water Treatment Plant.

The Pokeno Zone Substation demand forecast is shown in Figure 9-10.

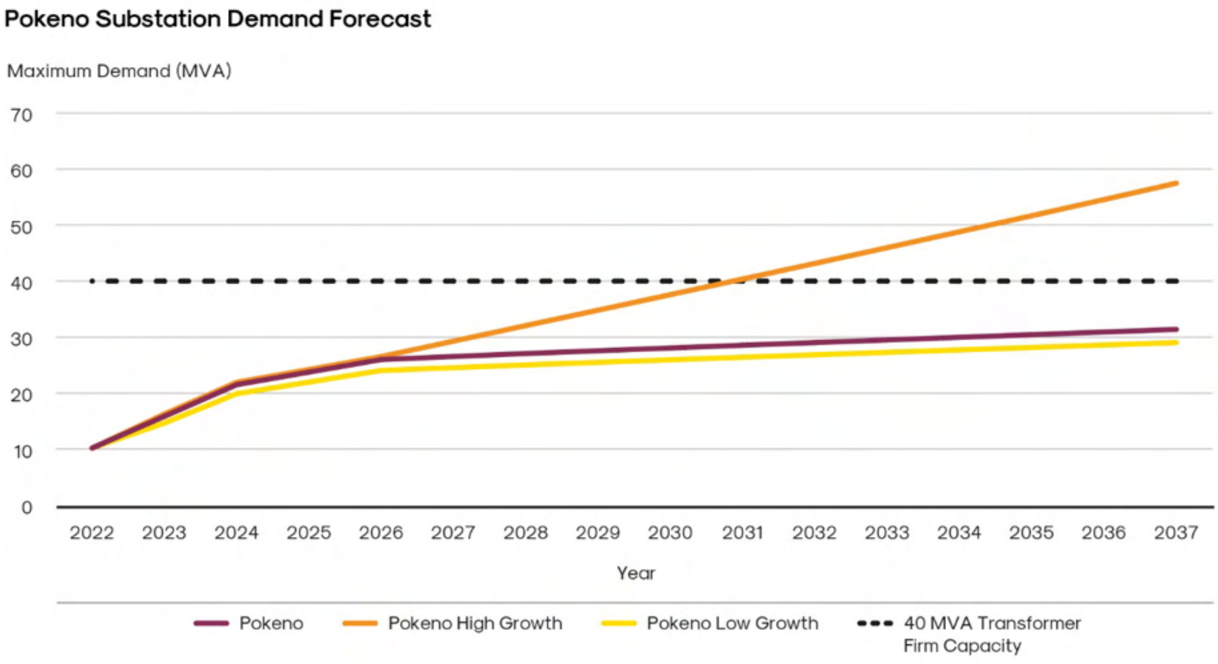


Figure 9-10 Pokeno Zone Substation Maximum Demand Forecast

Two 110/22 kV, 30/40 MVA transformers supply the load at Pokeno, providing an N-1 capacity of 40 MVA.

Provision has been made for a new feeder for forecast industrial load growth in FY29, the timing of which could be brought forward if a major load were to require supply. This can be accommodated quickly as the substation has spare capacity to supply new load.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
TRANSFORMER CABLES AND BAY CONTROLLER COMMUNICATIONS AGGREGATOR		FY25	300
Constraint	A strategic spare 110/22 kV transformer has been procured. At present, it cannot be immediately deployed to Pokeno. An issue has also been identified with the bay controller for the 110 kV switchgear at Pokeno.		
Solution	Contingency design and procurement to enable the strategic spare transformer to be deployed to Pokeno if required. A communications aggregator will be installed to resolve the bay controller issue.		
Options considered	Alternative options are not practical. 110 kV		
NEW 22 KV FEEDER		FY29	1,491
Constraint	Capacity constraints on existing feeders.		
Solution	Utilise a spare CB at the Pokeno zone substation to run a new feeder into Pokeno.		
Options considered	If possible, adding load to existing feeders would be considered in the first instance. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-8 Summary of Pokeno Area Development Plan

9.3.4 Pukekohe Zone Substation

The 110/22 kV Pukekohe zone substation is supplied by three 110 kV circuits from Bombay GXP. Two are directly connected to Bombay, and the third is connected via the Tuakau and Pokeno zone substations. Pukekohe supplies 668 distribution substations in the urban areas of Buckland, Cape Hill, Paerata and Pukekohe, and the rural residential loads towards the eastern parts of Pukekohe and Titi Mauku. The load is predominantly residential and commercial, with some industrial load in Buckland. Pukekohe is classed as a zone substation (C4) and fully complies with our security criteria (refer to Table 9-1). Major loads supplied by this substation include the Pukekohe town centre.

Figure 9-11 below shows the Rural-Urban Boundary (RUB) map for the Pukekohe zone substation supply area.

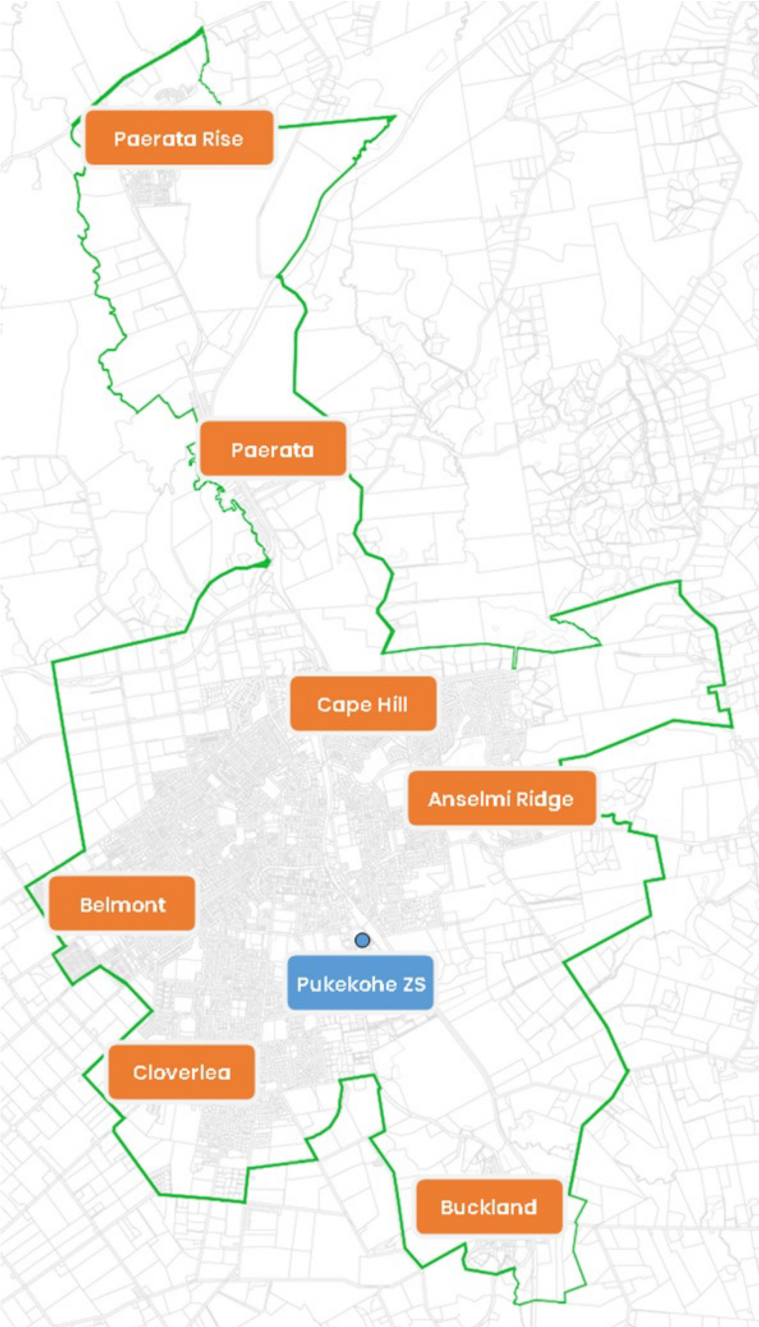


Figure 9-11 Pukekohe Zone Substation Rural-Urban Boundary

The Pukekohe load has a winter peak, and the forecast peak demand for Pukekohe zone substation and associated distribution feeders is shown in Table 9-9.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Anchor Factory	4.0	4.3	4.6	4.9	5.2	5.5	5.8	6.1	6.4	6.7	7.0	7.3	7.6	7.9	8.2	8.5	7.6%
Buckland	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	3.3	3.3	3.3	1.0%
Cape Hill	7.8	7.9	8.1	8.2	8.3	8.4	8.5	8.6	8.8	8.9	9.0	9.1	9.2	9.3	9.5	9.6	1.5%
Pukekohe East	3.0	4.0	4.3	4.6	4.9	5.1	5.4	5.7	6.0	6.3	6.6	6.9	7.2	7.5	7.5	7.5	10.3%
Pukekohe Hill	6.9	7.0	7.2	7.3	7.4	7.6	7.7	7.9	8.0	8.1	8.3	8.4	8.5	8.7	8.8	9.0	2.0%
Pukekohe Town	4.9	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.6	5.7	1.0%
Pukekohe West	7.8	7.9	7.9	8.0	8.1	8.2	8.2	8.3	8.4	8.5	8.6	8.6	8.7	8.8	8.9	9.0	1.0%
Railway	3.3	3.3	3.4	3.4	3.4	3.5	4.1	4.7	5.3	5.9	6.5	7.1	7.7	8.3	8.9	9.5	12.5%
Titi Mauku	3.3	3.4	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	1.0%
Pukekohe Zone Substation	38.8	40.4	41.3	42.3	43.2	44.2	45.6	47.1	48.5	50.0	51.4	52.9	54.3	55.8	57.0	58.2	3.3%

Table 9-9 Pukekohe Zone Substation Maximum Demand Forecast

Pukekohe Zone Substation and Feeder Investment

The Pukekohe zone substation demand forecast is shown in Figure 9-12.

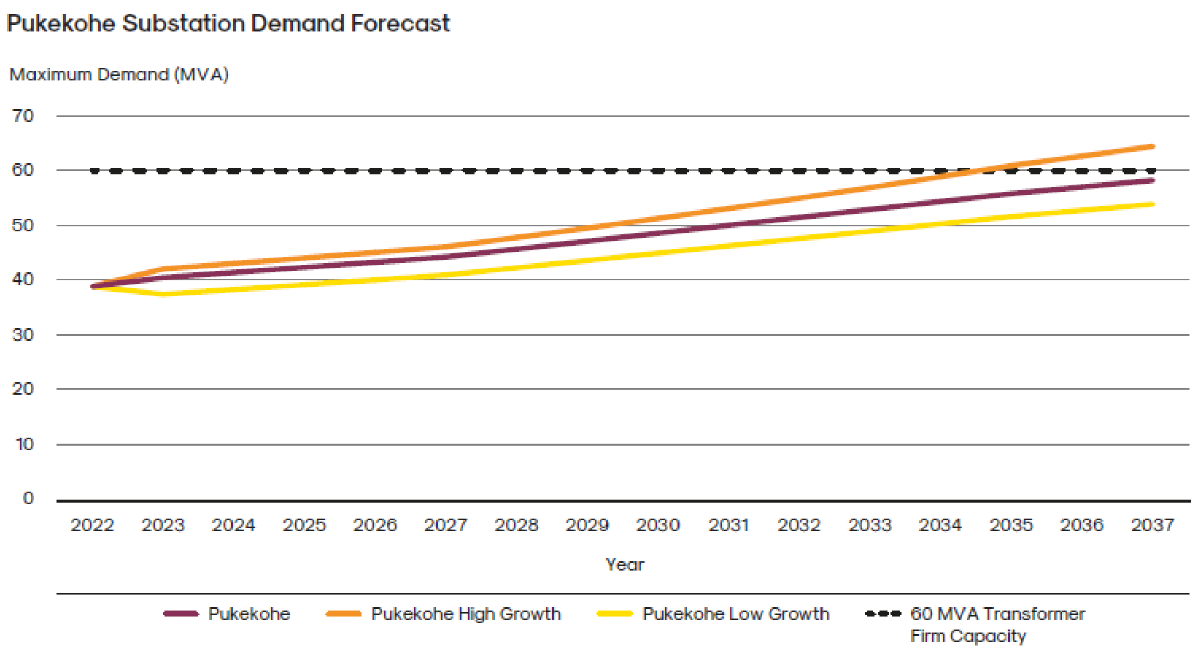


Figure 9-12 Pukekohe Zone Substation Maximum Demand Forecast

Two 110/22 kV, 30/60 MVA transformers supply the load at Pukekohe, providing an N-1 capacity of 60 MVA. The 22 kV switchboard supplying the load at Pukekohe also has a capacity of 60 MVA. The Pukekohe maximum demand is forecast to exceed the transformers' N-1 and switchboard capacity beyond 2038.

Auckland Council has adopted the Pukekohe-Paerata Structure Plan, which could see 12,500 new dwellings in the area over the next 30 years. The Auckland Council has zoned areas surrounding Pukekohe and Paerata as a future urban zone in the Auckland Unitary Plan. As part of the urbanisation of the Pukekohe and Paerata areas, a new township 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 4,500 dwellings with a local retail and services centre. The first residents moved into their homes in 2019, and we expect a growth of 150–200 dwellings per annum.

Further plan changes in the Karaka South and Drury West areas, combined with Paerata Rise, will significantly increase load. The proposed long-term solution is to establish a new Pukekohe North/Karaka South zone substation in this area. In anticipation of this, we have identified a suitable location for the substation.

Initially, the load growth will be supplied from existing feeders from the Pukekohe and Opaheke zone substations and new feeders from the proposed Quarry Road zone substation. Furthermore, flexibility solutions in line with our DSO strategy might further defer the timing for the Pukekohe North/Karaka South zone substation. As such, the timing of the substation will be reviewed annually by monitoring the uptake rates of the residential developments and relative to the progress of our DSO strategy.

Further subdivisions in the east of Pukekohe (Cape Hill and Pukekohe Hill) and the south (Buckland) are also expected within the planning period.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
FINAL PHASE - LAND ACQUISITION FOR PROPOSED PUKEKOHE NORTH/KARAKA SOUTH ZONE SUBSTATION (FY22 – FY24) [10]		FY24	50
PUKEKOHE NORTH/KARAKA SOUTH 110/22 KV SUBSTATION ESTABLISHMENT		OUTSIDE PLANNING PERIOD	
Constraint	Capacity constraints on Pukekohe Zone Substation within 15–20 years.		
Solution	Establish a new zone substation in the Pukekohe North/Karaka South area.		
Options considered	The initial load growth will be supplied from existing feeders from the Pukekohe and Opaheke zone substations and new feeders from the proposed Quarry Road zone substation. Non-network flexibility options in line with our DSO strategy might further defer the zone substation requirement.		

Table 9-10 Summary of Pukekohe Area Development Plan

9.3.5 Tuakau Zone Substation

The Tuakau 110/22 kV zone substation is supplied by two 110 kV circuits from Bombay GXP. One is connected via the Pokeno zone substation, and the other is connected via the Pukekohe zone substation.

