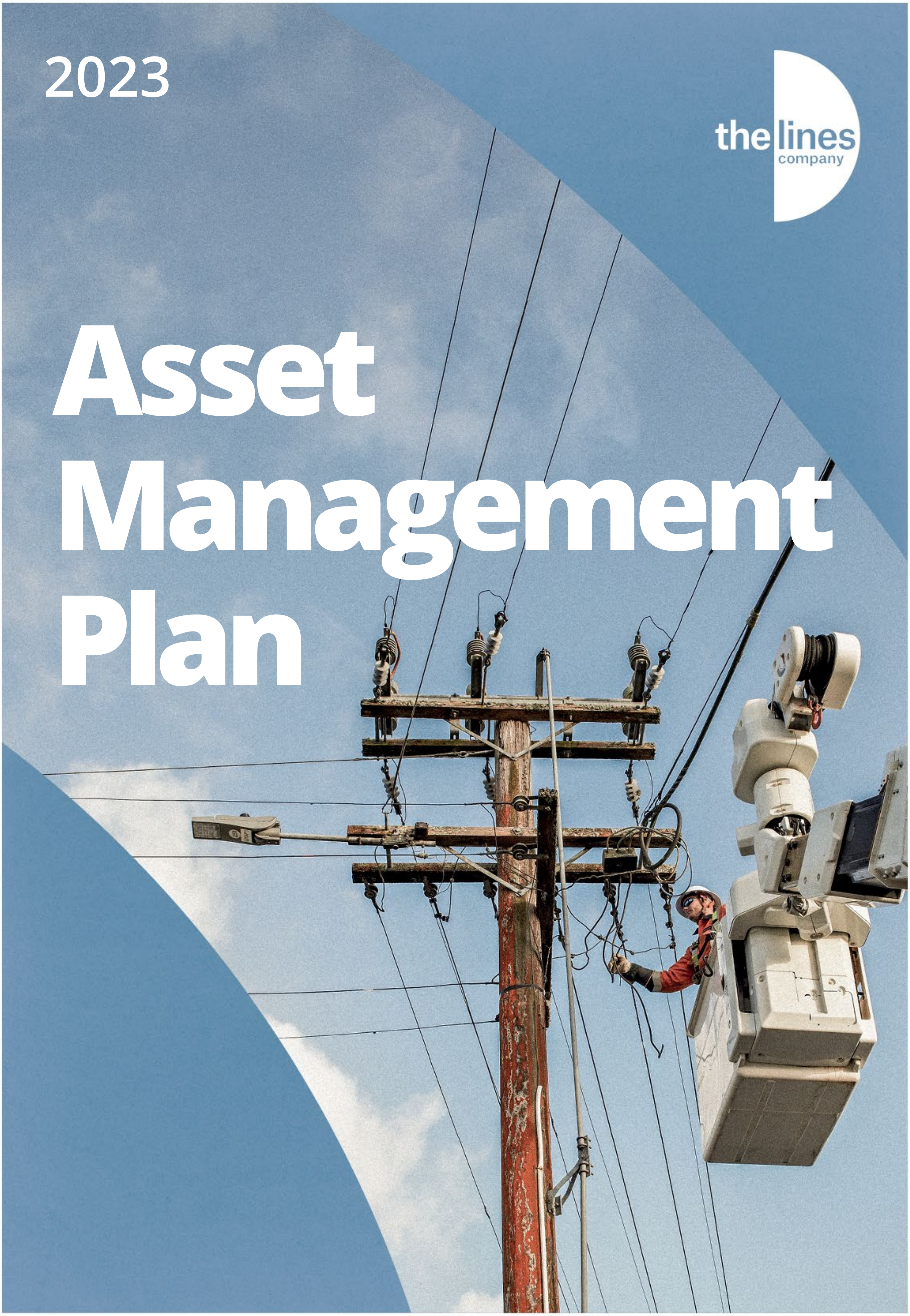
2023

the lines company

Asset Management Plan



Foreword

Welcome to The Lines Company's (TLC) 2023 Asset Management Plan (AMP). This AMP is forward looking and outlines how we maintain and develop our network into the future.

This AMP is published as Aotearoa recovers from the chaos caused by Cyclone Gabrielle. The cyclone event has highlighted the realities of climate change unlike ever before. Electricity networks have a key role in the nation's response to the climate challenge.

Firstly, networks will be vital in enabling the decarbonisation and electrification of modern society, particularly in the transport and industrial sectors. Electricity networks will need to meet this new demand while keeping electricity affordable. Secondly, the growing reliance on electricity as the sole energy source in households, combined with the increasing frequency of severe weather events, will require electricity networks of the future to be significantly more resilient than what was acceptable when they were first built.

As we embrace this challenge, we recognise the importance of providing clear signals to our customers, communities, and other stakeholders, of how we are transitioning our network to meet these challenges over the medium to long term.

Electricity distributors will experience increased demands for investment in their networks for a range of different reasons. The increase in demand for electricity will be universally felt across all networks.

We anticipate the immediate growth in demand on our network will occur initially in the industrial sector (process heat conversion), followed by the growth of electric vehicles (EVs) out to 2050. While certain elements of the transition are well-understood and reasonably well-fixed (e.g., the target to achieve net zero emissions by 2050), other elements which may have a significant impact are still uncertain (e.g., the phase-out of reticulated gas for home heating, hot water, and cooking).

Growth on our network will also be driven by new renewable generation required to meet future electricity demand. Remote and rural parts of our network, provide the ideal location for such installations. Investment in distribution technology such as low voltage (LV) network visibility and operations systems like Advanced Distribution Management Systems (ADMS) will assist with developing an integrated system that is capable of coordinating our network resources, enabling demand-side participation and management of multidirectional flows.

Networks will play a crucial role in unlocking value and ensuring energy equity for our customers. The smarter coordination of Distributed Energy Resources (DER) to assist with meeting peak demand will significantly reduce the physical network infrastructure needed. Every megawatt (MW) of avoided peak demand will save New Zealand millions in generation, transmission, and distribution investment costs.

Resilience of networks will improve by focusing on the 4Rs: risk reduction, readiness, response and recovery. Increasing alternate supply options, renewal of our overhead assets and the review of the tree regulations will be vital in allowing rural networks such as ours to reduce the risk posed by severe weather events. And our work with national institutes such as National Institute of Water and Atmospheric Research (NiWA) and forestry providers will enable us to be ready when storms do occur.

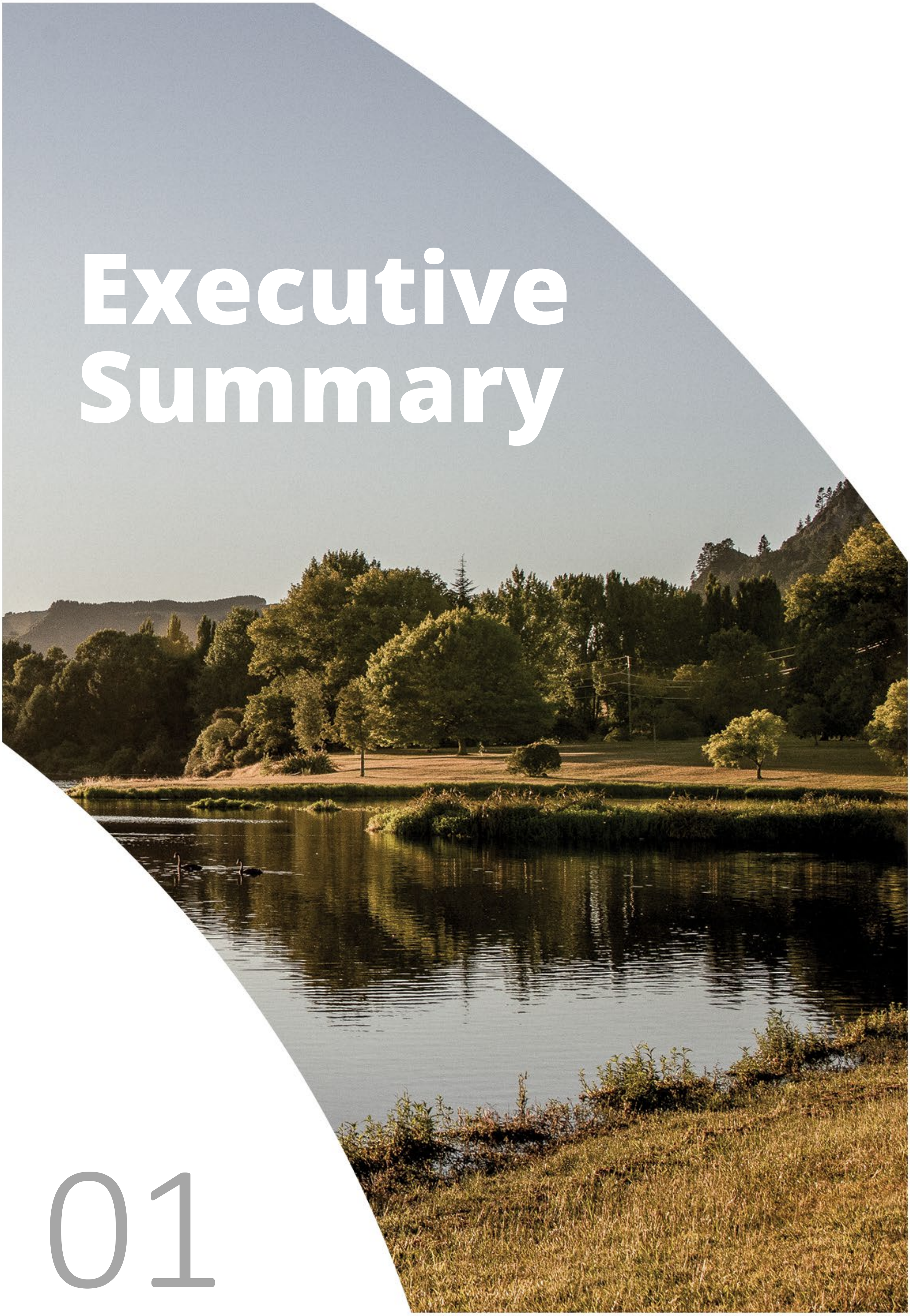
This AMP has been written to provide an overview of our asset management roadmap in an informative and easily read way. We are actively encouraging our stakeholders, customers, business partners, and the people living in our community - to engage with us on our role as an essential service provider with our asset management programme as the key vehicle for providing a secure electricity supply for generations to come.

The Lines Company

Mike Fox
Chief Executive

Contents

Executive Summary



01

Summary

1 Executive Summary

Introduces and summarises our asset management plan

Introducing our network and our long-term objectives

2 Our Background

An overview of our operating environment and the assets we own and operate.

3 Our Objectives

The long-term objectives we are seeking to achieve through this asset management plan.

Preparing our network for the future

4 Future Network

How we are preparing our network and our business to support the future needs of our customers.

5 Asset Management Approach

How we translate our business strategy into day-to-day investment and operational decisions.

Our key capital expenditure plans

6 Growing Our network

The key area development plans we are undertaking and supporting capital expenditure required to support them.

7 Renewing Our Network

The key asset renewal programmes we are putting in place to maintain the condition and serviceability of our assets, and the capital expenditure required to support them.

Supporting expenditure for our business and operations

8 Capital Expenditure

The non-network capital investments we are making to support our business.

9 Operational Expenditure

Our key operational activities and supporting expenditure for the next 10 years.

Supporting information for industry compliance

Appendix A	Provides a glossary of key terms used in this document
Appendix B	References the compliance requirements in our AMP
Appendix C	Provides summary schedules required by the Commerce Commission
Appendix D	Provides the Directors Certification for this AMP

1. Executive Summary

This chapter provides a summary of the AMP including the challenges that underpin our ten-year planning period and the expenditure required to address them.

1.1 Purpose

This AMP describes our electricity network, our assets, and our investment requirements. It also provides an overview of our asset management practices, our planning and our key risks and issues as we perceive them.

This plan covers a ten-year period from 1 April 2023 to 31 March 2034 (the planning period). As with any long-term plan, the details tend to be more accurate in the earlier years as it is easier to predict the near-term state of our assets and required actions, plans and expenditure.

The purpose of this AMP is to communicate with our stakeholders by:

- Providing readers with an understanding of the nature and characteristics of our network region.
- Describing the assets we own and operate.
- Detailing the investment requirements we foresee over the AMP period, so we can continue to operate our network safely and reliably and meet our strategic objectives, which are to optimise the lifecycle of our assets, create value from metering technology and data, and to generate value from productive labour and services.
- Outlining our asset management objectives which include **safety and environment, asset stewardship**, **customer and community**, **networks for today and tomorrow** and **operational excellence.**
- Outlining our short to medium term planning objectives, which are improving safety, improving reliability, improving security of supply, building resilience in our power transformer fleet and maintaining a sustainable line renewal programme.
- Detailing our asset management processes which have been put in place to meet those objectives.
- Describing the relationship between our AMP and our strategic plan, and its importance as a key planning document.

We last published a full AMP in March 2020, and since that time the operational context of our business has continued to change. In this document we outline some of the key drivers of those changes and how we plan to respond to those through our asset management and expenditure programme.

This Asset Management Plan was approved by The Lines Company Limited Board of Directors on 30 March 2023.

1.2 The key features of our AMP

The key features and drivers for developing this plan are summarised here.

Reliability is a key focus

The reliability of electricity supply will have a greater economic and social importance as the economy becomes more reliant on electricity for industry and transportation in the future. Maintaining consistent reliability performance is challenging in our region for three reasons:

1. Our network is heavily forested. Around 95% of our network lines are exposed to fall-in risk from trees that are outside our control. This issue currently accounts for more than 90% of our vegetation faults. We are seeing farmland being converted to carbon forestry and consequently we expect vegetation risk to increase over time.
2. Half of our lines are over farmland and not accessible by road, so fault identification is commonly by helicopter, and sometimes limited by weather conditions at the time.
3. Our faults are increasingly driven by storm activity, and we are noticing these are becoming more frequent and more intense.

The tree management regulations, which enforce landowners to main tree clearance of only 2.5m to the line, are a significant barrier to enabling reliability and we believe this is an urgent area of focus for our industry to address.

In this AMP we are continuing to invest in technology to facilitate our risk management, including working with NiWA to develop targeted weather and asset risk forecasting techniques, and continuing to assess vegetation risk through future Light Detection and Ranging (LiDAR) survey techniques.

Figure 1.1: Impacts of forestry (outside the notice zone) on our assets

We have renewed our focus on customer service

We have undertaken a significant transition over the last five years to change from demand-based charges and direct billing – to Time of Use (ToU) charging and billing through retailers. These initiatives have helped to standardise and align our customer experience with the wider industry. We are now sharpening our focus to customer service management and community engagement.

In 2021 we established a Customer and Community Engagement team to work more closely with our customers and to represent their voice within our business. Their mandate includes educating customers and working with communities to provide support, increase energy knowledge and reduce energy costs.

We have also commenced a review of key areas of customer interaction to ensure we are able to provide a consistent and effective experience across our customer groups. This includes:

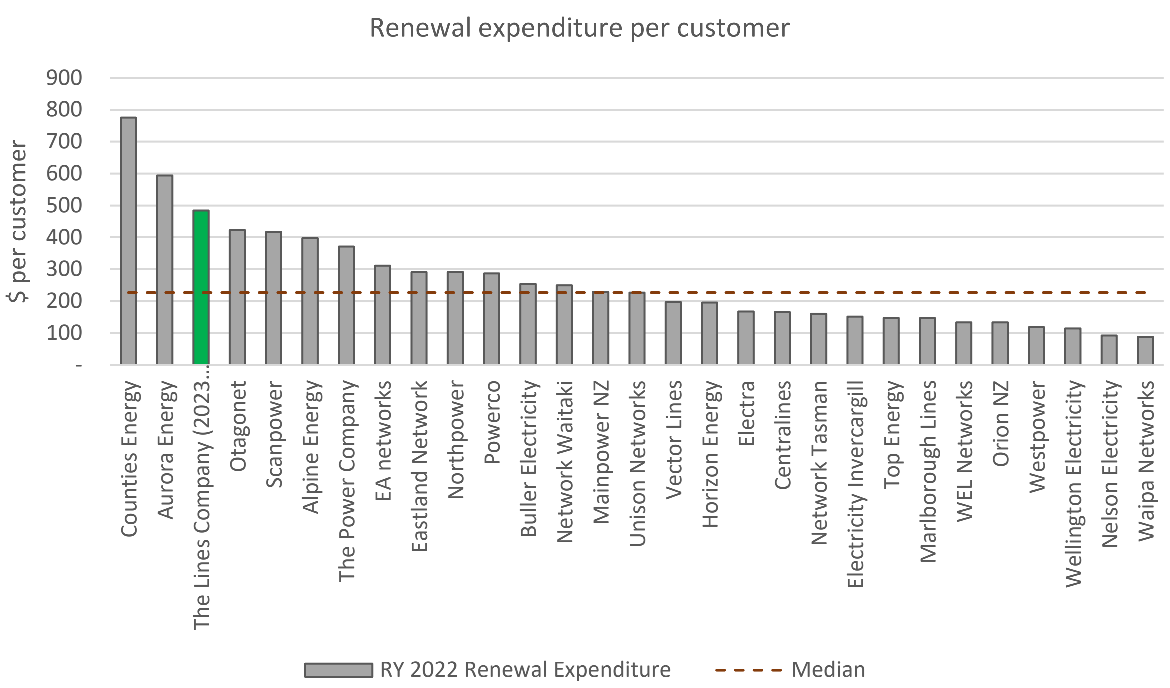
- New connection and alteration processes – including Distributed Energy Resources (DER).
- Major customer network investment processes.

Affordability remains a key driver in our decisions

Our operational area is geographically vast, has a very low population base and includes areas of significant deprivation. We are cognisant that while we need to invest in our network to support New Zealand's transition to a low carbon economy, we also must balance this with ensuring our service is affordable for customers we supply.

Our network is also in a renewal phase, having been originally constructed in the 1930-50's so our AMP planning necessarily includes significant renewal expenditure. We therefore need to ensure we can keep our network safe and reliable while also making sure it is affordable for our small customer base. Figure 1.2 shows our renewal expenditure per customer is amongst the highest in the industry at this time.

Figure 1.2: Renewal expenditure per customer, showing RY2022 data and TLC's 2023 AMP forecast



Supporting decarbonisation and industrialisation is a primary driver for our business

Historically, the economy of our region has been driven by primary industries, mining, and tourism. We are beginning to see changes within these industries. Changes which are seeing a direct increase in the need for electricity supply on our network. The key growth drivers are within industrial processing sector, being greater industrialisation (construction of new processing plants) and decarbonisation (the transition of fossil fuels to electricity in industrial processes).

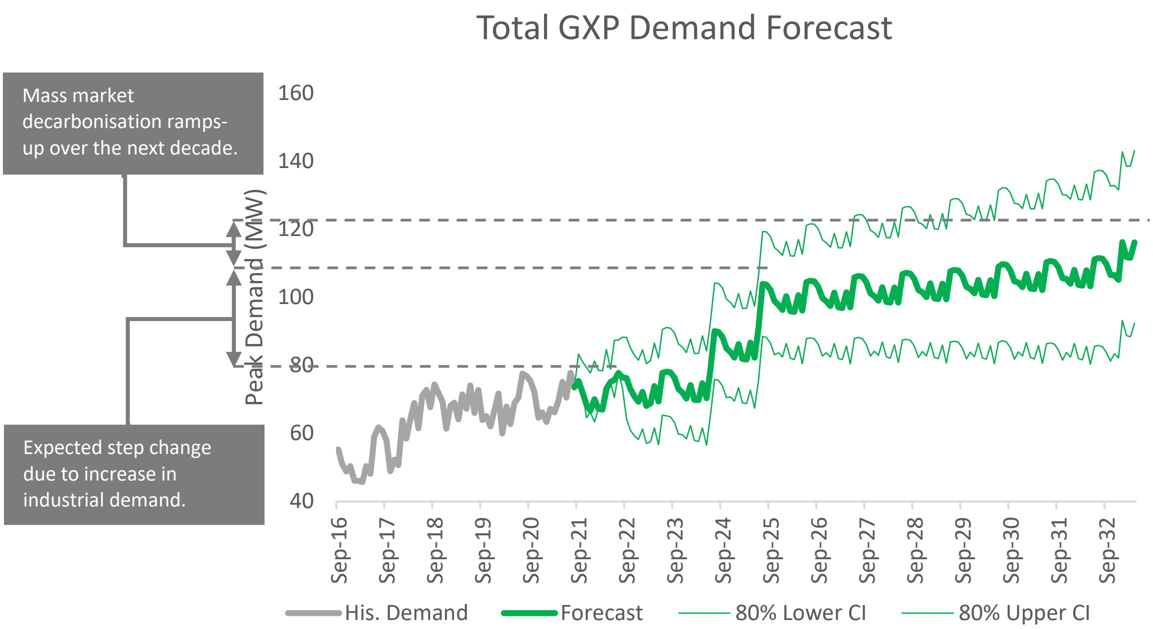
Our most recent growth forecasts indicate our electricity demand is likely to increase at around 4.0% per annum (compound annual growth rate) compared with an historic average of less than 0.5%.

This has two impacts on our planning. The first is to ensure we have sufficient capacity to support these changes. The second is to ensure our security of supply is appropriate and available in time to support the growth we expect.

To achieve this, we are planning to upgrade the grid exit point (GXP) at Hangatiki which supplies around half the customers on our network and revise the security of supply provisions on our key substations and supply lines. Our intent is to increase the free firm capacity (i.e., the available capacity that can be maintained even under a fault condition) from around 4% today to ~20% at the end of the ten-year planning period. We will do this in a targeted way and engaging with our customers and the community to balance their needs and the cost of supply.

Figure 1.3 shows our forecasting analysis, which we have modelled under a range of growth scenarios using confidence intervals (CI's). We expect a short-term step-change of our total system demand over the next five-year period, with continual growth driven by mass market decarbonisation throughout the planning period.

Figure 1.3: Growth modelling scenarios



We are investing in new tools to help optimise our decisions and to make our business more efficient

Although we have set our expenditure and growth forecasts based on our understanding of the needs of our network, our approach when finalising our near-term project planning is to be very targeted in where we apply our capital expenditure (Capex) and renewal expenditure. To do this we are investing in new tools and processes to enable decisions to be more timely and highly targeted. We are also investing to enable our business to become more efficient. Our improvement projects include:

- Systems
  - New asset management systems
  - Advanced Distribution Management systems (AMDS)
  - Customer relationship management systems (CRM)
  - Weather prediction systems
- Processes
  - Implementation of new inspection techniques
  - New connection process
  - Capital works management and delivery process

We recognise the importance of innovation

We recognise our network, business, and customers have a unique set of challenges and opportunities. Innovation through a combination of technology and novel business models can answer a lot of the pressing challenges that we face.

We are investing on both these fronts with our innovation efforts focused on enabling our customers to enjoy an affordable energy future. In 2022, we invested in several community projects, installing solar panels on Marae and whare, and testing peer-to-peer trading platforms to allow excess energy to be shared across the community.

The intention is to continue to expand our innovation initiatives, test the merits of new business models and alternative (non-network) supply models which can reduce cost and/or benefit our customers.

We have established new AMP objectives

We have revised our objectives for this AMP to reflect the broader needs of our customers and stakeholders. They are outlined in Table 1.1.

Table 1.1: Our asset management objectives

Asset Management Objectives High-level goals and targets to guide our asset management practices	
Safety and environment	The design, construction, and operation of our network will minimise safety and environment risks to our customers and staff.
Asset stewardship	We will be prudent custodians of the network, managing its population of diverse assets and keeping it in good health.
Customer and community	Our network will provide an effective and affordable electricity supply to support our customers and enable our community to thrive.
Networks for today and tomorrow	Our network will be developed to ensure it meets our customers' energy needs now, and into the future.
Operational excellence	Our people, processes, and systems, will have the capability to deliver a reliable and cost-effective service.

1.3 Key assumptions in developing this plan

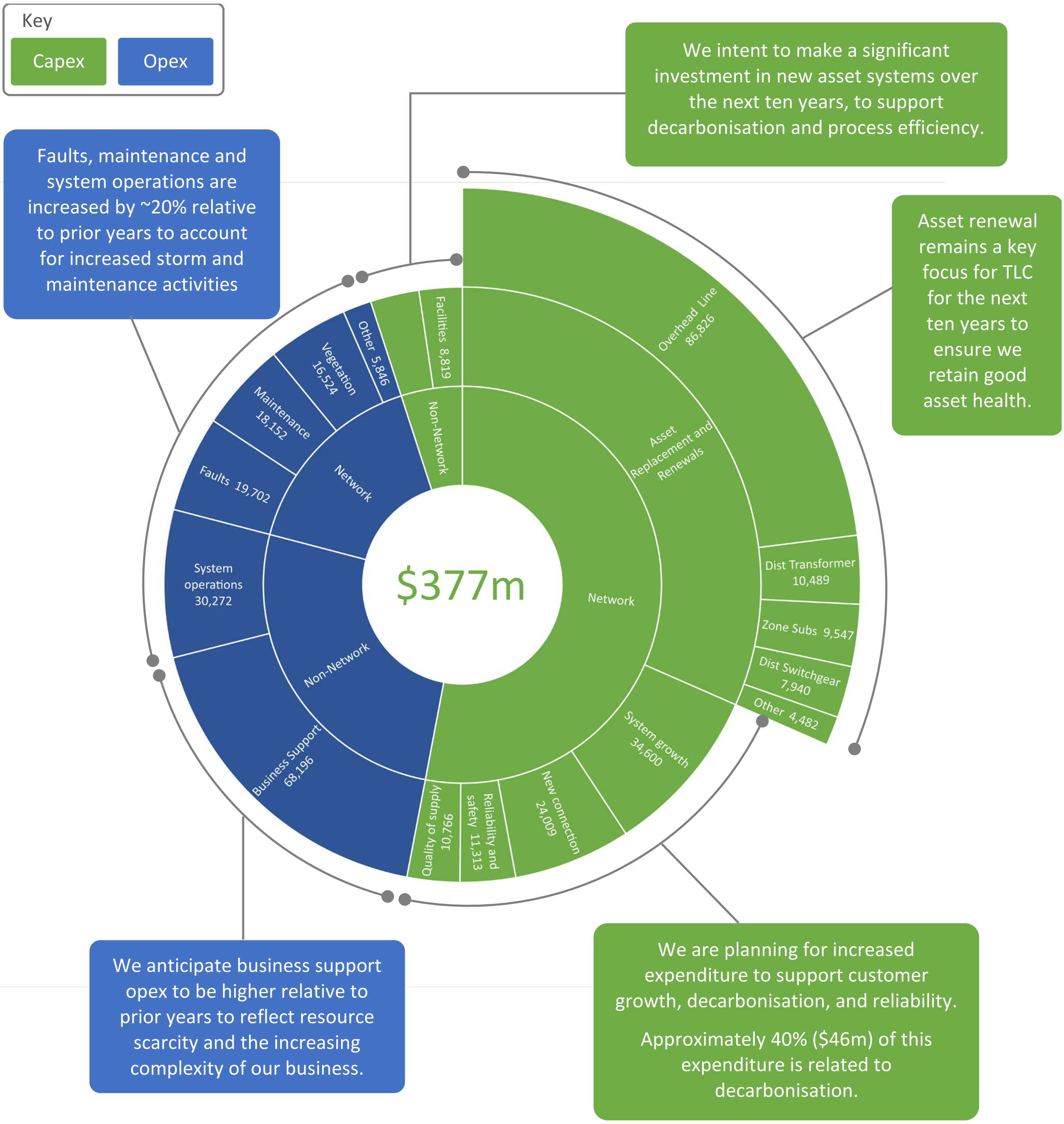
This plan has been developed with the following key assumptions:

- We are able to attract and retain staff and have access to contractors via the wider market to fulfil our capital programme.
- Conditions that affect our business (weather, business costs and operating environment) do not vary materially from where we understand them today.
- Access to capital and inflation remains stable.
- The regulatory environment does not change significantly over the planning period.
- The availability of resource and equipment is not materially changed from current market conditions, i.e., is not materially impacted by pandemic or other natural or un-natural material events.
- The ongoing impact of COVID-19 does not materially affect our revenue or prevent us from delivering planned works through lack of availability of material or resource.

1.4 Summary of our ten-year expenditure forecast

Figure 1.4 depicts a summary of our ten-year expenditure forecast and some of the core drivers that underpin our planning.

Figure 1.4: TLC summary of our ten-year expenditure forecast



02

Our Background

2. Our Background

This chapter provides an overview of The Lines Company including ownership and governance, business context, our customers and stakeholders, our network, asset summary and operating environment.

2.1 Overview of The Lines Company

Company profile

Our core business is the ownership, maintenance and operation of an electricity distribution business predominantly located in the King Country and Ruapehu regions of New Zealand.

TLC was established in 1999 when electricity industry reforms required the separation of retailing and distribution lines businesses. Before then, TLC's lines business assets were vested in King Country Energy Ltd and the Waitomo Energy Company, both of which had themselves been created out of the old Power Boards as part of reforms earlier that decade.

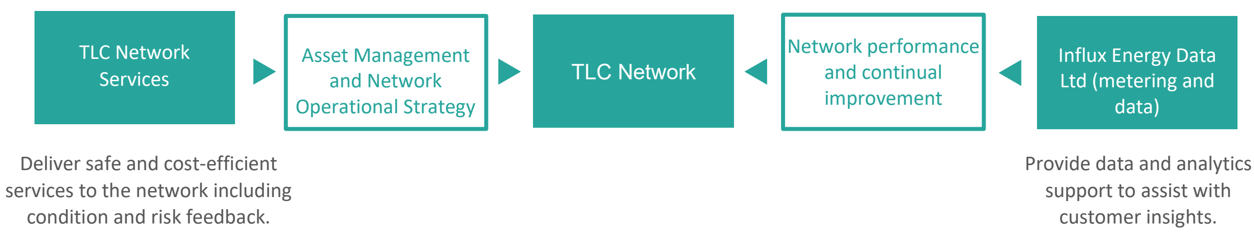
TLC is 100% owned by the Waitomo Energy Services Customer Trust (WESCT), which is governed by six trustees. Three trustees are elected by customers within in the northern area of the network (i.e., who's electricity supply is provided from the Hangatiki and Whakamaru supply points), who then appoint one further trustee. Major customers within the Hangatiki and Whakamaru area also elect two trustees.

TLC's head office is located in Te Kūiti with operational depots in Taumarunui, Ohakune and Tūrangi. The group has two company's; TLC Network Operations and Services, and 100% TLC owned subsidiary Influx Energy Data Limited (Influx).

Business structure

TLC's businesses and their supporting business units integrate to support the management of the distribution network. Further detail on the Network business unit is provided in Section 2.2. The relationship of the three business units to the core network and its asset management is set out below:

Figure 2.5: Integrated TLC business



These business units provide strategic opportunities for the ongoing refinement of TLC's approach to asset management.

Metering and data

Influx is a wholly owned subsidiary of TLC and represents the Group's metering interests. Influx owns both on-network meters (meters on the TLC Network) and off-network meters (which exist on non-TLC networks) where Influx derives income from electricity retailers and industrial sites throughout New Zealand.

In February 2021, Influx grew its metering base further through the acquisition of metering assts from Legacy Metering Group (LMG) and Northpower.

Influx is the fourth largest electricity metering business in the country and services, with around 200,000 meters across 140,000 sites nationally.

Network services

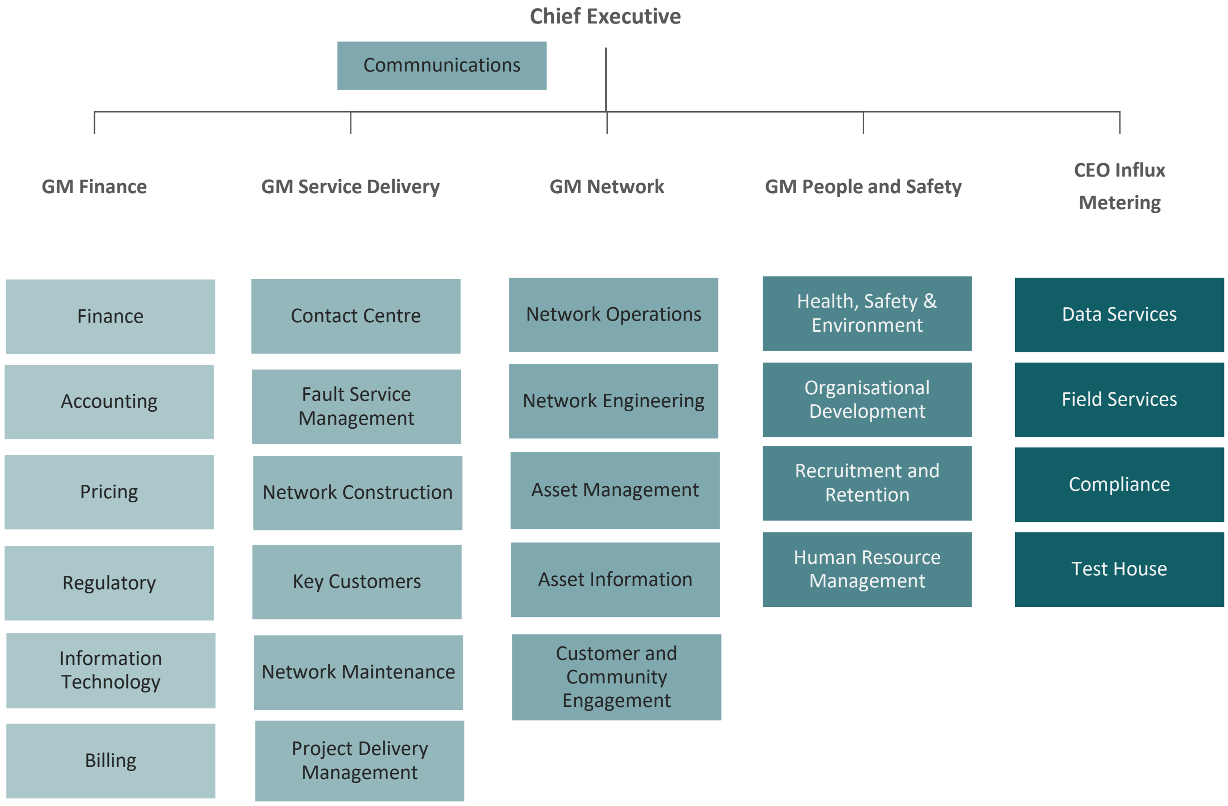
Our Network Services team provide network construction services, as well as maintenance, outage management and technical services to customers. This Network Services team has around 65 staff and is a specialist support unit to the network.

In addition to in-house teams, we also engage external service providers for vegetation management (arborist services) and other specific major construction projects.

Organisation structure

Our business is structured into five divisions which manage the TLC business unit portfolio. The organisational structure, along with the key functions they perform is shown in Figure 2.2.

Figure 2.6: TLC organisation structure and key functions



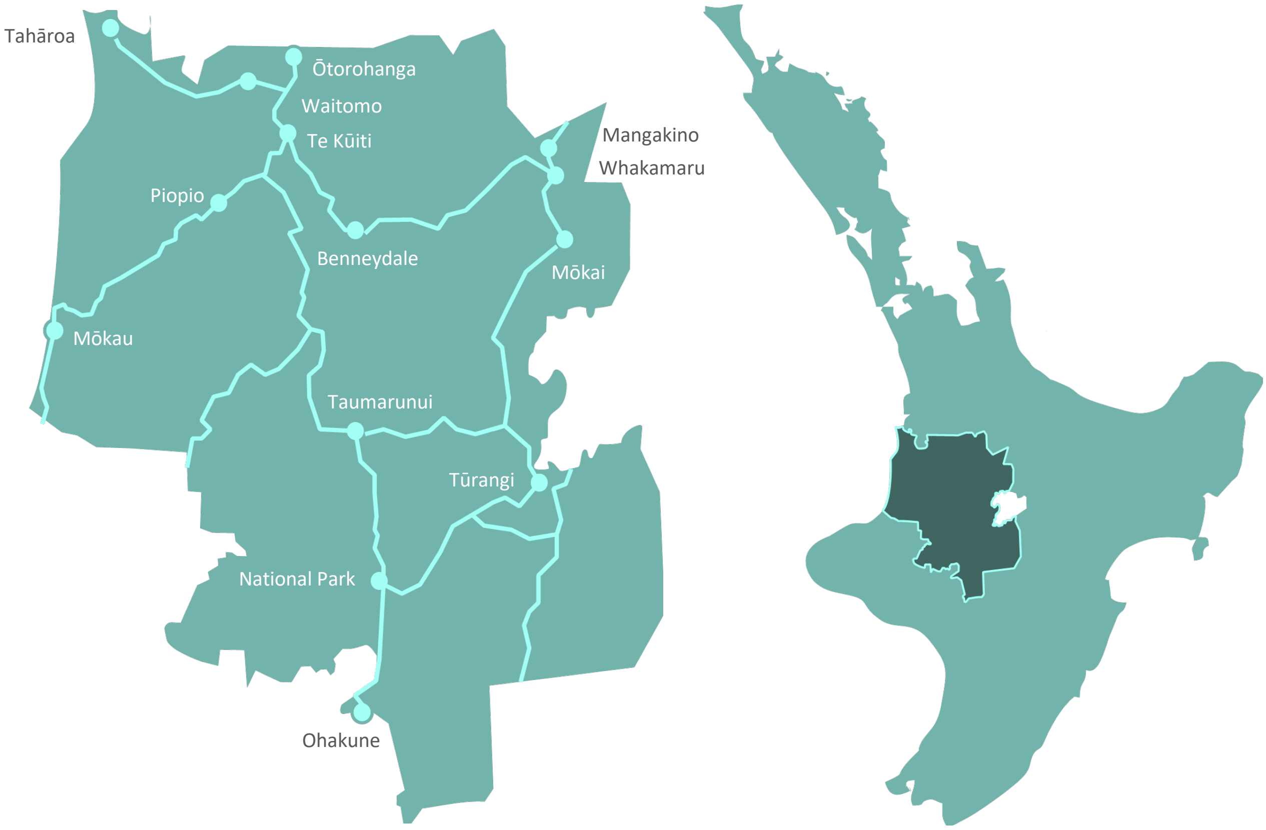
2.2 Our network

Our network provides an electricity distribution service to ~24,000 connection points covering 13,700 km^2. It is one of the largest network areas in New Zealand and is without the support of a major urban centre. Consequently, we have become a specialist in providing electrical distribution services to rural and sparsely populated areas. These areas include the highest points in the North Island of New Zealand, the Tūroa and Whakapapa ski fields on Mount Ruapehu.

The region's core economic industries are dairy farming, industrial processing (limestone and timber), mining (iron sand), and tourism. The network also includes popular ski fields with a consequent winter peak loading, plus an increasing uptake in holiday homes and tourist destinations. This can lead to significant swings in network loads in these regions from a low permanent resident base.

Our network supplies ~368GWh of electricity per year and has a Regulated Asset Base (RAB) value of $251 million (March 2022).

Figure 2.7: Our network region



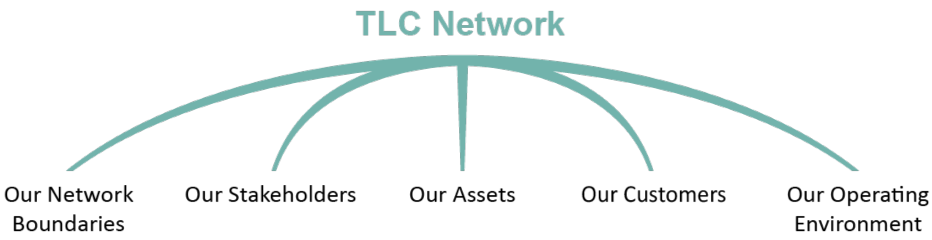
Points of Supply (POS) to the network are not only from Transpower GXPs, but also from major Waikato generation plants connected to our sub-transmission network. Supply to the network is also supported by a number of embedded hydro generators connected to the distribution network at 11kV and 33kV.

2.3 Key network influences

We are conscious that a safe and reliable electricity supply is a key enabler for regional economic growth, and our asset planning seeks to deliver ongoing improvements to energy supply to support our community over the long term.

Our network characteristics are influenced by our customers, our assets, our operating environment, our stakeholders, and our network boundaries.

Figure 2.8: Key influences on the TLC network



Our customers

TLC serves around 24,000 homes and businesses supplied through six points of supply being Hangatiki, Whakamaru, Ōngarue, Tokaanu, National Park and Ohakune.

Our customers are a mix of high value industry, dairy farming, traditional residential customers and a high proportion of tenancy or holiday-based accommodation. Table 2.1 below sets out our customer profile with Installation Control Point (ICP) numbers by category:

Table 2.2 Number of customers (ICPs) by category

Customer Group	Customers	% of ICPs
Accommodation	236	1%
Commercial	1,986	8%
Education	130	1%
Health Services	61	0%
Holiday Home	3,759	16%
Major	81	0%
Residential	14,625	61%
Unmetered	114	0%
Farming	2,957	12%
Other	154	1%
Total	**24,103**	**100%**

Figure 2.9: Location of major customers

Large load customers

There are several diverse, large load customers that generate considerable economic value to the region and have increased reliability and quality requirements. A number of these facilities are on the end of long sections of network, with no alternative supply. As large load customers may not always be able to fund high levels of network security, there is a heightened demand for network reliability as well as good communication for managing interruptions to supply. These large load customers include the following and are also shown in the supply coverage map shown in Figure 2.5.

- Iron sands processing and loading
- Ski fields
- Corrections facilities
- Limestone extraction and processing
- Meat processing
- Timber processing
- Milk processing
- Glasshouse complex food production

Our assets

We own a sub-transmission network operating at 33kV, connecting points of supply to zone substations. TLC's network is one of the most geographically complex and distributed networks in New Zealand. Its key characteristics include:

- One of the smallest customer populations in New Zealand (ranking 20th out of 29 electricity distributors in terms of number of customers).
- A relatively long circuit length (12th out of 29 in terms of the length of network) and no large urban centres, resulting in a low customer per km ratio.
- Sparsely populated, with long lines in rugged terrain, and few alternative supply options.
- Embedded hydro generation that is reliant on rain and water inflows.

- A customer mix (and need) that is widely varied, being a mix of high-value primary sector industry, dairy farming, a relatively low proportion of traditional residential customers, and a high proportion of tenancy or holiday-based accommodation.

To address the geographic and customer characteristics, our network has a unique asset configuration, which includes:

- Few network assets on roadsides and many across rugged mountainous terrain.
- Large numbers of Single Wire Earth Return (SWER) systems (60 plus).
- North-eastern areas supplied directly from major Waikato generation plants bypassing Transpower GXPs.
- A number of embedded hydro generators connected to the distribution network.
- Long lengths of 33kV network providing sub transmission.
- Long lengths of 11kV lines, often in remote rugged country.
- The majority of the distribution network operates at 11kV and is characterised by long rural feeders across terrain that is difficult to access, and as such is prone to a higher level of interruption than typical given its size.

Our stakeholders

In considering the operation of our business we consider the wide and varied interests of many stakeholders to ensure our network continues to provide a safe, reliable, and cost-effective electricity supply to our customers and the wider community.

Two engagement models are used to understand stakeholder requirements.

Representative: This model is used where the quantity of stakeholders is too large to consult with on an individual basis (e.g., customers and wider community). This engagement sees a mix of interaction with representative groups (e.g., community led organisations, Federated Farmers etc.), through to public meetings, surveys, customer service panel and customer engagement.

Direct: Where the stakeholder group is smaller, a direct engagement approach is used to understand specific requirements. This allows a more detailed level of interaction with individual stakeholders and allows us to optimise our approach to gain maximum benefit for all parties.

Our key stakeholders and their principal interests are summarised below:

Table 2.3 Key stakeholder requirements

Key stakeholders	Main Interests	Engagement
Our customers	Service quality and reliability; price; safety; connection agreements, TLC Discount (for WESCT Customers)	Representative, direct for key customers or where otherwise required
Communities, Iwi, landowners	Public safety; environment; land access and respect for traditional lands, economic development	Representative, direct where required
Department of Conservation	Environmental management; land access; supply to essential services; emergency management	Direct
Regional and District Councils	Public safety; environmental management; land access; supply to essential services; emergency management	Direct
Employees and contractors	Safe, productive work environment; remuneration; training and development; asset management documentation	Direct, representative where required
Waitomo Energy Services Customer Trust	Statement of Corporate Intent; company performance; Directors performance; Directors fees; Director and Trustee succession; annual meetings of WESCT Customers; administering Trust Deed	Direct (via Board of Directors)
Board of Directors	Efficient management; financial performance; governance; risk management	Direct
Electricity retailers	Business processes; access to the network; Use of Systems Agreements; customer service	Direct
Regulators	Pricing levels; effective governance; quality standards, reviews and audits leading to continual improvement, workplace safety, (WorkSafe); electrical compliance (WorkSafe, Energy Safety); market operation and access (Electricity Authority); environmental performance	Direct
Distributed generators	Access to the network; connection agreements, price, operations management	Direct
Transpower	Load forecasting; GXP planning, technical performance; technical compliance	Direct

Managing stakeholder conflicts of interest

Where material conflicts of interest emerge between different stakeholders, these are reported and discussed by TLC's senior leadership team to form a resolution, followed by further engagement with the affected parties or their representatives. Cases with high impact (which may be both objective and subjective) are reported to and discussed with TLC's Board of Directors.

Our network boundaries

Our network crosses the boundaries of seven District Councils and three Regional Councils. In some cases, we provide electricity distribution and other services to these Councils as customers. A high degree of coordination and interaction is required between our organisation and Councils to ensure that the services we collectively provide are safe, reliable, and cost-effective.

Table 2.4 List of regional and local councils

Regional Council	District Council
Waikato Regional Council	Ōtorohanga District Council
	Waitomo District Council
	Taupō District Council
	Waipa District Council
	South Waikato District Council
Horizons Regional Council	Ruapehu District Council
Taranaki Regional Council	New Plymouth District Council

TLC's network boundaries are defined as:

- **Supply from Transpower:** Supply from Transpower is at the connection to Transpower GXPs, as defined in Transpower connection agreements.
- **Supply from large Generation plants:** At Whakamaru, Ātiamuri and Mōkai, the demarcation point is that defined in connection agreements.
- **Supply from distributed generators:** The asset boundary for distributed generators is the POS as detailed in TLC's Standard Terms.
- **Supply to the Customer:** Supply to the customer is at the customer's POS as defined in TLC's Standard Terms.

Our operating environment

The environment we operate in is an important factor in delivering our services. The following factors determine our operating environment:

- Topography
- Geology and regional climate
- Land access
- Vegetation
- Access to human resource
- Sustainability
- Government policy
- Technological changes
- Energy consumption trends
- Pandemics
- Cyber terrorism

Topography

The topography of our supply area varies greatly from the iron-sand beaches on the west coast to the highest points in the North Island of New Zealand at the Tūroa and Whakapapa ski fields on Mount Ruapehu. It is an area of steep, rolling hills and valleys dissected by rivers and streams. As a result, lines tend to go from hill to hill and predominately through remote rugged terrain.

Geology and regional climate

The King Country is a broad expanse of uplifted sedimentary rock west of the North Island main divide and central volcanic zone, and is part of a larger, geologically similar tract of land that includes inland Whanganui and Taranaki. Mountain ranges flank the King Country – the greywacke and argillite Hērangi Range in the west and the greywacke and ignimbrite Rangitoto and Hauhungaroa Ranges to the east. The hills are siltstone, sandstone, and mudstone.

TLC's western coastal assets are subject to salt laden air; therefore, assets are chosen that perform well in this environment.

Thermal areas, such as Tokaanu, require components which can be installed in hot ground. In one case, TLC obtained special dispensation to not follow Taupō District Council District Plan for underground reticulations in urban areas, as the ground was too hot for an underground cable. TLC has also been compelled to install wooden poles in some regions due to the corrosive nature of the gases in the geothermal area that reduce the life of concrete poles.

Overall, the diversity of soil types of our network region (iron sand, peat soils, sandstone, pumice, etc.) along with the diversity of regional geological conditions (volcanic zones, coastal areas etc.) adds complexity to the design, construction, and operation of our network.

Land access

We support an extensive distribution system across private land in order to cost-effectively reach remote regions. Land access is fundamental to our continuing operations but is regularly constrained by climatic conditions (e.g., wet soils preventing vehicle access to hilly terrain during winter), and community considerations such as vehicle access across paddocks during animal breeding seasons.

As a network operator, TLC has existing rights under the Electricity Act 1992 for assets built prior to 1992. These rights give us permission to access and maintain the equipment constructed prior to 1992. Notwithstanding these rights, practical access is often restricted by the constraints mentioned above, and as such we rely on relatively high use of helicopters to support construction and maintenance.

Vegetation

Our network crosses through dense vegetative and forested areas. As such TLC has a high exposure to faults resulting from tree fall, particularly during storm events. The business invests significantly in vegetation management (tree-trimming (or removal) to maintain reliable supply to its rural customers and on Department of Conservation (DoC) estates. Technological changes are changing the way vegetation is monitored and managed. TLC completed its first LiDAR survey of the vegetation around its lines in 2021 to gain a deeper understanding of the vegetation quantum on the network and the risk it presents to our electricity supply.

Access to human resource

The labour market supporting the electrical distribution industry continues to be 'tight' with challenges finding sufficient skilled workers to carry out all planned works. This is expected to become even more challenging as other companies around New Zealand embark on significant investment programmes over the next 10 years to support decarbonisation. We are investing in staff training and development including the continued recruitment of line mechanic trainees each year to assist in mitigating the risk this skills shortage presents.

Sustainability

TLC is committed to the sustainability of our environment, region, network, and assets. Sustainability covers a wide range of areas from planning, to using environmentally friendly materials and maximising the lifecycle of our assets, through to planning for a reduced carbon future. Our sustainability efforts are influenced by both internal and external factors including supporting customers to commission renewable generation, and in setting our planning targets to align to wider government climate policy.

Government policy

Government policy sets out the broad objectives for the electricity industry, and for other industries that influence the development of our network. A key government policy area impacting us, and other electricity distributors, is the climate change targets. The relevance to our region is in the transition of industrial heating from fossil fuels to electricity, and in electrification of transport. Both are expected to significantly impact our network management strategy.

Technological changes

Developments in technology are changing the way we work and plan. From an operational perspective, TLC is now using technologies like tablets to streamline its business processes, including integrating field service operations with our back-office systems.

Technologies like LiDAR and aerial photography are improving the way we survey and assess the condition of our assets and the environment they operate within.

Technology change remains a key driver for renewable energy. Solar energy and battery storage, at both domestic level and at grid scale, continues to become more economically viable. The uptake of these technologies on our network is beginning to build momentum from its relatively low base. These technologies introduce some new challenges for us, including how we will manage the network in an environment where there is significant bi-directional power flow, and how we best support the growth of distributed generation while maintaining an affordable supply for our customers using traditional electricity lines.

Energy consumption trends

Worldwide there is a trend toward more efficient use of electricity. In New Zealand this is being driven by:

- Government policy seeking greater health and wellbeing outcomes for consumers.
- Improvements in building standards seeing better insulation of newly constructed buildings.
- Widespread uptake of heat pumps as an efficient means of home heating.
- The widespread adoption of LED lighting replacing traditional incandescent lamps.
- The replacement of old appliances with modern energy efficient designs.
- These changes have the effect of reducing consumption (kWh), however capacity requirements are increasing as more electrical equipment is used during peak times. In addition, there is a gradual but steady transition of New Zealand's transport energy from fossil fuels to electricity, which similarly increases energy consumption and demand on distribution networks.

Essential services

TLC's electricity distribution business is a lifeline utility as defined in the Civil Defence Emergency Management Act 2002 and our network supplies electricity to a number of other lifeline utilities and essential services as detailed below:

- District and Regional Councils – water, wastewater and roading infrastructure, emergency management
- New Zealand Transport Agency – roading infrastructure
- District Health Boards – hospital services at Te Kūiti and Taumarunui
- Emergency Services – Police, Fire and Ambulance
- Telecommunications companies – landline, mobile and internet
- KiwiRail – rail infrastructure

Specific network needs and operational interactions are determined on a case-by-case basis with these entities.

Pandemics

Our business operations continue to be affected by the COVID-19 pandemic. Our Incident Management Plan (IMP) provided a strong framework for our management of the impact of lockdowns. In response, TLC and its suppliers have significantly changed the way we operate and adapt. Our office workforce is now fully mobile and able to operate from home. Our suppliers and field staff have new protocols for how our equipment is supplied, maintained, and installed do support pandemic management, and these new health and safety protocols are now embedded.

2.4 Asset summary

To summarise our assets, we have grouped our distribution system (including non-TLC supply points) into eleven portfolios described in Table 2.4. The key information for each portfolio is set out in the following sections.

Table 2.5: TLC asset portfolio

Portfolio	Asset Class	Quantity
Points of Supply	Transpower Grid Exit Points Direct generator connections	5 3
Embedded Generators >1MW	Third-party owned generation plants	6
Zone Substations and power transformers	Zone substations Power transformers	28 39
Sub-Transmission Switchgear	Air-break switches and sectionalisers Circuit breakers Fuses and fuse links Load break switches Reclosers Solid links Transformer fuses	145 57 9 4 16 46 2
Support structures	Poles Crossarms	34,293 53,687
Overhead conductors	Sub-transmission Distribution Low Voltage	451 3,066 468
Cables	Sub-transmission Distribution Low voltage underground cables	11 132 182
Distribution transformers	Ground mounted transformers Pole mounted transformers	535 4,720
Distribution switches	Air-break switches Circuit breakers Fused switches and fused links Load break switches Reclosers RTE switches Sectionalisers Solid Links Transformer Fuses / Tap Off Fuses	639 208 1,072 215 137 71 62 569 5,638
Secondary systems	Supervisory Control and Data Acquisition (SCADA) and communication Protection relays Load Control Systems	994 281 8
LV Pillar Boxes	Pillar Boxes	4,163

Points of supply

Our network is supplied from eight locations which include five from Transpower's GXPs, two directly from hydro generators and one geothermal plant. Figure 2.6 shows a high-level depiction of the points of supply.

Figure 2.10: Location of Major Points of Supply

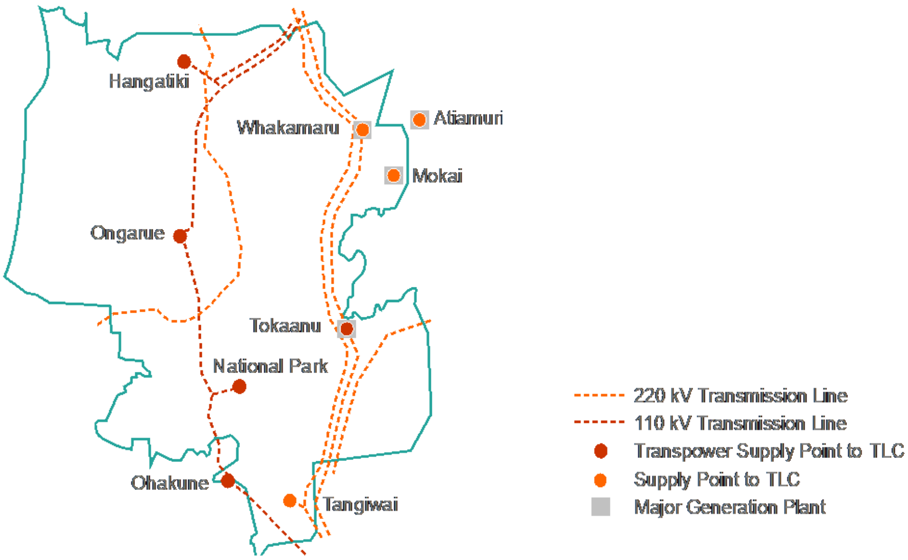


Table 2.5 outlines the characteristics of each POS to the network, and the key loads supplied from each.

Table 2.6: Characteristics of supply points

Supply Points	Description	Key Load Types Served
Hangatiki GXP	Supplied by three transformers with load below the capacity of two transformers	Industrial loads (iron sand extraction, timber, limestone and meat processing) Distributed generation (10.1MW) Rural loads (dry stock and dairy) Te Kūiti and Ōtorohanga towns
Ōngarue GXP	Single transformer supply with backup via a 33kV line from Tokaanu	Rural loads Taumarunui town Distributed generation (7.5MW)
Tokaanu GXP	Dual transformer supply with load below the capacity of one transformer	Holiday accommodation Corrections Department Tūrangi town
National Park GXP	Single transformer supply with backup via a 33kV line from Tokaanu	Whakapapa ski field Holiday accommodation National Park township
Ohakune GXP	Single transformer supply with limited backup from Tangiwai GXP	Tūroa ski field Holiday accommodation Ohakune town
Whakamaru	Single transformer supply directly from the large hydro generators on the Waikato River with limited backup from Ātiamuri)	Dairy farming Holiday accommodation

Supply Points	Description	Key Load Types Served
Ātiamuri	Single transformer supply directly from the large hydro generators on the Waikato River. Backup for Whakamaru.	Dairy farming Holiday accommodation
Mōkai Energy Park	Single supply from Tūaropaki Mōkai Geothermal Power Station with limited backup	Milk processing facilities Horticulture (glasshouses)

2.4.1 Key assets installed at bulk electricity supply points owned by others

Three of our substations are installed at bulk electricity supply points (Grid Exit Points or GXP's) where the land is owned by others. TLC's zone substations at Hangatiki and National Park are located on land owned by Transpower. Our Ātiamuri zone substation is located on land owned by Mercury Energy. We have 13 other zone substations located on land leased from other landowners, including local councils and electricity generators.

2.4.2 Embedded generators

We have six embedded hydro generating stations of greater than 1MW connected to the network. When available, generation output is used to support the operation of the network. However, as all of the generation has minimal storage, the generation output is not essential to maintain supply to customers.

Table 2.7: Distributed generation summary

	Ōngarue GXP[1]		**Hangatiki GXP[2]**	
Owner/Operator	Station/Machine	Rating (MW)	Station/Machine	Rating (MW)
King Country Energy	Kuratau 1 Kuratau 2 Piriaka 1 Piriaka 2 Piriaka 3	3.0 3.0 1.0 0.3 0.3	Wairere 4 Wairere 5 Mokauiti 1 Mokauiti 2	3.0 1.2 1.0 0.6
Southern Generation Limited Partnership			Mangapēhi 1 Mangapēhi 2 Speedys Road 3	1.5 1.5 2.2

Notes:

1. *Ōngarue generation can be switched to support National Park or Tokaanu GXPs as required*
2. *With the exception of Speedys Road, Hangatiki generation can be switched to support Whakamaru POS on a limited basis*

03

Our Objectives

3. Our objectives

This chapter outlines our objectives as a community owned organisation and the key objectives of our AMP. It summarises the key initiatives that underpin our ten-year planning period, as we see them at the current time.

3.1 Our strategic themes

Our purpose as an organisation is to support and facilitate business and community growth, to protect our environment, innovate what we do, and make energy accessible for all — we're helping people thrive, now and into the future.

The long-term aspirations of the business are to:

- Operate a safe and reliable future-proof network which serves generations to come;
- Generate diversified revenue from within the energy sector, both within and outside of the region;
- Facilitate decarbonisation of the region through long-term enablers;
- Continue to be a significant employer and community benefactor for those living in the region;
- Strive to generate benefits to our shareholders.

We will deliver on our purpose by focusing on four pou. In Māori a pou, or post, is made from a tree and re- erected in another place to make a statement — in this context, the pou represent our strategic pillars or focus for community, sustainability, growth, and efficiency. These pou shape our asset management objectives.

Figure 3.11: Our four pou (our strategic themes)

3.2 How our strategic themes guide our asset management plan

Our strategy sets the overall direction and high-level drivers that shape our AMP planning. The AMP delivers to the strategic themes by defining short-and long-term objectives, as well as targets and measurements that give visibility to our progress. Along with supporting the delivery of our strategy, the AMP must also consider the core functions of managing assets and operating a safe and compliant electricity network, which is defined by our Asset Management Policy.**Error! Reference source not found.** Figure 3.2 shows how our AMP is guided by our strategic themes, and how this is supplemented with additional guidance from our Asset Management Policy.

Figure 3.12: The relationship between strategy, AMP objectives and performance

Strategic Themes	Sets out the high-level business goals that the AMP must support.
Asset Management Policy	Sets out the guiding principles to ensure our network and assets are managed safely and effectively.
AMP Objectives	Outlines key objectives the AMP must achieve to successfully manage our assets and support the strategy.
Key Targets	Defines key measurements to give visibility to the effectiveness of the AMP.
Our Performance	Reviews our performance so far, and how we are tracking towards our targets.

In this section we discuss each of the core areas that form the basis of our AMP in detail.

3.3 Asset management policy

Our Asset Management Policy sets out high level asset management principles that link our company strategic framework to our asset management objectives. Our Asset Management Policy is:

Leadership and enablement

1. Safety is our highest priority, with a proactive approach to the safety of all personnel who work on our network; our communities who live, work, and play near our network; and our customers who use electricity from our network.
2. Asset management is how we realise sustainable value for our shareholder, community, and customers through balancing the opportunities, risks, and costs against the desired performance of our physical assets.
3. Asset management will be delivered by an informed leadership who communicate and engage with external and internal stakeholders to ensure an efficient approach which is cognisant of both current and future requirements of those stakeholders and the company.
4. We will support the sustainability of our community and company, by considering both cultural and environmental needs.
5. We will deliver value to our customers and community by providing choices for how they engage with the energy sector and receive their energy supply.

Asset planning

6. We will provide services that meet our customers' needs, including minimising planned network outages, reducing unplanned outages, and delivering electricity to customers at an efficient price through planning and scheduling the work in advance.
7. We will prioritise investment into our network to focus on areas that provide the best overall value to our customers and community.
8. We focus on maintaining network reliability at the least possible life cycle cost, addressing an aging asset base and low population densities.
9. Asset planning will consider options other than capital replacement to address issues associated with compliance, condition, and performance.
10. We will seek out and implement new and emerging technology where a demonstrable benefit in cost, risk or performance is determined.
11. We will take all reasonably practicable steps to comply with our regulatory requirements, as set out by the Commerce Commission, for all measures of our quality and asset management performance by appropriately and cost-effectively managing our asset and network risk.

Business processes

12. TLC is committed to ensuring rigorous risk management processes are in place including the development of Tier 2 and 3 risk registers.
13. We will implement risk management effectively, integrating it into TLC business operations, projects, and decision-making processes. It is part of our mind set and integral to the way we do things.

Continual improvement

14. Network services will be continually monitored, and this information used to determine future asset renewal work.

15. We will continually enhance our community reputation through ongoing improvements in services and improvements in cost expertly balanced alongside risk management of the network.
16. We will collaborate with our industry peers and partners drawing on their experience and expertise to improve the performance of our network.

3.4 Asset management objectives

Our asset management objectives set the direction and provide alignment for managing our electricity network assets. The objectives describe how we plan to apply funds to our business to improve our asset performance, and how we intend to improve some of our key business practices. They have been developed to achieve the following aims:

- Support the delivery of best value to our customers;
- Achieve our core function as a lifeline utility by safely and reliably delivering electricity to our customers;
- Drive our continuous improvement programme to ensure we continue to be an efficient, forward-thinking network business;
- Ensure our asset management practices support the delivery of our strategy.

We have defined five asset management objectives driving our asset management decisions. They reflect our lifecycle asset management approach, which considers all aspects of asset decision-making and activities from inception to decommissioning. This allows us to balance the longer-term term needs of the network alongside the immediate demands of our customer and regulatory drivers. It also ensures we develop institutional capabilities that we will need as technologies are made available to us, and the needs of our customers change.

Our five asset management objectives are illustrated in Table 3.1: Our asset management objectives

Table 3.8: Our asset management objectives

Asset Management Objectives High-level goals and targets to guide our asset management practices	
Safety and environment	The design, construction, and operation of our network will minimise safety and environmental risks to our customers, general public and staff.
Asset stewardship	We will be prudent custodians of the network, managing its population of diverse assets and keeping it operating reliably and in good health.
Customer and community	Our network will provide an effective and affordable electricity supply to support our customers and enable our community to thrive.
Networks for today and tomorrow	Our network will be developed to ensure it meets our customers' energy needs now, and into the future.
Operational excellence	Our people, processes, and systems, will have the capability to deliver a reliable and cost-effective service.

Details of each objective and the initiatives that support them are outlined below.

Safety and environment initiatives

In this AMP we are addressing several new safety and environmental issues along with completing some existing projects. In general, these are long-run projects spanning several years or are ongoing. We have set out the following initiatives to continue to reduce safety and environmental risks on our network.

- Ground mount transformer tin-shed replacement programme

  During the 2023 calendar year, TLC will complete the replacement of the remaining 10 tin-shed transformers, fulfilling a project began in 2018 which consisted of 67 transformer replacements. The approach to protect distribution transformers from the environment using wooden or tin-sheds was a common industry practice at the time of their construction but is no longer aligned with the safety practices we expect for our staff. The remaining transformer replacements require considered consultation with landowners and Iwi, and we expect the project to complete in the 2024 calendar year.

- Low lines across roads and state highways

  Following our LiDAR survey in 2021, we identified a number of road crossings on high-traffic roads and state highways that we are now seeking to replace with underground cable to reduce the potential for damage. We have identified 18 road crossings on state highways and 36 road crossings on high volume roads that we are seeking to upgrade over the next seven years, at an estimated cost of $2.8m. The project will bring these lines, which were built under the accepted practices of the day when originally constructed, into line with modern standards.

- Fire risk

  The key fire risks on our network are vegetation contacting live lines, and line clash. For vegetation encroachment we have planned for 4-yearly ongoing LiDAR surveys to continue to monitor trees growing within the contact zone (i.e., within 200mm of the lines). For line clash we have allocated annual expenditure throughout the planning period to identify and remediate line clash.

- Management of private lines

  Our records indicate there are approximately 7,000 poles on the network that are privately owned. We are commencing a process to confirm the ownership of these lines and we have allocated $4.7m across the ten-year planning period to ensure they are maintained to a safe and reliable operating condition.

Asset stewardship initiatives

Managing our existing assets to ensure they remain reliable, well maintained, and have flexibility to respond to network events, is a core business priority. We have set out the following initiatives to progress our asset stewardship.

- Pole top inspection

  We intend to increase the frequency of our condition observations on our pole top assets. Our intention is to begin a programme of regular pole top inspections using helicopter photography, on a five-yearly cycle. This is likely to increase the overall cost of inspections, but we expect it to result in reduced outages and better targeting of our renewal expenditure.

- Network automation

  We are continuing to invest in sectionalising and automating switches on the network, which enables faults to be isolated to the affected areas. We see this as an important reliability management tool given the network characteristics (i.e., a large geographic area with limited back-feed options). Our recent investments in this area are providing demonstrable benefits to our outage management processes.

- Maintaining a sustainable line renewal programme

  Overhead lines make up around 50% of TLC's assets (by value) and as such line renewal continues to be an important reliability management tool. We are steadily improving our line renewal planning using asset condition information and asset criticality to drive our decisions. This approach allowed us to reduce our renewal expenditure on the projects undertaken in the last financial year by ~$1.5m in the last with no discernible impact on network quality. It means we can direct any surplus expenditure towards additional renewals to extend the impact of our renewal programme on our reliability performance.

  We have undertaken analysis to determine if our renewal expenditure settings will provide the ongoing reliability improvements we are seeking to achieve. Defective equipment outages are the best indicator of the effectiveness of our renewal programme. In 2017 we increased our renewal expenditure and are now beginning to see a lower defective equipment fault count as a direct result from this and other initiatives we have put in place.

  Our analysis indicates we need to renew 2% of our overhead assets per year (around 700 poles every 12 months) to maintain a steady (no improvement) trend line. However, our planed renewal expenditure will allow us to approximately double this rate by renewing a greater volume of pole top assets and being more selective on what and when the pole structures are replaced.

  Figure 3.3 and Figure 3.4 show the historic tends and our forecasts for defective equipment outages.

Figure 3.13: Outages caused by defective equipment

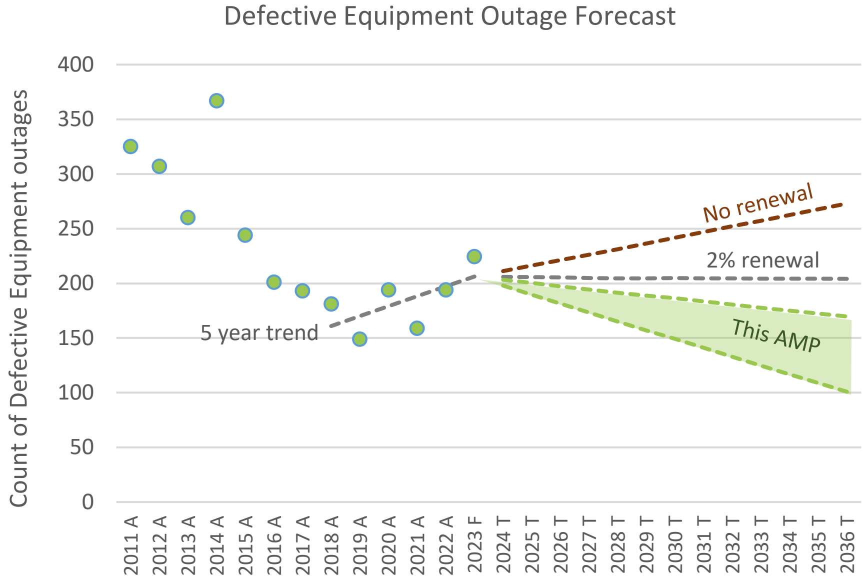
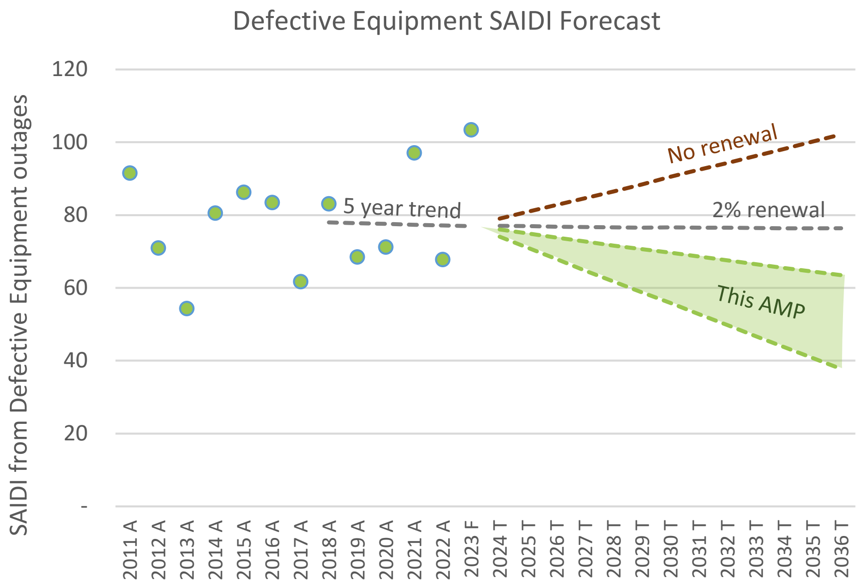


Figure 3.14: SAIDI caused by defective equipment

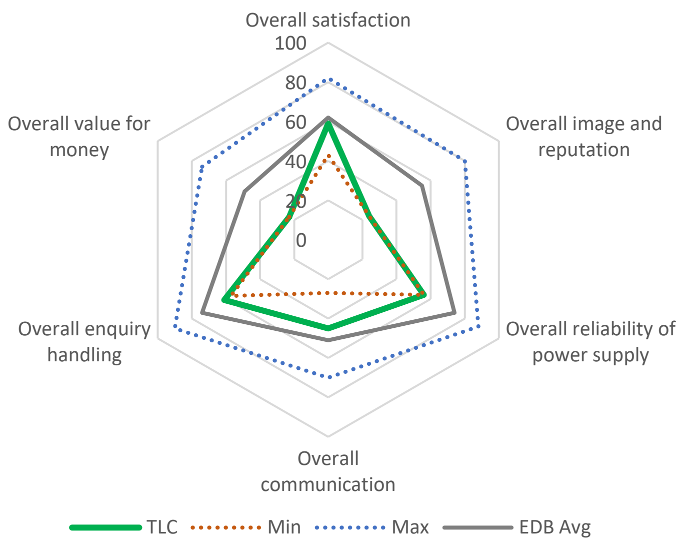


Customer and community initiatives

The experience our customers receive through their interaction and communication with TLC has and will continue to be important as electricity becomes a more critical fuel source for our customers and the economy.

Measuring customer experience is done through a series of customer surveys. Alongside our own Key Research customer surveys, we participate in a part-of-industry based survey alongside around nine other EBDs. Since 2019, TLC has implemented a number of important service changes that have been reflected in improved customer perception, including an improvement in overall value for money since moving to Retailer Billing. The most recent survey shows that TLC is below the industry average, but above the minimum in some areas. Figure 3.5 shows the result for TLC compared to a sub-section of peers.

Figure 3.15: 2021 part-of-industry customer satisfaction survey results



We have set out the following initiatives to improve our services to our customers and community.

- Customer Engagement

  We will continue to strengthen our decarbonisation, energy education, outage management and public safety engagement. This will be implemented through our dedicated Customer and Community Engagement (CCE) team.

  Th CCE team is also working to improve the way we engage with the community when we embark on asset renewal or growth projects. This includes working more closely with key community groups including iwi and councils to ensure we collaborate with the community early in the project lifecycle.

  We are continuing to increase visibility to customers on our business through traditional and social media platforms. This includes providing ongoing communication about what we are doing on the network and in the community, and how our work impacts our customers.

- Supporting systems

  We have commenced a digital utility programme which will integrate and enhance our core systems. As part of this programme, we are investing in systems and capabilities to strengthen our asset management practices and enhance customer experience. This includes systems that support Customer Relationship Management (CRM) and outage management.

Networks for today and tomorrow – initiatives

The energy sector is rapidly transforming. While we continue to provide a safe, secure supply of electricity to the region we also need to manage the impact of new technologies. Evolving customer needs are generating a change in the way our network and related services are used, and we are preparing for this change.

In the future, our customers will have greater choice and autonomy than ever before brought about through technology innovation. We are already seeing a significant use of electric vehicles on our network, and residential consumers are becoming electricity generators through the installation of solar panels on their homes.

Our industrial consumers are working toward electrifying their plant, transport companies are looking to shift towards hybrid technologies. As a result, we are preparing for a significant increase in electricity demand on network.

We have set out the following initiatives to prepare our network for a future that requires greater reliance on electricity supply.

- Security of supply programme

  In 2018 we commenced a security of supply upgrade programme which we are continuing to progress. In 2022 we reviewed and amended the programme which has resulted in some expenditure being deferred to outside the planning period (shaded in grey).