The Tuakau zone substation supplies 708 distribution substations in Tuakau and Church Corner's urban areas and the rural areas of River Road, Port Waikato and Whangarata. The load is predominantly residential in the Church Corner, Port Waikato and Tuakau areas. The Pukekawa Trunk feeder from Tuakau supplies the Pukekawa switching station, which in turn supplies the Churchill Road, Glen Murray and Onewhero areas. Tuakau is classed as a zone substation (C4) and is fully compliant in accordance with our security criteria (refer to Table 9-1).

The Tuakau residential load is winter peaking. The forecast peak demand for the Tuakau substation and the distribution feeders from the substation is shown in Table 9-11.

[10] The land procurement was completed in 2022. This allowance to for site improvements associated with this procurement.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Church Corner	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	1.0%
Port Waikato	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%
River Road	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0%
Tuakau	3.8	3.8	3.8	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.3	1.0%
Whangarat a	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5%
WWTP 1	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	0.0%
WWTP 2	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0%
WWTP 3 [11]	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%
Hitchen Road	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Tuakau Industrial	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	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	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	1.0%
Pukekawa Trunk	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	3.9	3.9	1.0%
Tuakau Zone Substation with Generation	12.8	12.2	12.3	12.3	12.4	12.5	12.5	12.6	12.7	12.7	12.8	12.9	12.9	13.0	13.1	13.1	0.2%
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 Zone Substation without Generation	18.3	17.7	17.8	17.8	17.9	18.0	18.0	18.1	18.2	18.2	18.3	18.4	18.4	18.5	18.6	18.6	0.1%

Table 9-11 Tuakau Zone Substation Maximum Demand Forecast

[11] WWTP 3 is a new dedicated backup feeder for Watercare's Waikato Water Treatment Plant.

Tuakau Zone Substation and Feeder Investment

The Tuakau zone substation demand forecast is shown in Figure 9-13 below.

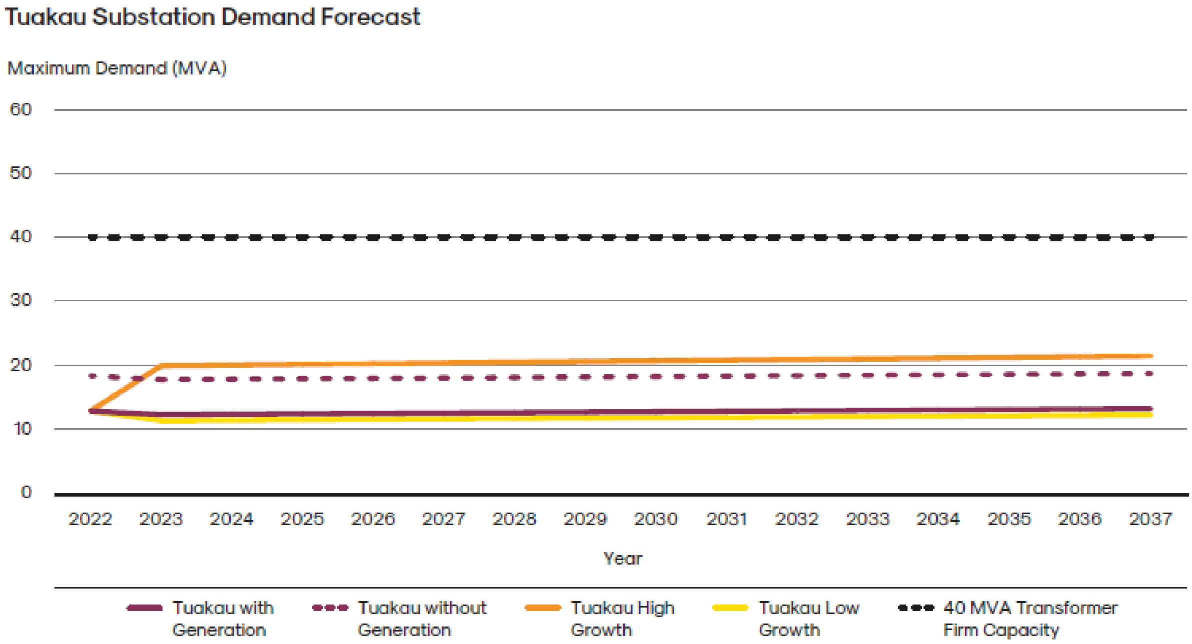


Figure 9-13 Tuakau Zone Substation Maximum Demand Forecast

Two 110/22 kV, 20/40 MVA transformers supply the load at Tuakau, providing an N-1 capacity of 40 MVA.

Significant reinforcement is underway to improve the security of supply to Watercare's Waikato Water Treatment Plant, which is expected to be completed early in FY24. This includes the installation of a new 110/22 kV, 30/40 MVA dedicated transformer for Watercare. This unit also serves as a strategic spare for Counties Energy.

There have been expressions of interest for supply to potentially major industrial loads near the zone substation. However, at present, none of these has eventuated into valid offers. We will continue to monitor this. The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
NETWORK BATTERY REDEPLOYMENT		FY25–FY26	400
Constraint	Voltage during backfeeds on Port Waikato and Glen Murray feeders.		
Solution	Redeploy the BESS previously installed at the Tuakau substation to provide voltage support during backfeed scenarios.		
Options considered	Reconductoring and voltage regulators were considered. However, the BESS will be utilised to defer traditional network investment.		
NEW 22 KV INDUSTRIAL FEEDER		FY26	796
Constraint	Capacity constraints on existing feeders to supply potential industrial load.		
Solution	Run a new feeder from the Tuakau zone substation.		
Options considered	Before committing to this project, utilising the existing feeder to supply the load will be considered in the first instance. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-12 Summary of Tuakau Area Development Plan

9.3.6 Mangatawhiri and Ramarama Zone Substations

Mangatawhiri and Ramarama substations supply the eastern areas of our network from Kaiaua, Paparata and Ararimu in the north to Mercer in the south.

The Mangatawhiri 33/11 kV zone substation is supplied by one 33 kV circuit from Bombay GXP. Mangatawhiri zone substation supplies 422 distribution substations in the rural areas of Kaiaua, Mercer, and Paparata. The load is predominantly rural residential. Mangatawhiri is classed as a small zone substation (C3) and fully complies with our security criteria (refer to Table 9-1).

The Ramarama 33/11 kV zone substation is supplied by two 33 kV circuits from Bombay GXP and supplies 346 distribution substations in the rural areas of Ararimu, Bombay and Great South Road. The load is predominantly rural residential. Ramarama is classed as a medium zone substation (C3) and fully complies with our security criteria (refer to Table 9-1).

We are building a new 110/22 kV, 30/40 MVA substation to supply the load presently fed from the Mangatawhiri and Ramarama substations. This is adjacent to Bombay GXP and will be known as the Barber Road zone substation. At the time of writing, the end-of-life Ramarama and Mangatawhiri substations are being progressively offloaded onto the new substation. The establishment of this substation is renewal driven and further detail on this investment is included in section 3.3.

The Mangatawhiri and Ramarama loads have a winter peak. The forecast peak demand for the future Barber Road substation and associated distribution feeders is shown in Table 9-13.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Ararimu	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	1.0%
Bombay	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.6	1.0%
Great South Road	1.3	1.6	1.8	2.1	2.3	2.5	2.8	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	8.9%
Kaiaua	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	3.0	1.0%
Mercer	1.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	5.5%
Paparata	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.0%
Pokeno Church	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	1.0%
Barber Road Zone Substation	0.0	15.6	16.0	16.3	16.7	17.1	17.4	17.8	17.9	18.1	18.2	18.4	18.5	18.7	18.8	18.9	1.0%

Table 9-13 Barber Road Zone Substation Maximum Demand Forecast

Mangatawhiri and Ramarama Zone Substation and Feeders Investment

Figure 9-14 shows the demand forecast for Mangatawhiri and Ramarama zone substations and the future Barber Road zone substation.

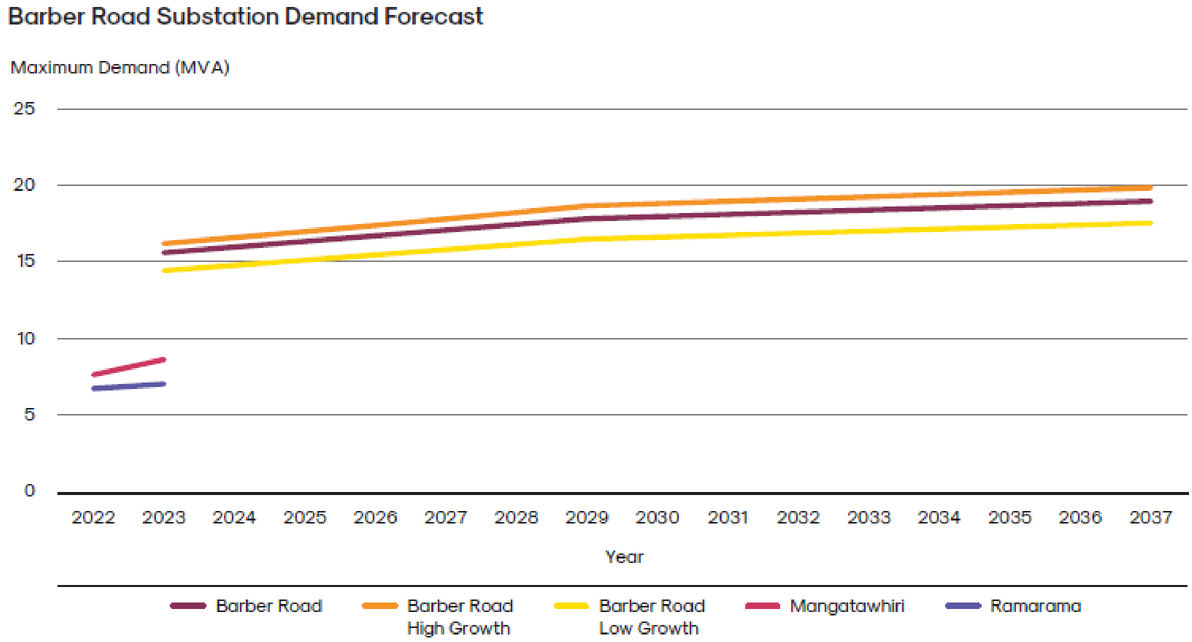


Figure 9-14 Barber Road Zone Substation Maximum Demand Forecast

The present supply configuration is made up of the following:

- One 33/11 kV, 7.5 MVA transformer supplying the load at Mangatawhiri with no N-1 capacity; and
- Two 33/11 kV, 5 MVA transformers supply the load at Ramarama, providing an N-1 capacity of 5 MVA.

Growth is generally flat in the areas supplied by the Mangatawhiri and Ramarama zone substations. Several larger EV chargers are being installed in Bombay adjacent to the SH1 off-ramp, and the impact of these on network demand is being monitored closely. Parts of the Hunua Views development (adjacent to Drury South Crossing) will initially be supplied from the Great South Road feeder. However, the future establishment of the Quarry Road zone substation will likely see this load shifted off this feeder.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
GREAT SOUTH ROAD FEEDER VOLTAGE CONVERSION (FY23 – FY24)		FY24	200
Constraint	Capacity augmentation to provide additional capability in the Drury South Crossing area.		
Solution	22 kV voltage conversion on the Great South Road feeder.		
Options considered	The feeder has undergone a renewal driven rebuild. Operation at 11 kV was considered in conjunction with the upgrade but did not result in the required capacity demands for the Drury South Crossing area.		
KAIAUA VOLTAGE SUPPORT		FY30	400
Constraint	Voltage constraints at times of peak demand.		
Solution	A voltage regulator will be installed on the feeder.		
Options considered	Reconductoring was considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Project		Timing	Estimated Investment ($000s)
PAPARATA RECONDUCTORING		FY30	598
Constraint	Voltage constraints at times of peak demand.		
Solution	Aged undersized conductor has been identified on the feeder backbone which will be replaced.		
Options considered	22 kV conversion and the use of a voltage regulator were considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		
NEW 22 KV FEEDER		FY31	1,491
Constraint	Backfeed constrained when backfeeding Pukekohe East.		
Solution	Utilise a spare CB at Barber Road zone substation to run a new feeder.		
Options considered	Reconductoring and the use of voltage regulators were considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		
ARARIMU RECONDUCTORING		FY32	427
Constraint	Voltage constraints at times of peak demand.		
Solution	Aged undersized conductor has been identified on the feeder backbone which will be replaced.		
Options considered	22 kV conversion and the use of a voltage regulator were considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-14 Summary of Ramarama and Mangatawhiri Area Development Plan

9.3.7 Future Eastern Subtransmission Network

Figure 9-15 below shows the single-line schematic for the future eastern subtransmission network supplied from the Bombay and Drury grid exit points.

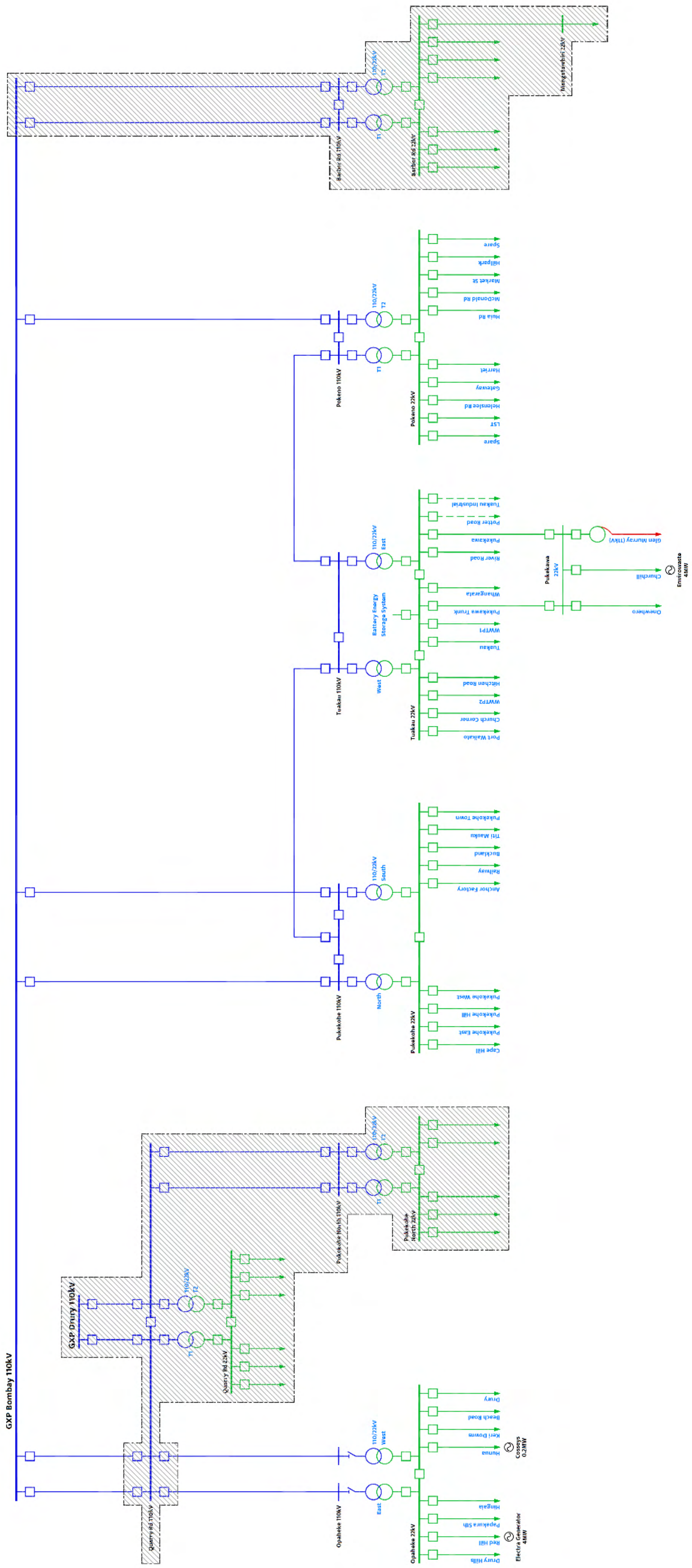


Figure 9-15 Single Line Schematic of the Future Eastern Region 110 kV Subtransmission Network

9.4 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 33 kV point of supply at Storey Road.