Table 3.9: Security of supply porgramme

Location	Security of Supply Issue	Solution	Cost (000s)	Targeted completion (Financial Year)
Hangatiki GXP	Peaking above firm capacity	New 30MVA Tx		Complete
Te Waireka	Peaking above firm capacity	2 x 15MVA Tx		Complete
Wairere Falls	33kV Bus at end of life	Bus replacement		Complete
Borough	Peaking above firm capacity	2 x 10MVA Tx		Complete
Arohena	Single spur line supply	11kV backup feeder		Complete
Ohakune	Supply constrained by a low capacity 11kV cable.	11kV Cable upgrade		Complete
Kuratau	Single transformer (following failure of the second unit in 2017)	Additional transformer and protection	$295	Complete
Waitete	Peaking at firm capacity	New substation	$4700	Complete
Tūrangi	Single 33kV supply with limited backfeed options	Cable across bridge to backfeed	$400	Complete
		Additional 33kV supply	$2300	2025 Delayed – awaiting land consent
Ātiamuri POS	Peaking above capacity	New transformer	$2600	2025 – we are considering options to defer this upgrade based on its very low load duration
Ohakune	Single GXP transformer, with minimal backfeed options.	Alternative Supply	$2800	Deferred (outside planning period) – we are investigating alternative back-feed options
Maraetai	The Maraetai substation runs at N security with a significant dairy load	New Switchgear	$700	Complete
		New Zone Substation at Sandel Road	$2400	Deferred (outside planning period) – will be managed by deployment of a Mobile Substation or site upgrade if required
Wairere	Single 33kV supply with limited backfeed options	New relays on feeders	$100k	2025
	Zone substation upgrade	Upgrade structure and transformers	$800	2029
Tahāroa	Zone substation upgrade	New 33kV and 11kV switchgear and protection	$4500	2024
		Additional transformer capacity to support growth	$1700	2024
Hangatiki	Hangatiki GXP Upgrade	Upgrade GXP Transformers	$12000	2027
Kuratau	Single line supplying ~1200 customers	Split the feeder to reduce risk to 600 customers	$925	2024
Mobile Substation	TLC has 22 substations with N transformer security	5MVA mobile substation that can be deployed on various sites	$2000	2024

- Digital utility project

Following a 2022 review of our core asset systems and capabilities, we are developing a roadmap to enhance our core systems and digitise many of our processes. This will enable greater integration of our information systems to allow us to more deeply analyse our network, and to become more efficient and responsive. Based on that review we have allocated $5m over a five-year period to upgrade our key systems.

- Substation upgrades

  Our analysis indicates that, in general, our lines have latent capacity and won't feel any medium-term impacts from decarbonisation. However, some of our substations are likely to reach capacity limits in the later part of the ten-year planning period. We have allocated an average of $3.1m per annum during the planning period (excluding the Hangatiki GXP upgrade) to increase the reliability and capacity of our 29 substations.

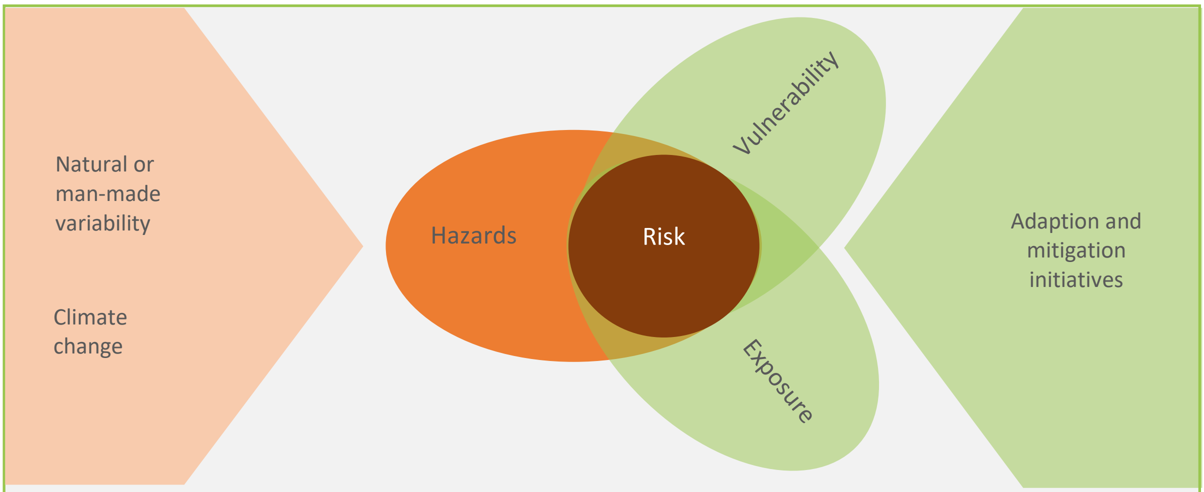
- Building resilience in our network

  Our network is exposed to a wide range of natural hazards due to proximity to active volcanoes and exposure to inundation risk from coastal storm surge and significant weather events (e.g., Cyclones Hale and Gabrielle). Along with weather-related risk, climate change and sea level rise are increasingly impacting our network. We are seeing more regular and more severe storm events and increased vegetation as farmland is converted to carbon sequestration forests.

  The risks imposed by significant weather events and climate change, along with other natural hazards, depends on the type of hazard, our exposure to it and the vulnerability of our assets to each hazard.

  The risks themselves can be interconnected and often arise from compounding hazard sources (e.g., flooding from sea-level rise, plus groundwater, plus more intense rainfall) and an create cascading impacts affecting assets in complex ways. Our AMP includes several strategies to understand, adapt our network and mitigate the key risks we expect. Figure 3.6 shows how we are thinking about resilience, and the key adaption and mitigation strategies we are incorporating into our long-term planning.

Figure 3.16: Drivers of natural hazards and key strategies to manage their risk



Hazard

- Rise in average temperature
- Heat waves
- Wildfire
- Wet days and heavy rainfall
- Snow
- Storms
- Relative humidity
- Seal level rise
- Earthquake
- Wind speeds
- Eruption
- Tsunami
- Land use increasing vegetation

Adaption and mitigation strategies in our AMP

- Risk monitoring tool (NiWA)
- Changing asset design and construction standards
- Increasing security of supply
- Relocating assets
- Redeveloping key assets to increase resilience

We have incorporated a number of adaption and mitigation strategies into our planning shown in Table 3.3.

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Table 3.10: Strategies we have incorporatied into our planning in this AMP

Mitigation	Update
Risk Monitoring	TLC is part of a consortia of EDB's that have access to NiWA high resolution weather and climate change data which is geo located to each EDB's assets. We have engaged NiWA to deliver further development of a risk forecasting tool for our network. The tool will provide a range of forward risk forecasts including: • **Storm and weather impacts:** The tool will incorporate locational weather forecasts that will predict outages and SAIDI impacts on individual feeders, based on known asset health and historic outage trends. • **Criticality**: The tool will also provide a view of criticality of our network model using regular smart meter consumption data. • **Climate change:** The tool will provide an ability to provide long term indications of changes to temperature, rainfall and wind and will allow us to stress test our network using a range of climate change scenarios. • **Vegetation:** Using data science, satellite imagery and AI, and combining historical outage events with the antecedent weather conditions (geo-located weather root cause) we are working to identify critical pruning workflows and the ability to forecast wind driven vegetation outage events.
Changing asset design and construction standards	We have been reviewing our processes and standards, to ensure we adapt our asset design and construction processes to increase resilience over time.
Increasing security of supply	We have a number of security of supply initiatives underway primarily focused on substation development. We are continuing this work to evaluate how we strengthen security of supply in our feeder assets, to provide more backfeed options.
Relocating assets	We are actively working to relocate our overhead line assets to avoid emerging risks when it makes sense to do so. We are also considering risks relating to substation assets positioned near natural hazards such as rivers.
Redeveloping our key assets to increase resilience	For some time, we have been reviewing the resilience of our substations relating to earthquakes. This work will continue and incorporate a wider set of risks for review.

Operational excellence Initiatives

Developing the capabilities of our people and our work practice is of paramount importance to ensure we can work effectively and adapt to new challenges. We have set out the following initiatives to improve our operational capabilities and effectiveness.

- Business process review

  Our business processes are at the core of its customer experience and business efficiency. This AMP will invest in targeted business process reviews and improvements as key enablers of the digital utility programme. This will result in an operational cost increase over a three-year period but will enable lower operating costs and better customer service in the longer term.

- Mobile substation

  We have now scoped and costed a mobile substation that can be deployed across the network to support our asset renewal activities. The mobile substation will allow field crews to completely de-energise sites when undertaking zone substation works, while retaining supply to our customers. This would allow crews to conduct work without the need for generators and minimise the risk of working around live equipment – resulting in safer and more cost-effective project execution. We expect to be able to take delivery of a mobile substation within the 2024 regulatory year.

- Vegetation

  Since 2019 we have maintained a high annual vegetation expenditure of ~$1.4m resulting in an improvement of in-zone vegetation outages. We plan on retaining this expenditure level to ensure our in-zone vegetation faults remain below 10%. We will review our process for identifying and addressing 'at-risk' trees outside the regulatory zones. We are also improving business processes to better coordinate vegetation along with our overhead line renewal capital expenditure. This includes using line diversion as a key tactic in reducing vegetation risk. We are currently considering several line diversions that will be more economic than undertaking a first trim on existing vegetation.

- Relationship management

  We continue to invest in long-term meaningful relationships with our key stakeholders including iwi, councils, and major forestry owners. This ensures the way we work in our community is both considered and enduring. As a business we aim to grow our understanding of how our work impacts the community we serve. This includes working with Iwi across our network to undertake cultural impact assessments and developing agreed working protocols.

- Major customer management

  A significant portion of our internal effort is committed to managing customer-initiated queries and projects. We are refining the process of managing large complex connections by developing and aligning a collection of pricing models, contractual frameworks, and project delivery structure. This will give our customers more clarity when engaging with us and allow us to minimise the impact these queries can have on our own capital works.

- Co-locating at the Waitete depot

  Jointly locating our Te Kūiti based asset management and network services staff will ensure our people are best set-up to deliver the Capex plan. The planned Waitete office redevelopment will allow us to permanently co-locate staff to maximise efficiency. In the interim, we are looking at opportunities to establish temporary project delivery teams by reorganising where key teams are located across our current sites.

3.5 Key targets

Our ongoing asset management improvement targets relate specifically to asset management (i.e., they are a subset of TLC's broader business objectives). In general, we have sought improvements in performance of between 1.0% and 1.5% per annum. compounding, with some exceptions where we considered progress should be more aggressive.

Table 3.11: Our key targets

AMP Objective	Performance objective	Metric	Current (3 year average)	Target Annual Reduction	2024 Target	2025 Target	2026 Target	2027 Target	2028 Target	10 year Target
Safety and environment	Health & safety	TRIFR	3.7							Ongoing reduction
	Public safety	No. of PS incidents	9.0							Ongoing reduction
	Accidental env. damage	No. of incidents	0	Nil	0	0	0	0	0	0
Customers & community	Responding to customer outages	Planned raw SAIDI Unpanned raw SAIDI	109 232	0.0% 5.0%	156 239	156 227	156 216	156 205	156 195	156 151
		Planned raw SAIFI Unplanned raw SAIFI	0.5 2.8	0.0% 5.0%	0.7 2.8	0.7 2.7	0.7 2.6	0.7 2.4	0.7 2.3	0.7 1.8
		Planned outage count Unplanned outage count	197 758	5.0% 5.0%	283 876	269 832	256 791	243 751	231 714	197 552
	Supporting customers	Complaints Count	38	10.0%	11	10	9	8	7	Ongoing reduction
	Customer satisfaction	Satisfaction survey			Ongoing improvement					>Industry average
Networks for today and tomorrow	Managing critical nodes on the Network	# zone substations that do not meet our security of supply standard	11		10	10	9	9	8	5
	Supporting decarbonisation	Progress on our decarbonisation roadmap			Ongoing progress					Complete
	Enabling customer growth	% of free firm capacity at zone substations	4%		5%	5%	6%	8%	9%	20%
Asset stewardship	Asset health	Defect count pa.	177	5.0%	196	186	177	168	159	123
	Veg. interference	Vegetation faults	93	5.0%	110	105	99	94	90	70
Operational excellence	Forecast efficiency	Capex delivered vs plan (Note 1)	+/-10%	5.0%	9%	9%	8%	8%	8%	+/- 5%
	Process efficiency	Opex per ICP Capex per ICP (Note 1)	$714 $791	0.0% 1.5%	$638 $822	$638 $757	$638 $899	$638 $1220	$638 $924	$638k $658k

Note 1. Our Capex targets exclude atypical non-network and customer growth Capex, which often have third party time and cost drivers outside our control. The Capex target is set to provide a measure of how we are managing the investment of our core network.

Rationale for our target settings

We have set improvement targets that are appropriate for our business given the context of its geographic and financial attributes.

Our safety and environment targets are designed to address the key public and staff safety risks on our network.

Our customer and community targets seek to reduce unplanned outages by 5% per annum. This follows further analysis of our network outages and reliability modelling that has indicated we could make material improvements by being very targeted in our asset renewal programmes particularly through selective overhead line pole-top upgrades.

Our customer complaints are now significantly lower than historic levels following the transition away from Demand based pricing and direct billing. We expect this to continue to improve driven by the recent establishment of a new Customer and Community Engagement team, and the planned investment to digitise our operational capabilities. We believe this will make significant customer experience improvements over a five-to-ten-year horizon.

Our targets for networks for today and tomorrow are focused on lifting our network security of supply and free capacity for growth, supporting the deployment of electric vehicles and industries seeking to transition away from carbon-based energy supply.

Our asset stewardship targets are set to provide ongoing pressure on defects and vegetation faults, noting that over 90% of the vegetation faults we are seeing are driven by trees from out of the notice zone falling over the lines in high wind or rainfall events. Our network continues to see expansion of carbon forestry and we expect vegetation related risk to increase over time. Our targets therefore set ongoing pressure to reduce the outage count through non-direct means, such as fostering relationships with forestry owners to widen line corridors over time.

In our operational excellence targets we have set at a flat Opex trend for future years. This is driven by our expectation the business will see increases in Opex to support the gradual digitisation of our core systems and significantly enhanced operational technology (such as an ADMS) which requires greater operational overhead to manage. This will be offset as we find savings in our Capex programme as our analysis and information management becomes more advanced.

3.6 Our performance trends and targets

Figure 3.7 shows our performance trends including our five-year forecast based on our performance targets.

Figure 3.17: Our performance trends and targets

Review of our RY 2023 reliability performance

Each quarter we undertake a detailed reliability review to understand the key drivers of our reliability, and to identify trends that are emerging. Table 3.5 summarises the key findings and actions of those reviews.

Table 3.12: Reliabilty review

Driver	Key finding / driver	Recommended actions
Adverse weather	Severe storms through June, July, November, December, and February (including Cyclone Gabrielle).	Initiatives underway in RY 2023. • Seven-day ahead weather prediction based on a new forecasting tool developed by NiWA. • New business rules to trigger earlier preparation and response based on weather and fault characteristics. • Additional generation to allow rapid response to major outages on our network. • Deploying spares in strategic locations around our network to ensure they are easily accessible by our field crews to reduce travel time. • Additional real-time weather stations in key locations. Initiatives planned in RY 2024 • Further develop our weather forecasting capabilities to extend to a 35 day forward view. • Overlay asset resilience, criticality, and fault history with localised weather forecasting to predict where extreme weather is most likely to impact supply on our network.
Vegetation	Out of zone vegetation (tree fall) is driving ~90% of our vegetation outages.	• Continue to monitor detail on tree faults (in/out of zone, native plantation, pine plantation, commercial and residential). • Increase line diversion as a key future mitigation option. • Extend vegetation plan to increase focus on in-zone saplings while inexpensive to trim and do not require an outage. • Participate in the regulatory reviews on vegetation management. • Continue to use LiDAR and other means to detect vegetation risk.
Defective equipment	Pole top defects dominate our fault count and impact.	• Increase our pole top observations to better identify emerging defects. • Become more targeted in our renewal to focus on assets reaching the onset of unreliability phase of their lifecycle. • Complete our network criticality model. • Continue to develop our outage analysis to identify trends in asset defects
Unknown cause	Unknown cause faults remain high with increasing consequences due to the new safety related business rules we have put in place to reduce blind closing and fire risk.	• Continue to deploy automation and sectionalising to enable faster identification of fault zone and reduce impact on upstream customers.

Review of our RY 2023 project delivery performance

Capex programme

Our Capex plan in RY 2023 included a higher than usual mix of large and complex, customer driven and non-network projects than is typical for our business.

In total, TLC planned to deliver 149 projects totalling $24.9m in capital expenditure. Of these, seven large projects account for around $13.2m or 53% of the total planned expenditure for the year (including our ground mount upgrade programme which encompasses 21 individual projects).

At the time of writing[1], we have noted that ten projects are delayed for a range of reasons. Consequently, our year end capital expenditure will be lower than forecast in that AMP plan. The drivers for the reduced Capex expenditure are outlined below.

Our focus for the year has been to continue our core network renewals that impact reliability for our customers. Of the deferred projects, two line renewals, which may directly impact reliability, have been deferred into the first half of RY 2023. Our risk assessment indicates their short-term deferral is not likely to have a material impact on network reliability.

Table 3.13: Project delivery review

Project Category	Deferred Projects	Reason for deferral	Capex ($000)
Customer projects	Various customer works	Deferred by customers	904
Non Network	Digital utility programme	Still in business case phase	1,000
	New corporate office	Still in business case phase	932
Renewals	Ground mount Transformers	Awaiting landowner consent	1,978
	Line renewals (2 of 29 deferred)	Resource availability (limited by fault activity)	860
	Tahāroa switch room renewal	Dependency on customer planning	1,700
	Whakapapa / Tūroa ski field	Access to site and lead time for components	400
Security of supply	Arohena substation upgrade	Transformer design issue being resolved with manufacturer	500
	Kuratau feeder split	Awaiting landowner consent	930
	Mobile Substation	Originally intended to be purchased as part of a customer project	1,500
	Total deferrals in RY 2023		**10,704**

[1] This estimate was undertaken prior to cyclone Gabrielle, which we expect will further impact our planned works for RY 2023

Our asset management roadmap

We have developed an asset management roadmap to progress our overall asset stewardship of our electricity network assets. The objective is to ensure we have the main elements of ISO55000 in place and operational by the end of RY 2024 and are progressively laying the foundations to manage a more complex future network. The roadmap and key areas of focus for the next twelve months are shown in Table 3.7.

Table 3.14: Our asset management roadmap

GOAL / ACTIVITIES CURRENTLY IN FOCUS	DUE	STATUS
Capability: Ensure the business has the requisite resourcing and capabilities to deliver the AMP.		
• Complete a review of the business resourcing needs to support the AMP.	Mar 2023	Complete. Business case to be presented to the Board in February 2023, resulting in ~20 new positions.
Decision making: Ensure the business has access to suitable information for decision making.		
• Increase frequency pole top inspections to build a more comprehensive understanding of asset risk.	Jul 2023	In progress. Market engagement underway to develop options.
• Broaden our business performance measures to provide greater oversight of resource performance and customer experience.	Oct 2023	In progress. Extended reporting functions for connections and maintenance in development.
Operational efficiency: Improve operational efficiency to ensure we are providing best value for our customers.		
• Put in place digital capabilities that support efficient operations, through our digital utility programme.		In progress. Business case to be presented to the Board in April 2023
Risk: Ensure we have requisite frameworks and information to manage risk in our changing environment.		
• Extend NIWA forecasting model to overlay asset performance, health, and criticality.	Mar 2024	In progress. Contract signed with NiWA to progress development over a 12-month time frame.
Future networks: Develop foundational capabilities aligned with our decarbonisation roadmap		
• Extend smart meter data from MEP from monthly consumption to data to daily delivery of power quality information.	Mar 2024	In progress. Contract signed with MEP to commence extended data provision to include power quality by March 2024.
• Complete the foundational aspects of our Decarbonisation roadmap and commence integration stage.	Jul 2025	In progress.
Maturity: Progress our asset management maturity to reach level 3 (competent asset manager)		
• Continue improving our asset management maturity.	Mar 2024	In progress. Aim to achieve maturity score of 3 at our next maturity audit.

04

Future Network

4. Future Network

This portion of the AMP outlines how we are preparing our network and our capabilities to support the future needs of our network and our customers.

4.1 Introduction

This chapter outlines how we are preparing our network for the future. There are six areas of focus:

- Enabling decarbonisation and growth
- Improving network performance
- Digitising our business
- Improving customer service management and experience
- Supporting innovation in energy supply
- Continual improvement in asset management

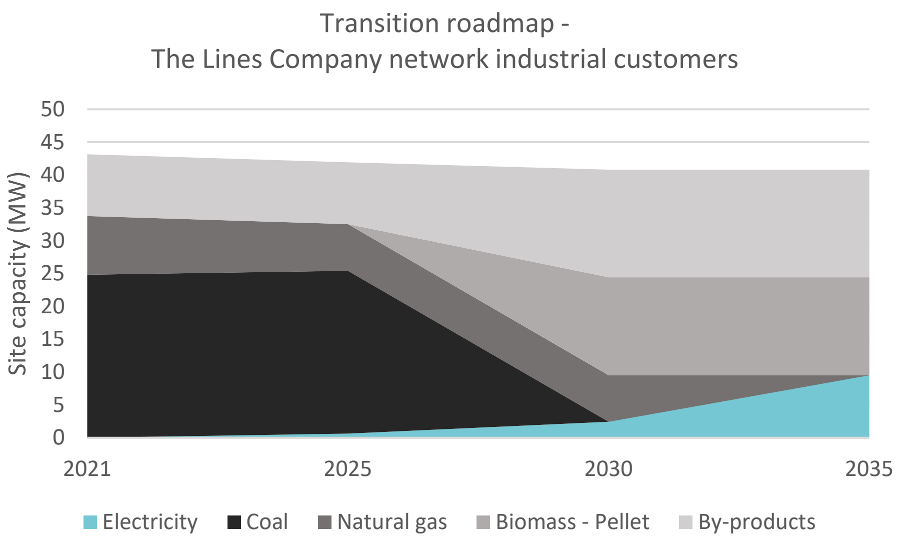
4.2 Enabling decarbonisation and growth

Decarbonisation refers to the process of reducing the consumption and production of carbon content in our energy sources and the overall economy. This is being achieved through a variety of means, such as shifting from using fossil fuels to more renewable energy sources like wind and solar power, or even by using carbon capture and storage technologies to reduce emissions from fossil fuel-based power generation.

One of the key impacts of decarbonisation on electricity distribution networks is the need for greater investment in grid infrastructure and new technologies to carry the increased energy required. Renewable energy sources often require specialised equipment and infrastructure to generate and transmit electricity, such as wind turbines and solar panels. Investing in these technologies can reduce New Zealand's carbon emissions but they may also require significant upfront costs to transport energy across the transmission and distribution lines to where it is ultimately used by customers.

The most immediate impact from decarbonisation we expect on our network is from industrial customers who are beginning their transition from fossil fuel-based energy to renewables. In 2022, TLC's industrial customers were surveyed to assess the timing and depth of that change. Figure 4.1 shows shift in the types of energy they expect to make over the next fifteen years, as they transition away from coal and natural gas.

Figure 4.18: Forecast change in energy sources for industrial process heat on our network (source: Deta major customer survey)



Overall, the process of decarbonisation presents both challenges and opportunities for us and our customers. While it may require significant investments and adaptations, decarbonisation is also driving new technologies to be developed that can support our network planning and management.

Our decarbonisation roadmap

To effectively respond to decarbonisation, we've created a roadmap aligned to the Electricity Network Association's (ENA) network transformation roadmap which is shown in Figure 4.2. It outlines our planned initiatives and involves significant customer engagement, industry collaboration and business transformation (people, systems, processes).

The first steps in our roadmap are focused on setting the foundations to support future decarbonisation impacts. These activities include extending our capabilities in both people and asset systems as well as developing new systems to provide network visibility, which has resulted in our digital utility programme discussed below.

Our objective is to extensively digitise our business to extract full value from the data we hold so that we can improve customer experience, maximise efficiency, optimise our investment decisions, and increase the visibility of our network to a broader set of stakeholders. We expect this transformation to occur over the next 3-5 years.

Figure 4.19: How our decarbonisation roadmap aligns to the ENA Network Transformation Roadmap

Set Foundations Integrate Advance Currently in progress

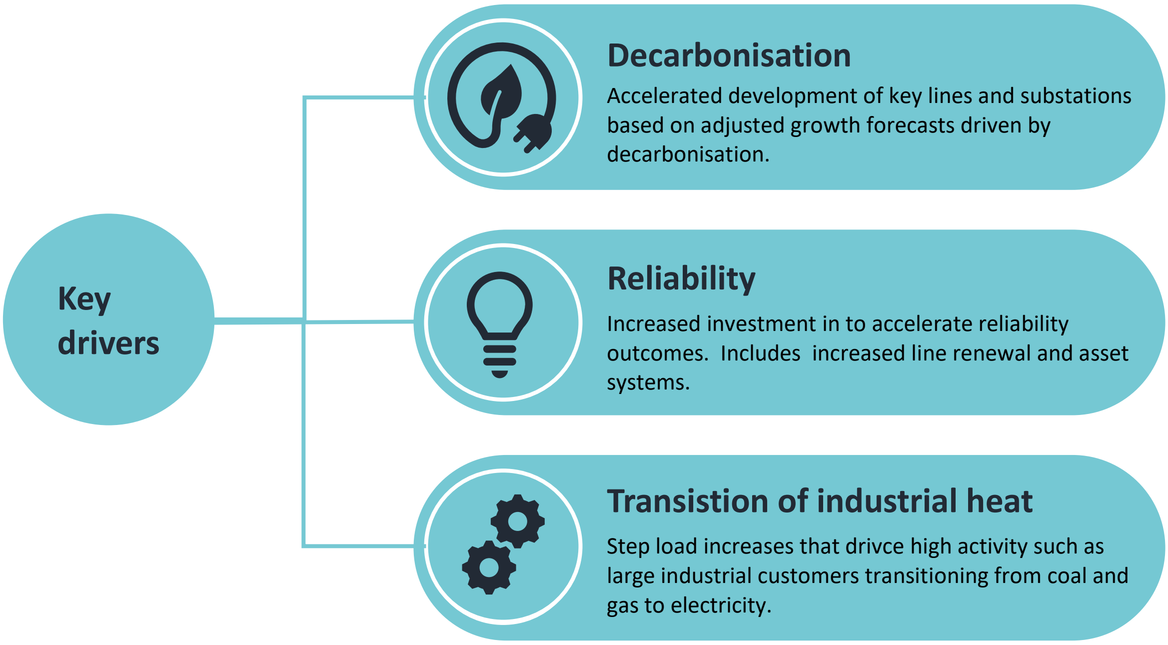
ENA Stream	TLC will collaborate with industry	TLC will initiate directly	Longer term	Customer value outcomes
Open framework	Encourage equitable access and open data policies and standards.	Trial a smart meter standardised API with a meter service provider. Share standardised network data using a common information model.	Introduce an equitable access policy. Adopt open data standards as they're made available.	○ Fair capacity allocation ○ New data driven services (e.g., energy efficiency insights)
Insights	Engage key stakeholders on their needs (e.g., retailers, councils). Develop balanced and consistent information on key technologies (e.g., process heat, solar, EVs). Develop customer tools (e.g., heat maps).	Survey key commercial and industrial customers. Engage and educate customers on key technologies. Publish hosting capacity (import/export) (@ ICP level).	Investigate and support non-network solutions, e.g. • Energy efficiency. • Process heat DSR. • Community solar. • EV charging. • Remote power supplies. • Other 3rd party solutions.	○ Customer needs are reflected in our strategy and plans ○ Assists technology purchase decisions (e.g., rooftop solar, EV chargers)
Standards	Develop and update equipment standards (solar, EV chargers etc) Update connection codes	Review and streamline connection processes.		○ Safeguards the customer, equipment, and network ○ Easier and faster network connections
Pricing	Support a shift to retailer transparency of network costs. Investigate cost-reflective pricing options to support prosumers. Ensure regulatory framework meets decarbonisation needs.	Simplify pricing and align to industry Reflect the impact of decarbonisation in our pricing roadmap.	Consult with customers on the pricing roadmap.	○ Fair and good behaviour is incentivised ○ Easier to understand
Operations	Monitoring and automation trials.	Enhance LV monitoring to understand the network's baseline performance Trial flexibility services with a retailer Understand how we operate in a Distribution System Operator (DSO) environment	Increase automation.	○ Identify hosting and reliability opportunities ○ Lower tariffs for flexible customers
Capability	Identify future knowledge and skill gaps. Share learnings from system and process changes.	Strengthening people, knowledge and skills required Digitise systems and processes. Develop scenarios and forecasting models for key technologies.	Collaborate on the development of a digital twin model.	○ Better customer support ○ Improved investment decisions

The key drivers of our decarbonisation planning

The impacts of decarbonisation manifest in different ways. The most obvious impact in New Zealand is in the additional capacity the network will be expected to provide to support electricity fuelled transport, but there are other impacts. For example, we expect that as reliance on electricity supply increases to support wider parts of the economy, there will be less tolerance for network outages. Consequently, our planning will see greater investment in network reliability moving forward.

An additional impact which is particularly significant on our network is the transition of industrial process heat to electricity. Although these are relatively few in number, they can result in very large and very sudden step changes in demand for the network. We also expect that significant upstream investment will need to occur over time to support such large increases in demand, so the cost impact can be very high in some cases. Our planning has considered these three, key drivers.

Figure 4.20: Key drivers of our decarbonisation planning



What decarbonisation means for our network

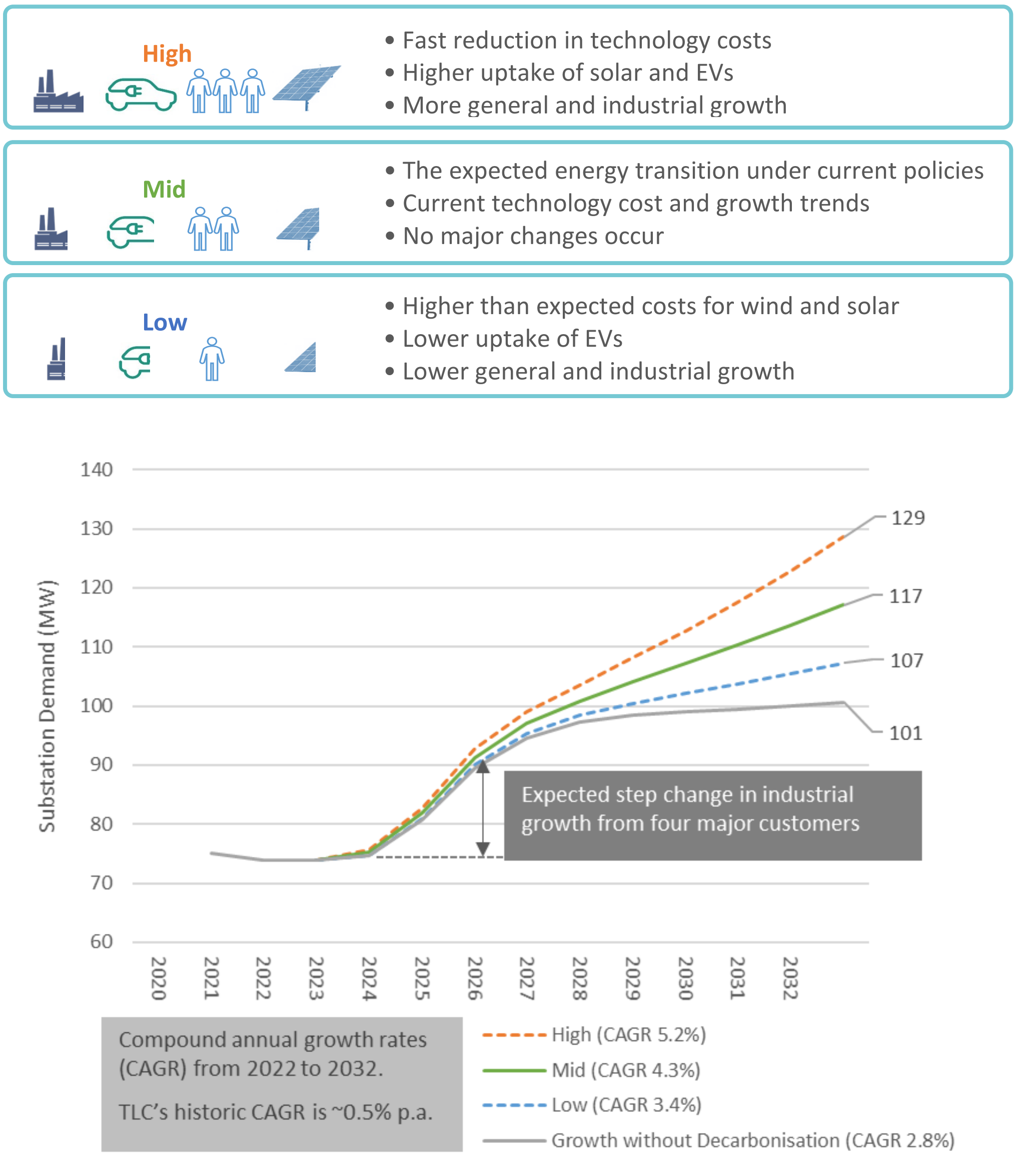
We expect that over time, the impact of decarbonisation and growth activities our network will be significant and will require investment to build additional system capacity and resilience, however there is a lot of uncertainty about how the energy transition will unfold.

In order to assess how decarbonisation and growth might impact our network and our expenditure planning, we have developed three growth scenarios shown in Figure 4.4.

- **The High scenario**: In the High scenario we expect to see a high uptake of EVs. In relation to electric vehicles our High scenario is aligned with the Ministry of Transport (or MOT) vehicle fleet emissions model for New Zealand EV growth (their Fast scenario) but reduced by 20% to recognise that the TLC network customers are likely to be slower than other areas of New Zealand to transition to EV's based on our customer demographics. The high scenario also includes new industrial growth and a more aggressive transition of process heat from fossil fuels to electricity. Residential growth is high to support new industrial growth on the network.
- **The Mid scenario**: In the Mid scenario, electric vehicle growth is moderate, aligned to the MOT Base scenario but reduced by 20% (for reasons noted in the High scenario above). Industrial growth on the network follows the current (5 year) historic trends with a small increase to recognise that TLC has a pipeline of additional industrial growth in planning. Residential growth continues to be strong, supporting the industrial activities that drive regional population increase.
- **The Low scenario:** In the Low scenario, electric vehicle growth is low, aligned to the MOT "Slow" scenario but reduced by 20% (for reasons noted in the High scenario above). Industrial and residential growth on the network follows the current (5 year) historic trends.

Figure 4.4 shows how these scenarios can impact network demand growth during the planning period

Figure 4.21: Decarbonisation modelling scenarios



All of our scenarios indicate higher than historic growth rates. The Mid scenario indicates that the TLC network is likely to see a higher-than-average compound annual growth rate (CAGR) in its substation demand of 4.3% per annum, compared with historic CAGR growth of less than 0.5%.

To provide greater visibility of how we are supporting decarbonisation and growth, we have created a new chapter in our AMP this year ("Growing our Network") which details the key initiatives we are undertaking to support growth, and their associated cost.

The impact of new connections and alterations on our network

Each year new customers connect to our network, or undertake alterations, usually to increase supply. The impact can be material, and so we model these changes into our growth forecasts each year.

However, the timing and size of those increases in load can be uncertain, and this is especially so with major customer growth. We currently manage this uncertainty by maintaining a key account management function, communicating regularly with customers on their planning and progress. TLC is typically involved at the project detail level to provide direct insight into the risk factors governing the customer's project timing.

Our current planning process makes assumptions of growth and the timing of its implementation based on our forecasts of mass market load growth (growth from residential and commercial customers) load growth, the expected uptake of distributed energy resources on our network (i.e., wind and solar generation, batteries, and electric vehicles), and the best estimates of load requirements given to us by our industrial customers.

The most significant impact in our current environment is load growth from our industrial customers. The reason for using their best estimates of load growth (rather than applying our own risk factors) is to ensure the network it is able and resourced to supply the load to support customer projects and makes commitments to do so based on customer project timelines.

Locational risk factors (such as the absence of available capacity to connect in a certain area of the network) are addressed in the planning phase with the customer, and the timeline and cost to supply that location is usually a key point of discussion and negotiation for major customers, and TLC is usually required to commit to those timelines once agreed.

The cost impact of decarbonisation on our network

The cost to support decarbonisation is a combination of investment to increase system capacity and to improve reliability of existing assets. To simplify, we assume the cost to support decarbonisation should be the long run marginal cost of capacity. In general, this can be assumed to be the construction cost multiplied by a margin factor of approximately 50%. The margin factor is required because increasing capacity does not require a full upgrade of assets in most cases, and where assets are required for upgrade some of this cost can also be counted as renewal expenditure.

Our analysis indicates the total marginal cost to provide capacity (including increased capacity of regional supply points, zone substations and lines) for our network is ~$2.95m per MW increase.

Our Mid growth assumption indicates that network coincident demand will increase by around 17MW by the end of the ten-year planning period. On that basis we estimate the cost of supporting decarbonisation is ~$50m for our network.

Balancing decarbonisation and affordability

During our planning we are highly cognisant that not all our customers will be able to access the advantages of decarbonisation in the next ten years. For example, EVs are likely to remain beyond the level of affordability for most of our customers in the next decade. On that basis we need to balance our investment to both enable the benefits of decarbonisation for those who are able to access them, but also retain an affordable energy supply service for those who can’t.