Our subtransmission network in the Western region consists of the following:

- Two 33 kV lines from Glenbrook GXP to Waiuku;
- One 33 kV line from Waiuku to Storey Road Pump Station and Maioro; and
- Two 33 kV lines from Glenbrook GXP to Karaka.

The figure below shows the single-line schematics for the subtransmission network supplied from the Glenbrook grid exit point.

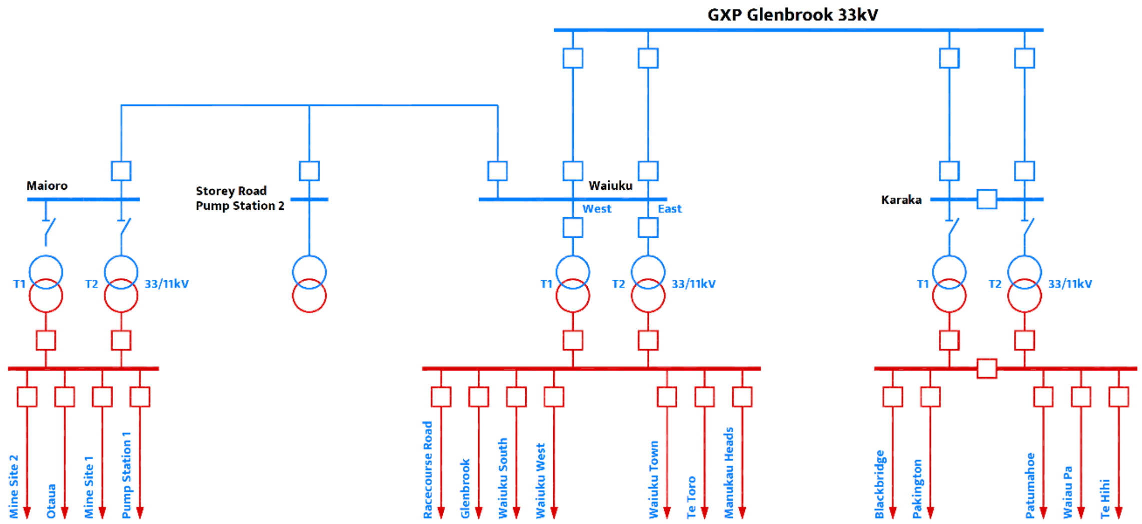


Figure 9-16 Single Line Schematic of the Western Region Subtransmission Network

Figure 9-17 and Table 9-15 show the total Western Region forecast demand.

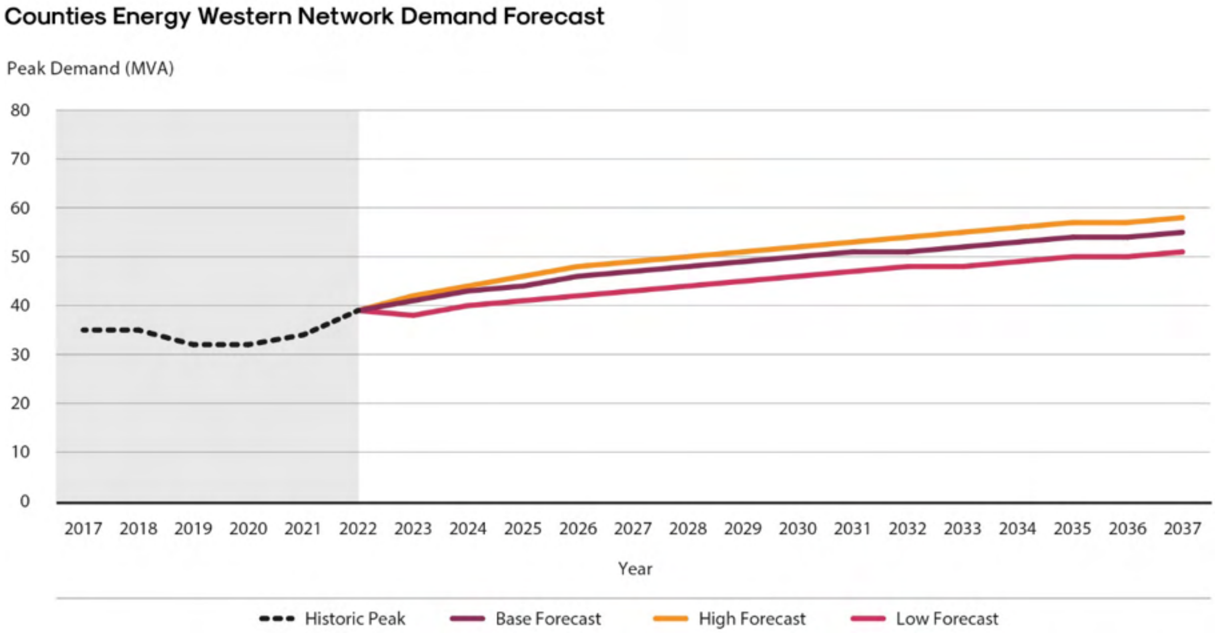


Figure 9-17 Western Region Maximum Demand Forecast

Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Waiuku	16.4	17.4	18.3	19.1	19.9	20.2	20.6	21.0	21.3	21.7	21.9	22.2	22.4	22.7	22.9	23.2	2.7%
Karaka	12.6	13.8	15.0	15.7	16.4	17.1	17.7	18.3	18.9	19.4	19.9	20.4	20.9	21.3	21.7	22.0	4.9%
Maioro	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.6	0.1%
NZS (Storey Road)	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 (Glenbrook GXP)	39.1	40.9	42.9	44.4	45.9	46.9	47.9	48.8	49.8	50.6	51.4	52.1	52.8	53.5	54.1	54.7	2.6%

Table 9-15 Western Region Maximum Demand Forecast

The western region is predominantly a more traditional 33/11 kV arrangement. As such, there is a capacity constraint due to the distances between the load centres and our zone substations being too great for efficient 11 kV distribution. We are experiencing and anticipating further growth in the Clarks Beach, Waiau Pa, Patumahoe and Kingseat areas (supplied by the Karaka zone substation) and the Waiuku and Glenbrook Beach areas (supplied by the Waiuku zone substation).

As there is no 110 kV supply from Transpower's Glenbrook GXP, it would require a significant load or generation increase in the area to make it economical for conversion to a 110 kV subtransmission network and a 22 kV 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 33/11 kV network architecture and to upgrade the 11 kV to 22 kV in places to achieve the required voltage performance on the longer feeders. An alternative is to establish 110/22 kV architecture as used in the eastern region.

9.4.1 Southwestern Subtransmission

Two 33 kV lines from Glenbrook supply Waiuku and the rest of the Southwestern Area (Maioro and Storey Road). The Waiuku West line is strung with Cockroach conductor (rated at 32 MVA), while the Waiuku East line is strung with lower rated Cricket conductor (rated at 24 MVA) for the total length of the line.

The loading on the 33 kV Glenbrook to Waiuku East line exceeded its N-1 capacity (the standard rating for the Cricket conductor section) from 2016. The use of cyclic ratings has allowed us to defer the reinforcement need. However, recent load forecasts place this need within the planning period.

The table below shows the development plan for this subtransmission network.

Project		Timing	Estimated Investment ($000s)
33 KV GLENBROOK-WAIUKU WEST LINE REINFORCEMENT		FY25–FY27	2,155
Constraint	N-1 limit exceeded during peak demand.		
Solution	Upgrade conductor on 33 kV feeder.		
Options considered	Cyclic ratings have already been used to defer investment. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-16 Summary of Southwestern Subtransmission Development Plan

9.4.2 Northwestern Subtransmission

Two 33 kV lines from Glenbrook supply Karaka. The Karaka North line is strung with Cricket conductor; the Karaka South line is strung with parts of Cricket (24 MVA) and the lower-rated Dog conductor (17 MVA) in parts.

The loading on the 33 kV Glenbrook to Karaka South line is expected to exceed its N-1 capacity (the rating for the Dog conductor section) in 2027. It is forecast to reach 110% of the N-1 rating by 2031.

The table below shows the development plan for this subtransmission network.

Project		Timing	Estimated Investment ($000s)
33 KV GLENBROOK-KARAKA SOUTH LINE CAPACITY CONSTRAINT INVESTIGATION		FY27	400
Constraint	N-1 limit exceeded during peak demand by 2031.		
Solution	Undertake a detailed study to identify options for addressing capacity constraints on the line (including the application of cyclic ratings).		
Options considered	Our proposed investment to address the identified constraint on the Karaka South line will be developed following the investigations to either reconductor the 33 kV South line from Glenbrook to Karaka with a higher rated Cricket conductor or restring the conductor, and defining operating limits to defer investment. Non-network alternatives will be included in the study.		

Table 9-17 Summary of Northwestern Subtransmission Development Plan

9.4.3 Karaka Zone Substation

The Karaka 33/11 kV zone substation is supplied by two 33 kV circuits from the Glenbrook GXP. Karaka zone substation supplies 456 distribution substations in the mainly rural areas of Blackbridge, Pakington, Patumahoe, Te Hihi and Waiau Pa. The substation has a predominantly residential load, is classed as a zone substation (C4), and fully complies with our security criteria (refer to Table 9-1).

The Karaka load is winter peaking. The forecast peak demand for the Karaka zone substation and the distribution feeders from the substation is shown in Table 9-18.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Blackbridge	1.4	1.6	1.8	2.0	2.2	2.4	2.6	2.8	2.9	3.1	3.3	3.5	3.7	3.9	3.9	3.9	11.5%
Pakington	2.2	2.8	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.5	3.6	3.6	4.0%
Patumahoe	2.7	2.8	2.9	3.0	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.4	3.4	3.4	1.7%
Te Hihi	2.3	2.5	2.7	2.9	3.0	3.2	3.4	3.6	3.8	3.8	3.8	3.9	3.9	4.0	4.0	4.1	5.0%
Waiau Pa	3.4	3.6	3.8	4.0	4.2	4.4	4.6	4.7	4.9	5.1	5.3	5.5	5.7	5.9	6.0	6.2	5.4%
Karaka Zone Substation	12.6	13.8	15.0	15.7	16.4	17.1	17.7	18.3	18.9	19.4	19.9	20.4	20.9	21.3	21.7	22.0	4.9%

Table 9-18 Karaka Zone Substation Maximum Demand Forecast

Karaka Zone Substation and Feeder Investment

The Karaka Zone substation demand forecast is shown in Figure 9-18.

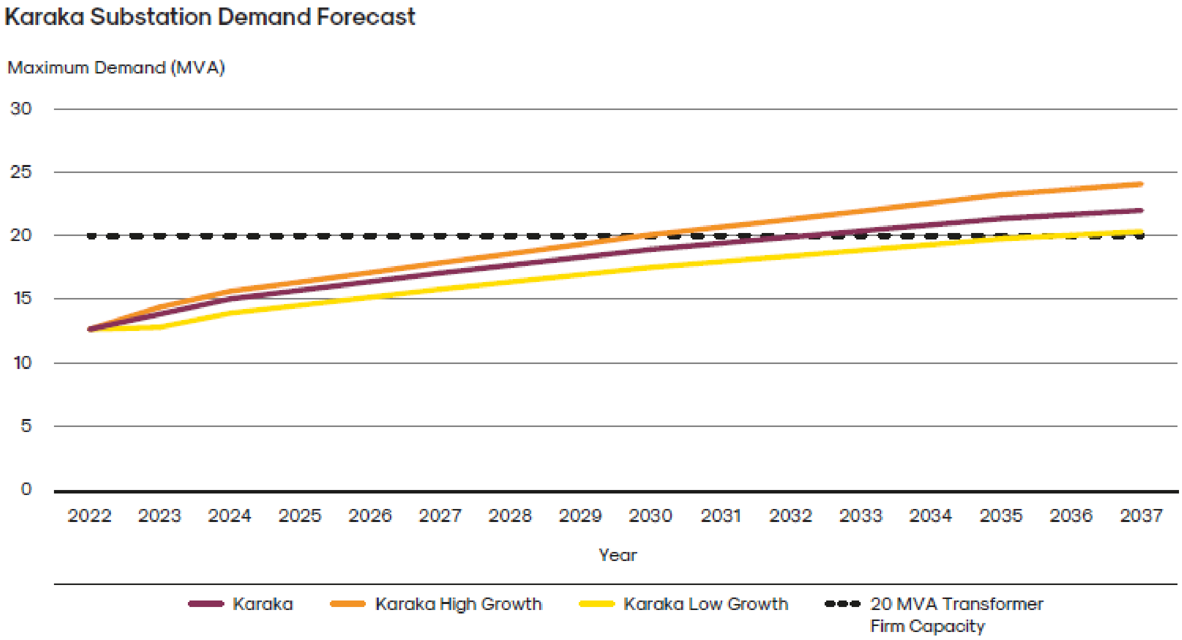


Figure 9-18 Karaka Zone Substation Maximum Demand Forecast

Two 33/11 kV, 10/20 MVA transformers installed at the Karaka substation provide an N-1 capacity of 20 MVA, which will be exceeded in 2033. The switchboard rating will be exceeded after 2038, 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 an additional 450 lots through the next 10 years. Additionally, the Clarks Beach and Karaka North areas are expected to add over 1,000 lots and 800 lots, respectively, over the planning period.

Our long-term plan is to build two new 33/11 kV 10/20 MVA substations in the Kingseat/Waiau Pa and Glenbrook Beach areas to supply the anticipated residential developments mentioned above. These new substations will reduce the reliance on the Karaka substation and existing rural distribution feeders.

Our network development plan allows for the proposed 33 kV Glenbrook Beach Area substation to be supplied directly from the Glenbrook GXP and the proposed 33 kV Kingseat/Waiau Pa Area substation to be supplied via a diversion from the Glenbrook-Karaka North line. The development will be staged with the Glenbrook Beach substation established first, followed by Kingseat/Waiau Pa substation. A single 33 kV line will be constructed initially, and the second line added when the load reaches 12 MVA.

Glenbrook Beach substation has been brought forward based on demand requirements for residential growth and infrastructure development. 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 its end-of-life.

Based on our updated load forecast, the need for Kingseat/Waiau Pa substation is beyond the planning window. However, the land for this substation will be procured within the planning period.