4.3 Using non-network solutions to support our network

Overview

Non-network solutions refer to the use of technologies other than traditional ‘poles and wires’ infrastructure to provide either a supply alternative or an improvement to supply. Examples are solar and battery systems, and new data systems that can reduce the expenditure on our network assets through better analysis or control.

Key considerations

We actively consider non-network solutions in our work, though we note that this is still a developing area in some cases. The key areas we consider when planning the use of non-network solutions include:

- **Availability:** Is the system or solution available to us and able to be deployed in the time frames we require?
- **Reliability:** Is the system or solution reliable, and can it improve reliability outcomes for our network?
- **Longevity:** Is the system or solution able to support out network over a long term, or is there significant uncertainty?
- **Maturity:** Is the system or solution mature (tested by others) to provide confidence that has been proven to be effective?
- **Affordability**: Does the system or solution make financial sense – i.e., will it improve the affordability of supply for our customers?

Use of flexibility traders to support network constraints.

Over time we expect to see new energy traders emerge that can offer 'generation on demand' services to support the network. The underlying concept is that we may be able to increase demand on its network beyond the absolute capacity of the network poles, wires and transformers. Instead, an energy trader may be able to supply energy at points of constraint when those constraints occur.

If managed well these new energy traders (often referred to as 'Flexibility Traders' may offer a more cost-effective alternative to investing in more network assets.

This is a developing area, and we are actively engaging with our customers and other market participants to understand what non-network options like flexibility trading might exist for our network.

4.4 Improving network performance

Overview

The performance of our network is becoming increasingly important as more New Zealand's economy becomes reliant on electricity as its primary fuel source. It means we need to continually improve our reliability performance. Figure 4.5 and Figure 4.6 show the count and average outage time per customer (SAIDI) over the last five years, along with our current regulatory year forecast (2023F) and future year targets (2024T to 2028T).

Figure 4.22: Fault count by cause

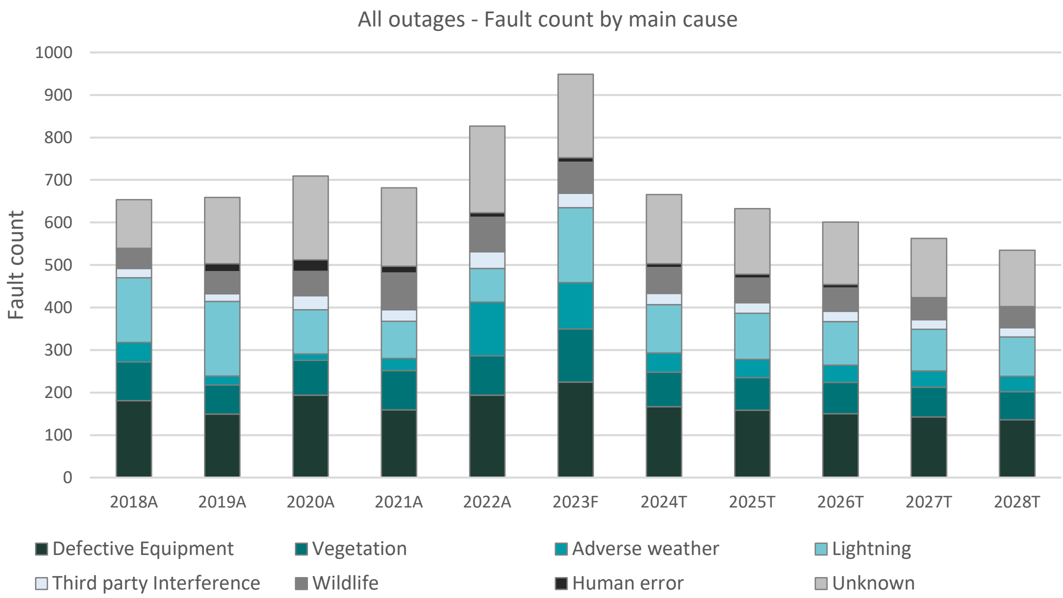
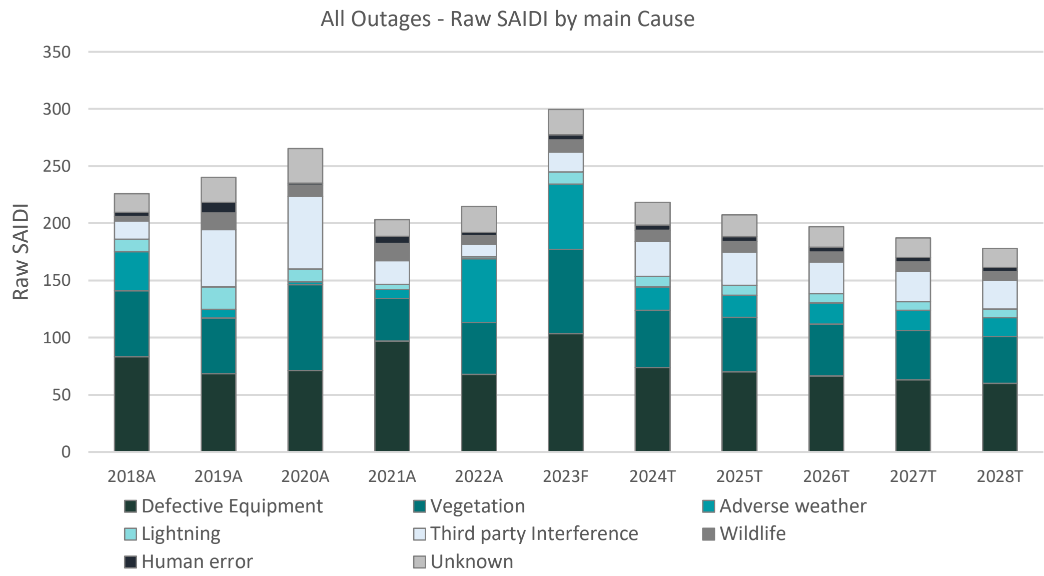


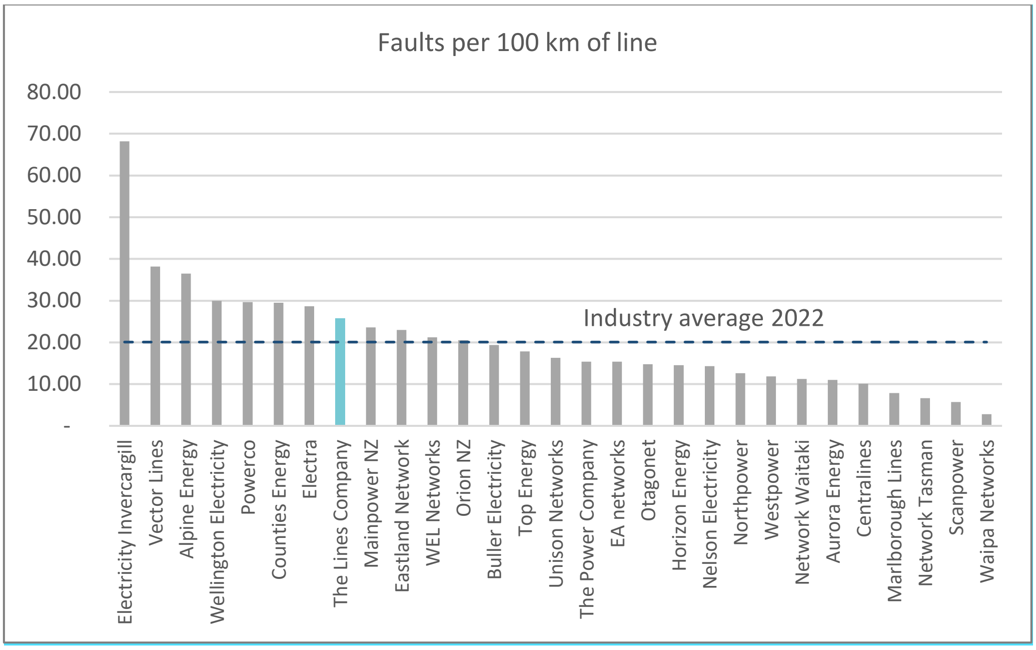
Figure 4.23: Raw SAIDI (average outage time per customer) by cause



The 2023 regulatory year was characterised by higher storm activity than prior years and pushed our fault count higher than our recent average. Although this was higher than average, it is indicative of the future challenges we may face from climate change resulting in more intense and more frequent weather events in the future.

Figure 4.7 shows how we currently rank against New Zealand's other electricity distributors in terms of faults per km of 11kV line. Overall, we are seeking to reduce our fault count be below the industry average over time.

Figure 4.24: Faults per 100km of medium voltage distribution line (source: Electricity Lines Business 2022 Information Disclosure Compendium (PwC, December 2022)



There are three main drivers of interruptions on our network:

1. Defective equipment
2. Vegetation interference
3. Adverse weather (storm frequency and intensity)

Managing defective equipment interruptions

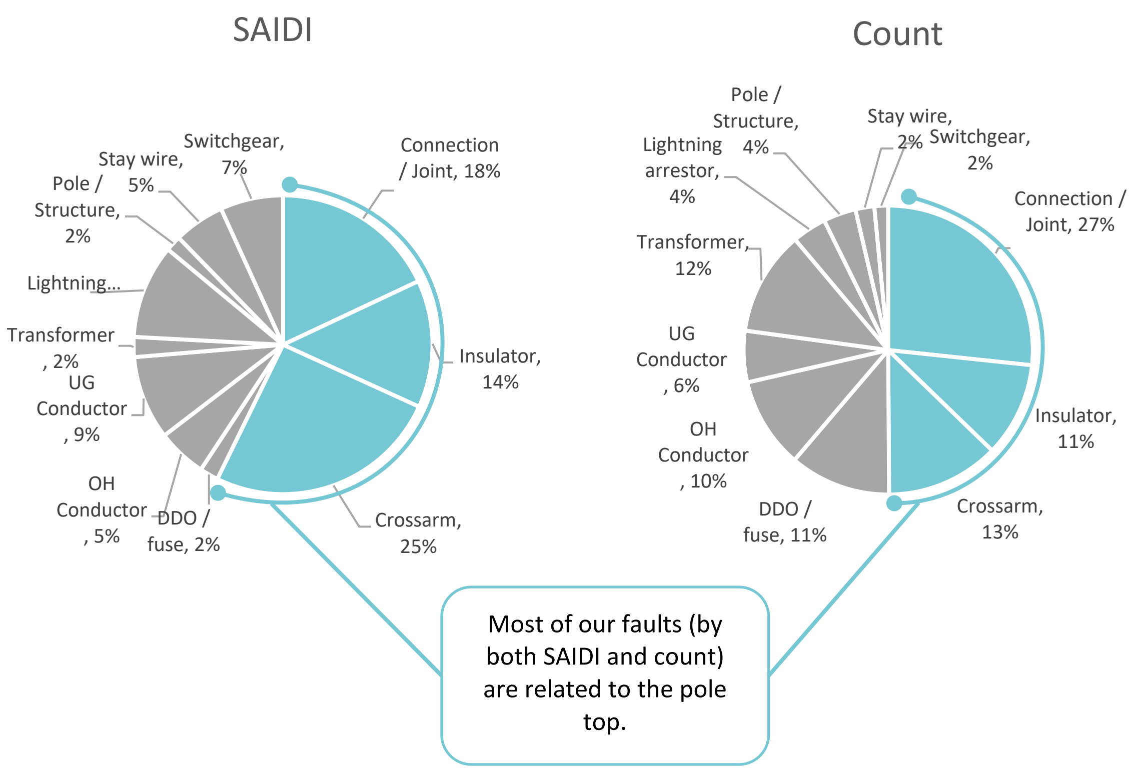
Defective equipment is assets that have failed in service. It may be that the assets have reached their end of life or have failed due to a fault or other reason.

We monitor these faults and try to ensure our assets are renewed before they reach the point of failure. Defective equipment typically contributes 23% of TLC's unplanned interruptions by count, however some defective equipment outages can have a significant customer impact (i.e., they can create long outages because they can be hard to repair or replace.

In the past three years we have been monitoring our defective equipment faults in greater detail to better understand the causes of failures.

Figure 4.8 shows the proportion of defective equipment outages since regulatory year 2021.

Figure 4.25: Defective equipment outages by cause



Key insights from our analysis indicate around half our defective equipment faults are related to the pole top - such as failures of the crossarms, insulators or the connections holding the overhead conductors to the insulators.

Our response to managing defective equipment

We are undertaking three initiatives to improve our management of defective equipment failure risk. These focus on inspections to understand the probability of failure, and the criticality of individual asset parts to better understand the impact of failure. These initiatives include:

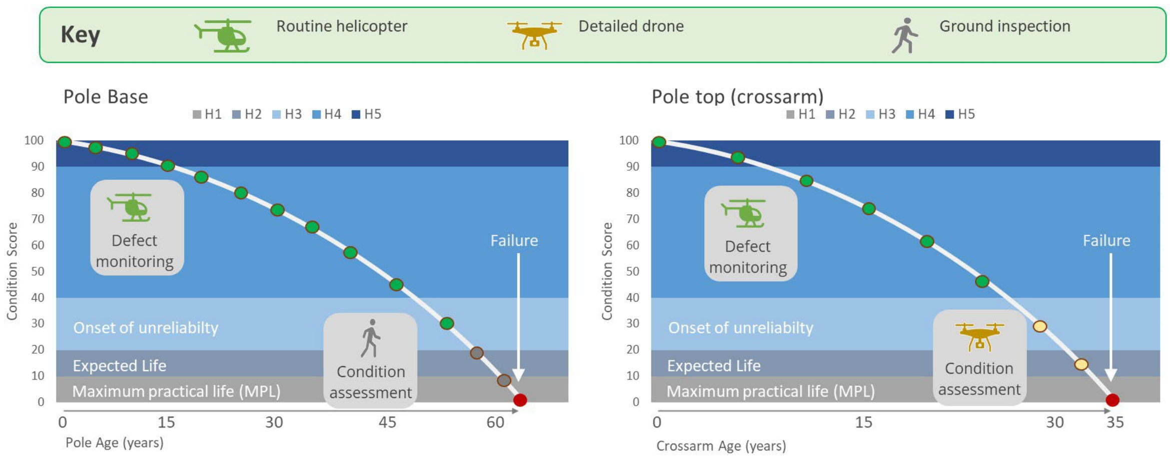
- Separate pole base inspections from pole top inspections;
- Inspect the pole top more regularly to get a stronger understanding of their risk of failure;
- Overlaying this information with the criticality of each line segment, to ensure we focus on assets that are most critical for our network and customers.

Pole top assets have a shorter life than the pole structure, so they require monitoring more regularly than the pole structure that supports them. Although we visually monitor these by helicopter defect observations every three years, sur intention is to increase the frequency of detailed pole top inspections by capturing high resolution photographs of all pole-top assets on a five-year cycle and use this data to inform our condition monitoring work. The pole base has a longer life and requires a different set of inspection methods that must be undertaken by a physical site visit.

In both cases the assets rarely fail in the first half of their service life, so visual inspections focusing on defects is an effective strategy to identify emergent issues. However, as the assets reach the end of their expected life, our inspection process will become more detailed, using a drone (for pole top) and ground inspection (for pole base) to provide a comprehensive condition assessment. These are more costly and so they would be used at the more critical points in the asset lifecycle.

Figure 4.9 shows the changes we are considering to our inspection programme.

Figure 4.26: Changes we are considering to our inspection programme



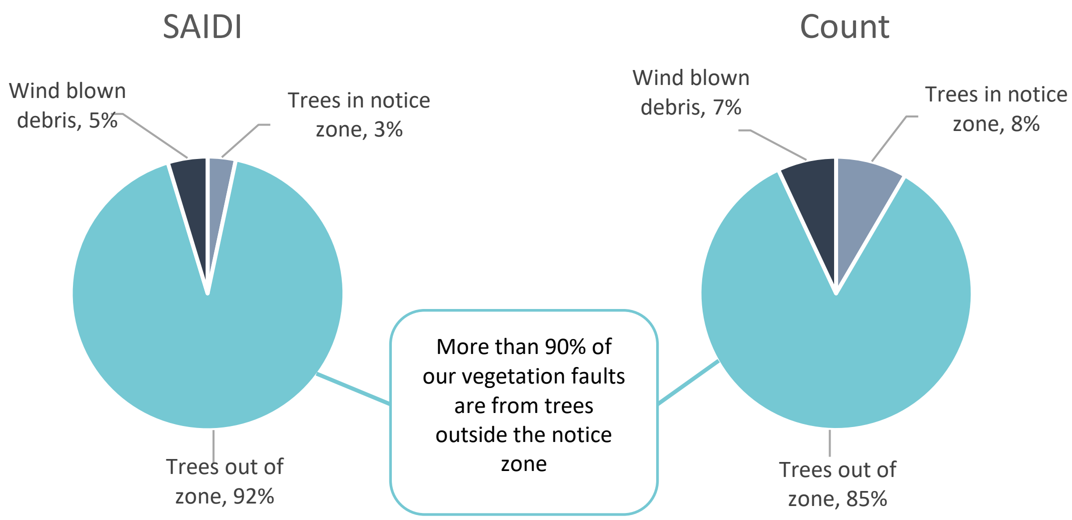
Managing vegetation interference

Vegetation interference typically accounts for 23% of our outage interruption minutes. In the past three years we have undertaken extensive analysis to better understand our vegetation risk. This has included undertaking a LiDAR scan to identify where our trees are interfering with our lines and incorporating more detail into our fault data capture.

Figure 4.27: In 2021 we completed a LiDAR survey of our vegetaton using helicopers and drones

This analysis has revealed that more than 90% of our vegetation related faults are caused by trees falling onto our lines from out of the regulated notice zone. Figure 4.11 shows the main causes of vegetation interference on our network.

Figure 4.28: Causes of vegetation interference



Vegetation interference is a growing problem on the network due to a marked increase in farmland being converted into carbon forests.

The primary issue is the trees are not planted far enough from our lines to prevent fall-in risk. During storms or heavy rainfall, the trees on the outer edge of plantations break under wind load and damage our lines.

Figure 4.12 and Figure 4.13 show the two key issues related to our vegetation management, conversion of farmland to forestry and fall-in damage under strong winds.

Figure 4.29: Farmland is being converted to carbon forests on our network

Figure 4.30: Tree fall-in from outside the notice zone accounts for more than 90% of our vegetation outages

There are few options available to us to manage these risks today, and so we will work closely with New Zealand's regulatory authorities to expedite the further development of New Zealand's tree regulations so that they are fit for purpose for our network. While we work through these issues, we will maintain our current vegetation strategy which is outlined in Table 4.1.

In 2020 we developed a vegetation management strategy which is reviewed and updated annually. It defines our vegetation goals and sets out initiatives reduce vegetation related outages and their impact on the TLC network and consumers. The vegetation management strategy outlines three key areas of focus, with initiatives related to each.

Table 4.15: Vegetation management strategy

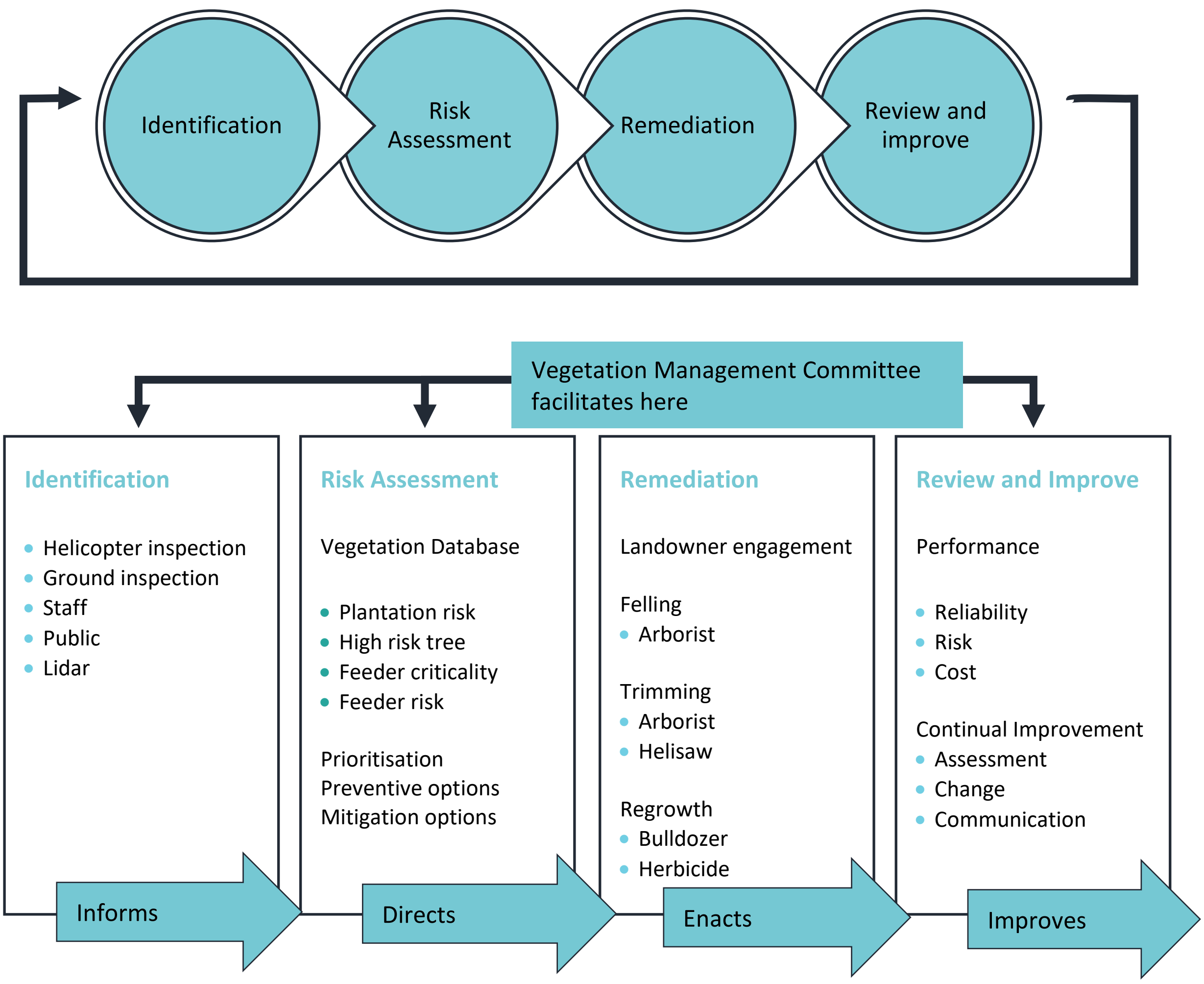
Strategy	How we are progressing
Retain the key initiatives outlined in the 2019 Vegetation Management plan	• **Undertake a survey of vegetation to establish and maintain a baseline.** • **Complete.** TLC completed a LiDAR survey of its vegetation in 2021. Further surveys are planned in this AMP to maintain visibility of how our vegetation risk is changing over time. • **Establish and populate a vegetation database.** **Operationalised.** We have transferred the risks identified in our LiDAR survey to our GIS system and through to our vegetation remediation plans.
Embed risk management and continuous improvement frameworks	• **Apply a comprehensive risk management framework to vegetation.** **In progress.** We are working with NiWA to develop a comprehensive risk forecasting tool, that overlays vegetation fault history with asset condition, network criticality, and forecast weather conditions. • We are also working to develop a forward-looking vegetation growth and plantation model, to understand how and where the land use on our network is changing from traditional farming to forestry. • **Establish a continuous improvement framework for vegetation management.** **Operationalised.** This is actioned through our vegetation management committee, who meet monthly to consider strategic vegetation issues.

Strategy	How we are progressing
Maintain a Vegetation Management Committee	• **Establish a vegetation management committee**. Operationalised. TLC's Vegetation Management Committee has been in operation since 2020 and consists of subject matter experts from across the asset management team. Their role is to facilitate planning, review, communication, and project delivery, with the following key responsibilities: ○ Making vegetation management a business wide responsibility ○ Supporting the change initiatives with resources and project disciplines ○ Setting up the structure and providing operational support for risk management and continuous improvement.

The Vegetation Management Committee is a key enabler to implement the vegetation management strategy and was established in 2020. Its purpose is to broaden the visibility, responsibility, and support for vegetation management across the business. The outcome we are seeking is a framework that enables vegetation to be supported by a whole of company approach creating greater capacity, more structure, and a broader set of support tools.

Figure 4.14 shows vegetation management process and role of the Vegetation Management Committee.

Figure 4.31: Key vegetation management fuctions



Our vegetation management targets

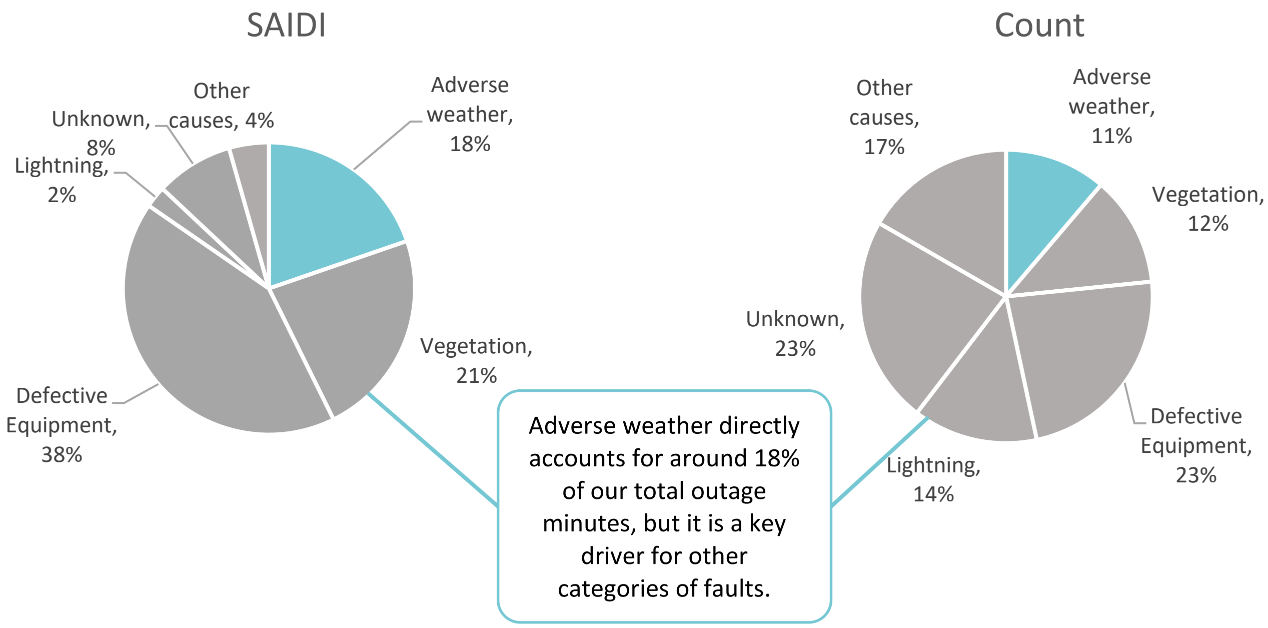
We have set an ambitious target to reduce vegetation related outages to no greater than 15% of unplanned SAIDI. Achieving this target will be challenging due to the increase in vegetation on our network, and because reducing fall-in outages relies substantially on the voluntary co-operation of landowners. With a better understanding of our core vegetation risk drivers, generated from new a new vegetation fault reporting framework put in place in 2020, we are reviewing our vegetation strategy. However, given TLC's terrain and topography, vegetation remains a key reliability issue and an important area of focus for our asset management for the medium term.

Adverse weather

Adverse weather is a core driver of faults. We record faults as being caused by adverse weather when our weather stations show that winds are higher than normal conditions. However, our wind monitoring is limited, and we expect that localised winds are very likely to be the key drivers of other fault causes.

Figure 4.15 shows the outages directly attributed to adverse weather (in orange), and the related fault categories that may also be impacted by adverse weather at a local level (in grey).

Figure 4.32: Adverse weather faults and how it influences other categories



How we are developing our management and response to adverse weather

Our primary management strategies to manage the impacts of adverse weather are shown in Table 4.2: Adverse weather management strategy

Table 4.16: Adverse weather management strategy

Strategy	How implemented
Improve our monitoring and understanding of weather on our network	In 2021 we participated in a trial weather prediction tool developed by NiWA which can provide a seven day ahead view of storm activity. We are continuing this work to extend the tool to include: • Longer term forecasting • Real-time identification of assets that will be impacted by an incoming storm • Real time impact risk assessment based on assets likely to be affected, their condition and criticality.
Targeted 'hardening' of our network through our renewal programme	As we further develop our understanding of weather risk, we will target assets for renewal based on their failure risk and criticality of supply and bring our assets in line with modern design standards as renewal is undertaken.
Maintain our vegetation strategy	Vegetation is significantly impacted by high winds and rainfall (which destabilises the tree base root stability). Our vegetation management strategy seeks to minimise these impacts and is the core mitigation for supporting the impacts of adverse weather.

4.5 Digitising our business

Overview

In response to the increasing importance and value of electricity to our customers and community, we are seeking to streamline our business operations to continually improve the way we work. To do this we are investing to provide a better operational toolset for our workforce and empower our customers through the provision of online services.

We are establishing a digital utility roadmap

We are currently forming a digital utility roadmap which we intend to finalise and commence in the 2023 regulatory year. Although this roadmap will encompass a range of our core asset, operational and customer systems, we expect much of our focus in the next three years will be in developing an ADMS. These advanced software systems are used to monitor and control the flow of electricity on distribution networks. ADMS's typically consist of a central control platform, which is connected to a network of sensors and other devices on the grid. This allows utilities to collect real-time data on the flow of electricity on the grid and use this information to optimize the operation of the network.

Some key features of ADMS systems include:

- **Real-time monitoring of the grid:** ADMS systems use sensors to monitor power flow in real time. This can help quickly identify potential problems or outages and take corrective actions from with the control and field teams to prevent them.
- **Optimisation of grid operations:** ADMS systems use advanced algorithms to analyse data on the network and use this information to optimise supply. For example, ADMS systems can help utilities re-route electricity around faulted areas to supply downstream customers.

- **Integration of renewable energy sources:** ADMS systems can help utilities integrate renewable energy sources, such as solar panels and wind turbines, into the grid. This can help increase the use of clean, renewable energy on the grid, and reduce our reliance on fossil fuels.

Overall, ADMS systems can help improve our process efficiency and provide greater visibility of our distribution system, which we expect will result in ongoing reliability improvements for our customers.

4.6 Improving customer service and experience

Overview

Our customers' experience with us and the service levels they receive from our network are key elements in how we operate our business. We remain focused on ensuring that our network remains reliable and when our customers contact us, we respond in a timely and professional manner to resolve their queries.

Our customer charter

TLC is different to most electricity distributors in New Zealand in that we have a direct relationship with our customers through our conveyance agreements with Retailers. Because of this we maintain a customer charter within our Terms of Service. This defines what our customers can expect from us as a supplier of line function services (our commitments to the customer), as well as our customers responsibilities for us to undertake that service effectively (our customer's commitments to us). The Terms of Service are available at:

https://www.thelinescompany.co.nz/forms/standard-terms/

How we monitor our customer satisfaction

In 2018, we established a Customer Service Panel to proactively engage on our approach and overall performance.

We also engage our broader customer base through quarterly surveys and regular energy efficiency seminars across the region. The energy efficiency seminars offer advice on improving energy efficiency within the home, tips on managing power bills and general information on the services that we offer as a company. Through quarterly Key Research surveys, we solicit feedback on the level of service customers receive from us at both a company and a network level.

How we notify our customers of planned and unplanned outages

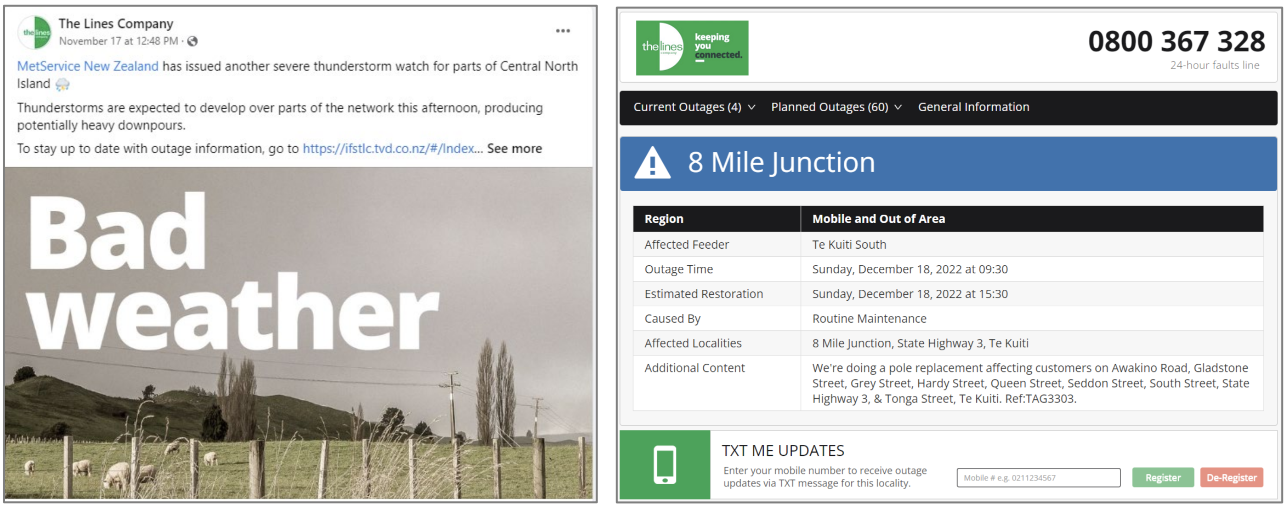
Following the transition to Retailer Billing, the way we notify our customers of planned outages changed.

Planned and unplanned outages are notified to customers in several ways:

Channel	Outage type	How accessed
Via Retailer’s	Planned	Retailers are notified by TLC at least two weeks in advance of a planned outage. They then notify customers by email or text message.
Direct emails	Planned	For customers that choose to sign-up to receive notifications directly from TLC.
Direct text updates	Planned and unplanned	For customers that choose to sign-up to receive notifications directly from TLC.
Website	Planned and unplanned	This is accessible through TLC’s website.
Facebook	Planned and unplanned	TLC’s Facebook page is regularly updated with significant faults or planned outage information.
Faults phone line 0800 376 328	Planned and unplanned	TLC’s faults phone line has recorded voice messages on fault locations and estimated restoration times.

Figure 4.16 shows the examples of outages notifications on Facebook and TLC’s website.

Figure 4.33: Facebook alerts (left) and TLC’s website (right) showing planned and unplanned outages



Over time we expect to further integrate our core notification processes with our outage planning systems, via an ADMS aligned to the delivery of our digital utility roadmap.

How we manage customer service

We actively track and monitor customer service through our customer and community engagement team. Their work includes managing and monitoring the number of inbound calls, emails, number of online chats with customers, number of inquiries resulting in transfers to other departments, customer complaints and their resolutions.

When complaints occur, our teams seek to resolve the complaint by liaising with the customer and the responsible TLC department to resolve the issue. If the issue cannot be resolved to the customers satisfaction it is escalated to line managers, who may liaise directly with the customer to find a resolution.

TLC also participates in an annual part-of-industry benchmarking customer satisfaction survey programme.

How we manage new connections and alterations applications on our network

Customers connect to our network or undertake alterations (usually to increase supply) on an ongoing basis. New connections and alterations usually fall into two categories:

- Standard residential and commercial customers
- Major customers that are connecting or making material step changes in their demand growth.

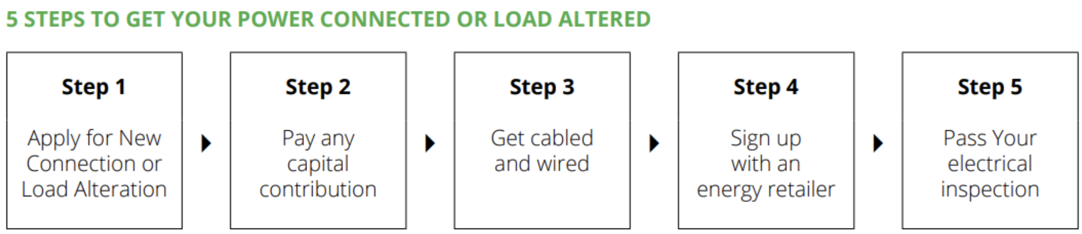
We manage these three areas in different ways.

- Standard residential and commercial customers

Our connections and alterations team directly manages new connection and alteration applications and TLC also has a private works division that may provide project management and construction services if requested. The connection or alteration process is laid out at a high level on our website, shown in Figure 4.17 below.

In general, standard connections can be managed with minimal engineering design and support, using standardised designs and project business rules. In addition, we have a dedicated Engineers to support this customer group, ensuring the existing infrastructure is adequately dimensioned to support the connection or alteration.

Figure 4.34: New connections and alterations process outlined on TLC's New Connections and Alterations from, available on TLC's website.



TLC has recently updated its Capital Contribution Policy to reduce the cost of new connections to consumers. The policy can be found on its website here:

https://www.thelinescompany.co.nz/site/uploads/2021/09/TLC-Capital-Contribution-Policy.pdf

For standard connections with no design or significant alteration requirement, we target 20 working days to complete the application and approval process and schedule an electrician for livening. However, this time frame can be longer if complexities are found on the site, if the customer requirements change, or there is significant design work required. Longer time frames are expected for large subdivisions that typically require several site visits or ongoing design discussions with key stakeholders.