Refer to Figure 9-21 for the future subtransmission single-line diagram, including the proposed new Glenbrook Beach and Kingseat/Waiau Pa substations and 33 kV supply from the Glenbrook GXP.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($'000)
LAND ACQUISITION FOR PROPOSED GLENBROOK BEACH AREA ZONE SUBSTATION		FY24	1,600
GLENBROOK BEACH 33/11 KV SUBSTATION ESTABLISHMENT		FY26–FY33	23,064
Constraint	Capacity constraints on Waiau Pa and Glenbrook Feeders (supplied from Waiuku).		
Solution	Establish a new zone substation in the Glenbrook Beach area.		
Options considered	Initial residential growth will be supplied from existing feeders. However, infrastructure-related development will require a new zone substation. 22 kV conversion was considered; voltage regulators are already deployed. Non-network flexibility options in line with our DSO strategy might further defer the zone substation requirement resulting from residential growth.		
LAND ACQUISITION FOR PROPOSED KINGSEAT/WAIAU PA AREA ZONE SUBSTATION		FY24	1,200
KINGSEAT/WAIAU PA 33 KV LINE DESIGN		FY33	500
KINGSEAT/WAIAU PA 33/11 KV SUBSTATION ESTABLISHMENT		OUTSIDE PLANNING PERIOD	
Constraint	Capacity constraints on Te Hihi and Waiau Pa Feeders.		
Solution	Establish a new zone substation in the Kingseat/Waiau Pa area.		
Options considered	Initial residential growth will be supplied from existing feeders and any spare capacity from establishing the Glenbrook Beach area zone substation. 22 kV conversion was considered; voltage regulators will be deployed in the interim for Te Hihi Feeder within the planning period. Non-network flexibility options in line with our DSO strategy might further defer the zone substation requirement resulting from residential growth.		
PAKINGTON FEEDER RECONDUCTORING		FY24	1,900
Constraint	New load growth (industrial) will result in voltage constraints.		
Solution	The feeder will be reconductored.		
Options considered	22 kV conversion and the use of voltage regulators were considered. Non-network alternatives will not provide an economically viable solution based on current pricing.		
TE HIHI FEEDER VOLTAGE REGULATOR		FY26	360
Constraint	Voltage constraints at times of peak demand.		
Solution	Install a voltage regulator.		
Options considered	22 kV conversion and reconductoring were considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-19 Summary of Karaka Area Development Plan

9.4.4 Waiuku Zone Substation

The 33/11 kV Waiuku zone substation is supplied by two 33 kV subtransmission lines from the Glenbrook GXP. Waiuku zone substation supplies 649 distribution substations in the urban areas of Waiuku, Racecourse Road and the rural area of Glenbrook, Te Toro and Manukau Heads. The substation has a mix of residential and commercial loads, is classed as a large zone substation (C4), and fully complies with our security criteria (refer to Table 9-1).

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 Table 9-20 below.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Glenbrook	1.8	2.0	2.1	2.3	2.5	2.6	2.8	3.0	3.1	3.3	3.3	3.4	3.4	3.5	3.5	3.5	6.3%
Manukau Heads	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	1.0%
Racecourse	2.9	3.4	3.9	4.4	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.7%
Te Toro	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	2.3	1.0%
Waiuku South	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	1.0%
Waiuku Town	3.8	4.2	4.2	4.3	4.4	4.5	4.5	4.6	4.7	4.8	4.9	4.9	5.0	5.1	5.2	5.2	2.4%
Waiuku West	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.4	4.5	4.6	4.7	4.7	2.0%
Waiuku Zone Substation	16.4	17.4	18.3	19.1	19.9	20.2	20.6	21.0	21.3	21.7	21.9	22.2	22.4	22.7	22.9	23.2	2.7%

Table 9-20 Waiuku Zone Substation Maximum Demand Forecast

Waiuku Zone Substation and Feeder Investment

The Waiuku zone substation demand forecast is shown in Figure 9-19.

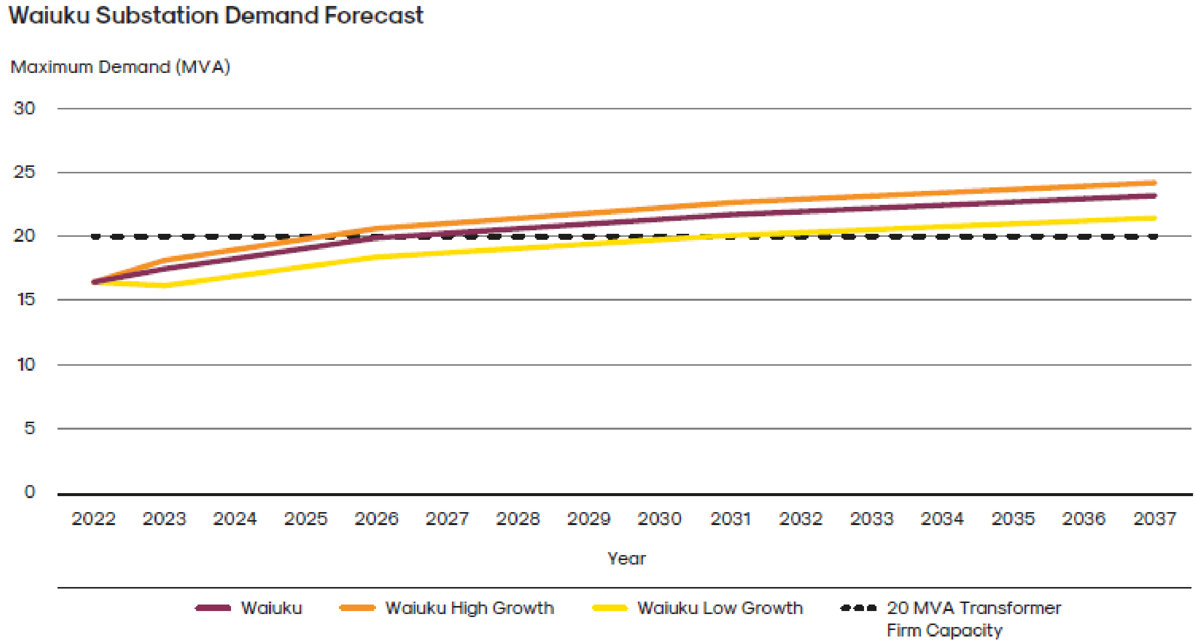


Figure 9-19 Waiuku Zone Substation Maximum Demand Forecast

Two 33/11 kV, 10/20 MVA transformers supply the load at Waiuku, providing an N-1 capacity of 20 MVA. The Waiuku maximum winter demand will exceed the transformer N-1 capacity by 2027.

Short-term cyclic ratings over nominal ratings will be adopted to defer the need for transformer upgrades at Waiuku beyond 2038. With the current plans to establish the Glenbrook Beach and Kingseat/Waiau Pa area zone substations, the transfer of load from Waiuku will further defer investment.

Feeder reinforcement is forecast to be required by FY27 for industrial load growth and FY32 based on load growth on Waiuku Town and Waiuku West feeders.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
NEW INDUSTRIAL FEEDER		FY27	796
Constraint	Insufficient capacity on existing feeders for forecast growth.		
Solution	A new feeder will be installed using a spare CB at the Waiuku substation.		
Options considered	22 kV conversion was considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		
NEW FEEDER TO OFFLOAD WAIUKU TOWN AND WAIUKU WEST FEEDERS		FY32	3,500
Constraint	Backfeed capability exceeded on existing feeders.		
Solution	A new feeder will be installed using a spare CB at the Waiuku substation.		
Options considered	22 kV conversion was considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-21 Summary of Waiuku Area Development Plan

9.4.5 Maioro Zone Substation

The Maioro 33/11 kV zone substation is supplied by one 33 kV circuit from the Waiuku zone substation 33 kV bus and ultimately from the Glenbrook GXP. Maioro zone substation supplies 113 distribution substations in the rural area of Otaua, with a mix of residential and industrial loads. Most of the demand for this substation is used by a major consumer, NZ Steel, at their iron sands mine. Maioro is classed as a small zone substation (C3) and is not compliant with our security criteria (refer to Table 9-1) for maintaining maximum demand for both first and second outages. However, we have commercial arrangements with the major customer supplied from this substation for the reduced security and capacity constraints. This, in effect, makes the Maioro zone substation compliant under category C5.

Table 9-22 shows the winter maximum demand for the Maioro substation and the distribution feeders from the substation.

Zone Substation and Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA); Winter Peak															Avg. Annual Increase (%)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
Otaua	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.5%
NZS Mine site & Pump Station 1	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	0.0%
Maioro Zone Substation	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.6	0.1%

Table 9-22 Maioro Zone Substation Maximum Demand Forecast

We do not anticipate any significant load growth in the area supplied from Maioro over the next 10 years. As such, only minor increases have been allowed in the demand forecasts.

As Maioro is predominantly used for the supply to NZ Steel, and the Otaua feeder can be fully backfed from the Waiuku substation, the future of the NZ Steel site brings uncertainty into future investment decisions.

Maioro Zone Substation and Feeder Investment

The Maioro Zone Substation demand forecast is shown in Figure 9-20.

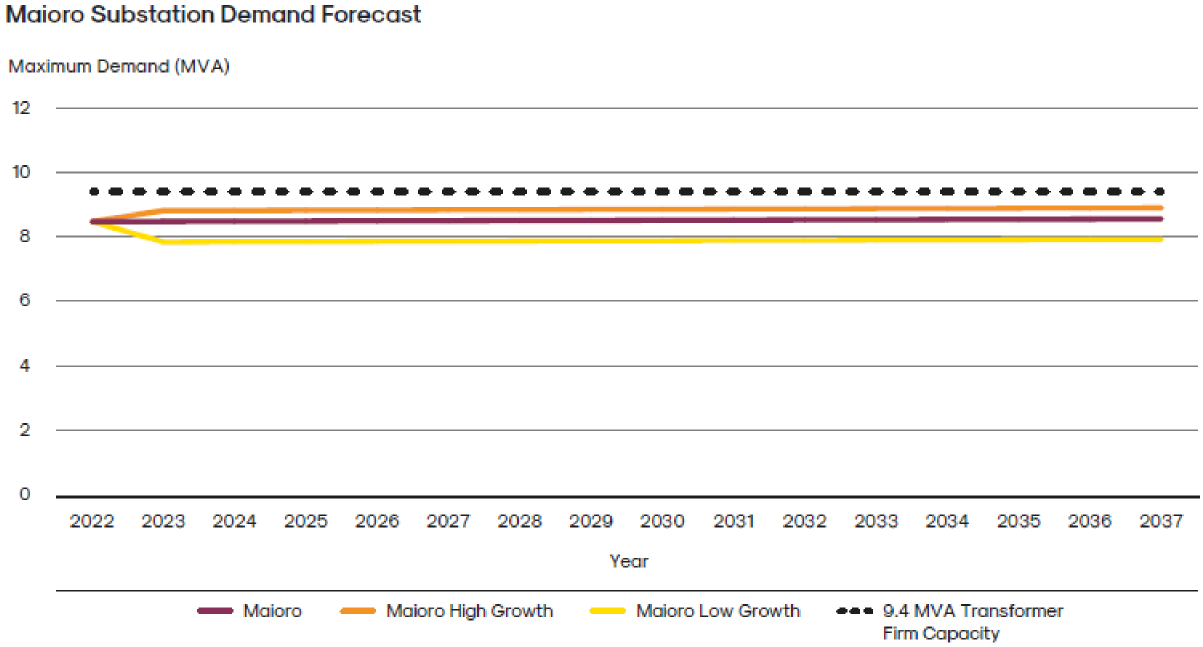


Figure 9-20 Maioro Zone Substation Maximum Demand Forecast

Two 33/11 kV, 7.5 MVA transformers supply the load at Maioro, providing an N-1 capacity of 7.5 MVA (9.4 MVA 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 Maioro Zone Substation is replacing the 11 kV switchboard due to age and condition, detailed in section 8.3.4.

Additionally, should the major customer require a higher level of firm capacity, closer to their demand of 10 MVA compared with the existing firm capacity of 9.4 MVA, transformer upgrades or relocation (utilising spare units) could be undertaken.

The table below shows the area development plan.

Project		Timing	Estimated Investment ($000s)
VOLTAGE REGULATOR ON THE OTAUA FEEDER		FY27	360
Constraint	Voltage constraints at times of peak demand.		
Solution	Install a voltage regulator.		
Options considered	22 kV conversion and reconductoring were considered. Non-network alternatives will not provide an economically viable solution based on current pricing. This will be revisited closer to the time of project need.		

Table 9-23 Summary of Maioro Area Development Plan

9.4.6 33 kV Storey Road Point of Supply

Storey Road Point of Supply is supplied off the 33 kV Maioro-Waiuku line and supplies the No. 2 pump station on the New Zealand Steel slurry pipeline. We have no assets on this site apart from a 33 kV disconnector. We do not expect any load growth from this point of supply and consider the existing arrangement adequate for the foreseeable future.

9.4.7 Future Western Subtransmission Network

Figure 9-21 shows the single-line schematic for the future western region subtransmission network supplied from the Glenbrook grid exit point.

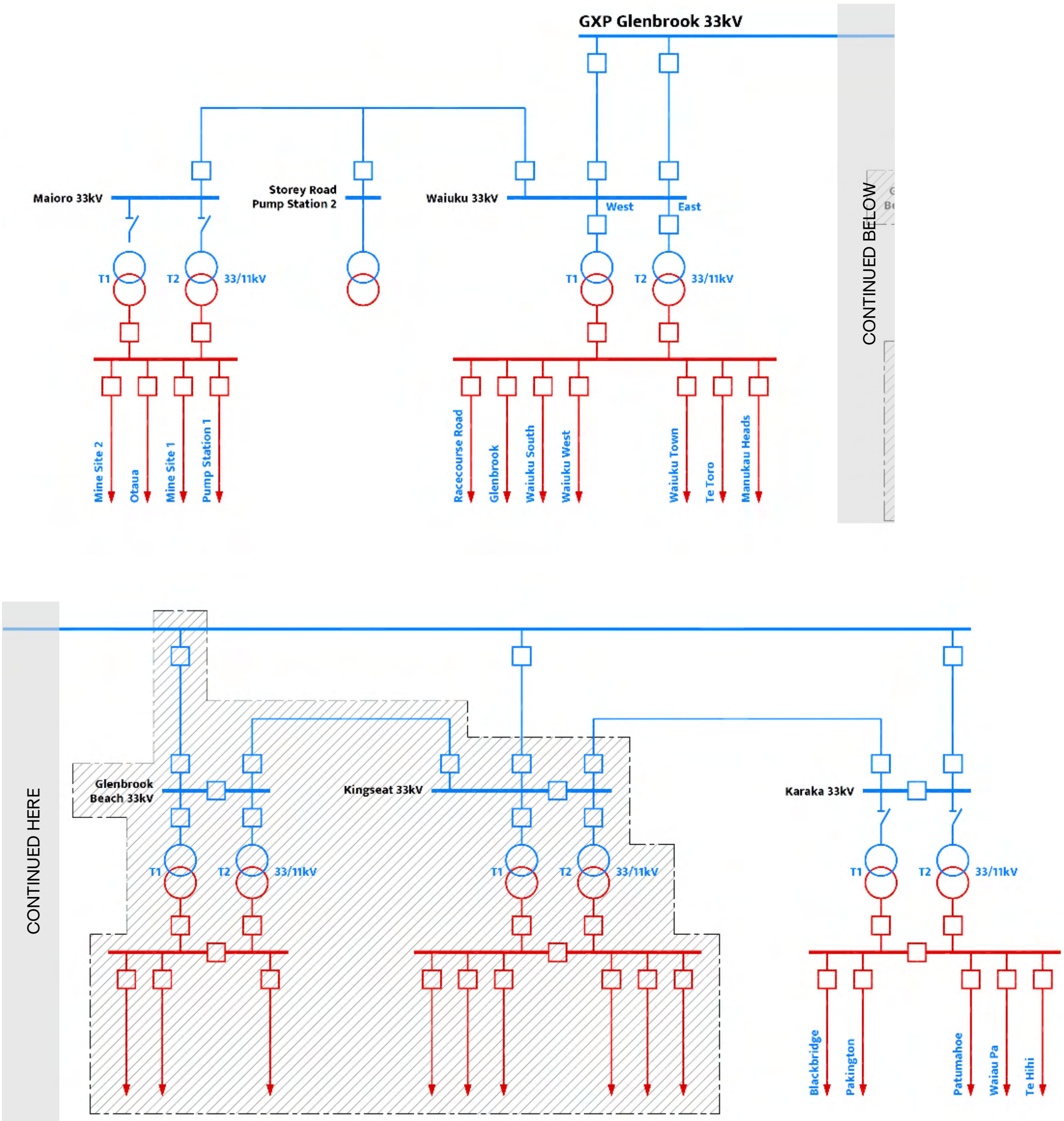


Figure 9-21 Single Line Schematic of the Future Western Region 33 kV Subtransmission Network

10.0 Other Non-network Investment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10.0 Other Non-Network Investment

The non-network operational expenditure for the 2023 AMP planning period is $48.0m (constant $).