- Standard residential and commercial customers

  Where large customers seek to connect to our network or make significant increases to their load growth, we manage these customers directly through a key account management process. These projects are typically complex and require material investment. We have recently developed a major projects process that defines the key stages for major projects, that includes concept development, front-end engineering, detailed design, and construction. These processes are managed directly with the customer and TLC's Project Management team.

Improving our customer connections and alterations processes

We currently undertake around 500 new connections and a similar number of alterations each year. TLC's website provides customers with the process and application forms needed to apply for a new connection or alteration. The process is managed via our connections and alterations team consisting of administrators and engineers that are dedicated to supporting that activity and have direct contact with customers.

A recent review of our connections and alteration processes has highlighted a number of areas for improvement and are now working on a number of improvements. These include:

- Improving communication with our customers through the project lifecycle;
- Digitising the key artifacts (connections and alteration forms) to make the application process easier and faster;
- Standardising our designs and streamlining project management to reduce the requirement for engineering oversight;
- Making the connections and alterations process simpler and more visible for our teams and customers;
- Standardising the pricing for new connection and alteration types to accelerate our processes and give greater certainty to our customers;
- Where required, strengthening resourcing to facilitate the growth in connection and alteration activity.

These changes will be implemented through 2023 and we expect they will improve our customer experience and provide more certainty on costs and project outcomes.

4.7 Innovation

We need to continue to innovate to enable our electricity network to provide a safe, reliable, and affordable service while supporting a future with greater diversity in generation and consumption.

We are actively working with our customers and suppliers to innovate in three key areas:

- Community solar projects (solar on Marae using peer-to-peer trading)
- Smart load management
- Power quality management.

Community solar (including community peer to peer trading)

Peer-to-peer energy trading refers to a system in which individuals or businesses can buy and sell electricity directly with each other, without the need for a traditional utility or electricity provider. This type of trading is made possible by the use of smart meter technologies and advanced trading platforms.

We have commenced pilot programs with several key stakeholders in our community to trial community solar schemes in our networks, including with Tūwharetoa Health Charitable Trust (THCT), Te Nehenehenui Trust (formerly Maniapoto Māori Trust Board), and Maru Energy Trust (Maru).

These Ministry of Business Innovation and Employment (MBIE) funded trials will see energy generated from solar panels traded through a technology platform. One such trial is a joint initiative between Te Nehenehenui Trust and TLC is the deployment of solar panels on two Marae. The scheme enables Māniaroa Marae and Taarewaanga Marae to gift surplus energy to whānau of their choice anywhere on our network.

Another pilot includes the installation of solar panels and new hot water cylinders at whare in Tūrangi. The project sees excess solar generated energy, heat hot water cylinders in recipient households. With hot water heating accounting for around 30% of household electricity costs, pilot households are benefiting from significant cost savings while helping to support renewable energy targets.

Overall, the future of peer-to-peer energy trading is likely to be shaped by a range of factors, including consumer demand, technological developments, and market forces. While the specific developments and trends in this area are difficult to predict, energy trading has the potential to play a significant role in the future of the electricity grid.

Figure 4.35: Māniaroa Marae in Mōkau

Smart load management

TLC uses dynamic load management for domestic hot water to reduce peaks on the network and on Transpower's transmission system. The current technology utilises a Ripple Control system that injects signals into the electricity network, which are then detected by ripple control receivers located in homes and businesses. A key constraint of this system is it cannot address individual homes, so our ability to manage load is limited to bulk control groups.

Through our incumbent meter provider, Influx, we intend to deploy a cloud-based smart load management for hot water system – the Influx service is named Demand Management for Hot Water. Some key benefits we envisage from transitioning to a smart load management service include:

- **Reduced infrastructure:** By using already deployed smart metering infrastructure, TLC will no longer need to invest in maintaining its ripple control transmission systems, which will see a reduction of ~$3m in capital expenditure over the next ten years, which will result in cost savings for our customers.
- **Targeted control during faults.** The smart meter platform can be addressed to an ICP level. It means system operations can reduce demand in specific areas of our network which may be constrained (for example during a system fault) without impacting the service levels of other customers outside the area of constraint.

Overall, we expect smart load management to help improve the efficiency of our network and enable new services for customers.

Power quality management

TLC doesn't currently have a systemised way of monitoring power quality at the LV level. Voltage quality is measured at medium voltage level (11kv or 33kV) to ensure it is maintained within compliance levels. Our current practice is that when power quality is poor in the LV network, the resulting quality issues are usually reported by customers and managed with them on a case-by-case basis.

In partnership with Influx, we have developed a smart meter roadmap that will provide ongoing information on power quality at individual ICP level including:

- Voltage maximum and minimum
- Power factor
- Half hourly consumption
- Reactive power.

We are working to put this capability in place over the next twelve months. As we develop our planning on this initiative we will communicate the progress of this important project to our customers, to provide visibility of the fact that power quality is an emerging priority to support greater renewable generation on our network.

How we anticipate our use of smart meters to support our customers

Smart meters are advanced meter systems that are used to measure and record electricity consumption at individual homes and businesses. These meters are typically equipped with advanced sensors and communication technologies that allow utilities to collect detailed data on electricity usage in real-time.

Smart meters are installed at ~90% of homes and businesses on the TLC network, and we are actively looking to leverage their capabilities for asset management. For example, smart meter data can help us:

- Better understand the patterns of electricity usage on the grid and use this information to optimize the operation of the network. This can help improve the efficiency of the grid and reduce the need for expensive upgrades or new infrastructure.
- Identify potential problems or outages on the grid and take corrective action to prevent them. For example, if a smart meter detects a sudden drop in electricity usage, it may indicate a power outage, and we can dispatch a crew to investigate and fix the problem.
- Engage with consumers and provide them with information on their electricity usage. For example, consumers may access their smart meter data through online portals or mobile apps, which can help them better understand their energy consumption habits and take steps to reduce their electricity use.
- Improve safety by identifying neutral faults and lines down on our network.

Overall, we expect smart meter data to be an increasingly important tool for managing our distribution network. By providing detailed, real-time data on electricity usage, smart meters can help us optimise our operations, identify, and prevent problems, and engage with consumers.

How we decide whether to progress with new innovations, and how we seek supporting information

The decision to commence, progress or adopt of new innovations is determined through our standard asset management and delegation processes. New innovations are typically presented and discussed at our Asset Management Committee meetings (held quarterly) and may also be presented for discussion with the TLC Board if the investment is significant. The decision depends on our analysis of the costs and benefits for each innovation proposal, and this is typically measured either financially or qualitatively (e.g., improvements in quality outcomes or reduction in time).

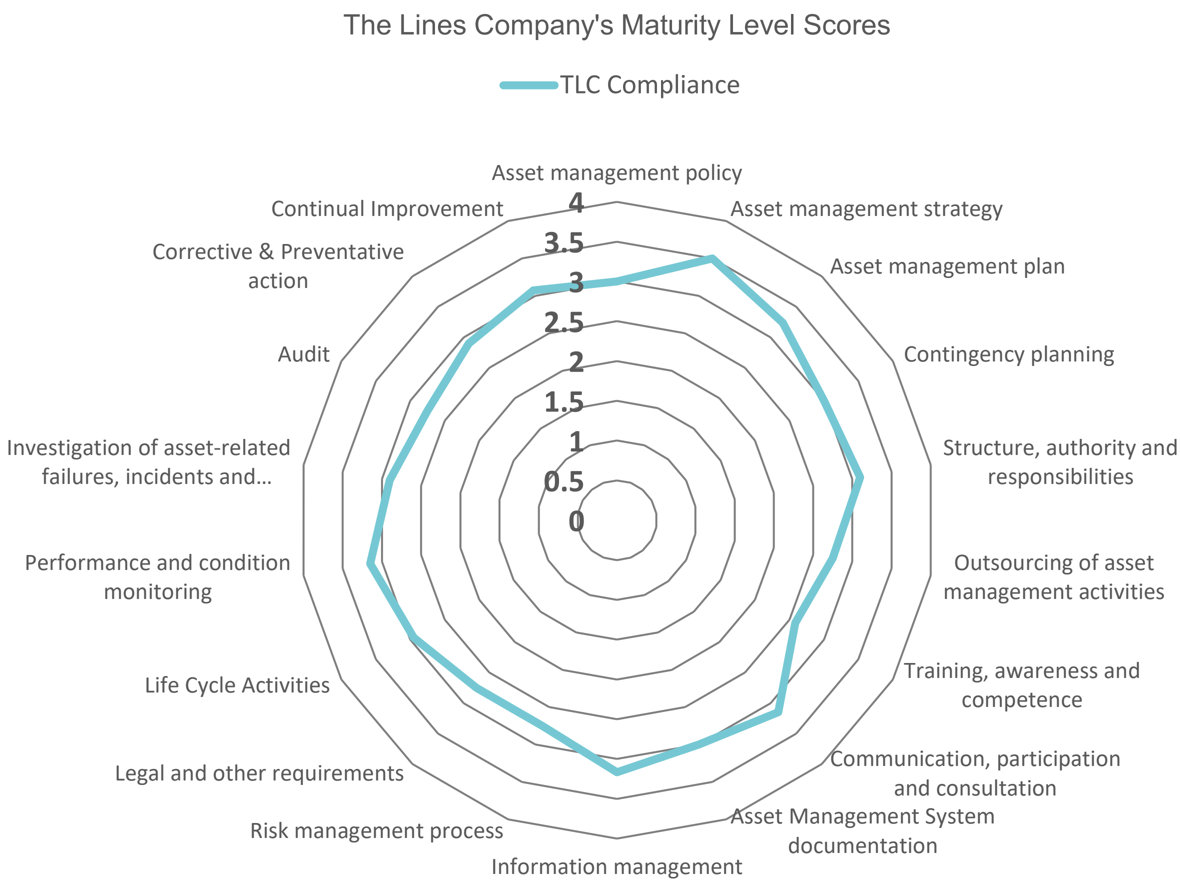
Innovation often depends on the work of other companies that provide us with capabilities or support. The selection or adoption of these services and companies is made in a number of ways. For significant investments, we typically seek responses from the market through an RFI (request for information) or RFP (request for proposal) process. These processes usually seek out information relating to service levels, integration with our systems, costs and ongoing support processes. However, for some innovations the investment may be small and does not warrant a market engagement process. In these cases, we may work directly with suppliers in an agile way to put in place innovations rapidly, and this may include adjusting the scope, and assessing benefits as the project progresses.

4.8 Continual improvement

We are continually improving the way we manage our assets and the outcomes we provide our customers and community. The Commerce Commission provides a standard framework for measuring asset management improvement, which ranks our maturity level from 0 to 4. For the last three years, we have had this independently assessed by an external party.

This year our competency level has increased resulting from the development work undertaken in asset management over the last 12-month period. The conclusion from this review says we are making steady progress in our asset management maturity and identifies areas we can further strengthen. These will be key focal points on our future development.

Figure 4.36: Asset management improvement



05

Our Asset Management Approach

5. Our Asset Management Approach

This chapter sets out how we translate our business strategy and objectives into our day-to-day investment and operational decisions, ensuring effective line of sight between business goals and asset management practice.

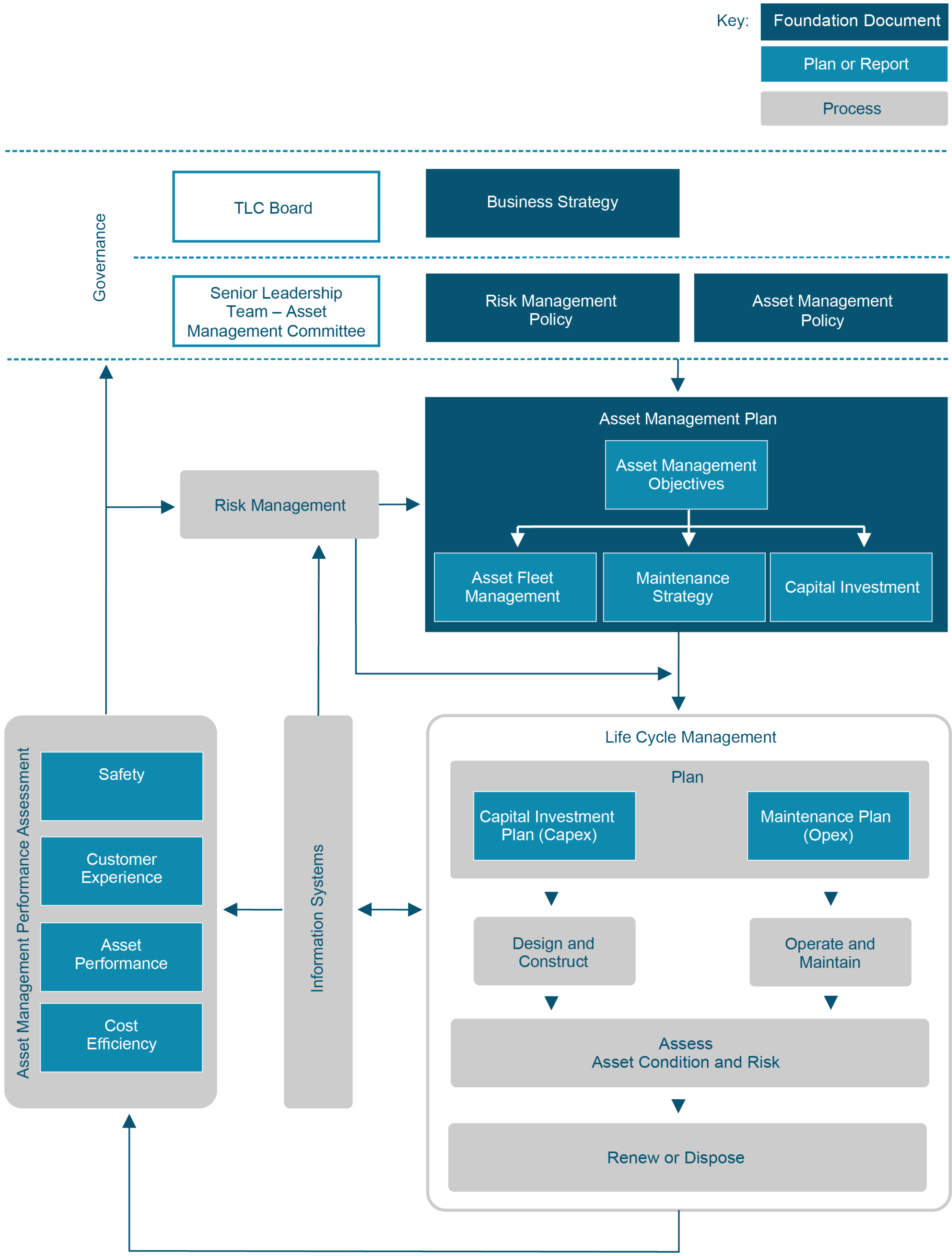
We are transitioning our asset management approach to align with the ISO 55000 framework. As part of this, an assessment against the requirements of ISO 55001:2014 was conducted and alignment with a four-pillar interpretation of that standard has been adopted as summarised below:

- **Leadership and Enablement** of the asset management approach, which is aligned with our business objectives and meets the requirements of both external and internal stakeholders.
- **Asset Planning** – a detailed end-to-end planning process across the asset portfolio which commences with risk profiling of the assets, through options analysis in the Capex plan.
- **Business Processes** – well defined quality processes for the delivery of capex
- **Capex and Opex work** to the assets along with other tasks such as switching, investigations, materials supply and so forth. The intent is to reduce the cost of work through quality management, assure consistency of approach and promote the competency of all teams involved with service delivery.
- **Continual improvement** – consistently improving asset management processes as well as determining future options for network resilience and reliability.

5.1 Asset management system

Our Asset Management System is shown in Figure 5.1 as a structured framework with multiple functions which work together to deliver the asset management pillars listed above. Implicit in this framework is a quality management approach, based on ISO 55001, leading to continual improvement to reduce the overall cost of asset ownership as well as manage risk within defined risk appetites. Figure 5.1 shows our current asset management process. This will further evolve over time the business continues to develop its people, processes, and systems to strengthen its alignment with the ISO 55001 methodologies.

Figure 5.37: Our asset management system



5.2 Asset management accountabilities

Asset management is a multi-level process involving governance, management, and execution for many areas of the business. Table 5.1 shows the accountabilities across the business as they relate to the asset management process.

Table 5.17: Asset management accountabilities

Role	Accountability
Board	• Set strategic direction of business • Approve and monitor risk appetite and associated risk management framework • Review and approve AMP and associated budgets
Chief Executive	• Develop and implement the business strategy • Enable delivery of AMP outputs
Asset Management Committee	• Monitor the implementation of the Asset Management Policy and Objectives • Review material network risks • Monitor the condition and performance of the assets and ensure they are maintained • Review changes to key policies that impact the network assets and expenditure plans
General Manager Network	• Develop and implement Asset Management Framework • Define and monitor Asset Management and Operational Key Performance Indicators (KPIs) • Manage and monitor delivery of AMP outputs • Oversee management of network performance and compliance
Assets and Engineering Manager	• Oversee the development of the Strategic and Regulatory Asset Management Plans • Develop and maintain a technical risk management process to identify and prioritise network safety, reliability, and quality risks, as input to the asset management planning process • Guide Asset Engineers in developing maintenance programmes that improve the reliability of the network • Develop and evaluate business cases for investment in Network Assets • Maintain an overview of compliance requirements as they relate to Assets
Asset Strategy Manager	• Plan the long-term development of the TLC network to meet TLC's safety, growth, performance, and resilience requirements • Develop TLC's Strategic Asset Management Plan (SAMP), including asset class strategies • Determine requirements for capitalised maintenance and major asset renewals • Develop annual Capital Expenditure plans for the AMP process • Review and rationalise risk ranking of issues and proposed work in the AMP
Manager, Asset Information	• Manage the asset information systems • Report on the performance and cost profiles within the AMP • Report on the preventative maintenance schedule in the asset information system • Manage entry new assets into TLC's asset systems • Manage asset data improvement • Develop and improve business processes and systems to enhance business performance related to the use of asset data
Network Analyst	• Assess asset health, criticality, and risk • Estimate asset lifecycle and optimal replacement • Assess impacts and root causes of network outages

Role	Accountability
	• Investigate the root causes of key asset failures and identify maintenance asset management improvements
Network Planning Engineer	• Address load constraints and risks to voltage compliance across the network • Develop strategies to reduce unplanned SAIDI • Assist planning for network growth • Undertake scenario analysis to consider impact of disruptive technology on the network
Engineering Manager	• Plan and co-ordinate delivery of capital and maintenance projects • Oversee the development of design standards and adherence to them
Project Managers	• Manage construction and delivery of the AMP projects
Asset Engineers	• Define criteria for monitoring of asset health, risk, and performance • Specify equipment and installation standards for assets • Develop the preventative maintenance schedule of asset surveillance • Determine feedback. requirements and trigger points on asset condition • Monitor equipment condition following maintenance inspections and advise when remedial action or renewals should take place
Manager Programme Delivery and Key Accounts	• Profiling and budgeting for expected customer driven growth • Engagement with major customers on scheduled future work • Manage annual work scheduling for the registered AMP projects
Manager, Operations	• Oversee the operation of the network • Plan control, SCADA and operational asset requirements • Oversee the development of public safety standards and policies
General Manager Network Services	• Enable delivery of assigned AMP capital and maintenance activities • Provide fault response services • Carry out inspection activities and provide feedback for asset condition analysis

5.3 Governance structures

AMP governance

Asset management decisions are authorised according to our Delegated Financial Authority Policy, which defines the capital and operational expenditure limits of the Senior Leadership Team. Separate limits are defined for budgeted and unbudgeted expenditure. Any expenditure that exceeds these limits is submitted to the Board of Directors with a business case for separate consideration and approval.

The asset management capital and maintenance programmes are reported to the Board of Directors by the Senior Leadership Team as part of the Board reporting cycle, with explanatory notes on deviations from the plan.

Operational governance

Oversight of operational performance and improvement is managed by a number of internal review groups and committees. Three groups (Design Review Group, Vegetation Management Group, and the Outage Management Group) provide a forum for decision making, performance management and analysis within our operational teams. A fourth group (Maintenance Review Group) will be established in 2023 to provide similar oversight function for our maintenance activities.

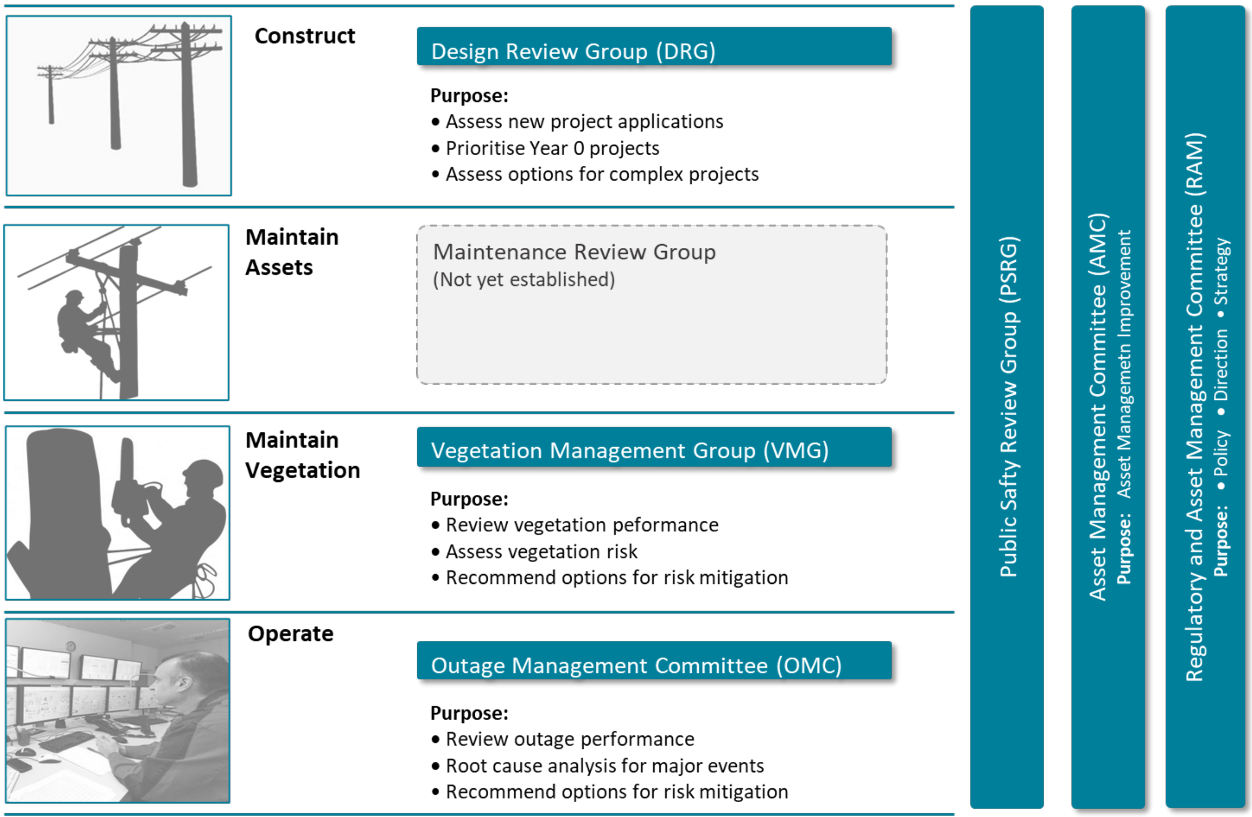
Three additional governance structures work across the business to manage public safety (Public Safety Review Group), asset management improvement (Asset Management Committee) and strategic direction (Regulatory and Asset Management Committee or RAM).

The RAM is a subcommittee of the TLC Board and provides a forum for more detailed interaction between the Board and management in areas relating to asset management, pricing, and regulation.

Figure 5.3: Asset Lifecycle Process

shows the operational governance structure.

Figure 5.38: Operational goverance structures used at TLC



5.4 Risk management

Risk management is a fundamental asset management discipline. It requires robust processes in place to assess and manage all business-related risk. We are transitioning our risk management processes to align with ISO 31000:2009 commencing with Tier 1 as detailed below.

Risk is defined as the effect of uncertainty on the ability of an organisation to meet its objectives. The purpose of a risk management framework is to actively apply risk treatment options, so we ensure any uncertainties of meeting its objectives can be avoided, reduced, removed, or managed.

Tier 1 Risk Management Framework

Tier 1 risks are those risks that are visible to the Board with accountability for managing them assigned to a Senior Leadership Team member. The Board is involved in setting the risk appetite for each type of risk identified.

Risk identification and evaluation encompasses assessment of the following areas:

- People safety and resource availability
- Stakeholder confidence/reputation; environmental and cultural preservation
- Commercial/financial sustainability
- Performance of core services
- Regulatory.

Following identification of the risks, strategies, and processes to manage risks in line with the business' risk appetite are implemented. These efforts are supported by a comprehensive risk monitoring and reporting regime, with visibility provided to the Board Audit, Risk and Finance Committee on a bi-annual basis and any changes to Tier 1 risks reported to the Board as part of regular management reporting.

Tier 2 and 3 risks

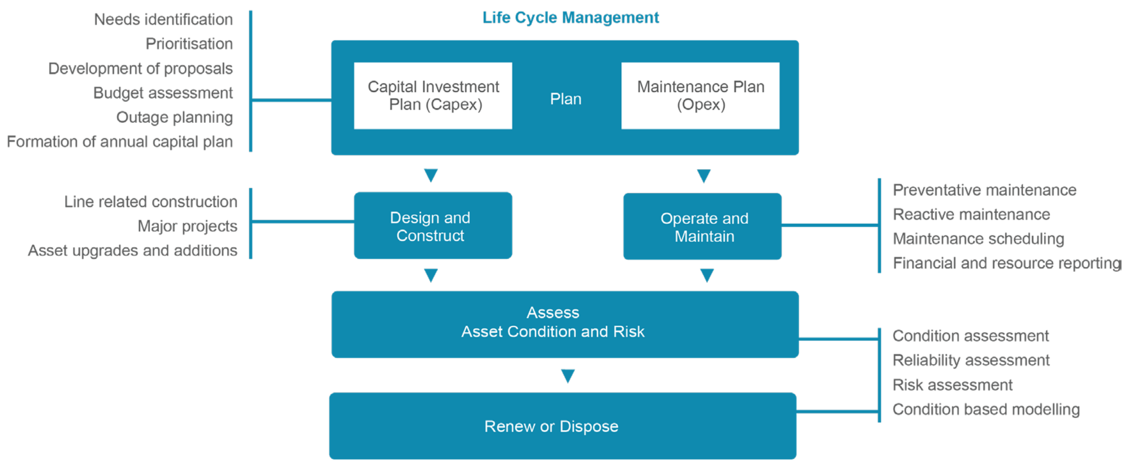
Tier 2 and 3 risks are currently managed within individual business units in a manner that best reflects the needs of the business unit. Tier 2 and 3 risks are being aligned with the Tier 1 risk framework across the company to enable a consistent approach to managing risks. This will allow common and cascading risks to be identified and ensure they are managed appropriately.

Detailed asset related risk is currently considered at both Tier 2 and 3 levels and is used as a means to prioritise activity developed as part of the asset management process. The assessment methodology is further detailed in Section 0.

5.5 Lifecycle management

Management of our assets is based on taking a whole of life approach to asset management. Our interpretation of the lifecycle is shown in Figure 5.3.

Figure 5.39: Asset lifecycle process



A detailed description of our asset lifecycle management is provided in the following sections.

Plan

Our planning process identifies specific network requirements that will deliver stakeholder expectations for service and price, investigating options and authorisation of expenditures.

Our capital project planning and acquisition process consists of the following steps:

Needs identification

There are three broad workstreams in our planning – asset renewals, network development (to address growth and security requirements) and customer required work.

Asset renewals

Needs identification for asset renewal planning uses the information gathered from condition, reliability, and risk assessments. This ensures that assets that have been identified as approaching end of life or are a high safety risk, are scheduled for renewal. An assessment is made on the scope of the renewal, which may comprise refurbishment, overhaul, or outright replacement.

Network development

Monitoring and modelling of network performance and customer load use patterns drives investment planning for network development purposes. This assessment takes a medium to long term view of network requirements to ensure performance remains within statutory limits and that incremental growth due to changes in population and network configuration are able to be accommodated with minimal impact. Asset relocation for improving security or quality of supply is also included in this category.

Customer required

Customer required work is usually initiated by a major customer due to establishment of a new plant or a change in the electricity requirements of an existing plant. Agreement is reached with the customer on how to fund this development, which may see a full or partial capital contribution from the customer with any additional funding requirements being met through ongoing connection charges.

Prioritisation

Prioritisation of asset renewal and network development projects is carried out based on risk assessment outlined in Section 0, which includes asset related risks and business-related risks. This process analyses consequences including safety, loss of load or loss of security, and a likelihood of occurrence. Prioritisation of customer required projects is based largely on the timing requirements of the customer. Once the assessment process is complete, a ranked list of capital projects is produced.

Development of proposals

Proposals for identified capital projects are developed to ensure all requirements are identified and incorporated into the planning process, and that financial approval is gained in line with company delegated authorities.

The development process includes the following:

- Scope technical and performance requirements;
- Identify any project pre-requisites (e.g., land access, consenting, design, and procurement lead times);
- Consider alignment with other projects to minimise cost and outage impacts;
- Consideration of the use of standardised designs or asset types to minimise lifecycle costs;
- Consideration of alternative options, including non-network options, if these present lower cost outcomes;
- Schedule projects across the planning period (10 years);
- Where projects are identified for years 1-3, more detailed planning (Design & Construct) commences.

Financial and outage budgeting

The financial budget is based on a combination of historical project information and estimation of costs through our Network Services business unit. Following the development of proposals, cost estimates for projects are co-optimised with outage availability. This is to ensure that an optimal point is met between the cost of delivering the project, and the outage impact that it will have when the work is carried out.

This includes:

- Phasing of planned outages to ensure they are executed at the optimal time of year (consideration is given to weather patterns, land access, dairy season, and historical outages)
- Use of generators to reduce customer outages (cost versus outage co-optimisation)
- Additional resourcing to reduce the time associated with a project outage.

Formation of annual capital plans

The outputs from the preceding stages that result in projects in year 1 are consolidated and assessed at a Management and Board level to ensure that all identified risks have been managed within the Company's risk appetite, and once complete the capital spend is confirmed.

Detailed planning for execution of project work then commences.

Design and construct

Design

In-house design capability is maintained for line related works. New lines are designed to AS/NZS7000. Minor design changes to other asset classes are carried out by internal engineering staff where resource and skillset allows. Major projects on asset classes other than lines and pole mounted equipment are completed by external parties. The impact of any changes to design or introduction of new equipment are assessed by engineering staff as part of the design review process. Soil condition and climate impact on assets is assessed in the design phase.

Construct

Line related construction activity is carried out by the Network Services business unit, with support from key contractors where needed to manage resource or outage constraints. Network Services also carries out minor project works where their skillset and resource allow.

Major projects (e.g., construction or renewal of zone substations) are outsourced either as a design and build package or design is completed by specialists with construction contracted out separately.

Project related work is managed by the project management team to ensure stakeholder, technical and commercial requirements for work completed are met.

Operate and maintain

Operate and maintain means that we operate the network and assets in such a way as to deliver the service levels sought by customers, in line with our regulatory requirements, and effectively maintain the equipment and network through defect identification and planned maintenance activities. Network operations and our approach to maintenance are detailed in Section 6 and summarised below.

Preventive maintenance

Preventative maintenance is predominantly condition, operating cycle, or time-based maintenance and involves the collection of operational and asset condition information through site inspection, asset routine service and asset condition test. TLC's preventive maintenance strategy seeks to provide essential information about the health of the assets, reduce preventable defects and meet all statutory obligations.

Our preventive maintenance schedule ensures that routine work is scheduled as required to ensure our assets meet all performance requirements and remain compliant with regulations. The schedule is defined by and managed in accordance with the strategy approved by the Asset Engineers and budgeted in the Annual Works Plan.

Reactive maintenance

Reactive maintenance comprises fixing defects identified from preventative maintenance inspections and fault response. Focused primarily on fault response, reactive maintenance makes up the largest proportion of our maintenance by spend. Most of the reactive maintenance spend is driven by external factors (generally weather, vegetation, and third-party related events) rather than a high rate of asset failure. The balance between preventative and reactive maintenance is monitored on an ongoing basis to ensure the network performance is maintained to target levels in the most cost-efficient manner.

Maintenance scheduling

Preventative maintenance activities are scheduled as part of the annual planning process and are based on the current understanding of asset condition and performance requirements for the planning period. These activities are incorporated into the annual works plan. Planned maintenance activities are scheduled such that they do not create resource or outage constraints during peak work times, which often means this work carried out during winter when land access for line renewal work is constrained.

Financial and resource budgeting

An allowance for both cost and resource for corrective maintenance is made in the annual planning process. This is based on historical requirements and as noted above is driven largely by weather, vegetation, and third-party events.

Assess asset condition, renew or dispose

Asset condition assessment is the process of identifying assets which meet the end-of-life criteria and to decide when to renew and/or dispose of assets.

An essential part of managing the life cycle of our assets is understanding their condition, the impact that has on overall reliability of the network and the business risk that the combined condition and reliability presents. The following sections outline our approach to this.

Condition assessment

The condition of assets is assessed through a combination of factors. At the time of commissioning an expected life is applied to an asset based on its design and performance of similar assets. This provides a baseline view of expected life assuming the asset is operated within design parameters and required maintenance is completed. Failure modes for the asset are identified and, where possible, indicators of these failure modes are monitored during preventative inspections or when routine or corrective maintenance is carried out.

The majority of assets are assessed on a combination of age and observed condition basis with engineering judgment applied to determine when best to renew them.

Reliability assessment

Overall reliability of the network is monitored using the SAIDI and SAIFI performance targets determined by the Commerce Commission. Detailed analysis of historical faults has been completed in the development of this Asset Management Plan with plans developed to target underperforming asset classes and areas of the network. Network reliability is monitored on a daily, weekly, and monthly basis at various levels of the organisation to ensure targeted service levels are achieved.

Asset risk assessments and AMP prioritisation

The Design Review Group (DRG) provides governance over project prioritisation for the AMP. This is done both pre-year (i.e., needs analysis and prioritisation for long term planning) and in-year (prioritisation of existing and emergent works in the current year). The DRG evaluates several factors including the benefits each project can bring and the associated risks. This includes analysing how a project will impact the network's risks such as reliability, worker and public safety, environmental impact, and reputational damage.

The DRG also assesses how a project aligns with our strategic goals, such as reducing carbon emissions, improving customer satisfaction, and achieving cost savings. By analy**s**ing project benefits and risks, the DRG ensures that scope of our projects deliver the value for our customers.

How this section aligns with Commerce Commission investment categories

When developing our expenditure plan, we consider the current business drivers and the key objectives related to each asset portfolio. Each asset portfolio covers a range of investment categories that TLC is required to report on in its Information Disclosure to the Commerce Commission. The table below shows the association between investment category in the Information Disclosure and TLC's capital investment portfolio, and the key business drivers. Often one business driver is associated with multiple investment categories and appears in more than one project type.

Table 5.18: Capital investment portfolio

Portfolio	Investment Category (Commerce Commission)	Business Drivers
Asset Renewal	Asset replacement and renewal Other Reliability, safety, and environment	Equipment renewals Hazardous equipment Safety
Network Reliability	Other Reliability, safety, and environment	Network Reliability
Network Development	System growth Quality of supply	Security of supply Quality of supply
Customer Required	Consumer connection Asset relocations	Cumulative capacity
Non-Network	Non-system fixed assets – Atypical Non-system fixed assets - routine	Business support

Deferral of investment – a key consideration before we invest

Although maintaining our electricity supply assets requires ongoing investment, we optimise investment timing and maximise the lifecycle of assets where it makes sense to do so having regard for safety, risk, economic outcomes, and customer service. We undertake several innovations that defer asset replacements by easing network constraints. These include:

- **Use of mobile and fixed power factor correction capacitor banks.** Mobile capacitor banks are a bank of capacitors mounted on a trailer that can be deployed at short notice to support network constraints during faults or outages.
- **Installation of voltage regulators.** TLC uses voltage regulators extensively in its rural reticulation. These improve power quality and allow small conductors to remain in service which defers reconductoring projects.
- **Extensive deployment of load control and metering technologies** that enables shedding of up to 16MW load (25% of our coincident GXP demand) at critical times.
- **Time of use pricing** that incentivises customers to shift load out of peak times, and to utilise controlled water heating.
- **Use of drones for confirming line condition prior to replacement.** TLC now regularly uses drones to verify asset condition prior to commencing planned line renewal work. This has resulted in some projects being de-prioritised and their replacement deferred.
- **Development of Business Intelligence (BI) tools. We are investing in business intelligence technologies and systems to provide deeper analysis of our assets and their performance. This is providing new insights on how our assets perform against a range of environmental and electrical conditions, allowing more informed decisions in our asset renewal planning.**

Asset lifecycle assessment

We use an asset condition and risk modelling database known as Asset Altitude. The database incorporates asset deterioration profiles to predict asset failure. The deterioration curves can be generated from either modelled or measured data points.