10.1 Buildings

The FY24 capital programme includes a budget allowance for upgrading yard areas to safely store and manage minimum inventory holdings for the works schedule.

10.2 Tools and Equipment

Non-network expenditure forecasts allow for the ongoing replacement of tools and equipment used by our teams in the delivery of our works programme.

10.3 Vehicle Fleet and Machinery

We own a fleet of light and heavy vehicles, as well as field machineries such as excavators and transport trailers. FY24 expenditure will include forecasting that allows for renewal and maintenance of our fleet, which may include the electrification of vehicles or vehicle components.

10.4 Digital Strategy

The digital strategy for the planning period is $27.4m; more detail on the core system upgrades can be found in in Chapter 7.0.

The Company continues to invest heavily in the Digital area to improve systems, automate business processes and ensure cyber security requirements are addressed.

The Core system investment for FY24 and FY25 is below;

Project Area	System	Financial Year	Cost ($000s)
CORE SYSTEMS			
ERP & Project Management	Upgrade of the Microsoft NAV Dynamics platform, and provision of capital project management system.	FY24-FY25	450
Digital & Mobility Transformation	Application of digital technology across all business functions, including vegetation	FY24-FY25	550
Customer Channels	CRM, customer experience, digital channels	FY24-FY25	100 (Per Annum)
Asset Management	Enterprise asset management system	FY24-FY25	1,200
Network Operations	SCADA replacement through ADMS	FY24-FY25	1,200
Other Core Systems	IT system, data and security enhancements	FY24-FY25	1,250
ROUTINE REPLACEMENT			
Core Network Infrastructure	Network infra such as switches, servers, UPS, etc. to maintain network reliability	Annual	200 (per annum)
PCs, Laptops, and Field Mobile Devices	Replacement of devices to ensure fit for purpose	Annual	125 (per annum)

11.0 Expenditure Summary


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11.0 Expenditure Summary

This chapter outlines the forecast expenditure from the four investment sections. All expenditure is displayed in constant dollars.

- Network Reliability;
- Renewals and Maintenance;
- Network Development; and
- Non-Network.

11.1 Capital Expenditure Summary

11.1.1 Network Reliability

Asset Category	Financial Year Expenditure ($000s)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
LEGISLATIVE AND REGULATORY										
Regulatory	300	-	-	-	-	-	-	-	-	-
OTHER RELIABILITY, SAFETY AND ENVIRONMENT										
Asset Safety	75	77	77	-	-	-	-	-	-	-
Power Quality	655	350	350	350	350	350	350	350	350	350
QUALITY OF SUPPLY										
Network Performance	5,928	5,009	2,341	1,074	1,399	-	431	-	-	-

Table 11-1 Network Reliability

11.1.2 Renewals and Maintenance

Asset Category	Financial Year Expenditure ($000s)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
SUBTRANSMISSION										
Bombay -Ramarama Tower Rebuild	942	-	-	-	-	-	-	-	-	-
Barber Road – Tower 1 Refurbishment	900	-	-	-	-	-	-	-	-	-
Pukekohe Line Reinsulate	-	-	650	550	-	-	-	-	-	-
Subtransmission Renewal	20	20	20	20	20	20	20	20	20	20
ZONE SUBSTATIONS										
Barber Road Substation	500	-	-	-	-	-	-	-	-	-
Decommission Ramarama and Mangatawhiri	-	2,000	-	-	-	-	-	-	-	-
Karaka Substation Rebuild	-	-	-	-	-	-	-	-	3,000	6,450
Maioro Switchboard Replacement	-	100	1400	-	-	-	-	-	-	-
Other Zone Sub Renewal	50	50	50	50	50	50	50	50	50	50
Quarry Road/ Opaheke Programme	200	3,500	3,000	700	700	-	-	-	-	-
Zone Sub Seismic	250	300	-	-	-	-	-	-	-	-
DISTRIBUTION AND LV LINES										
Barber Road – Feeder Rebuild	1,400	-	-	-	-	-	-	-	-	-
Copper Programme	-	2,645	1,537	3,076	5,387	1,452	3,253	1,473	1,281	4,661
HV Rehabilitation	1,512	1,980	4,051	1,081	-	-	-	-	-	-
LV Rehabilitation	226	1,083	1,291	542	361	361	361	361	-	-
Overhead Renewal	4,009	4,009	4,009	4,009	4,009	4,009	4,009	4,009	4,009	4,009
Private Service Lines	500	500	500	500	500	500	500	500	500	500
Safety Compliance	100	100	100	100	100	100	100	100	100	100
Swan Programme	3,358	1,319	3,507	1,964	4,815	4,369	6,746	6,105	4,269	6,746
DISTRIBUTION AND LV CABLES										
HV Rehabilitation	195	195	195	195	195	195	195	195	195	195
Pillar Renewal	203	203	203	203	203	203	203	203	203	203
UG Cable Renewal	296	296	296	296	296	296	296	296	296	296
DISTRIBUTION SUBSTATIONS AND TRANSFORMERS										
Distribution Transformer Renewal	475	475	475	535	475	475	341	281	281	281
DISTRIBUTION SWITCHGEAR										
Distribution RMU Renewal	565	555	673	428	488	593	1,262	691	916	210
Overhead Switchgear Replacement	309	309	309	309	309	309	309	309	309	309
OTHER NETWORK ASSETS										
Communication Network	1,400	-	-	-	-	-	-	-	-	-
LCP Renewal	-	-	450	-	-	-	-	-	-	-
Relay Replacement	1,300	2,000	-	-	-	-	-	-	-	-
Karaka Fibre Upgrade	2,500	-	-	-	-	-	-	-	-	-
Capitalised Maintenance	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300

Table 11-2 Renewals and Maintenance

11.1.3 Network Development

Asset Category	Financial Year Expenditure ($000s)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
EASTERN REGION										
Barber Road Substation Supply Area	200	–	–	–	–	–	998	1,491	427	–
Opaheke Substation Supply Area	1,000	4,000	–	–	435	–	–	–	655	–
Pokeno Substation Supply Area	–	300	–	–	–	1,491	–	–	–	–
Pukekohe North Substation Supply Area	50	–	–	–	–	–	–	–	–	–
Quarry Road Substation Supply Area	1,000	3,000	15,026	12,539	1,948	–	–	–	–	–
Tuakau Substation Supply Area	–	50	1,146	–	–	–	–	–	–	–
WESTERN REGION										
Glenbrook Substation Supply Area	1,600	–	500	5,210	10,354	2,000	–	–	–	5,000
Karaka Substation Supply Area	1,900	–	360	400	–	–	–	–	–	–
Kingseat Substation Supply Area	1,200	–	–	–	–	–	–	–	–	500
Maioro Substation Supply Area	–	–	–	360	–	–	–	–	–	–
Waiuku Substation Supply Area	–	200	797	1,954	–	–	–	–	3,500	–
NETWORK WIDE										
Network Wide	150	–	–	–	–	–	–	–	–	–

Table 11-3 Network Development

11.1.4 Customer Connection

Asset Category	Financial Year Expenditure ($000s)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Consumer Connection	13,500	10,000	10,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000

Table 11-4 Customer Connection

11.1.5 Non-Network

Asset Category	Financial Year Expenditure ($000s)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Land and buildings	3600	437	433	428	424	424	424	424	424	424
Digital strategy	3,970	4,126	3,269	3,237	3,206	3,206	3,206	3,206	3,206	3,206
Tools, Plant & Fleet	887	959	890	926	961	961	961	961	961	961

Table 11-5 Non-Network

11.2 Operational Expenditure Summary

11.2.1 Network Operating Expenditure by Asset Category

Asset Category	Financial Year Expenditure ($000s)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
SUBTRANSMISSION NETWORK										
Subtransmission Lines	94	84	84	91	84	84	84	84	91	84
Subtransmission Cables	17	7	7	14	7	7	7	7	14	7
ZONE SUBSTATIONS										
Zone Substation Transformers	139	139	139	139	139	139	139	139	139	139
Zone Substation Switchgear	91	91	91	91	165	91	91	91	91	91
Zone Substation Other Equipment	56	56	56	56	56	56	56	56	56	56
Zone Substation Buildings and Grounds	87	87	87	87	87	87	87	87	87	87
DISTRIBUTION AND LV LINES										
Distribution Poles and Crossarms	683	228	228	683	228	228	683	228	228	683
Distribution Conductor	345	645	345	345	345	345	345	345	345	345
Fault Indicators and Earthing	27	27	27	27	27	27	27	27	27	27
DISTRIBUTION AND LV CABLES										
Distribution and LV Cables	55	55	55	55	55	105	105	105	105	105
LV Pillars	106	110	115	120	125	131	136	142	148	155
DISTRIBUTION SUBSTATIONS AND TRANSFORMERS										
Distribution Transformers	453	472	492	513	536	559	583	608	634	661
DISTRIBUTION SWITCHGEAR										
Ring Main Units	68	70	71	73	74	76	77	79	80	82
Overhead Switchgear	166	169	172	176	179	183	186	190	194	198
OTHER SYSTEM FIXED ASSETS										
Capacitors and Voltage Regulators	16	17	18	18	19	20	21	22	23	24
Protection	476	96	96	96	96	96	96	96	96	96
Load Control Equipment	45	47	49	51	53	56	58	61	63	66
Battery Bans	90	94	98	103	107	112	116	121	127	132
SCADA and Communications	343	343	335	335	335	335	335	335	335	335
Network Operations Control	600	600	600	600	600	600	600	600	600	600
VEGETATION										
Vegetation	2,500	2,500	2,500	2,500	2,500	2,100	2,100	2,100	2,100	2,100
PUBLIC SAFETY SERVICES										
Public Safety Services	300	306	312	318	325	331	338	345	351	359
FAULTS AND REACTIVE MAINTENANCE										
Faults	2,838	2,876	2,901	2,927	2,954	2,980	2,994	3,007	3,021	3,034

Table 11-6 Network Operating Expenditure by Asset Category

11.2.2 Network Operating Expenditure by Disclosure Category

Asset Category		Financial Year Expenditure ($000s)									
		FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Maintenance, corrective and replacement	Subtransmission Network	111	91	91	105	91	941	91	91	105	91
	Zone Substations	373	373	373	373	447	373	373	373	373	373
	Distribution and LV Lines	1,055	900	600	1,055	600	600	1,055	600	600	1,055
	Distribution and LV Cables	161	165	170	175	180	236	241	247	253	260
	Distribution Substations and Transformers	453	472	492	513	536	559	583	608	634	661
	Distribution Switchgear	234	239	243	248	253	258	264	269	274	280
	Other System Fixed Assets	1,571	1,197	1,197	1,204	1,211	1,219	1,227	1,235	1,244	1,253
Public Safety Services		300	306	312	318	325	331	338	345	351	359
Vegetation Management		2,500	2,500	2,500	2,500	2,500	2,100	2,100	2,100	2,100	2,100
Service interruptions and emergencies		2,838	2,876	2,901	2,927	2,954	2,980	2,994	3,007	3,021	3,034

Table 11-7 Network Operating Expenditure by Disclosure Category

12.0 Evaluation of Performance

12.0 Evaluation of Performance

12.1 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 (FY22) 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 4 Service Levels.

12.2 Performance Against Last Complete Financial Year

12.2.1 Capital Expenditure FY22

Disclosure Category	Target ($000s)	Actual ($000s)	Variance	Reason for variance
Consumer connection	8,500	18,871	122%	Increased industrial and residential network growth
System growth	8,105	762	(91%)	Deferral of land purchases
Asset replacement and renewal	38,568	35,522	(8%)	
Asset relocations	300	330	10%	Higher than anticipated customer demand.
Expenditure on non-network assets	17,748	6,070	(66%)	Timing of spend for Glasgow Road site upgrade

Table 12-1 Capital Expenditure FY22

12.2.2 Operational Expenditure FY22

Disclosure Category	Target ($000s)	Actual ($000s)	Variance	Reason for variance
Service Interruptions and Emergencies	2,100	3,154	50%	Higher than expected fault volumes, including vegetation. Increased overhead costs due to COVID-19 protocols.
Vegetation Management	2,000	1,786	(11%)	COVID-19 interruptions on the maintenance programme
Routine and Corrective Maintenance and Inspection	1,650	1,223	(26%)	COVID-19 interruptions on the maintenance programme
Asset Replacement and Renewal	1,030	561	(46%)	COVID-19 interruptions on the maintenance programme
System Operations and Network Support	3,566	3,705	4%	
Business Support	8,812	8,574	(3%)	

Table 12-2 Operational Expenditure FY22

12.2.3 Project Performance FY22 Plan Against Actual

Project	Scope	Budget ($000s)	Actual completion
ASSET REPLACEMENT			
Beach Road 11 kV (Papakura South) RMU Replacement	Replacement of 11 gas and oil-filled switchgear and link Beach Road Rehab	2,000	Completed FY22
Drury Hills RMU Replacement	Replacement of gas and oil-filled switchgear	877	Completed FY22
OT Communications Network and Infrastructure Upgrade		1,000	Multiyear programme forecast to complete in FY24
Pukekohe East (Coulston Rd) CU Replacement	Copper replacement	571	Completed FY22
Queen St, Pukekohe – LV	Aged conductor replacement	394	Completed FY22
Red Hill Feeder Swan Replacement	OHUG Overhead section of Red Hill feeder	1,000	Due completion FY23, delay due to conflicting utility works in area.
Tuakau Swan Replacement	Swan Replacement, Dominion Road	495	Completed FY22
Barber Road Feeder Works – Year 1		7,533	Multiyear project forecast to complete in FY24.
Barber Road Substation		11,422	Multiyear project forecast to complete in FY24.
Bombay-Ramarama Tower Line Rebuild Design		200	Multiyear project forecast to complete in FY24.
Karaka 33 kV and TX Micom Relay Replacement (incl. Glenbrook End)	Replacement of Micom protection relays	500	Replaced with Karaka Substation Rebuild in FY32
Karaka 8 Relay Replacement – Rollover	Replacement of Micom protection relays	510	Replaced with Karaka Substation Rebuild in FY32
Karaka Sub Comms Upgrade		500	Reprogrammed for FY24
Substation Security (Opaheke, Pukekohe, Maioro, Karaka) – CARDAX		400	Completed FY23.
Tuakau/Pukekawa Micom Relay Replacement	Replacement of Micom protection relays	1,500	Pukekawa completed FY23, Tuakau due completion FY24.
Waiuku Stage 2 – Transformer Replacement		1,000	Completed FY22.
SYSTEM GROWTH			
Great South Rd 22 kV Feeder Conversion		2,225	Multiyear project forecast to complete in FY24.
Install Voltage Regulator at Switch 47 (Te Hihi)		360	Reprogrammed for FY26.
Kingseat Substation Land Procurement		2,050	Reprogrammed for FY24.
Kingseat Substation Line Design		500	Reprogrammed for FY33.
Pukekohe North Substation Land Procurement		2,350	Reprogrammed for and completed in FY23.
Pukekohe North Substation Line Design		400	Reprogrammed outside of planning window
Upgrade Auto Transformer on Glen Murray Feeder		220	Completed FY22

Table 12-3 Project Performance FY22 Plan Against Actual

12.3 Performance Against Current Year Forecast

12.3.1 Forecast Capital Expenditure FY23

Disclosure Category	Target ($000s)	Forecast ($000s)	Variance	Reason for variance
Consumer Connection	14,000	23,500	+9,500	Increased customer and residential network growth
System Growth	12,287	8,287	(4,000)	Deferral of land purchases
Asset replacement and renewal	32,447	28,447	(4,000)	Reprioritisation of major projects.
Asset Relocations	300	300	-	
Reliability, safety and environment:	1,842	1,842	-	
Expenditure on Non-Network Assets	15,022	12,903	(2,119)	Timing of Glasgow Road site upgrade

Table 12-4 Forecast Capital Expenditure FY23

12.3.2 Forecast Operational Expenditure FY23

Disclosure Category	Target ($000s)	Forecast ($000s)	Variance	Reason for variance
Service Interruptions and Emergencies	2,800	3,265	+17%	Impact of Cyclone Gabrielle
Vegetation Management	2,090	2,300	+10%	Accelerated vegetation programme in response to performance
Routine and Corrective Maintenance and Inspection	2,097	2,300	+10%	Reallocated budget from Asset Replacement to Routine Maintenance. To allow for accelerated UAV and LiDAR as response to performance
Asset Replacement and Renewal	1,628	750	(54%)	
System Operations and Network support	3,868	3,908	+1%	
Business Support	10,684	10,966	+3%	Increased spending due to rebranding, site upgrade and initiation of DSO strategy

Table 12-5 Forecast Operational Expenditure FY23

12.3.3 Project Performance FY23 Forecast to Plan

Project	Scope	Budget ($000s)	Actual completion
REPLACEMENT AND RENEWAL			
Karaka to Glenbrook Communications Network	Installation of fibre between Karaka and Glenbrook GXP	1,300	FY24
Substation Security (Opaheke, Pukekohe, Maioro, Karaka)		50	FY23
Karaka Protection Design		1,500	Replaced with Karaka Substation Rebuild in FY32
Barber Road Substation		2,000	Multiyear project forecast to complete in FY24

Project	Scope	Budget ($000s)	Actual completion
REPLACEMENT AND RENEWAL			
OT Communications Network and Infrastructure Upgrade (rollover)		100	Multiyear programme forecast to complete in FY24
Red Hill Feeder Swan Replacement Rollover	OHUG of overhead network	500	FY23
River Road Swan and CU replacement	Copper and Swan replacement (3.7 km total)	1704	FY23
Wellington St, Pukekohe, LV	Wellington Street LV OHUG	390	Completed FY23
Racecourse Swan Replacement – Hyland Place	0.66 km Swan replacement	274	Completed FY23
Blackbridge (Lewis Rd) CU Replacement	Copper Replacement	650	Completed FY23
Pukekohe West Swan Replacement	Reallocated due to condition assessment	1,450	Cancelled
Dominion Road CU Replacement – Tuakau Feeder	Continuation of conductor replacement on Dominion Road	740	Completed FY23
Te Toro HV Rehabilitation Backbone	Defect remediation and conductor replacement	1,429	FY24
CT Replacement – Tuakau		950	Completed FY23
OT Communications Network and Infrastructure Upgrade		2,000	Multiyear project forecast to complete in FY24
QUALITY OF SUPPLY			
Harrisville Road Harmonics		290	Reprogrammed to FY24.
NETWORK PERFORMANCE			
Anchor Factory Rehabilitation		547	Reprogrammed to FY24-FY25.
Beach Road OHUG		586	
SYSTEM GROWTH			
ANSA Model		150	Reprogrammed to FY24.
Pukekohe North Substation Line Design		400	Reprogrammed outside of planning window
Kingseat Substation Line Design		500	Reprogrammed for FY24.
Pukekohe North Substation Land Procurement		2,350	Completed FY23.
KiwiRail Drury 25 kV/110 kV Circuits (TBC Pricing)		3,500	Cancelled
Great South Rd 22 kV Feeder Conversion		2,687	Multiyear project forecast to complete in FY24.
Purchase Land in the Vicinity for Glenbrook Beach Substation		2,300	Reprogrammed for FY24.
33 kV GLB-WKU East Line Upgrade Detail Design		200	Reprogrammed for FY25.
Quarry Rd 110 kV GIS Predesign		200	Multiyear project ongoing.

Table 12-6 Project Performance FY23 Forecast to Plan

13.0 Appendices

13.0 Appendices

13.1 Appendix A – Schedules

Company Name: **Counties Energy Ltd**
AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 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
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	23,500	13,500	10,300	10,609	9,835	10,130	10,433	10,746	11,069	11,401	11,743
11		System growth	8,287	7,100	7,777	18,914	22,360	14,335	4,047	1,191	1,834	5,804	7,176
12		Asset replacement and renewal	28,447	22,509	23,626	25,478	17,327	21,617	16,497	22,619	19,545	21,190	33,048
13		Asset relocations	300	303	312	322	331	341	351	362	373	384	396
14		Reliability, safety and environment:											
15		Quality of supply	640	5,928	5,160	2,484	1,174	1,575	-	515	-	-	-
16		Legislative and regulatory	-	300	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,202	730	440	453	382	394	406	418	430	443	457
18		**Total reliability, safety and environment**	1,842	6,958	5,600	2,937	1,557	1,969	406	933	430	443	457
19		**Expenditure on network assets**	62,377	50,369	47,615	58,260	51,409	48,392	31,735	35,852	33,252	39,223	52,820
20		Expenditure on non-network assets	12,903	8,457	5,688	4,871	5,017	5,167	5,322	5,482	5,647	5,816	5,990
21		**Expenditure on assets**	75,279	58,826	53,303	63,130	56,426	53,559	37,058	41,334	38,898	45,039	58,810
22													
23	*plus*	Cost of financing	550	491	451	494	423	387	246	270	243	279	364
24	*less*	Value of capital contributions	21,000	15,000	11,124	11,139	10,326	10,636	10,955	11,284	11,622	11,971	12,330
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	54,829	44,317	42,630	52,485	46,524	43,310	26,349	30,320	27,519	33,347	46,844
28													
29		Assets commissioned	54,829	44,317	42,630	52,485	46,524	43,310	26,349	30,320	27,519	33,347	46,844
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	31 Mar 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
32			**$000 (in constant prices)**										
33		Consumer connection	23,500	13,500	10,000	10,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000
34		System growth	8,287	7,100	7,550	17,829	20,463	12,737	3,491	998	1,491	4,582	5,500
35		Asset replacement and renewal	28,447	22,509	22,938	24,015	15,857	19,206	14,231	18,943	15,892	16,728	25,329
36		Asset relocations	300	303	303	303	303	303	303	303	303	303	303
37		Reliability, safety and environment:											
38		Quality of supply	640	5,928	5,009	2,341	1,074	1,399		431			
39		Legislative and regulatory	-	300	-	-	-	-					
40		Other reliability, safety and environment	1,202	730	427	427	350	350	350	350	350	350	350
41		**Total reliability, safety and environment**	1,842	6,958	5,437	2,769	1,424	1,749	350	781	350	350	350
42		**Expenditure on network assets**	62,377	50,369	46,228	54,916	47,047	42,995	27,375	30,025	27,036	30,963	40,482
43		Expenditure on non-network assets	12,903	8,457	5,523	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591
44		**Expenditure on assets**	75,279	58,826	51,750	59,507	51,638	47,587	31,966	34,616	31,627	35,554	45,073
45													
46	**Subcomponents of expenditure on assets (where known)**												
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											
50													

Company Name	Counties Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	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
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	-	300	609	835	1,130	1,433	1,746	2,069	2,401	2,743
55	System growth	-	-	227	1,086	1,897	1,599	556	193	343	1,222	1,676
56	Asset replacement and renewal	-	-	689	1,462	1,470	2,410	2,266	3,676	3,653	4,462	7,719
57	Asset relocations	-	-	9	18	28	38	48	59	70	81	93
58	Reliability, safety and environment:											
59	Quality of supply	-	-	150	143	100	176	-	84	-	-	-
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	13	26	32	44	56	68	80	93	107
62	**Total reliability, safety and environment**	-	-	163	169	132	220	56	152	80	93	107
63	**Expenditure on network assets**	-	-	1,387	3,344	4,362	5,396	4,360	5,827	6,216	8,260	12,338
64	Expenditure on non-network assets	-	-	166	280	426	576	731	891	1,056	1,225	1,399
65	**Expenditure on assets**	-	-	1,553	3,624	4,788	5,972	5,092	6,718	7,271	9,485	13,737
66												

11a(ii): Consumer Connection

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	$000 (in constant prices)					
70	Urban residential	11,750	6,750	5,000	5,000	4,500	4,500
71	Urban commercial	4,700	2,700	2,000	2,000	1,800	1,800
72	Rural residential	3,995	2,295	1,700	1,700	1,530	1,530
73	Rural commercial	3,055	1,755	1,300	1,300	1,170	1,170
74							
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	23,500	13,500	10,000	10,000	9,000	9,000
77	*less* Capital contributions funding consumer connection	21,000	13,500	10,000	10,000	9,000	9,000
78	**Consumer connection less capital contributions**	2,500	-	-	-	-	-
79	**11a(iii): System Growth**						
80	Subtransmission		-	200	1,297	4,494	2,936
81	Zone substations		4,850	7,350	9,850	11,500	7,500
82	Distribution and LV lines		2,100	-	-	274	-
83	Distribution and LV cables		150	-	6,322	3,834	2,300
84	Distribution substations and transformers		-	-	360	360	-
85	Distribution switchgear		-		-	-	-
86	Other network assets	8,287					
87	**System growth expenditure**	8,287	7,100	7,550	17,829	20,463	12,737
88	*less* Capital contributions funding system growth		1,500	1,124	1,139	1,326	1,636
89	**System growth less capital contributions**	8,287	5,600	6,426	16,690	19,137	11,101
90							

Company Name	**Counties Energy Ltd**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		1,150	1,862	20	670	570	20
95	Zone substations		1,350	1,000	5,950	4,450	750	750
96	Distribution and LV lines		17,728	12,404	12,935	16,295	12,571	16,471
97	Distribution and LV cables		569	694	694	694	694	694
98	Distribution substations and transformers		400	475	475	475	535	475
99	Distribution switchgear		960	874	864	982	737	797
100	Other network assets		6,290	5,200	2,000	450	-	-
101	**Asset replacement and renewal expenditure**		28,447	22,509	22,938	24,015	15,857	19,206
102	*less* Capital contributions funding asset replacement and renewal							
103	**Asset replacement and renewal less capital contributions**		28,447	22,509	22,938	24,015	15,857	19,206
104								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
107	**11a(v): Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	Asset Relocations		300	303	303	303	303	303
110								
111								
112								
113								
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		300	303	303	303	303	303
117	*less* Capital contributions funding asset relocations							
118	**Asset relocations less capital contributions**		300	303	303	303	303	303
119								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
122	**11a(vi): Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Network Performance		640	5,928	5,009	2,341	1,074	1,399
125			-		-	-	-	-
126								
127								
128								
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply							
131	**Quality of supply expenditure**		640	5,928	5,009	2,341	1,074	1,399
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		640	5,928	5,009	2,341	1,074	1,399
134								

AMP Planning Period **1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136		for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
137	**11a(vii): Legislative and Regulatory**							
138	*Project or programme**		$000 (in constant prices)					
139	Regulatory			300				
140								
141								
142								
143								
144	**include additional rows if needed*							
145	All other projects or programmes - legislative and regulatory							
146	**Legislative and regulatory expenditure**		-	300	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory							
148	**Legislative and regulatory less capital contributions**		-	300	-	-	-	-
149								
150			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
151	**11a(viii): Other Reliability, Safety and Environment**							
152	*Project or programme**		$000 (in constant prices)					
153	Asset Safety		-	75	77	77	-	-
154	Power Quality		350	655	350	350	350	350
155	Other		852					
156								
157								
158	**include additional rows if needed*							
159	All other projects or programmes - other reliability, safety and environment							
160	**Other reliability, safety and environment expenditure**		1,202	730	427	427	350	350
161	*less* Capital contributions funding other reliability, safety and environment							
162	**Other reliability, safety and environment less capital contributions**		1,202	730	427	427	350	350
163								
164			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165		for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
166	**11a(ix): Non-Network Assets**							
167	**Routine expenditure**							
168	*Project or programme**		$000 (in constant prices)					
169	Land and buildings		1,742	3,600	437	433	428	424
170	Digital strategy		3,468	3,970	4,126	3,269	3,237	3,206
171	Other non-network assets		1,033	887	959	890	926	961
172								
173								
174	**include additional rows if needed*							
175	All other projects or programmes - routine expenditure							
176	**Routine expenditure**		6,243	8,457	5,523	4,591	4,591	4,591
177	**Atypical expenditure**							
178	*Project or programme**							
179	Head office site and building upgrade		6,660					
180								
181								
182								
183								
184	**include additional rows if needed*							
185	All other projects or programmes - atypical expenditure							
186	**Atypical expenditure**		6,660	-	-	-	-	-
187								
188	**Expenditure on non-network assets**		12,903	8,457	5,523	4,591	4,591	4,591