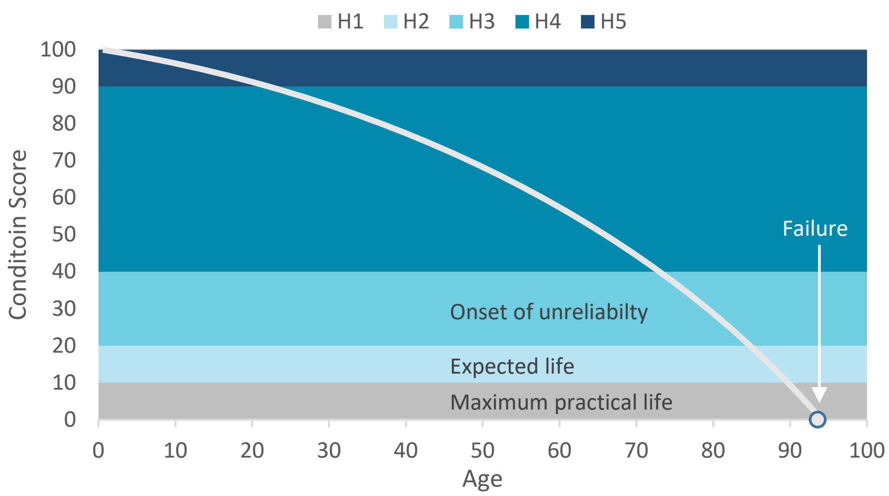
We also use this database to estimate the current health of our assets, referenced to industry guidelines. Figure 5.4 shows a typical asset deterioration curve, and the relationship to asset deterioration and health indices that we have used in our asset grading process.

Asset health provides an indication of the probability of failure of an asset. Other factors, such as the criticality of the asset (i.e., the number and type of customers served, and whether there is a backup supply to those customers) are used to determine the consequence of that asset failing, and together these factors indicate overall asset risk.

At this stage we have completed a full review of asset health, and we have used this data for the first time to estimate our long-term asset renewal expenditure (years 2027 to 2031) more accurately. Consequently, those years show a more significant asset renewal expenditure profile in this 2021 AMP than in our previous AMPs.

Our asset lifecycle modelling is a work in progress, and relies heavily on our asset data accuracy, which we are separately and purposefully improving. Our objective is to complete a full asset risk model (including both probability and consequence) for each major asset class in FY2022.

Figure 5.40: Condition and asset grades



5.6 Information systems

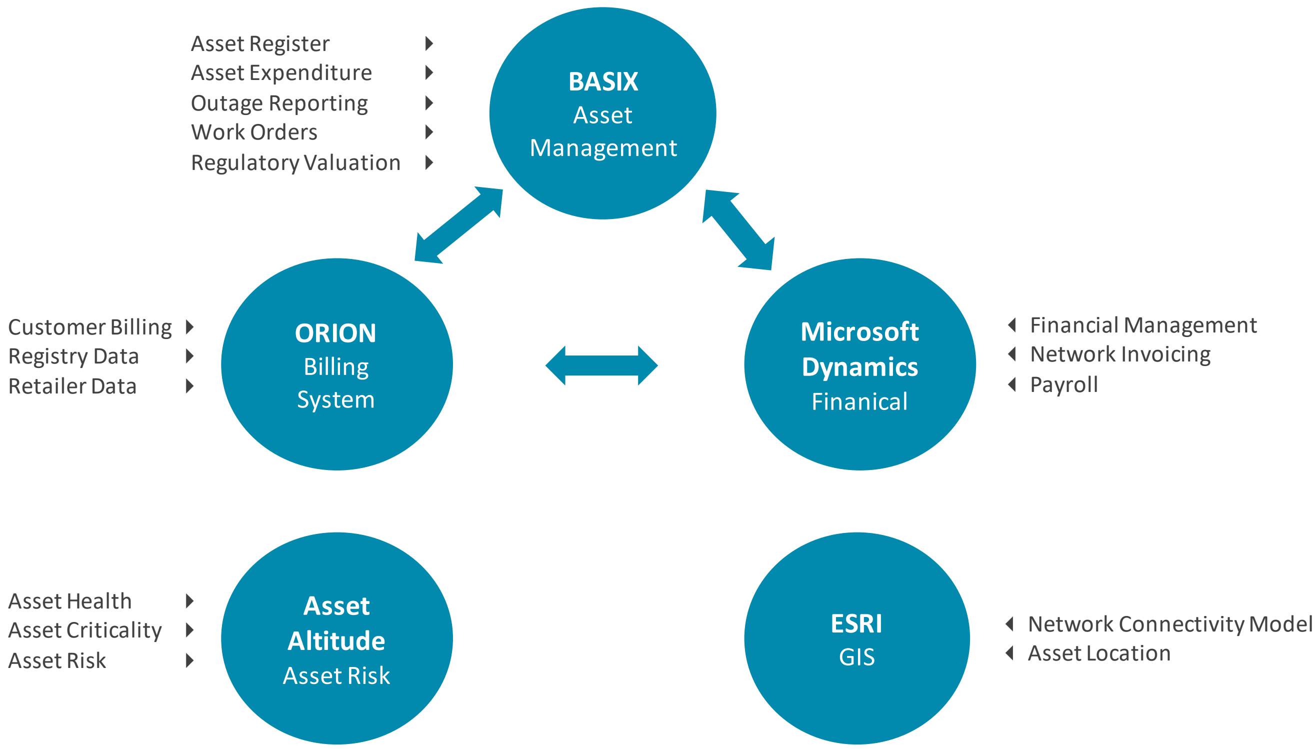
Systems overview

To assist in managing our assets, we operate five core Information Technology platforms.

- BASIX asset management system
- Microsoft Dynamics financial system
- Orion billing system
- ESRI GIS platform
- Asset Altitude asset risk system.

Key information is exchanged between three of these systems automatically as demonstrated in a simplified format in Figure 5.5. The Asset Altitude and ESRI GIS platform currently operate independently of the other systems.

Figure 5.41: Overview of system layout and interaction



BASIX

BASIX is our core asset management system and used as a tool to support and provide information for our asset management processes and planning. It contains asset data and is used to calculate reliability statistics and regulatory valuations. It also produces reports that align with the network performance criteria.

The system comprises various modules including:

- Regulatory Asset Register
- Works Management
- Outage and Reliability
- Reporting
- Annual Planning.

Assets are organized into a hierarchy allowing both vertical (e.g., feeder or substation) and horizontal (asset class, e.g., distribution transformer) analysis and reporting.

The asset register is used to access the network data and is broken down into:

- Lines
- Installations
- Zone substations
- Transformers
- Switchgear
- Protection and Control
- Network Model
- Property
- Batteries
- SCADA & Radio.

Details of proposed projects that result from the asset management planning process are entered into the annual planning section of the BASIX database, providing an ongoing reference and ability to track progress against plan in a structured manner. Financial forecasts are then extracted from the database for AMP and disclosure purposes.

Microsoft Dynamics

Microsoft Dynamics is the Company's financial system and is also used by the Network Services business unit to track and record costs associated with work carried out for the Network and external customers.

ESRI Geographical Information System (GIS)

The ESRI GIS system primarily records geographical information for TLC's assets. The system is currently stand alone and is used to identify where assets currently or may, in the future impact property owners.

Asset Altitude (asset risk database)

Asset Altitude is an asset risk system that uses asset condition data combined with predictive algorithms to estimate asset life and the optimal replacement period. TLC commissioned Asset Altitude in 2020 and is in the process of integrating it with TLC's asset database (BASIX). When complete Asset Altitude will provide TLC with a dynamic asset risk management system.

How these systems are used in developing our capital expenditure plans

These systems form the core of our asset information capabilities. They hold key information on the condition and serviceability, capability and capacity of each asset.

Each year our Asset Information and Asset Engineering teams review these attributes and make decisions on what assets should be renewed, and how our network should be augmented to support ongoing safety, reliability, quality and capacity of supply. The decisions are made via an assessment of a range of factors, led by asset condition but including the criticality of the asset to supply (some assets may be upgraded sooner than others if they are upstream on a feeder).

Processes for managing data quality

Our Asset Information team monitors and continuously improves the data quality of our assets. For information on new assets, asset data quality is managed by an automated report that is reviewed each week to identify anomalies and gaps. For existing assets, asset data quality is improved by specific data cleansing initiatives undertaken by the team from time to time.

Data accuracy is an ongoing challenge, as many of TLC's assets were installed prior to computerisation. Because of the volume of assets we have, this information can only be improved over time, and in most cases requires a field visit to confirm the specific characteristics of the asset.

Identifying the business needs for information

The Asset Information team also liaises with teams from across the business to understand their information needs, and to automate processes to aid data capture and data quality from field to the back-end system.

5.7 Business continuity planning

TLC manages business continuity risk through the implementation of an Incident Management Plan. The framework is based on Civil Defence Coordinated Incident Management System (CIMS) and uses the Four Rs of Emergency Preparedness ***Reduction***, ***Readiness***, ***Response*** and ***Recovery***.

The Incident Management Plan identifies a Duty Manager who is able act as Incident Controller during an emergency event. If necessary, an incident management team will be established to ensure that any public and staff safety risk is minimised and that our obligations as a lifeline utility are able to be met with minimal interruption to supply.

Reduction of business risk is managed through the organisational risk framework detailed in section 5.4. This sees risk management plans implemented to reduce either the likelihood and/or consequence of an event occurring that would have a negative impact on the business. At an asset level risk is managed through ongoing monitoring, maintenance and renewal of assets as determined in the asset class strategies and this AMP.

Readiness for an emergency event is covered at multiple levels through the organisation. The Incident Management Plan provides a generic emergency management framework which includes:

- Defined responsibilities for readiness and for response – in particular for incident controllers who are required to co-ordinate emergency response activities during an event. Background and reference information
- Contact details for internal and external parties and key stakeholders
- Communication systems, options, and protocols
- Defined responsibilities for readiness and for response.

A number of specific incident response guides have been developed as detailed below:

- Serious Injury/Fatality
- Significant threat to employees
- Terrorism
- Environmental Incident
- Medical Emergency
- Building relocation
- Cyber Security breach or IT system failure
- Earthquake
- Volcano
- Major Storm Activity
- Significant Asset Failure
- Network Event
- Pandemic

Desktop emergency exercises are conducted to give staff exposure to the incident management framework and identify any areas of improvement required in either business process or field response during an emergency.

Staff are also encouraged to ensure they and their family are prepared for civil defence emergencies.

Response to an event is determined depending on the cause and extent. The Incident Management Plan makes provision for establishment of a small incident management team for local events, network event management teams in the event of a major network incident, and a full incident response team including the Board should it be deemed necessary by the Incident Controller.

Following any activation of the Incident Management Plan, an event review is conducted with any learnings incorporated into the Incident Management Framework for use during future events.

Recovery following an incident is managed on a case-by-case basis with input from appropriate levels within the organisation as required.

5.8 Communication and participation

TLC's asset management plan development is a business wide activity. In 2018, we redeveloped our asset management policy and framework, including redeveloping this regulatory AMP to improve readability and communication for staff, customers, communities and key stakeholders.

The communication of this regulatory AMP with our wider stakeholder group is by way of news stories published in community newspapers and on our website, and direct engagement with our major customers, our Board and our Trust. All AMP documents are publicly available on TLC's website.

A key next stage of our asset management maturity is to develop a strategic asset management plan (SAMP) which sets out the objectives, asset strategies, business rules, processes and standards that underpin this AMP. This is a business wide activity and will bring together staff and other stakeholders in its development. This initiative will extend participation and ownership in our asset management process.

5.9 Our security of supply standard

Figure 5.9.1: Point of supply security

Class	Description	Size of Load		Failure Type		
		Load (MVA)	Cust Count	Single cable, line, or transformer	Double cable, line, or transformer fault	Bus or switchgear fault
S1	Large Supply Point	>15	>4000	No interruption	Restore within 4 hours	No interruption for 50% and the rest within 1 hour
S2	Small Supply Point	<15	<4000	Restore within 0.5 hour	Restore within 4 hours	Restore 50% within 1 hours and the rest in repair time

Figure 5.9.2: Substation security

Class	Description	Size of Load		Failure Type		
		Load (MVA)	Cust Count	Single cable, line, or transformer	Double cable, line, or transformer fault	Bus or switchgear fault
Z0	Special Industrial	>2		Commercial Agreement	Commercial Agreement	Commercial Agreement
Z1	Large Zone Substation	>5	>1500	No interruption	Restore 75% within 2 hours and the rest in repair time	No interruption for 50% and restore within 2 hours
Z2	Medium Zone Substation	2.5 - 5	500-1500	Restore within 0.5 hour	Restore 50% within 4 hours and the rest in repair time	Restore 50% within 4 hours and the rest in repair time
Z3	Small Zone Substation	<2.5	<500	Restore 50% within 4 hours and the rest in repair time	Restore in repair time, Generators support if over 12 hours	Restore within 4 hours

Feeder security

Feeders connect substations to customers. Most of our feeders are very long and commence their supply to a town or urban centre. However, they usually continue to supply rural and remote customers. Because of this our security standard applies to parts of a feeder, not the feeder in its entirety and is based on customers connected.

Class	Description	Size of Load		Failure Type		
		Load (MVA)	Cust Count	Single cable, line, or transformer	Double cable, line, or transformer fault	Bus or switchgear fault
F1	Urban Feeder section	1 - 3	>400	Restore within 0.5 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
F2	Rural Feeder section	0.5 - 2	>100	Restore within 4 hours	Restore 50% within 4 hours and the rest in repair time	Restore 50% within 4 hours and the rest in repair time
F3	Remote Rural and Rural spurs	<0.5	<100	Restore in 8 hours	Restore in repair time	Restore in repair time
F4	Urban Feeder section	1 - 3	>400	Restore within 0.5 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours

06

Growing Our Network

6. Growing Our Network

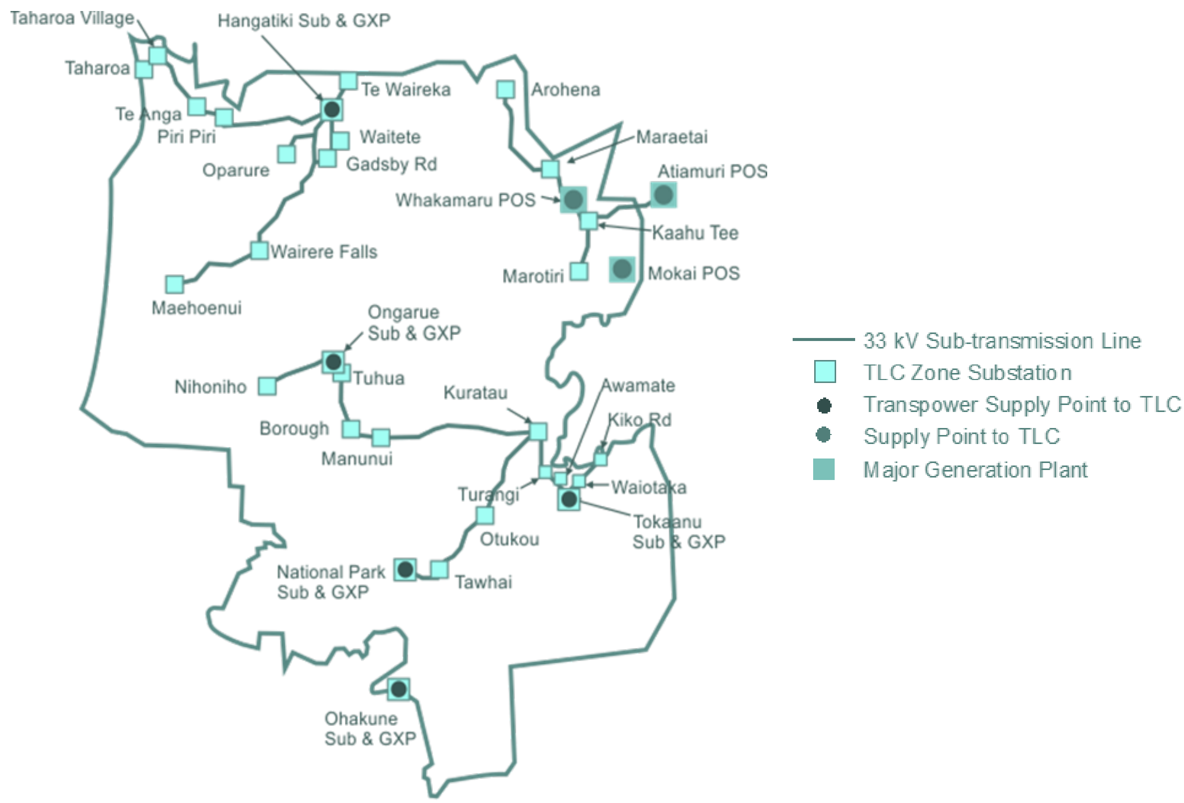
This chapter describes our plans to ensure supply and security of the network. It summarises our area development plans and explains how we intend to invest in the automation of our network to enhance reliability and performance.

6.1 Network overview

TLC maintains and operates 29 zone substations which transform electricity from our 33kV sub-transmission network to supply our 11kV distribution network. Figure 6.1 shows TLC's 33kV sub-transmission network and the location of its zone substations.

Our 33kV sub-transmission network is one of the longest in New Zealand at 451 km and as such its exposure to faults caused by weather and vegetation related incidents is high. Sub-transmission line backups between points of supply are long and amongst the oldest parts of the network. Reliability-centred maintenance of the sub-transmission network is an essential part of our asset management approach, coupled with targeted reinvestment to minimise interruptions to customers' supply.

Figure 6.42: TLC's supply points, sub-transmission (33kV) Network and zone substations



In our growth forecasts, all expenditure in this section is presented as constant values, meaning that it is not adjusted for Consumer Price Index (CPI) in future years.

6.2 Points of supply

Overview

Table 6.1 shows a summary of our supply points and outlines the level of security we have at each point and impact that a loss of supply would cause.

Table 6.19: Supply point summary

Points of Supply	Asset Owner	Cust. Serviced	Operating Security Level[2]	Peak Load (MVA)	Installed Capacity (MVA)	Trans-former Security	11kV or 33kV Backup[3]
Hangatiki	Transpower / TLC[4]	9042	N-1	41.3	70	N-1	Light (2.0MVA)
Tokaanu	Transpower	4870	N-1	11.2	40	N-1	Yes
Ōngarue	Transpower	4638	N-S	13.3	20	N	Yes
Ātiamuri[5]	TLC	2566	N-S	11.4	10	N	Yes
Whakamaru	Tūaropaki			11.3	23	N	Yes
Ohakune[6]	Transpower	2061	N	8.0	20	N	Light (2.0MVA)
National Park	Transpower	813	N-S	6.5	20	N	Yes
Mōkai	TLC	13	N	4.9	7.5	N	Light (1.0MVA)

[2] The Operating Security Levels mean:

- N-1: Full backup of all components
- N-S: Backup provided by manual switching
- N-S(A): Backup provided by automated remote switching
- Agree: Security of site as agreed with major customer

[3] The 11kV or 33kV backup designations mean:

- No: There is no backup supply
- Light backup: The distribution system can supply < 20% of peak load
- Medium backup: The distribution system can supply 20% to 50% of peak load
- Yes: The distribution backup system can supply the total peak load of the substation

[4] A third 110kV/33kV 30MVA Power transformer was commissioned at Hangatiki in 2019 bringing its transformer security to N-1.

[5] Ātiamuri is a backup supply for Whakamaru

[6] Ohakune currently operates over the backup capacity of 2MVA for 40% of the year

Demand forecast for our points of supply

Table 6.2 shows the demand forecasts at TLC's points of supply. Cell shown in grey indicate when we expect to exceed the firm capacity of our GXP

Table 6.20: Point of supply demand forecasts (MVA). Shaded cells represent non-conformace of security criteria.

Point of Supply	Security	Capacity (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Hangatiki	N-1	48	48.6	59.6	61.2	61.8	62.3	62.9	63.5	64.4	64.9	65.5
Ohakune	N	20	5.6	5.5	5.3	5.1	5.0	4.8	4.6	4.5	4.3	4.3
Ōngarue	N-S	20	10.2	10.3	10.8	11.0	11.2	11.3	11.5	11.6	11.8	16.0
Tokaanu	N-1	20	10.5	10.8	11.0	11.3	11.5	11.8	12.0	12.3	12.5	12.1
National Park	N-S	10	5.3	5.2	5.1	5.1	5.0	4.9	5.3	5.2	5.2	5.2
Whakamaru	N-S	23	12.8	12.9	13.2	13.3	13.4	13.5	13.6	13.7	13.8	13.9
Mōkai	N	7.5	6.0	8.0	8.1	8.7	8.8	8.9	8.9	9.0	9.1	9.1
Ātiamuri	N	10	12.6	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8

Note: Growth on the the Hangatiki points of supply is driven by major customer projects that are currently in planning. Our current forecast includes our best estimate of that load over the planning period, but this may change pending finalisation of those projects.

The key constraints in our points of supply

Two of our supply points are currently experiencing constraints or approaching constraint.

Site	Constraint Description
Hangatiki	Peak load at Hangatiki 33 kV grid exit point already exceeds the n-1 capacity of the supply transformers. The Waikato 110kV network is already constrained and demand growth at Hangatiki and Te Awamutu will eventually result in n-1 overloading of the 110 kV circuits that connect the two grid exit points to the wider grid.
Mōkai	The Mōkai Point of Supply is a single supply from Tūaropaki Mōkai Geothermal Power station with limited backup. This supply is primarily used as a supply Tūaropaki owned Miraka Milk Plant, Mōkai Gourmet greenhouse complex and other farming type supplies in the immediate Mōkai station area.
Ātiamuri	The Ātiamuri Point of Supply acts as a backup to the main point of supply at Whakamaru. It is used for two weeks of the year when Whakamaru is taken offline for planned maintenance, and during unplanned outages. The 10MVA transformer is exceeding its rated capacity with a peak loading of 11.5MVA.

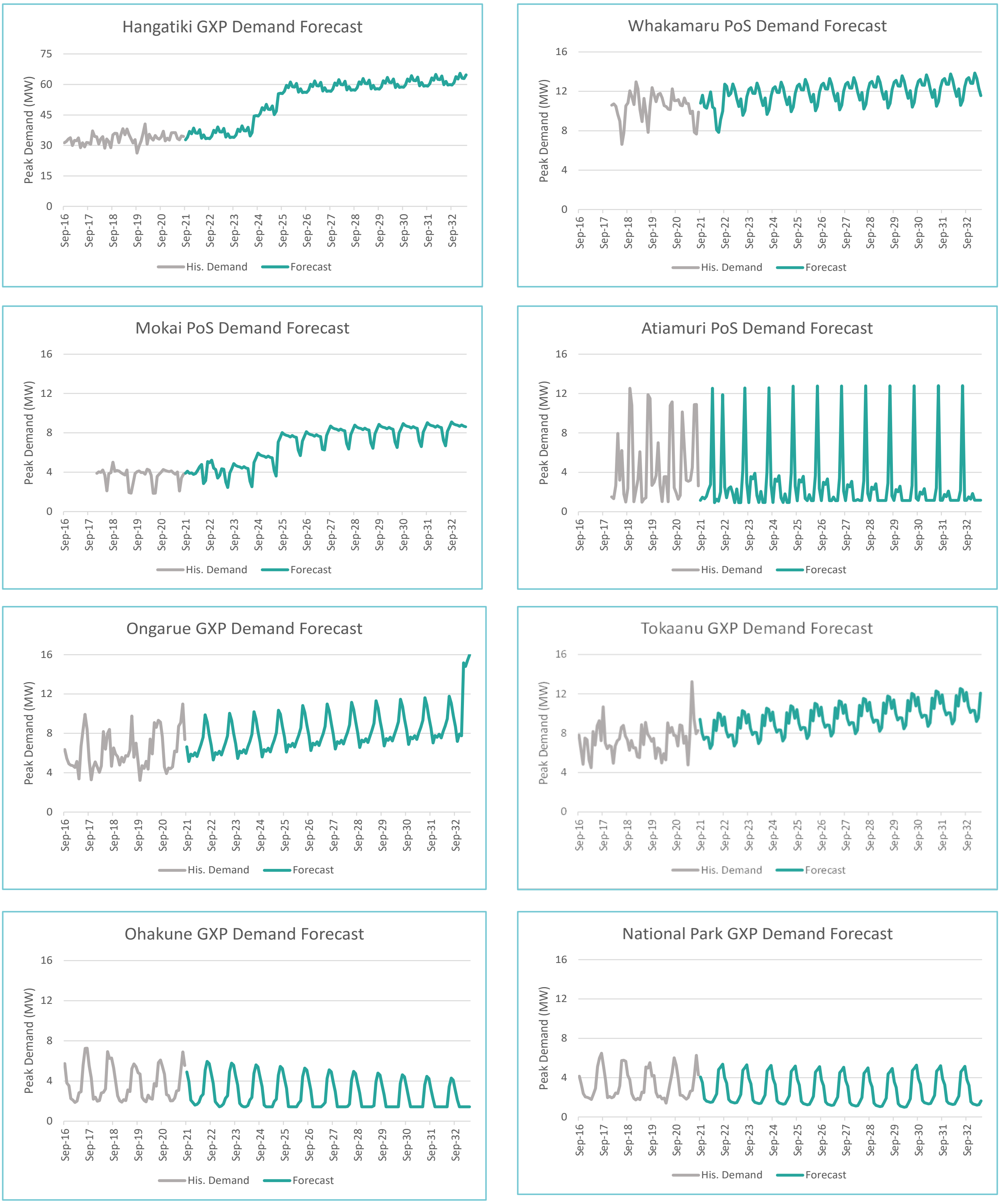
Proposed projects

We are planning two significant upgrades to address these issues.

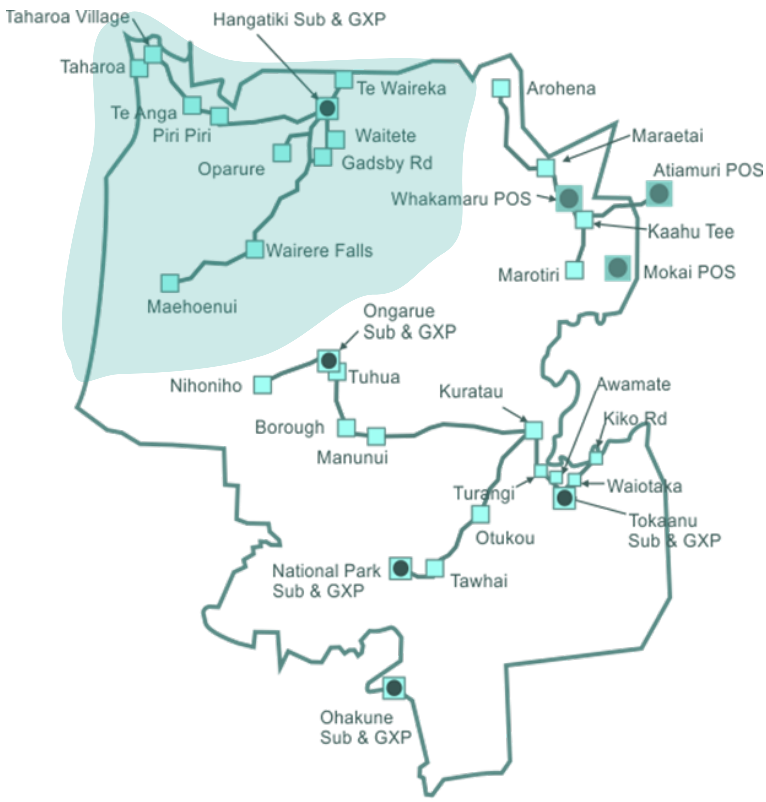
Project	Works Description	Year Estimated	Budget ($000)
New Southern Waikato Regional GXP	Create a new regional 220/110kV interconnector on the border of the Waipa and TLC boundaries. Also upgrade the 110/33kV transformers that are currently located at the Hangatiki GXP **Alternatives Option Considered:** a) Only upgrade the 110/33kV transformers at Hangatiki b) Procure flexibility supply from the open market. c) Reduce security and implement a load shedding scheme on the new load	2027-2030	50,000 (est. 12,000 TLC contribution)
Mōkai Supply Agreement	The Tūaropaki Trust is responsible for the growth, as well as the generation that can supply the demand. TLC is working with the Mercury and Tūaropaki Trust to ensure that the supply can be maintained. **Alternatives Option Considered:** a) New Substation at Miraka ($5.5M – see customer projects) c) Increase capacity of existing 11/11kV transformer	2024	0
Ātiamuri PoS Upgrade	Investigate options for upgrade 10MVA Alstom transformer by installing larger fans, and re-filling it with ester fluids. Also uprate the existing CTs and circuit breaker. **Alternatives Option Considered:** a) Install new 20MVA transformer	2023-2024	500

Figure 6.2 shows the demand forecasts for our major points of supply over the forthcoming ten-year period.

Figure 6.43: Grid exit points and point of supply demand forecasts



6.3. Northern network



Area overview

The Northern Network area covers most of the Northern King Country district, from Ōtorohanga in the north to Tahāroa in the west and south to Mount Messenger. Ōtorohanga and Te Kūiti are the major towns on this network with combined a population of approximately 8,000. The terrain is predominantly hill country with difficult access. Weather is predominantly temperate with a prevailing westerly wind.

The network is primarily rural with some large industrial loads. Forestry, sheep, beef, and dairy farming are the primary industries in this area, however there is also significant limestone quarrying and mining. Ironsand mining is the single largest load on the network.

Tourism, though comparatively smaller is also significant for the regional economy with Waitomo Caves located on the network.

The Mangapēhi, Wairere Falls and Speedys Road run-of-the-river generation systems are embedded in this part of the network. There is potential for large-scale windfarms to be developed along the western coastline.

The entire region is supplied by a single GXP at Hangatiki. It supplies 11 substations on this network and is reticulated by a strong 33kV sub transmission system.

Table 6.21: Northern network zone substations security of supply

Zone Substation	Customers Serviced	Operating Security Level	Peak Load (MVA)	Installed Capacity (MVA)	Security				Substation Building Strength (% of new building standard
					Tfmr	33kV Line	Bus	11kV Back-up	
Gadsby Road	1283	N-S	5.6	5	N	N-1	N	Yes	100%
Hangatiki	393	N	3.9	5	N	N-1	N	Light	20%
Mahoenui	617	N	1.2	3	N	N	N	Med	No building
Oparure	72	N	1.7	3	N	N	N	Light	100%
Piripiri	N/A	N-S	-	5	N	N	N	Yes	100%
Tahāroa	1	N-1	15.8	15	N-1	N-1	N	No	Unassessed[7]
Tahāroa Village	113	N-S	0.3	2	N	N-1	N	Yes	100%
Te Anga	306	N-S	2.2	2	N	N	N	Yes	100%
Te Waireka	3051	N-1	11.1	30	N-1	N-1	N-1	Light	100%
Wairere Falls	1339	N-S(A)	2.5	5	N-1	N	N	Med	100%
Waitete	1867	N-1	9.4	30	N-1	N-1	N-1	Med	100%

Demand Forecasts

Table 6.22: Northern network summary - shaded cells represent non-conformance of security criteria

Zone Substation	Security	Capacity (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gadsby Rd	N-S(A)	5	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Hangatiki	N-S(A)	5	4.2	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.6
Mahoenui	N-S(A)	3	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Oparure	Agree	3	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2
Piripiri	N-S	5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Tahāroa	Agree	15	15	15	15	15	15	15	15	15	15	15
Tahāroa Village	N-S	1.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Te Anga	N-S	2.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Te Waireka	N-1	15	13.3	13.6	13.9	14.1	14.4	14.6	14.9	15.2	15.2	15.2
Wairere Falls[8]	N-S(A)	2.5	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Waitete	N-1	15	9.4	9.4	9.4	9.4	9.4	10.2	10.2	10.2	10.2	10.2

[7] The substation building at Tahāroa is owned and maintained by Tahāroa Ironsands Ltd.

[8] The 3MVA load on Wairere is a generation load, that uses the site to step-up onto the 33kV system. As such we do not expect any need to upgrade the site.

Key constraints

The Northern network system has potential to grow rapidly pending confirmation of several major industrial projects that our customers are currently planning. They main constraint to achieve this is in the 33kV lines supplying the Ōtorohanga region.

Site	Constraint Description
Te Waireka-Te Kawa 33kV lines	The lines from Hangatiki to Ōtorohanga (Te Waireka Zone Substation) require upgrade to support the industrial load growth in the Ōtorohanga area.
Gadsby Road	The transformers at Gadsby road are near capacity and proposed increases in industrial customers could push the demand over the transformer rating.

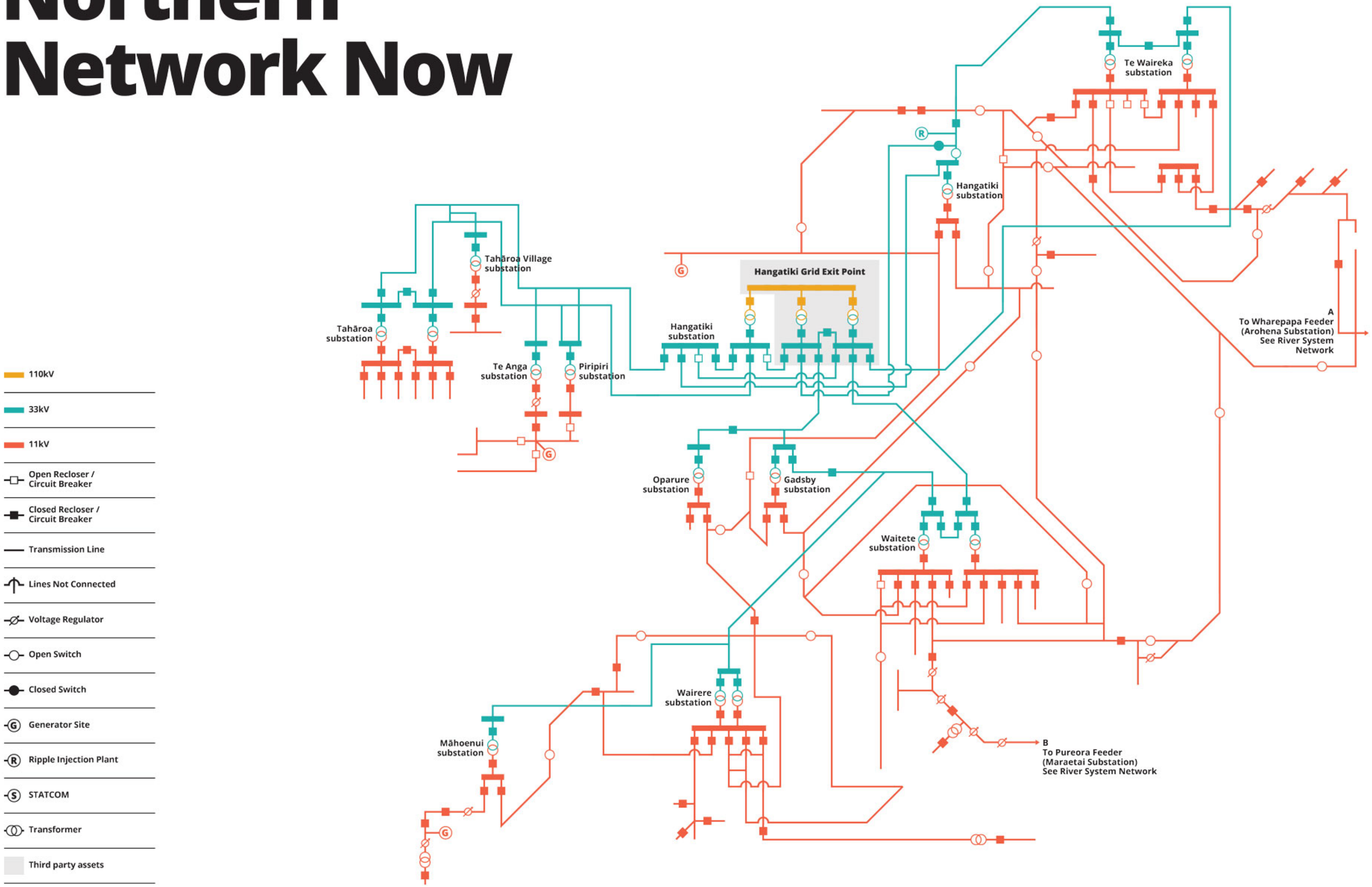
Proposed projects

To address these constraints, we are planning three significant upgrades to our network.