Company Name: **Counties Energy Ltd**

AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 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
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	3,265	2,838	2,962	3,078	3,199	3,324	3,455	3,574	3,698	3,826	3,959
11	Vegetation management	2,300	2,500	2,575	2,652	2,732	2,814	2,434	2,508	2,583	2,660	2,740
12	Routine and corrective maintenance and inspection	2,300	2,940	2,699	2,816	3,336	3,164	3,289	3,863	3,609	3,791	4,424
13	Asset replacement and renewal	750	1,316	1,157	875	1,025	936	962	1,118	1,025	1,066	1,228
14	**Network Opex**	8,615	9,594	9,393	9,421	10,292	10,238	10,140	11,063	10,915	11,343	12,351
15	System operations and network support	3,908	4,411	4,446	4,694	4,955	5,232	5,523	5,831	6,156	6,500	6,862
16	Business support	10,966	11,620	11,995	12,399	12,817	13,249	13,234	13,681	14,144	14,623	15,119
17	**Non-network opex**	14,874	16,031	16,441	17,093	17,772	18,481	18,757	19,512	20,300	21,123	21,981
18	**Operational expenditure**	23,489	25,625	25,834	26,514	28,064	28,719	28,897	30,575	31,215	32,466	34,331

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 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
21		$000 (in constant prices)										
22	Service interruptions and emergencies	3,265	2,838	2,876	2,901	2,927	2,954	2,980	2,994	3,007	3,021	3,034
23	Vegetation management	2,300	2,500	2,500	2,500	2,500	2,500	2,100	2,100	2,100	2,100	2,100
24	Routine and corrective maintenance and inspection	2,300	2,940	2,620	2,654	3,053	2,811	2,837	3,235	2,935	2,993	3,390
25	Asset replacement and renewal	750	1,316	1,123	825	938	832	830	937	833	841	941
26	**Network Opex**	8,615	9,594	9,119	8,880	9,418	9,097	8,747	9,265	8,875	8,954	9,466
27	System operations and network support	3,908	4,411	4,316	4,424	4,535	4,648	4,764	4,884	5,006	5,131	5,259
28	Business support	10,966	11,620	11,646	11,687	11,729	11,772	11,415	11,458	11,500	11,544	11,587
29	**Non-network opex**	14,874	16,031	15,962	16,112	16,264	16,420	16,180	16,341	16,506	16,674	16,846
30	**Operational expenditure**	23,489	25,625	25,081	24,992	25,683	25,516	24,927	25,606	25,381	25,629	26,312
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	567	624	658	694	732	773	815	860	907	957	1,010

37 * *Direct billing expenditure by suppliers that direct bill the majority of their consumers*

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 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
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	86	177	271	371	475	581	691	806	925
43	Vegetation management	-	-	75	152	232	314	334	408	483	560	640
44	Routine and corrective maintenance and inspection	-	-	79	162	283	353	452	628	675	798	1,033
45	Asset replacement and renewal	-	-	34	50	87	104	132	182	192	224	287
46	**Network Opex**	-	-	274	541	873	1,142	1,393	1,798	2,040	2,389	2,885
47	System operations and network support	-	-	129	269	421	583	759	948	1,151	1,369	1,603
48	Business support	-	-	349	712	1,088	1,477	1,818	2,223	2,644	3,079	3,531
49	**Non-network opex**	-	-	479	981	1,508	2,061	2,577	3,171	3,794	4,448	5,134
50	**Operational expenditure**	-	-	752	1,522	2,381	3,203	3,970	4,969	5,834	6,837	8,019

Company Name: **Counties Energy Ltd**

AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	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
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.07%	5.31%	18.56%	34.99%	41.07%	0.00%	3	7.75%
11	All	Overhead Line	Wood poles	No.	8.71%	10.58%	22.48%	2.87%	55.32%	0.06%	3	8.33%
12	All	Overhead Line	Other pole types	No.	-	24.36%	7.69%	2.56%	56.41%	8.97%	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	4.73%	-	64.97%	9.64%	20.66%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	37.50%	62.50%	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	12.99%	-	87.01%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	N/A	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	100.00%	-	4	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	50.00%	33.33%	-	-	16.67%	-	3	33.33%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	75.00%	25.00%	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	16.67%	-	50.00%	33.33%	-	4	58.33%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	76.67%	3.33%	13.33%	6.67%	-	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	100.00%	-	4	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	100.00%	-	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	9.38%	16.67%	12.50%	34.38%	27.08%	-	3	11.34%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	
35												

Company Name: **Counties Energy Ltd**
AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	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
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5.88%	23.53%	11.76%	23.53%	35.29%	-	3	16.67%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.04%	11.83%	31.56%	34.04%	20.52%	0.00%	3	7.55%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.14%	0.17%	2.91%	23.77%	72.45%	0.55%	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	13.24%	24.65%	55.22%	6.89%	-	3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	33.50%	66.50%	-	4	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	7.14%	21.43%	38.10%	33.33%	-	3	13.51%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11.18%	13.67%	18.36%	25.58%	30.25%	0.94%	3	10.95%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.06%	3.24%	8.24%	30.29%	55.59%	0.59%	3	5.24%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.26%	11.97%	30.70%	41.67%	12.06%	0.34%	3	1.94%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.82%	2.88%	30.48%	39.55%	25.64%	0.62%	3	1.80%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	13.33%	86.67%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.05%	2.42%	31.05%	40.21%	24.53%	0.74%	4	
55	LV	LV Line	LV OH Conductor	km	-	0.19%	0.75%	92.46%	6.29%	0.32%	3	4.24%
56	LV	LV Cable	LV UG Cable	km	0.59%	0.74%	1.09%	45.91%	49.92%	1.76%	3	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	1.01%	0.02%	10.54%	88.38%	0.05%	3	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	-	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	0.70%	11.27%	6.34%	27.46%	54.23%	-	3	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.00%	-	-	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	84.22%	15.78%	-	-	3	-
62	All	Load Control	Centralised plant	Lot	-	-	33.33%	33.33%	33.33%	-	3	-
63	All	Load Control	Relays	No.	4.59%	30.03%	0.47%	63.78%	1.13%	-	3	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Company Name: **Counties Energy Ltd**

AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Opaheke	28	40	n-1	7	71%	40	96%	No constraint within +5 years	
10	Pokeno	10	40	n-1	10	26%	40	66%	No constraint within +5 years	
11	Pukekohe	39	60	n-1	8	65%	60	74%	No constraint within +5 years	
12	Tuakau	13	40	n-1	5	32%	40	31%	Transformer	
13	Ramarama	7	5	n-1	5	133%	40	43%	Transformer	Ramarama Substation will be decommissioned and replaced by Barber Rd substation in 2023
14	Mangatawhiri	8		n	5	-			No constraint within +5 years	Mangatawhiri Substation will be decommissioned and replaced by Barber Rd substation in 2023
15	Waiuku	16	20	n-1	5	82%	20	101%	Transformer	Cyclic rating of transformer will be utilised.
16	Karaka	13	20	n-1	2	63%	20	85%	Other	
17	Maioro	8	9	n	3	94%				Maioro Substation firm capacity is subject to commercial agreement with the major customer on site for new investment in the 5-year period.
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	Counties Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11	*Consumer types defined by EDB**							
12	Standard domestic		476	488	500	513	525	539
13	Low user domestic		631	646	663	679	696	714
14	Mass market business		12	12	13	13	13	13
15	Time of use business		60	61	63	64	66	67
16	Distributed streetlights		12	12	13	13	13	13
17	**Connections total**		1,190	1,220	1,250	1,281	1,314	1,346
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		220	240	260	280	300	320
21	Capacity of distributed generation installed in year (MVA)		2	2	2	2	2	3
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
25	GXP demand		126	137	147	154	160	164
26	*plus* Distributed generation output at HV and above		8	10	10	10	10	10
27	**Maximum coincident system demand**		134	147	157	164	170	174
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		134	147	157	164	170	174
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		641	657	674	691	709	729
32	*less* Electricity exports to GXPs		-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation		48	49	50	51	52	53
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		690	707	724	742	761	782
36	*less* Total energy delivered to ICPs		659	676	693	710	728	746
37	**Losses**		30	31	31	32	33	36
38								
39	**Load factor**		59%	55%	53%	52%	51%	51%
40	**Loss ratio**		4.4%	4.4%	4.3%	4.3%	4.4%	4.6%

Company Name	**Counties Energy Ltd**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	176.2	188.5	168.0	194.9	216.2	203.0
12	Class C (unplanned interruptions on the network)	100.1	101.3	97.5	94.3	91.9	89.6
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.54	0.72	0.66	0.74	0.79	0.75
15	Class C (unplanned interruptions on the network)	1.92	1.86	1.79	1.72	1.68	1.64

Company Name	Counties Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	The Asset Management Policy had previously been captured and detailed in the Asset Management Plan, with sections of the plan outlining 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. This is currently under review.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	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.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	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 lifecycles are well understood for major 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. Asset Health studies are being progressed to feed into the life cycle strategy documents.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	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 Asset Management team. Lifecycle management plans take into account the long term optimisation of asset investments and trade-offs required. In the medium term, these will be better documented as standalone lifecycle management plans to be summarised in the AMP for disclosure purposes.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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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.

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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 made 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 relating to plans in their areas, some within formally minuted account management meetings. Internal circulation is supplemented with briefings during monthly meetings; team meetings; and presentations of work programmes, key projects and other asset management initiatives.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	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 explores how	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 (e.g. bringing 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 deliver on those requirements. Whilst preferring to use internal resources		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Risk mitigation and emergency response plans are in place to maintain continuity of supply, such as; Grid Emergency Procedure, Cyber Security and Disaster Response Plans, Critical Infrastructure Outage Standard, Storm Response Plan and Zone Substation Contingency Plans. CE is a member of both AC and WDC CDEM Lifelines Utilities Groups, where close alignment is maintained during all regional events. Personalised Metservice forecasting, provides network specific advance warning of potential events. The AMP considers network and environmental risk, including disaster response and assessment of HILP events.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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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
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence
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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	As outlined by the Asset Management Policy, the responsibility for AM activities sits with the GM Asset Management. The GM Field Operations has 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 people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	The development of the programmes of work presented in this AMP consider resourcing - financial, and phycial 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, and outher resource constraints to ensure efficencieny and sustainability in the long term. Consideration is given to outsourcing some activities where phycal resource capacity is not available. Significant effort has been made to resource the team to deliver on asset management objectives including an increase in engineering, field delivery and support functions within the business.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	The significance of core asset management activities and meeting stated AM requirements is emphasised in newsletters, management communication, team meetings, company meetings, celebrations of particular programme successes, detailed reviews of issues and other asset related communications.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	The organisation has an internal workforce so has 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 resources where necessary, 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.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	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.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency requirements are identified through the job descriptions for different roles, as they relate to 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, including an e-learning portal.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	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) and tracked through the e-learning portal.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	The AMP is made available to all staff, and other stakholders 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. The business communicate the plans, processes and changes through targetted roadshow presentation internally, including service provider, and to the board and trust.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Main systems and functions are detailed in the AMP. There is no clear documentation outlining the relationships between different systems and processes. This has been identified and an ISO55000 gap analysis has been completed with improvement projects proposed. ISO55000 alignment assessment projects are also underway to formalise the asset management system structure and document hierarchy.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	The asset management information systems supports core business function. An asset management system has been initially implemented and in progress, undergoing process and data hierarchy revision. tThis is a deliverable for completion in FY22/23 - delayed due to COVID and review of delivery model. The GIS system is in place for geospatial asset information.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Asset information is primarily maintained within the company ERP. This provides access controls and auditing. GIS is used to provide the 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 geo-spatial and specific asset information. Analytic tools provide access to infomation held in different systems to present in a holistic manner to support asset management practices.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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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
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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 geospatial system is now in place and undergoing continuous audit and improvement providing data as required by the business. An EAMS (asset management system) has been implemented, however a revision of the data hierarchy and business requirements ar under review - an EAM re-start project is underway due completion in FY22/23		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	The corporate risk framework and audit programme identifies a number of 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 AMP. A series of FMECA studies are underway to close gaps in these processes.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Actions arising from risk assessments relating to training, competency development and resourcing are captured in training and development plans, as well as updating job specific 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 implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	The business has established a compliance framework, and through active monitoring of the regulatory environment, along with particpation in industry bodies such as the EEA and ENA identifies ongoing requirements, and new or ammended requirements. The business subscribes to a legal compliance monitoring/tracking system for updates and to monitor 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 s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Procedures for planning, design and construction 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 contruction. Asset management processes have been implemented to ensure stakeholder engagement through planning and concept design.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	Procedures for maintenance and inspection of assets exist in varying forms, with some not as current as others. As part of the ISO55000 alignment project the information and data requirements, data capture requirementsand document hierarchy will be established, due completion FY23 and implementation through FY23/24		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The routine inspection process captures information relating to defects and hazards, but not a specific, objective assessment of asset condition. Mobile technology is used for inspection records and the quality of information for decision making has improved. As part of the ISO55000 alignment project the information and data requirements, data capture requirementsand document hierarchy will be established, due completion FY23 and implementation through FY23/24		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	An incident reporting process in place, and asset-related failures, worksite incidents and emergency situations all initiate processes for investigation and mitigation. Outcomes of audits and 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 to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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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
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Procedures for audit exist in some aspects of the AM systems and processes, such as safety, quality 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 done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	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 related documentation. Trend 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 investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	Exploration 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 senior management. The business continue to engage in initiatives to improve data analysis, and data collection - through FY22 there have been condition assessments of critical overhead equipment, improvements in defect management processes, and performance reporting		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Participation in industry forums ; conferences; joint initiatives; participation in relevant industry groups; international data gathering and research and inclusion of appropriate goals in personal development and business plans. Business case assessment for new technologies and operating 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 on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Company Name: Counties Energy Ltd
AMP Planning Period: 1 April 2023 – 31 March 2033
Asset Management Standard Applied:

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
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

13.1.1 Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

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 3% 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 3% per annum.

13.2 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	Executive Summary
3.2 Details of the background and objectives of the EDB's asset management and planning processes	5.0
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	2.0
3.3.2 states the corporate mission or vision as it relates to asset management	2.0
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2.0
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	2.0
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2.0
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, consumers etc.) which identifies important stakeholders and indicates-	
3.6.1 how the interests of stakeholders are identified	2.6
3.6.2 what these interests are	2.6
3.6.3 how these interests are accommodated in asset management practices; and	2.6
3.6.4 how conflicting interests are managed	2.6
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	2.4.2
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured and	2.4.1
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	2.4.1, 2.4.2
3.8 All significant assumptions-	
3.8.1 quantified where possible	1.7 and throughout AMP
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	1.7 and throughout AMP
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	1.7 and throughout AMP

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.7 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	1.7 and throughout AMP
3.10 An overview of asset management strategy and delivery	5.1, 5.3, 5.5
3.11 An overview of systems and information management data	5.4
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	5.4.2
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	5.5.1
3.13.2 planning and implementing network development projects	5.5.1,7.1
3.13.3 measuring network performance.	5.4.2,7.1
3.14 An overview of asset management documentation, controls and review processes	5.4.1
3.15 An overview of communication and participation processes	5.4.1
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
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	2.1,13.4
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities	2.7.2
4.1.3 description of the load characteristics for different parts of the network	2.8
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.7.4
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;	2.8, 9.3, 9.4
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;	3.2, 9.3, 9.4
4.2.3 a description of the distribution system, including the extent to which it is underground;	2.8.2
4.2.4 a brief description of the network's distribution substation arrangements;	2.8.2
4.2.5 a description of the low voltage network, including the extent to which it is underground; and	2.8.2
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	8.9

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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;	2.8.2
4.4.2 description and quantity of assets;	3.1 to 3.2.2
4.4.3 age profiles; and	3.1 to 3.2.2
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.	3.1 to 3.2.2
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)	8.1.1, 8.2.4 to 8.9.7
4.5.2 Assets owned by the EDB but installed at bulk electricity supply points owned by others	8.10
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand	8.9.1
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.	4.1to 4.6
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.	4.3 to 4.5.2
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;	4.5
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.	4.0
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.	4.0
9 Targets should be compared to historic values where available to provide context and scale to the reader.	4.0
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.	4.0
NETWORK DEVELOPMENT PLANNING	
11 AMPs must provide a detailed description of network development plans, including—	
11.1 A description of the planning criteria and assumptions for network development;	9.0
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;	9.1
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;	9.1.4, 9.1.5

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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;	9.1.5
11.4.2 the approach used to identify standard designs.	9.1.5
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	5.3.5
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network.	9.1
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.	9.1, 5.3
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;	9.0
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	9.2
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;	9.2.4, 9.3
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	9.0
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.	9.0
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-	9.3, 9.4
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	9.3, 9.4
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;	9.3, 9.4
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	9.1.5, 9.3, 9.4
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-	9.3 to 10.0
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;	9.3, 9.4
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	9.3, 9.4
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period.	9.3, 9.4
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.	9.1.5
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	7.0
11.12.2 the potential for non-network solutions to address network problems or constraints.	7.0
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;	

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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-	8.2 to 8.9
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;	8.2 to 8.9
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	8.2 to 8.9
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	11.1, 11.2
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;	5.0
12.3.2 a description of innovations that have deferred asset replacements;	5.2, 6.0, 7.0
12.3.3 a description of the projects currently underway or planned for the next 12 months;	8.2 to 8.8.1
12.3.4 a summary of the projects planned for the following four years (where known); and	8.2 to 8.8.1
12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	8.9, 8.10
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in subclause 4.5.	8.2 to 8.9
NON-NETWORK DEVELOPMENT, MAINTENANCE AND RENEWAL	
13 AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	
13.1 a description of non-network assets;	10.0
13.2 development, maintenance and renewal policies that cover them;	10.0
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	10.0
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	10.0
RISK MANAGEMENT	
14 AMPs must provide details of risk policies, assessment, and mitigation, including—	
14.1 Methods, details and conclusions of risk analysis;	5.8
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	5.9
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2;	5.9
14.4 Details of emergency response and contingency plans.	5.10
EVALUATION OF PERFORMANCE	
15 AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1 A review of progress against plan, both physical and financial;	12.0
15.2 An evaluation and comparison of actual service level performance against targeted performance;	4.1 to 4.5.2
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

Information Disclosure Requirements 2012 (consolidated at April 2018) clause reference	AMP Section
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.	4.1 to 4.4, 6.0
CAPABILITY TO DELIVER	
16 AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic, and the objectives set out in the plan can be achieved;	Throughout AMP
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.4.1

13.3 Appendix C — Directors' Certificate

Schedule 17 Certificate for Year-beginning Disclosures

We, Vernon John Dark and Hamish William Stevens, being directors of Counties Energy, certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Counties Energy prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 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 Energy's corporate vision and strategy and are documented in retained records.

Vernon John Dark

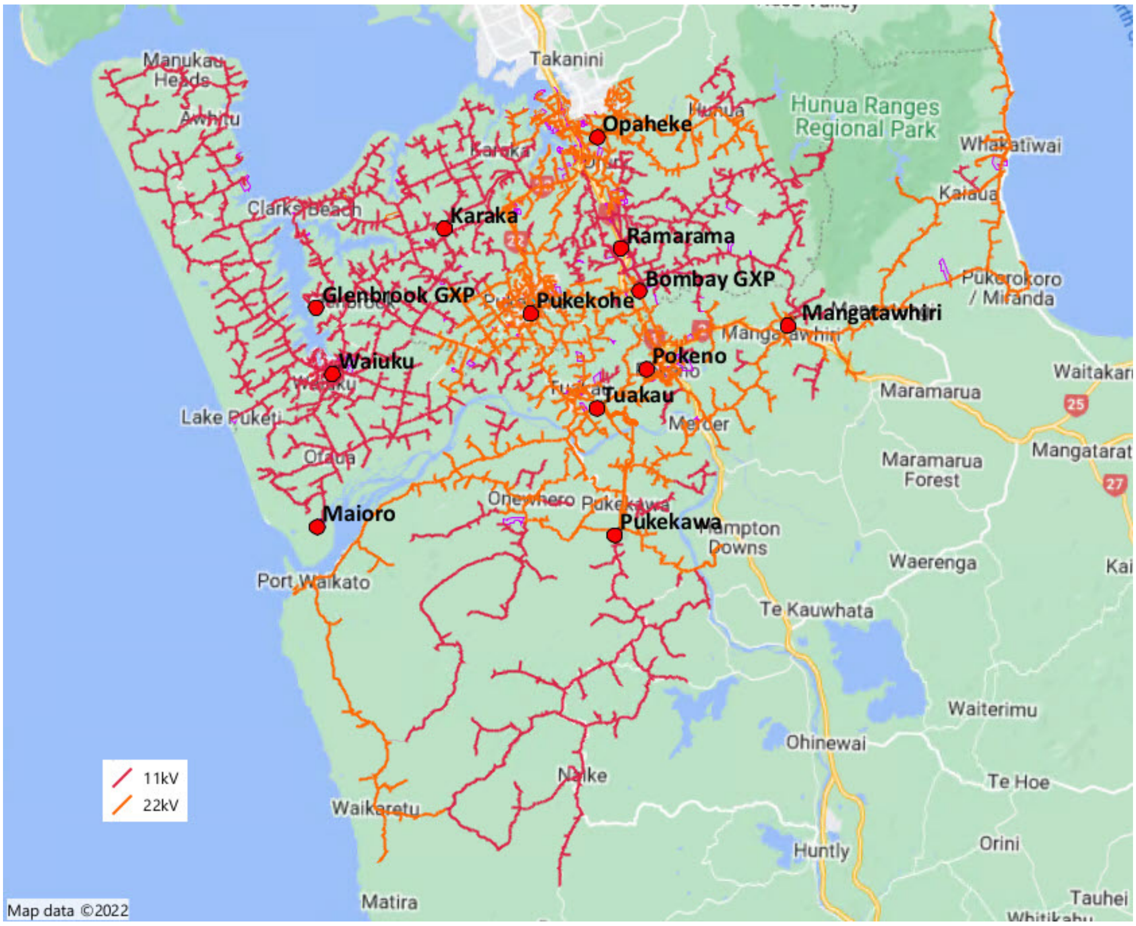
(Director)

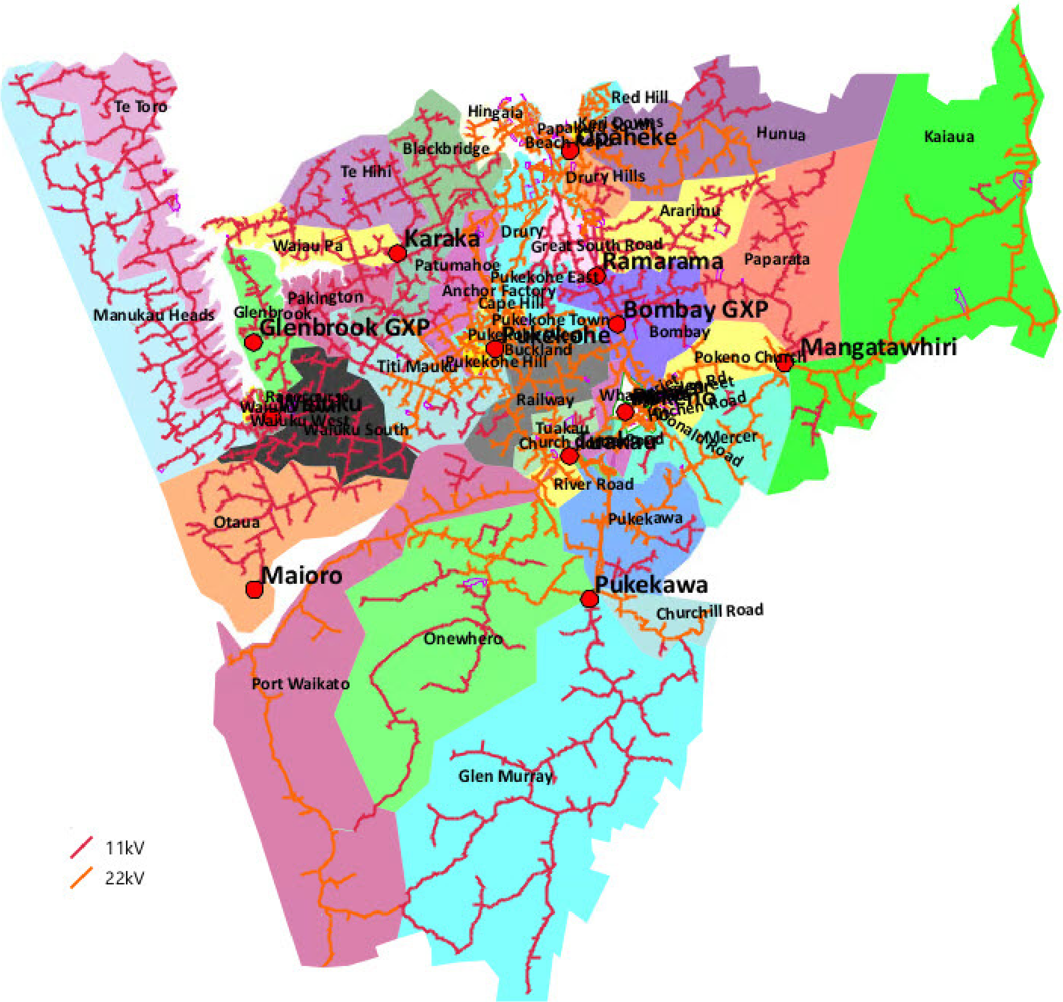
Hamish William Stevens

(Director)

Certified this 29th Day of March 2023

13.4 Appendix D – Network Overview Diagrams





Te Toro
Hingaia
Red Hill
Hunua
Kaiaua
Blackbridge
Te Hihi
Opaheke
Drury Hills
Ararimu
Waiau Pa
Karaka
Drury
Great South Road
Ramarama
Paparata
Patumahoe
Pukekohe East
Anchor Factory
Cape Hill
Pakington
Manukau Heads
Glenbrook
Glenbrook GXP
Pukekohe Town
Bombay GXP
Bombay
Buckland
Pokeno Church
Mangatawhiri
Titi Mauku
Pukekohe Hill
Railway
Waiuku
Waiuku West
Waiuku South
Tuakau
Mercer
River Road
Pukekawa
Otaua
Maioro
Pukekawa
Churchill Road
Onewhero
Port Waikato
Glen Murray
11kV
22kV

13.5 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
ADMS	Advanced Distribution Management System
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
Ampere (A)	Unit of electrical current flow, or rate of flow of electrons
ARMM	Asset Risk Management Modelling
AUP(OP)	Auckland Unitary Plan (Operative in Part)
BEV	Battery Electric Vehicle
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 – 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
CX	Customer Experience
Demand	The amount or energy sought by the consumers
DDO	Drop-out Fuse Switch or Disconnector/Isolator
DERs	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
Disconnector	Also known as a disconnecting switch, isolator, or drop-out
Distribution Line	[Ref NZECP 34] Means works that are owned by Counties Energy used for the conveyance of electricity to one or more electrical installations
DMS	Distribution Management Systems
DNO	Distribution Network Operator
DPP	Default Price-Quality Path (Commerce Commission)
DSO	Distribution System Operator
Earth-fault	A circuit conductor unintentionally grounded
Easement	An easement is a right given to another person or entity to access upon land that person or entity does not own

Term	Description
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association NZ (Inc)
EECA	Energy Efficiency and Conservation Authority
EIPC	Electricity Industry Participation Code 2010 (the 'Code')
ENA	Electricity Networks Association
ERP	Enterprise Resource Planning
ESI	Electricity Supply Industry
ETS	Emission Trading Scheme
EV	Electric Vehicle
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
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
FMEA	Failure Mode & Effects Analysis
FMECA	Failure Mode, Effects & Criticality Analysis
FULSS	(Auckland) Future Urban Land Supply Strategy
FY	Financial Year, e.g. FY2020 is Financial Year 2020 which covers 1 April 2019 to 31 March 2020
GIS	The Geographic Information System used for electronic mapping of the network
GPD	Group Peak Demand
GSA	Geospatial Analysis
GWh	Giga-watt Hour
GXP	Grid Exit Point – The point at which Counties Energy equipment is deemed to connect to the Transpower Grid System
Harmonics	Distortion of the sine wave which represents ideal AC power. Usually by super imposed higher frequencies
HILP	High Impact, Low Probability
HSR	High-availability Seamless Redundancy
HV	High Voltage – Any voltage exceeding 1000 V AC or 1500 V DC but usually pertaining to the 11 kV or 33 kV distribution system
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
ID	Information Disclosure
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
LiDAR	Light Detection and Ranging — A pulsed laser measurement technology

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.
Load Break Switch	A switch that can be operated under load
LTI	Lost Time Injury
LTIFR	Lost Time Injury Frequency Rate
LTISR	Lost Time Injury Severity Rate
LV	Low Voltage – Any voltage exceeding 32 V AC or 115 V DC but not exceeding 1000 V AC or 1500 V DC
Maximum Demand	The highest value of the power or apparent power taken within the account period, such as, month or year
MBIE	Ministry of Business, Innovation and Employment
MEP	Metering Equipment Provider
MW	Mega-Watt
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 Energy is Microsoft Dynamics NAV R2 2009
NOC	Network Operation Centre
NZ CSSIE	New Zealand Control Systems Security Information Exchange
NZECP	New Zealand Electrical Code of Practice (A series of Publications)
OSI	Open Systems Interconnection Model
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 property's boundary containing the fuses for a service supply
PRP	Parallel Redundancy Protocol
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 Energy
Risk	Probability (likelihood) and consequences, positive or negative, of an event. In some situations, risk is a deviation from the expected
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

Term	Description
RUB	Rural Urban Boundary
SAIDI	System Average Interruption Duration Index – The average total duration of interruption per connected customer
SAIFI	System Average Interruption Frequency Index – The average number of interruptions per connected customers
SANS	SysAdmin, Audit, Network and Security
SCADA	Counties Energy's computerised Supervisory Control and Data Acquisition System, being the primary tool for monitoring and controlling access, and switching operations for Counties Energy's Network
SF_6	Sulphur hexafluoride – A gas used as an insulator in some switchgear
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 Energy, 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
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 Energy Networks overhead lines
Voltage Regulator	An electrical regulator device designed to automatically maintain a constant voltage level
VPP	Virtual Power Plans
VT	Voltage Transformer
XLPE	Cross-linked Polyethylene – A type of cable insulation
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