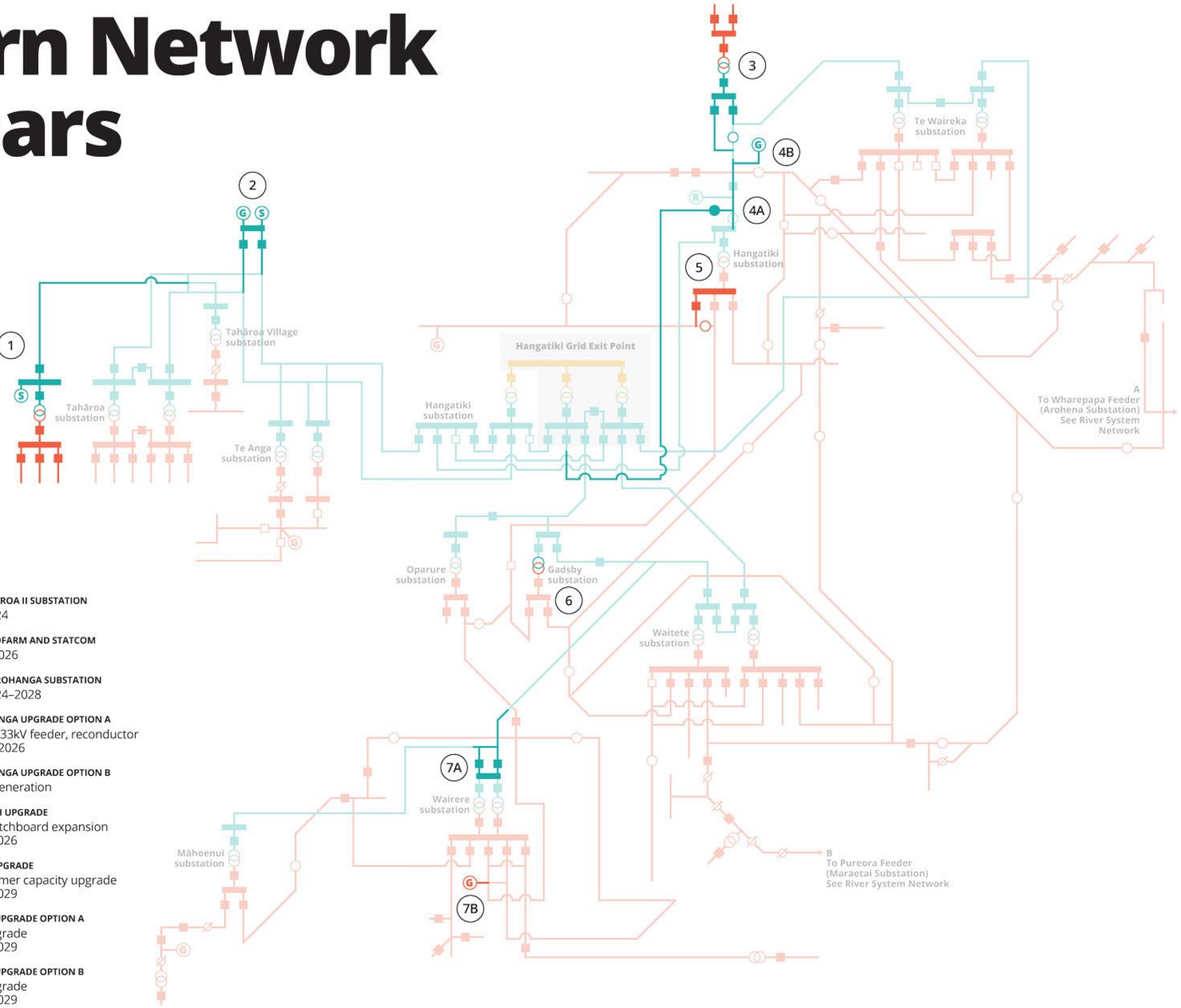
Project	Works Description	Year Est	Budget ($000)
Reconductor Te Kawa Feeder	Reconductor the 33kV Te Kawa feeder. The timing of this is dependent on load growth. We expect this project to be driven by a major customer connection in Ōtorohanga. **Alternative Option Considered:** Have diesel generators or battery banks available to limit peak demand.	2026	1,050
Hangatiki 11 kV	Take building core samples and confirm building strength. Extend existing Switchboard and split Caves feeder if building strong enough. **Alternative Option Considered:** Install new 5-bay 11kV switchgear	2026	400
Gadsby Road Upgrades	Gadsby Rd Transformer and 11kV Renewal and upgrade to 15MVA transformer	2030	1,250
Wairere Upgrades	Upgrade structures, transformers and 33kV switchgear, and new ring main unit to allow backfeed option. **Alternative Option Considered:** Have diesel generators or battery banks available to provide backup support.	2029	800

The following diagrams show the Northern network now, and where we are targeting the key upgrades mentioned above.

Northern Network Now



Northern Network in 10 Years



- 110kV
- 33kV
- 11kV
- Open Recloser / Circuit Breaker
- Closed Recloser / Circuit Breaker
- Transmission Line
- Lines Not Connected
- Voltage Regulator
- Open Switch
- Closed Switch
- Generator Site
- Ripple Injection Plant
- STATCOM
- Transformer
- Third party assets

1. **NEW TAHĀROA II SUBSTATION**
   $5M, 2024
2. **NEW WINDFARM AND STATCOM**
   $3.5M, 2026
3. **NEW ŌTOROHANGA SUBSTATION**
   $6M, 2024–2028

4A. **ŌTOROHANGA UPGRADE OPTION A**
   Te Kawa 33kV feeder, reconductor
   $1.05M, 2026

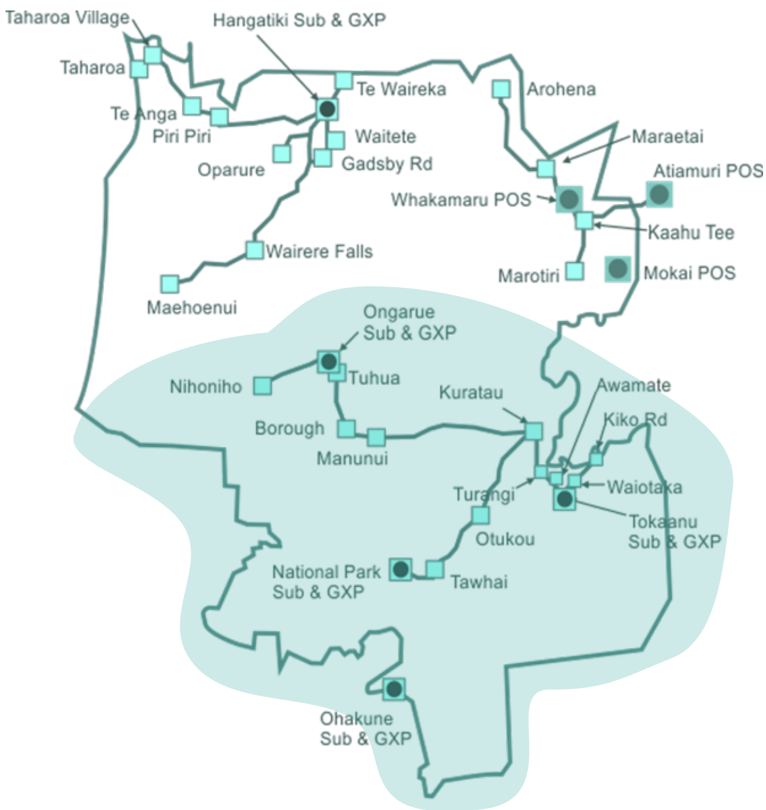
4B. **ŌTOROHANGA UPGRADE OPTION B**
   Peaker generation

5. **HANGATIKI UPGRADE**
   11kV switchboard expansion
   $400k, 2026
6. **GADSBY UPGRADE**
   Transformer capacity upgrade
   $800k, 2029

7A. **WAIRERE UPGRADE OPTION A**
   33kV upgrade
   $800k, 2029

7B. **WAIRERE UPGRADE OPTION B**
   33kV upgrade
   $800k, 2029

6.4 Southern network



Area overview

The Southern Network covers most of the Ruapehu district as well as parts of the Taupō district. It extends from north of Taumarunui to Ohakune in the south, and all along the western shores of lake Taupō to Tūrangi. Tūrangi and Taumarunui are the major towns on this network with combined a population of approximately 8,500 customers. The region covers large parts of the central plateau with a lot of alpine terrain. The region has predominantly a winter climate, not unlike that of the South Island of New Zealand. The Tongariro National Park experiences snow several times a year.

The network is primarily rural with some small industrial loads. The Western Bay areas of lake Taupō have many holiday homes that are occupied for part of the year. Agriculture and forestry are the main industries on this network. The popular Whakapapa and Tūroa ski fields are located on the network, and seasonal arrival of tourists is a major factor influencing load in this area.

Kuratau and Piriaka run-of-the-river generation systems are embedded in this part of the network. There is also significant potential for large-scale solar farms to be developed in this area.

The region is supplied by four GXPs – Tokaanu, Ōngarue, Ohakune and National Park. They supply 13 substations which are interconnected by a 33kV sub transmission system that runs parallel to Transpower's 110kV transmission system.

Table 6.23: Southern Network Zone Substations Summary

Zone Substation	Customers Serviced	Operating Security Level	Peak Load (MVA)	Installed Capacity (MVA)	Security				Substation Building Strength (% of new building standard
					Tfmr	33kV Line	Bus	11kV Back-up[1]	
Awamate	308	N-S	1.4	2	N	N	N	Yes	100%
Borough	2833	N-1	8.6	20	N-1	N-1	N-1	Light	100%
Kiko Road	841	N-S	-	2.5	N	N	N	Yes	No building
Kuratau	1640	N	2.5	8	N	N-1	N	No	No building
Manunui	1096	N	3	5	N	N-1	N	Light	No building
National Park	621	N-S	2.3	3	N	N-1	N	Yes	100%
Nihoniho	356	N-S	0.9	1.5	N	N	N	Yes	No building
Otukou	60	N	0.3	0.5	N	N-1	N	No	No building
Tawhai	131	N	4.8	5	N	N-1	N	Light	No building
Tokaanu	79	N	0.2	1.25	N	N-1	N	No	No building
Tuhua	353	N-S	1.4	1.5	N	N	N	Yes	No building
Tūrangi	1994	N	4.9	10	N-1	N	N-1	Med	>66%
Waiotaka	6	N-S	2.3	2	N	N	N	Yes	100%

Demand forecasts

Table 6.24: Northern Network Summary - shaded cells represent non-conformance of security criteria

Zone Substation	Security	Capacity (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Awamate	N S	2.4	0.7	0.7	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.3
Borough	N-1	10	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Kiko Road	N S(A)	2.5	1.6	1.7	1.7	1.8	1.8	1.9	1.9	1.9	2.0	2.0
Kuratau	N-1	3	2.5	2.5	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9
Manunui	N S(A)	3	3.3	4.5	4.6	4.7	4.8	4.8	4.8	4.9	5.0	5.0
National Park	N S(A)	3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Nihoniho	N S	2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Otukou	N S	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Tawhai	N S(A)	5	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Tokaanu	N S	1.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Tuhua	N S	2	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Tūrangi	N-1	5	4.7	4.7	4.7	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Waiotaka	N S	2.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1

Key constraints

The Southern network system is relatively static, with minor growth around the fringes of Lake Taupo.

Site	Constraint Description
Tūrangi Substation	The transformers at Tūrangi may exceed their secured capacity during the planning period. They are scheduled for upgrade when they reach end of life beyond the planning horizon. However, this could be fast tracked if new customer demand requires it to happen.
Manunui Substation	There is an expectation that industrial growth will occur on the feeders connected to Manunui Substation. An upgrade of the site will be required if this growth eventuates.
Ohakune Security of Supply	Under contingency scenarios, the supply to Ohakune township would be restricted to 2MVA. This does not meet our security of supply criteria

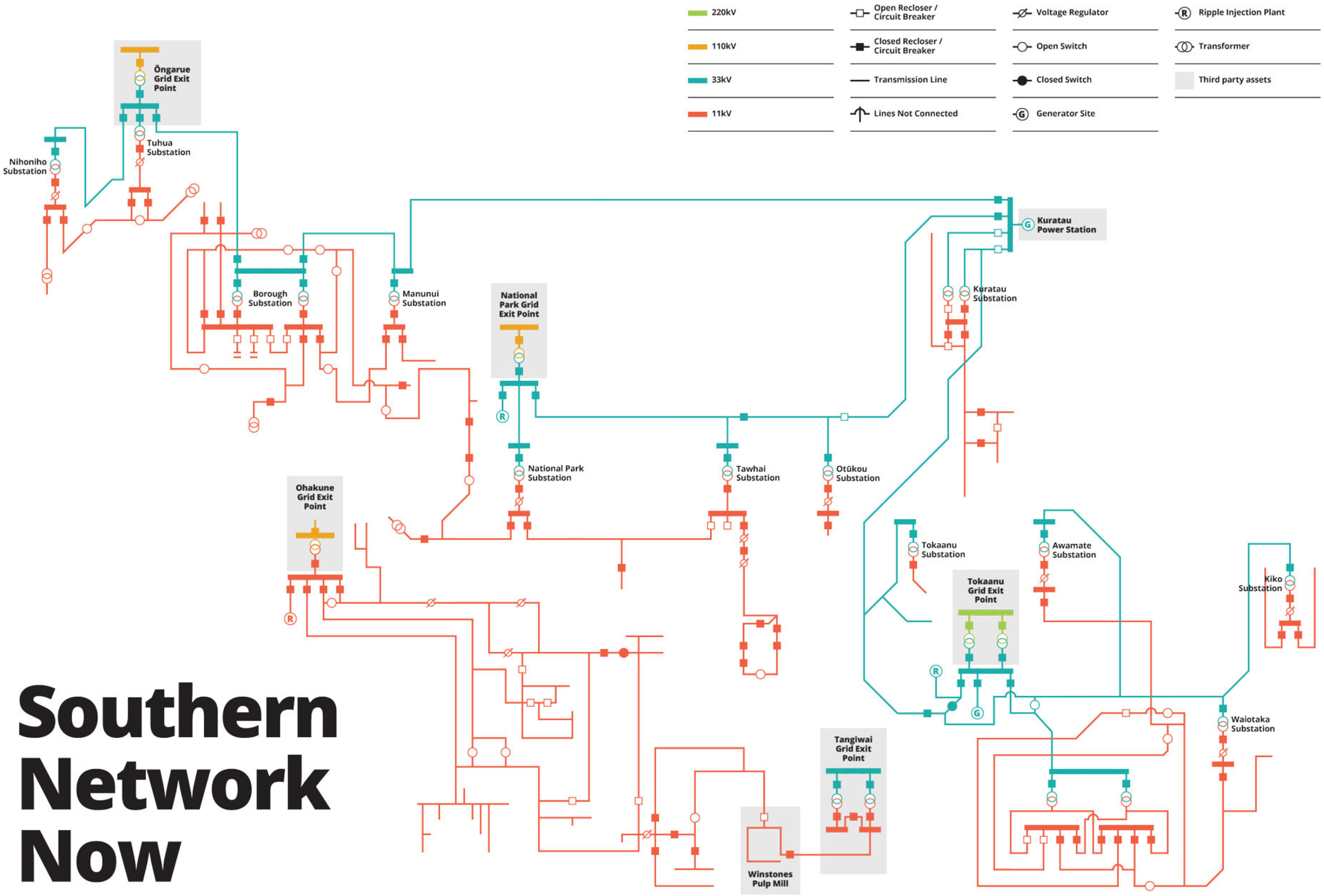
Proposed projects

To address these constraints, we are planning the following upgrades to our network.

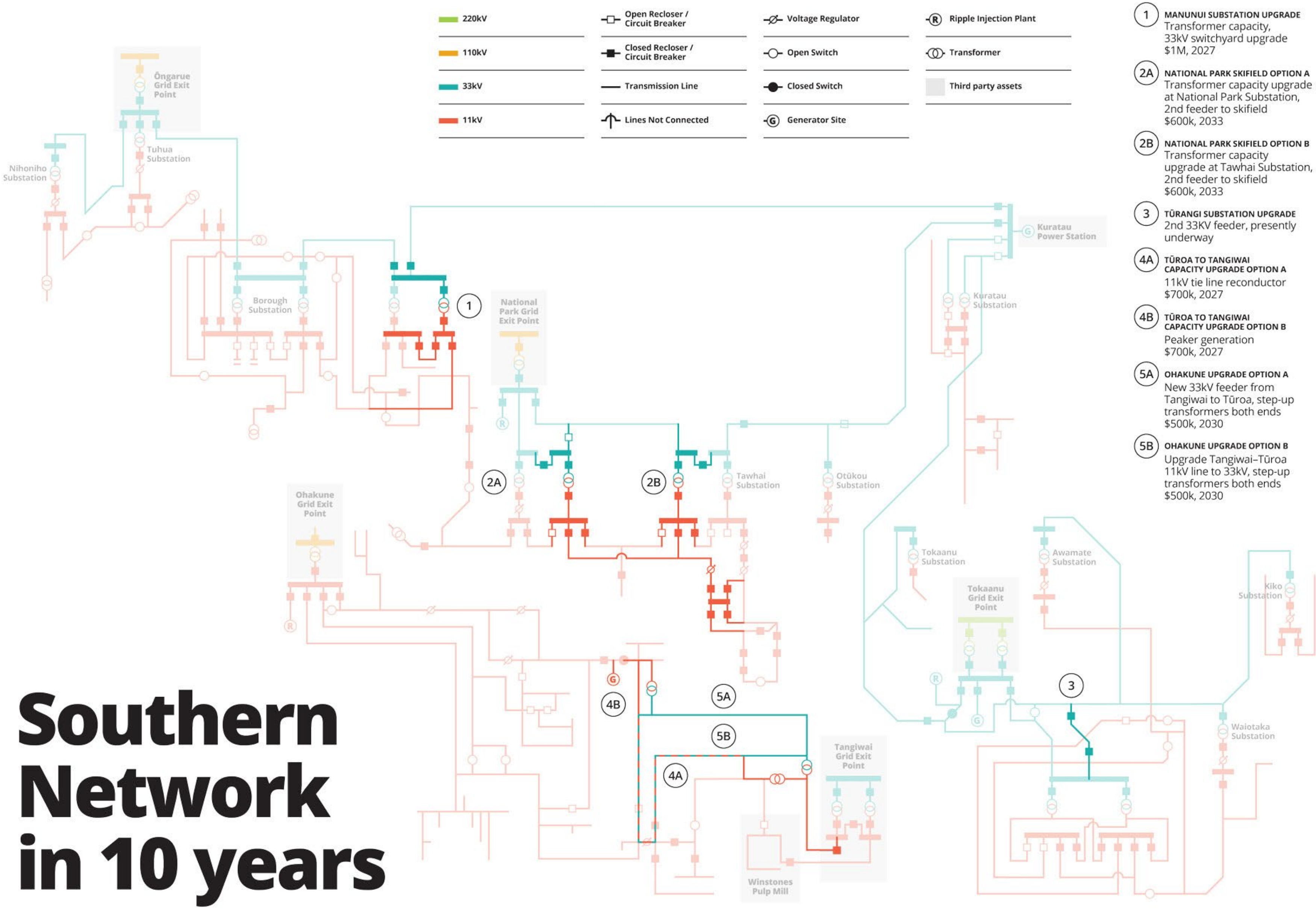
Project	Works Description	Year Est	Budget ($000)
Ohakune Upgrades	Alternative supply from Tangiwai GXP to provide an alternate supply to Ohakune. **Alternative Option Considered:** Upgrade the Tangiwai to Tūroa line to 33kkV to provide a high-capacity alternative supply to the Ohakune town. This would involve step up transformers and a new 33kV zone substation. ($2.8M)	2030	500
National Park	Capacity upgrades of transformer may be required if the ski-field is brought back into service as it previously intended.	2033	600
Tūroa to Tangiwai 11kV Tie Line	Reconductor the Tūroa / Tangiwai feeder tie between switch 5695 and 5680 to strengthen the back feed from Tangiwai and install a switch to connect directly to the Transpower 11kV bus. **Alternative Option Considered:** Install diesel generators or battery banks to support load during outages.	2027	700

The following diagrams show the Southern network now, and where we are targeting the key upgrades mentioned above.

Southern Network Now



Southern Network in 10 years



1 **MANUNUI SUBSTATION UPGRADE**
Transformer capacity, 33kV switchyard upgrade
$1M, 2027

2A **NATIONAL PARK SKIFIELD OPTION A**
Transformer capacity upgrade at National Park Substation, 2nd feeder to skifield
$600k, 2033

2B **NATIONAL PARK SKIFIELD OPTION B**
Transformer capacity upgrade at Tawhai Substation, 2nd feeder to skifield
$600k, 2033

3 **TŪRANGI SUBSTATION UPGRADE**
2nd 33KV feeder, presently underway

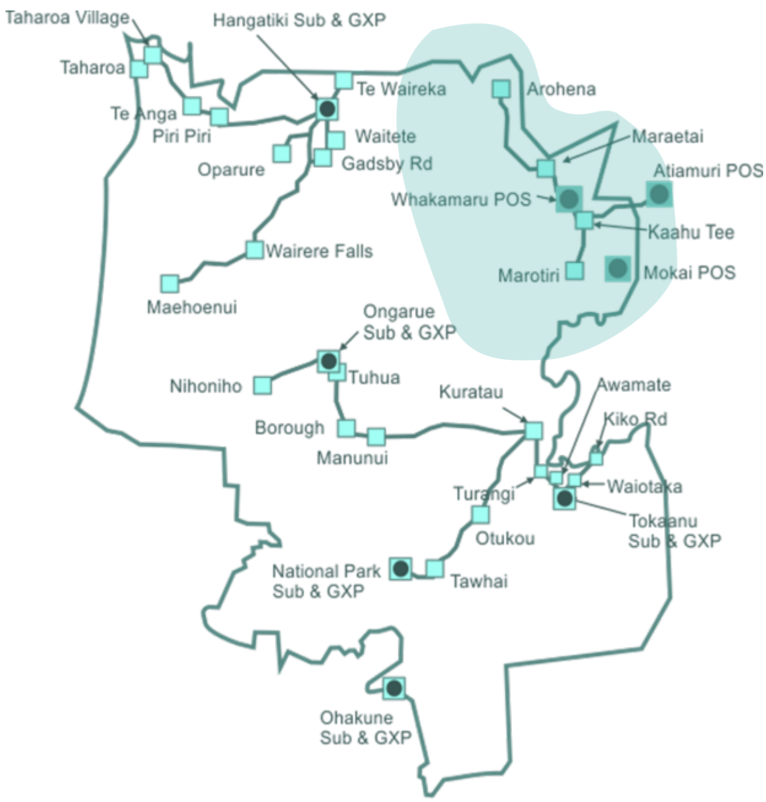
4A **TŪROA TO TANGIWAI CAPACITY UPGRADE OPTION A**
11kV tie line reconductor
$700k, 2027

4B **TŪROA TO TANGIWAI CAPACITY UPGRADE OPTION B**
Peaker generation
$700k, 2027

5A **OHAKUNE UPGRADE OPTION A**
New 33kV feeder from Tangiwai to Tūroa, step-up transformers both ends
$500k, 2030

5B **OHAKUNE UPGRADE OPTION B**
Upgrade Tangiwai–Tūroa 11kV line to 33kV, step-up transformers both ends
$500k, 2030

6.5 Waikato River system



Area overview

The Waikato River System covers parts of the Waipa, Ōtorohanga and Taupō districts. There are no large towns in this region with the largest village being Mangakino. The network is not connected to a GXP and derives its power instead directly from a series of hydro generators along the Waikato River. The 33kV sub transmission system for this part of the network was purchased from Transpower in 2000, which used to be reticulated at 50kV, but was re-rated to 33kV to standardise the network.

The Whakamaru area is supplied from three non-Transpower supply points:

- Whakamaru T8, 220/110/33 kV, 23 MVA transformer owned by Tūaropaki. Supply is derived from the Mōkai geothermal power station that supplies power at a 110 kV to the T8 transformer or from Whakamaru power station G4 generator and TLC take supply from a tertiary winding on this transformer. An earthing transformer is used for earth fault detection at this site.

- Ātiamuri T5, 11/33 kV, 10 MVA transformer owned by TLC. Supply is derived from the Mercury Ātiamuri Station 11 kV Station Bus.
- Mōkai Station 11/11 kV 7.5 MVA Transformer owned by TLC. Supply is derived from Mōkai II 11 kV station bus.

Table 6.25: Waikato River System Zone Substations Summary

Zone Substation	Customers Serviced	Operating Security Level	Peak Load (MVA)	Installed Capacity (MVA)	Security				Substation Building Strength (% of new building standard
					Tfmr	33kV Line	Bus	11kV Back-up[1]	
Arohena	543	N	2.4	3	N	N	N	Med	100%
Kaahu Tee	251	N	2.1	2.4	N	N-1	N	Med	100%
Maraetai[9]	1259	N	5.8	10	N	N	N	Light	Unassessed
Marotiri	513	N-1 Switched	3	3	N	N	N	Yes	100%

Demand forecasts

Table 6.26: Northern Network Summary. Shaded cells represent non-conformance of security criteria

Zone Substation	Security	Capacity (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Arohena	N S(A)	3	2.7	2.8	2.9	2.9	3.0	3.1	3.2	3.3	3.4	3.5
Kaahu Tee	N S	2.4	1.6	1.6	1.7	1.7	1.8	1.9	1.9	2.0	2.0	2.1
Maraetai	N	10	5.9	6.0	6.2	6.4	6.5	6.7	6.8	7.0	7.1	7.3
Marotiri	N S(A)	3	2.8	2.9	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6

Key constraints

The Waikato River System has two primary constraints located at Arohena and Maraetai substations.

Site	Constraint Description
Arohena	The substation is no longer meets our security of supply standard due to short duration load increases in recent years. However, the load increase is driven by one industrial customer that caused the non-conformance and they have agreed to supply their own generators in that circumstance.
Maraetai	The substation no longer meets our security of supply criteria. An outage on this part of the network can severely impact a large number of customers.

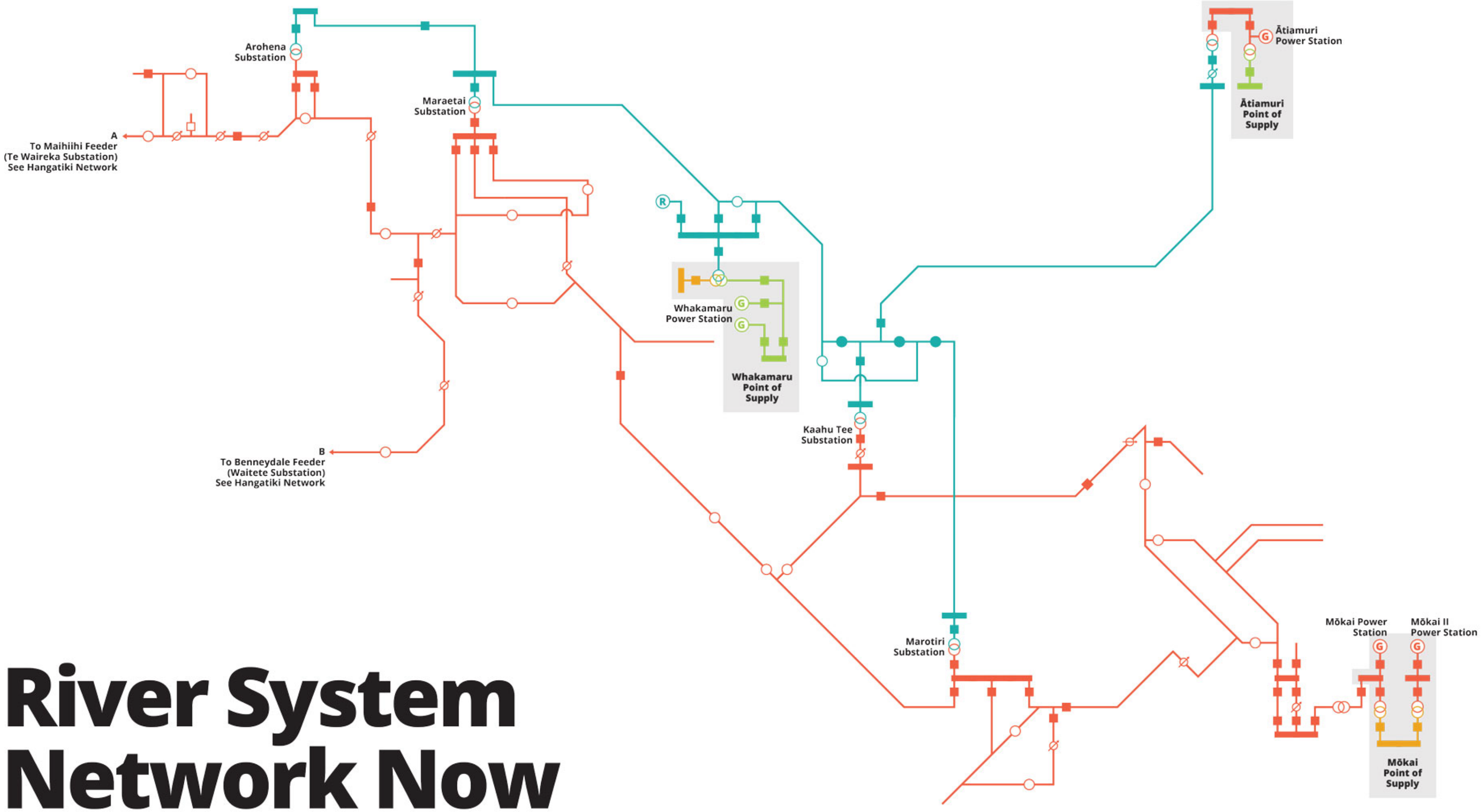
[9] The substation building at Maraetai is not owned by TLC, and the equipment currently contained within is being removed and mounted outside the building.

Proposed projects

To address these constraints, we are planning the following upgrades to our network.

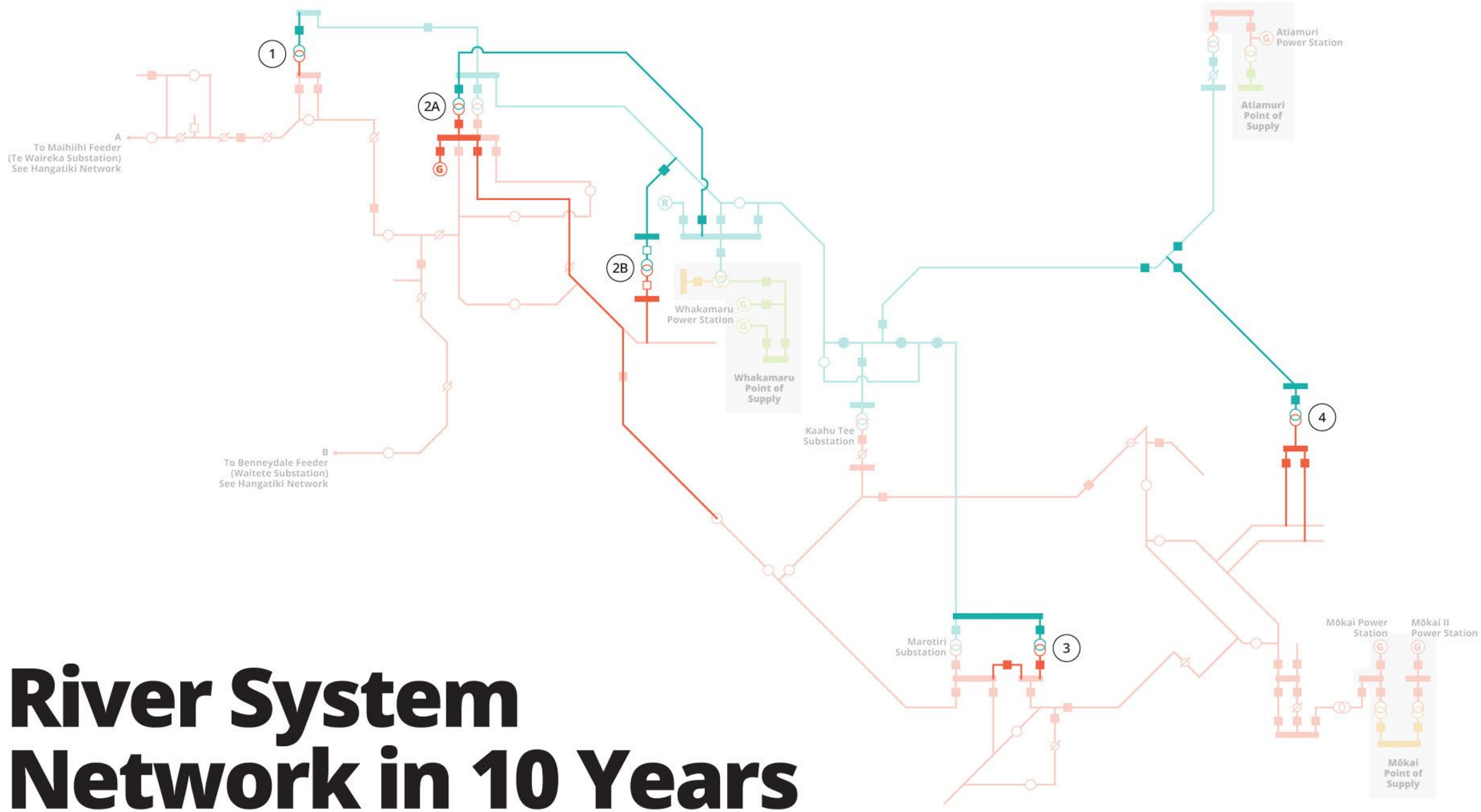
Project	Works Description	Year Est	Budget ($000)
Marotiri upgrade	Upgrade site to 1 x 5 MVA or 2 x 3 MVA	2027-2028	400
Maraetai Security of Supply	Upgrade the Maraetai substation by installing a second transformer and additional switchgear to provide N-1 security. **Alternative Options Considered:** **a.** Install additional 33kV line and reconductor Whakamaru 11kV feeder. Install additional transformer at Maraetai. Install diesel generators or battery banks to cater for peak demand. **b.** New substation in the Whakamaru area to cater for increasing dairy load and to provide an 11kV backup to Maraetai and Kaahu Tee.	2028	2,000
Arohena Upgrade	Increase the size of the transformer from 3MVA to 5MVA to cater for the additional step change load at the substation.	2023	600

The following diagrams show the Waikato River System now, and where we are targeting the key upgrades mentioned above.



River System Network Now

220kV	Open Recloser / Circuit Breaker	Voltage Regulator	Ripple Injection Plant
110kV	Closed Recloser / Circuit Breaker	Open Switch	Transformer
33kV	Transmission Line	Closed Switch	Third party assets
11kV	Lines Not Connected	Generator Site	



River System Network in 10 Years

- 220kV
- 110kV
- 33kV
- 11kV
- Open Recloser / Circuit Breaker
- Closed Recloser / Circuit Breaker
- Transmission Line
- Lines Not Connected
- Voltage Regulator
- Open Switch
- Closed Switch
- Generator Site
- Ripple Injection Plant
- Transformer
- Third party assets

1 **AROHENA UPGRADE**
Transformer Capacity
$400k, 2027–2028

2A **MARAETAI SECURITY OF SUPPLY OPTION A**
New 33kV feeder, new transformer, peaker generation, 11kV feeder upgrade
$2M, 2028

2B **MARAETAI SECURITY OF SUPPLY OPTION B**
New substation Sandel Rd
$1.4M, 2028

3 **MAROTIRI UPGRADE**
New second transformer
$400k, 2027–2028

4 **NEW MIRAKA SUBSTATION**
$5.5M, 2028

6.6 Reliability and automation

Overview

We use network automation to help manage the reliability performance of our network. In this context, network automation refers to the systems and devices that are used to undertake remote switching and reconfiguration of our networks. Automation of distribution switchgear allows us to:

- Remotely isolate and reconfigure networks
- Automate fault response actions
- Gain better visibility of network operating conditions
- More easily pinpoint fault locations.

Automation is an important investment focus as it enables reliability improvements to be achieved reasonably quickly. This helps us stabilise reliability outcomes on our networks while we work to address and stabilise emerging asset health and network security issues.

We have recently developed a security of supply standard for our feeders. The standard sets the service levels we expect from our feeders and substations to restore supply, or to reduce the impact of lost supply to our customers.

Automation plan

We can reduce the impact of lost electricity by developing the network to better withstand such outages. This can be achieved by:

- Additional manual switching points
- Additional remotely operated switching points
- Additional protection/reclosers
- Adding line fault indicators to air break switches
- Adding communications to dark assets (e.g., SWER reclosers)
- Feeder splits
- Feeder ties
- Generation
- Feeder strengthening (batteries/capacitors/voltage regulators/reconductor).

In addition to our 'business as usual' application of reclosers, sectionalisers and fault passage indicators, we intend to apply the types of technology required to facilitate our ADMS strategy and to transition to an open-access network with our role ultimately aligned to a distribution system operator.

Automation projects are prioritised based on forecast improvements on annualised SAIDI and SAIFI. The projects are modelled by calculating the number of customers that would benefit from the proposal, estimating the time savings gained, and the number of annual faults that would benefit from the initiative (faulted section line length and faults per 100 km on that feeder).

Other drivers are also considered to build a more complete risk picture, such as:

- Key customers (e.g., hospitals, supermarkets, fuel stations, emergency centres, communication facilities)
- Large industrial customers that support the local economy.

Each feeder is analysed one by one looking for opportunities to develop our reliability. Where there is opportunity for development this is modelled for potential benefit.

6.7 Customer projects

Introduction

Customer required projects are projects that have either been requested by customers to provide for their specific needs, or projects where the system demand has risen significantly due to the impact of growth from a specific customer.

There are various processes for customer driven development based around the size of customer needs.

Once a customer need is established, concept options are developed. Needs for major customers are normally established by site visits and discussions. Tools such as load flow studies and fault analysis are used to develop the concepts. The network details, down to distribution transformer level, are stored and regularly updated on the ETAP network analysis program to assist with the process.

Once viable options are determined, high-level costs are estimated, and the advantages and disadvantages of each option are articulated. This will include customer consultation so that the benefits of each option can be accurately assessed by the customer. These discussions are used to determine a number of things, including the amount of future proofing a developer or industrial customer wants to fund.

At the current time, TLC has a range of customer driven projects that are in various stages of consultation. We have estimated costs for these projects but in most cases, these are provisional estimates prior to detailed scoping and design.

Key customer projects

Other customer driven projects include incremental demand from industrial processing and general new connections and upgrades.

Table 6.9: Summary of Major Customer Driven Projects

Project	Works Description	Year Est	Budget ($000)
Windfarm	Development of a new 30MVA windfarm. Connecting on the Tahāroa A&B lines. Project includes: **1)** Installing a new statcom at the 33kV bus at Hangatiki **2)** Creating a new 33kV switchroom at the windfarm site.	2026	3,500
New milk processing plant	Establish a new 15MVA substation in Ōtorohanga to supply a new milk processing facility. Project will be developed in stages, with a forecast maximum demand of 12MVA.	2024-2028	6,000
New industrial substation	Capacity increase for mine expansions. This includes: **1)** Creation of a new 10MVA Central Mine substation **2)** Installing voltage support on the 33kV Tahāroa A&B lines **3)** Creating a load shed scheme.	2024	5,000
Miraka Substation	Establish a new 15 MVA substation to address growth at Miraka milk plant and the glasshouse complex	2028	5,500
Manunui Substation Upgrade	The transformer and 33kV switchyard at Manunui will require upgrading if the industrial load on the site decide to proceed with their planned works	2027	1,000

Apart from the projects listed above, our mass-market customer-initiated projects are forecast as shown in the table below.

Table 6.10: Summary of Mass Market Customer Driven Projects

Project Name	Est.Cost ($ 000's)	Timing (FY)
Large Industrial Customer Growth Projects	7,200	2022 - 2024
Other Customer Growth Projects	947	2022 - 2026
General New Connections and Upgrades	1,545	2022 - 2026

6.8 Determination of equipment capacity

When planning for all growth and security of supply projects, the rated nameplate capacity is used for project planning. The only exception to this relates to transformers where the short time overload capacity, based on the international standard that the transformer was constructed to, may be taken into account. Short time overloading may reduce the overall life of the transformer, but it does not greatly increase the risk of failure.

07

Renewing Our Network

7. Renewing Our Network

The renewal investment ensures assets are safe and in a suitable condition to remain in service. Renewal investment seeks to optimise the total cost of ownership while maintaining our service standards. This chapter explains the renewal investment programmes for key asset classes.

7.1 Overview

Introduction

Asset renewal is expenditure that focuses on replacing an asset because it has reached its end of life, or because it presents a safety, reliability, environmental or performance issue or risk. Our decision to replace an asset may be driven by a single issue related to performance, condition or other factor, or a combination of these. Our key drivers for asset renewal are outlined in the table below.

Area	Description
Safety of staff, contractors, and the public	Where asset condition and health are degraded, the likelihood of failure increases. This increases safety risk for the public and anyone working on the assets, especially in the case of overhead transmission lines. We prioritise replacement of assets that present elevated safety risks.
Asset health	We use asset health to reflect the expected remaining life of an asset based on a variety of factors, including its condition, age and known type issues. Maintaining appropriate levels of asset health is a key driver for our renewal's investment. Assets in poor health pose an increased risk of failure, leading to additional reliability and safety risks.
Reliability	Our renewal investments target assets that have the potential to degrade, or have already degraded, the service reliability because of faults or forced outages. Some of our customers experience interruption levels exceeding our targets. We prioritise our renewal investment in these areas to improve our service.
Obsolescence	Asset renewal can become necessary when existing assets become incompatible with our modern systems and standards, lack necessary functionality, or are no longer supported by the manufacturer. We also consider the level of diversity in our fleet, as removing 'orphan' models streamlines our approach to maintenance, helping to manage costs. Renewing obsolete assets supports our future readiness objectives and will enable us to deliver our forecast efficiencies.

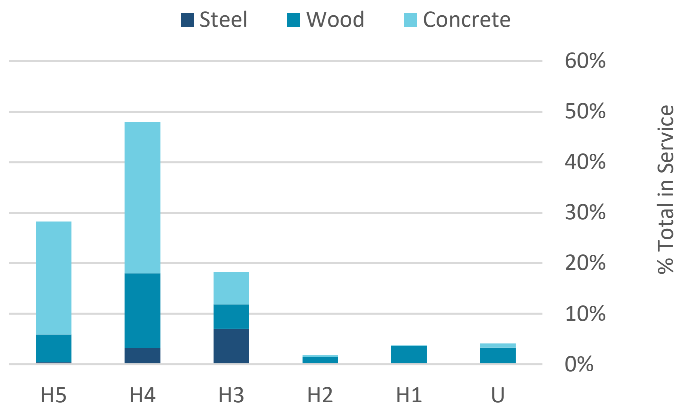
How to interpret the condition information in this section

The sections within this asset renewal overview present the current state of key assets classes, like poles, conductors, transformers etc, and describe the issues we are seeking to address with our planned expenditure. Each asset class shows a view of the current condition of the assets using a condition profile table, similar to the one below.

The next table shows the percentage of assets in each class ranked against six condition categories: U, H1, H2, H3, H4 and H5. The meaning of these categories is also outlined in the next table.

The condition scoring reflects the condition of the assets at their last inspection, and this one key input used for planning and prioritising the asset renewal programme, along with a number of other inputs that reflect the overall status of risk and priority for replacement. An exception is the condition of conductors (overhead lines and cables) which has been based on their age rather than inspection.

Description of Health Indicator	Example Condition Chart
U - Asset health unknown	
H1 - Replacement recommended	
H2 - High risk	
H3 - Increasing risk	
H4 - Asset serviceable	
H5 - As new condition	



In our renewal forecasts, all expenditure is presented as constant values, meaning that it is not adjusted for Consumer Price Index (CPI) in future years.

7.2 Overhead assets

Overview

Poles, crossarms and conductors are the primary components of our overhead network. They are the primary means for connecting our customers to the transmission system at GXPs and enabling the flow of electricity on circuits of varying voltages.

The performance of these assets is essential for maintaining a safe and reliable network. As most of our overhead network is accessible to the public, managing our overhead structure assets is also critical in ensuring public safety.

The following sections provide an overview of these asset fleets, including their population, age, type, and condition.

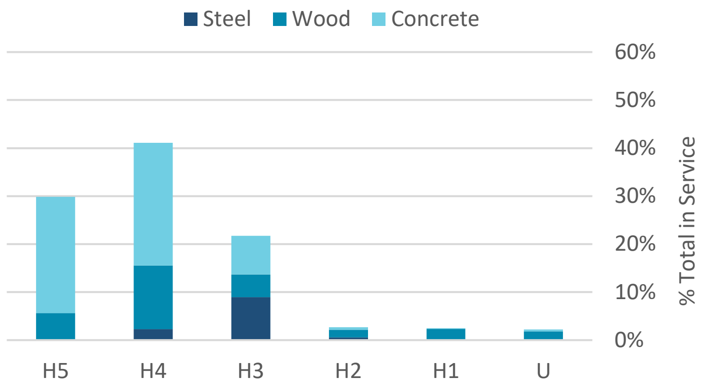
Poles

We have 34,792 poles supporting our overhead line network, along with around 7000 poles that connect to our network and are privately owned. Our pole types include concrete, wood, and steel (which are typically iron rail). The age and condition of our pole assets is summarised below.

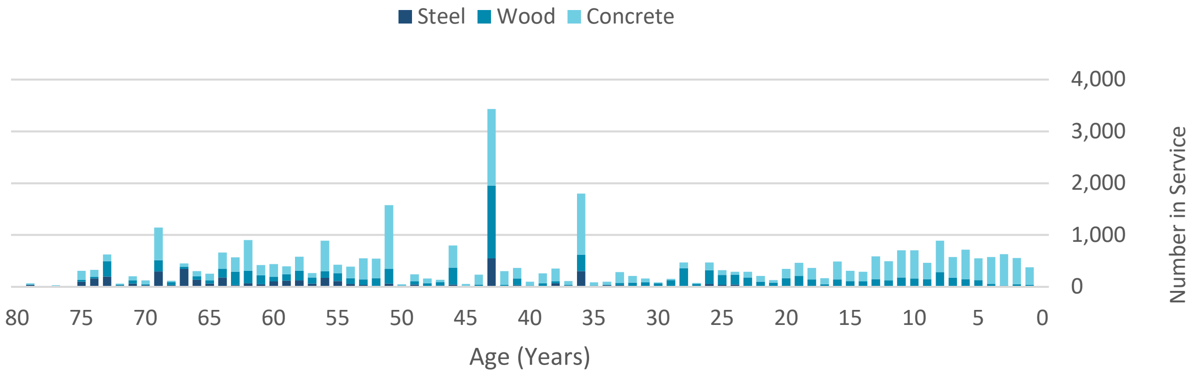
Table 7.27: Pole Population by Network Voltage

Network	Quantity	Material	Description
Sub-transmission Line (33 kV)	3,341	Pre-stressed Concrete Mass reinforced Concrete Hardwood Softwood	Over 50% of poles supporting 33kV conductor are pre-stressed concrete. Poles that have 33 kV conductor above 11kV conductor and/or low voltage conductor under built are included in this group.
Distribution Line (11 kV)	26,161	Pre-stressed Concrete Mass reinforced Concrete Hardwood Softwood Iron Rail	Over 60% of poles supporting 11kV conductors are concrete, and the majority of them are pre-stressed. Poles that have 11kV conductor above the low voltage conductor under built are included in this group.
Low Voltage Line	5,227	Hardwood Softwood Iron Rail	60% of poles supporting LV overhead conductor are wooden poles. Poles that have streetlighting are included in this group.
Total	34,729		

Condition profile



Age profile



Notes

1) Most poles installed in the last 15 years have been concrete with the exception of some wood poles used for areas with difficult access.
2) In some cases, our pole data is populated with default rather than actual commissioning date values, which has the effect of showing abnormal pole installation volumes in specific years. Default values were populated when TLC's records were transferred from paper to a digitised format, and it is assumed they represent instances where the commissioning dates were missing from the paper records. We are continually working improve our asset data to enhance our understanding of the age of these poles.

Crossarms

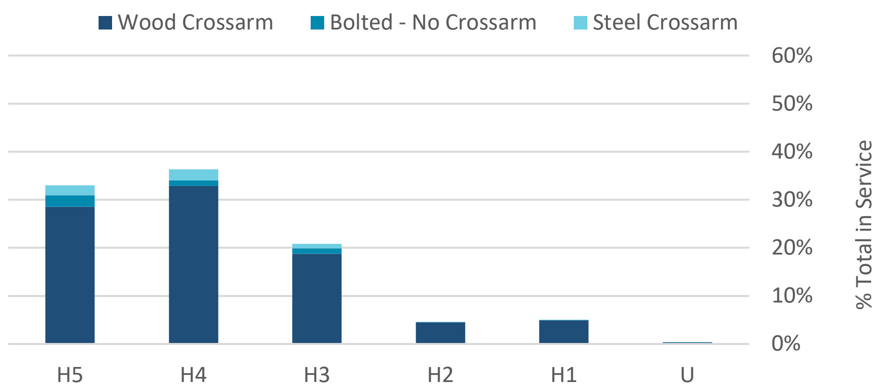
A crossarm assembly is part of the overall pole structure. Its role is to support and space the insulators that connect to the overhead conductor. A crossarm assembly is made of one or more crossarms and a range of ancillary components can be mounted, such as insulators, high voltage fuses, surge arrestors, vibration dampers, bird spikes, earthing systems, armour rods, binders and jumpers, and arm straps.

From this point, the term crossarm refers to a crossarm assembly including all components.

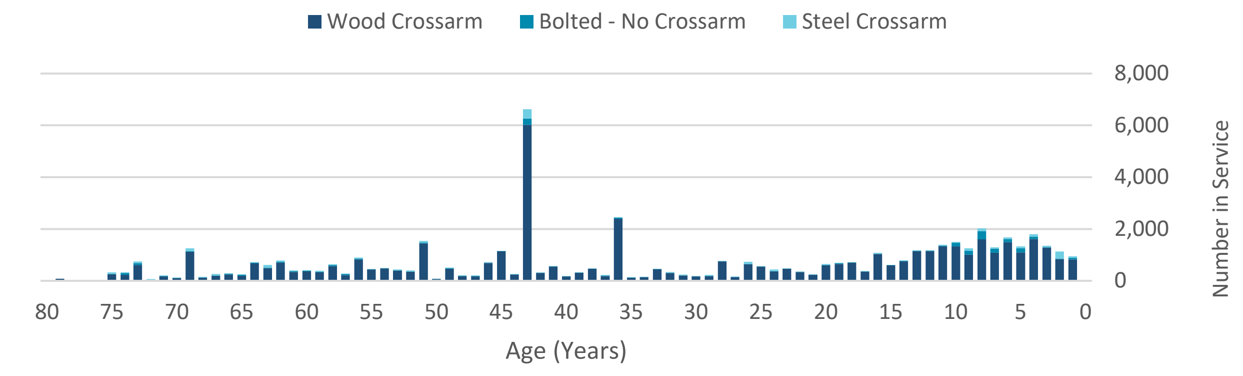
A pole may have more than one crossarm, such as when 11kV and 400V circuits share the same structure. We have 53,871 cross arms in service, most of which are wooden. The Crossarm summary above includes bolted (no crossarm), steel crossarms and wooden crossarms.

Table 7.28: Crossarm by Network Configuration and Material

Network	Quantity	Material	Description
Sub-transmission Line (33 kV)	3,530	81% are wooden	
Distribution Line (11 kV)	34,468	85% are wooden	
Low Voltage Line	16,696	83% are wooden	
Total	55,871		
Condition profile			



Age profile



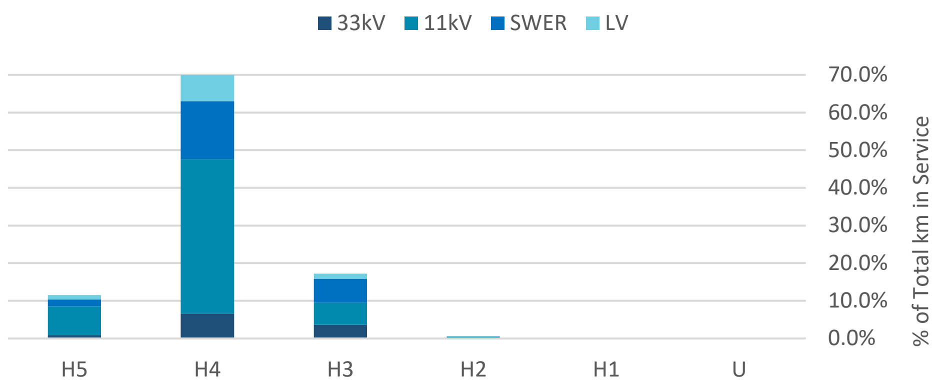
Overhead conductors

Our network consists of 2,058 km of overhead line conductor, with the majority being 3-phase 11kV. However, we also have a substantial amount of 33kV (414km) and 11kV SWER (885km) conductor, which are proportionally higher than most New Zealand networks.

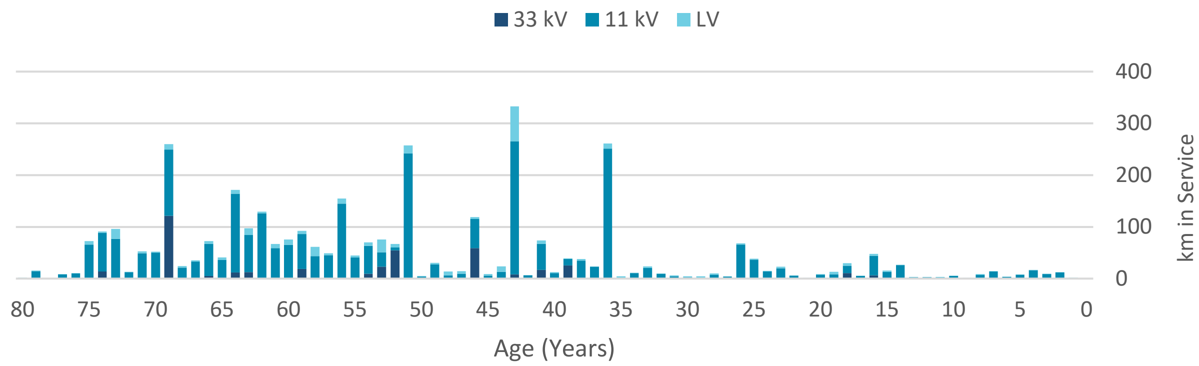
Table 7.29: Conductor Population

Network	Length (km)	Description
Sub-transmission Line (33 kV)	414	
Distribution Line (11 kV)	2058	
Distribution – 11 kV SWER (Single Wire Earth Return)	885	SWER systems are single conductor lines. Two feeders (Tokaanu River and Pihanga) operate at 6.6kV to earth, all others operate at 11kV to earth.
Low Voltage	379	
Total	3736	

Condition profile



Age profile



Notes

1) Conductors are long life assets, and to date the condition scoring has been assessed based on age, rather than physical inspection results. However, most of TLC's conductors remain from the original electrification of the King Country region. Consequently, sample line sections are removed on occasion to test their condition and ongoing resilience. This may occur when line renewals are undertaken or when conductors fail, to improve our understanding of the rate of deterioration of these conductors, and how the locational influences impact their performance. We are also investigating the use of a corona camera to assess the condition of conductors.
2) Our data accuracy is gradually improving resulting from LiDAR surveys and ongoing data work. This has resulted in minor adjustments to our line lengths from our 2021 AMP.

Overhead assets – key risks and issues

There are two primary issues when considering our work programme for overhead assets. The first is that as a group, the earliest overhead assets are reaching the end of their first lifecycle, having been installed int eh 1950's and 1960's. We therefore need to ensure that we are planning for a financially sustainable line renewal programme that will likely extend over the next thirty years.

The second key issue is that our operating environment is changing. The core drivers of that change are the increase in vegetation (primary pine forests) on our network that threaten our lines, and changes of weather (wind and rain) that may push our assets to beyond their original design standards or reduce their lifecycle.

We are responding to these risks in several primary ways – i.e., by:

- Maintaining a strong renewal programme.
- Capturing high quality asset condition information and using this for targeting our renewal work.
- Developing our design standards to ensure our assets can withstand future environmental conditions.
- Continually developing and improving our vegetation management strategy.

These issues mean that overhead assets will dominate our renewal expenditure over the next decade.

Overhead assets expenditure plan

$000	2024	2025	2026	2027	2028
Poles	3,432	5,400	5,578	5,755	5,933
Crossarms	1,572	2,100	2,100	2,100	2,100
Conductor	734	734	1,484	734	734

7.3 Underground assets

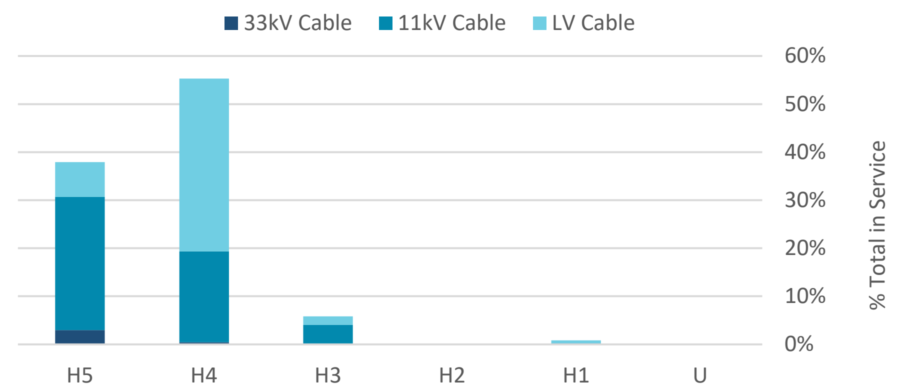
Cables

Underground cables form a critical part of our network and are used largely to mitigate a cascade pole failure scenario around zone substations, and to reticulate the ski-field areas.

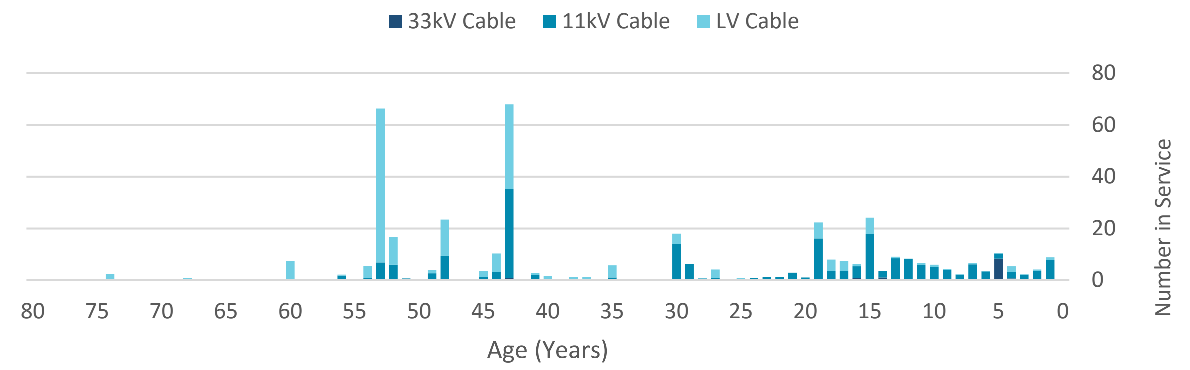
Table 7.30: Underground Cable Network Summary

Network	Quantity	Material	Description
Sub-transmission (33 kV)	14	Largely modern XLPE	4.4km of 33kV cable was installed at the Tahāroa mine in 2017.
Distribution (11 kV)	211	Mostly older generation XLPE cable in average condition.	Steel wire armoured cables used in the two ski fields.
Low Voltage Line	190	Includes solid core, double pass, PVC insulated single core and stranded aluminium cables	Often no marking or mechanical protection.
Total	415	Largely modern XLPE	4.4km of 33kV cable was installed at the Tahāroa mine in 2017.

Condition profile



Age profile



Notes

1) Data quality on age and condition on our older cables is poor, particularly low voltage cables. Over 55% of our low voltage cable and 25% of our 11kV cables have a default date.
2) Underground cables are generally not accessible for inspection, and hence the physical condition of most of TLC's cables is unknown.
3) TLC has only a 14 km of 33kV cable in service with the majority in as-new condition having recently been installed at the Tahāroa mine.

Cables – key risks and issues

Most of the cables installed on Mount Ruapehu are over-ground. These are visually inspected annually for damage and repaired as required. In some cases, these cables have experienced ongoing damage and maintenance and are now being considered for targeted replacement.

Cables expenditure plan

$000	2024	2025	2026	2027	2028
Cable Renewals	383	162	162	162	162

Note: The large expenditure in 2024 is a planned upgrade of the LV cable reticulation in the Whakamaru village, in tandem with transformer replacement.

7.4 Transformers

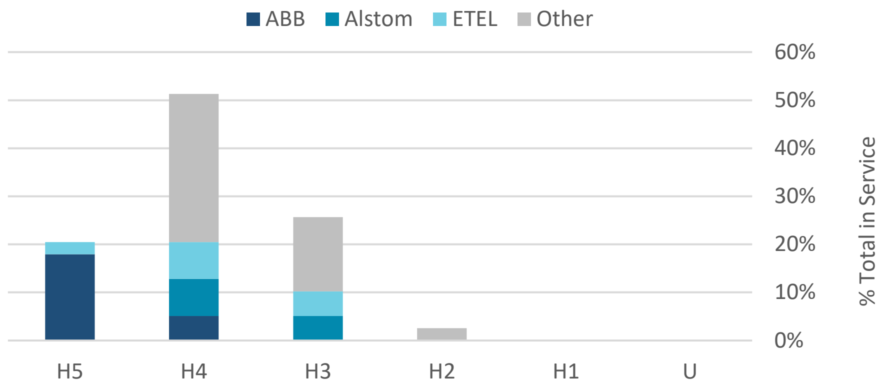
Power transformers

Power transformers are primary plant that is used to feed power to or from our distribution network. Our fleet consists of 39 power transformers located at our 29 zone substations. In general, each make (manufacturer) has a different risk profile.

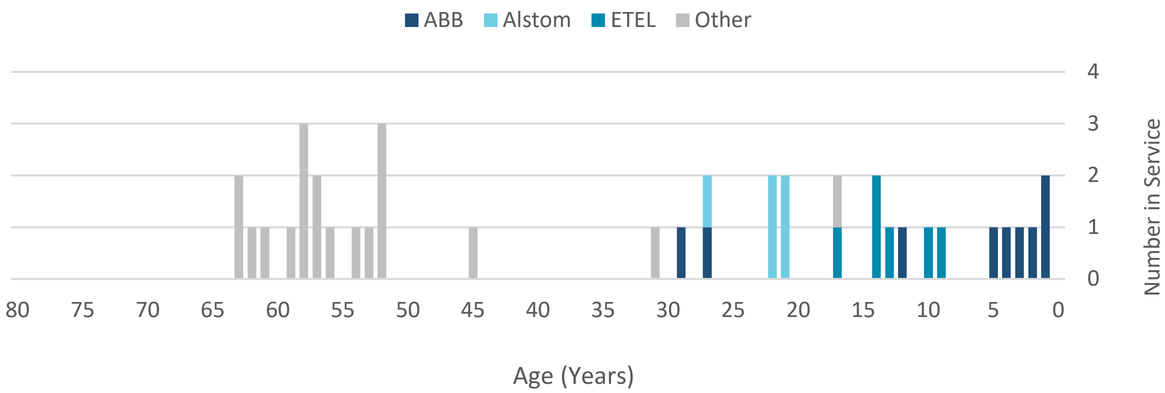
Table 7.31: Power Transformer Overview

Network	Quantity	Description
ABB / Hitachi	9	Hitachi transformers make up the majority of our large power transformer fleet (>10MVA)
Alstom	5	
ETEL	6	ETEL Transformers are used primarily in container substations
Other	28	
Total	39	

Condition profile



Age profile



Power transformers – risks and issues

TLC has a large number of small power transformers. Of the total fleet, 74% are rated at 5MVA or smaller. These smaller sizes are not typical for distribution businesses, and we are seeing indications of accelerated ageing in this group. TLC's ETEL power transformers, which fit into this category, continue to show high levels of hydrogen due to partial discharge. At this stage it presents no imminent safety issues or risk of failure it is expected to represent a significant reduction in the expected life of the transformers.

Our key mitigation for this issue is to hold sufficient stock of power transformers that can be uplifted and installed if emergency replacement is required. We have increased the total stock of our power transformers over the last three years for this purpose.

Proposed projects

Project	Works Description	Year Est	Budget ($000)
Tawhai - Upgrade	5 MVA 33/11kV transformer replacement due to paper and bushing condition (1964 manufactured)	2036	1,000
Wairere - Upgrade	Replacement of both 33/11kV transformers 2.5 MVA transformers due to age and DGA tests results	2029	500
Awamate - Renewal	Replace 2.4MVA ETEL transformer	2037	200
Arohena - Upgrade	Arohena New 5MVA transformer	2024	85
Kiko Rd - Relocation	Kiko Road 33/11kV transformer upgrade	2024	102
Kaahu - Tee Relocation	Swap gassing ETEL transformer for ABB transformer	2024	100

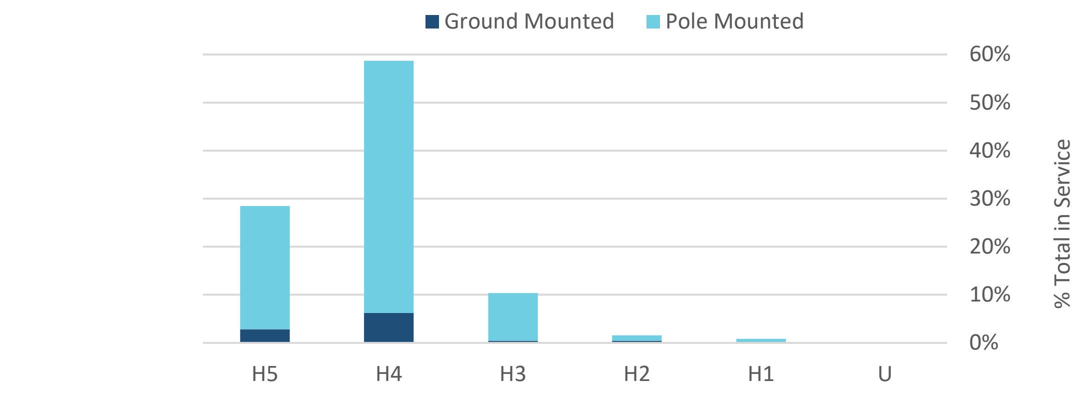
Distribution transformers

TLC has 5255 distribution transformers in service, with the majority being pole mounted. Distribution transformers convert 11kV distribution energy to low voltage for direct supply to homes and businesses.

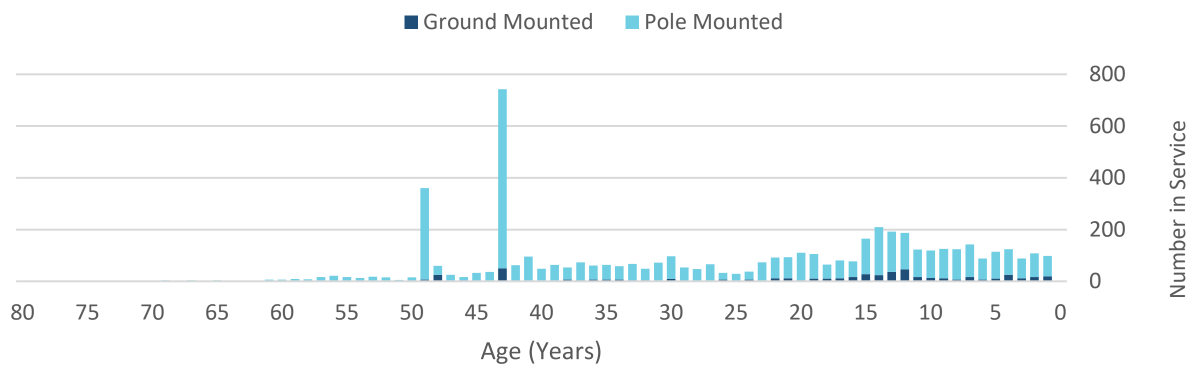
Table 7.32: Distribution Transformer Summary

Type	<=15	30	50	100	200	300	500	>500	Total
Pole Mount									
Single Phase	2562	379	35	36	22	0	0	0	3034
Two Phase	137	35	10	0	0	0	0	0	182
Three Phase	**399**	**567**	**296**	**215**	**30**	**2**	**0**	**0**	**1509**
Ground Mount									
Single Phase	6	6	7	0	0	0	0	0	19
Three Phase	10	15	27	65	188	132	31	43	511
Total	**3114**	**1002**	**375**	**316**	**240**	**134**	**31**	**43**	**5,255**

Condition profile



Age profile



Notes

1) There are significant gaps in age data of our older transformers. The age graph above shows a large number of transformers that have their commissioning date set to a default value (1974 and 1980). These default commissioning dates were used for transformers that had no record of commissioning when TLC's asset records were digitised. It is known that many of these transformers were commissioned after this date, and consequently this business rule has the effect of increasing the average asset age.

2) TLC is undertaking an ongoing data cleansing programme to improve our age estimates for these assets.

Distribution transformers – risks and issues

In the 2018 AMP, we identified 65 ground mounted transformers that were considered high risk because they were enclosed in wooden or tin sheds or were an open enclosure style.

We are now nearing the completion of this programme and we expect to see last transformer replaced during 2023. All transformers that presented a public safety risk have now been replaced including all transformers in wooden structures. For the remaining transformers, protective insulation barriers have been installed to prevent accidental contact of live conductors by staff and contractors who work on this equipment, as an interim measure.

Figures 5.1 Wooden and tin shed transformers being replaced

Transformer expenditure plan

$000	2024	2025	2026	2027	2028
Power Transformers	288	150		250	
Pole Mount	222	472	222	222	222
Ground mount	669	1,199	745	745	745

Notes

1) Transformer Renewals expenditure reflects the ongoing replacement of transformers that fail from environmental factors (such as lightning) and end of life.

7.5 Switchgear

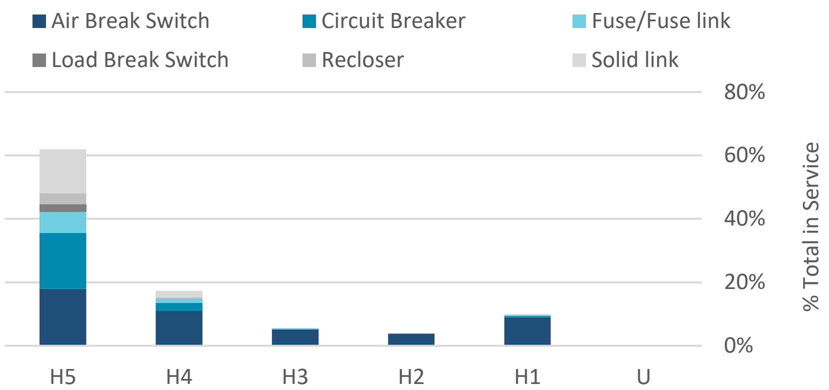
Sub-transmission switchgear

TLC has 289 sub-transmission switches. Some of the assets are located in zone substations and others are in the field on sub-transmission lines. The switch ages and condition vary, and they are renewed when no longer serviceable.

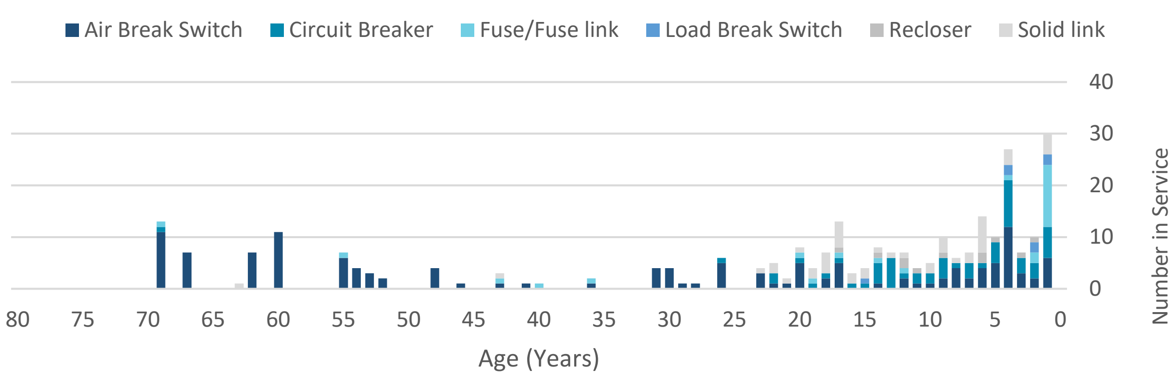
Table 7.33: Sub-transmission Switchgear Assets and Location

Description	Field	Zone Subs	Total
Air Break Switches	73	72	145
Circuit Breakers	14	43	57
Fused Links	4	5	9
Load Break Switches	4	-	4
Reclosers	10	6	16
Solid Links	33	13	46
Transformer Fuses	-	2	2
Total	**138**	**141**	**279**

Condition profile



Age profile



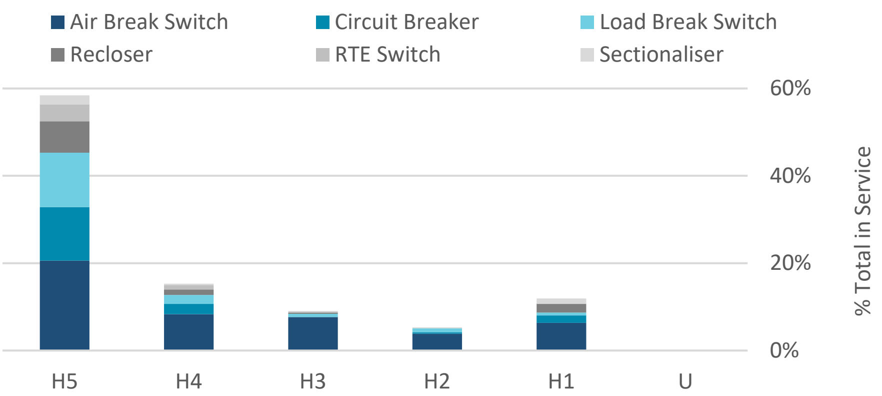
Distribution switches

TLC has 8,611 distribution switches in service with the majority being pole mounted.

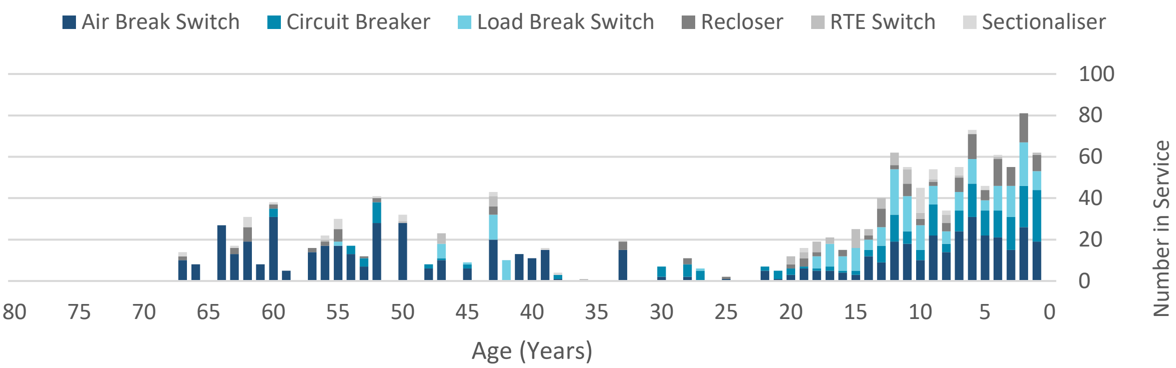
Table 7.34: 11kV Distribution Switchgear and Control Assets

Switch Type	Pole Mt	Ground Mt	Total
11kV Air Break Switches	639	-	639
11kV Circuit Breakers	35	173	208
11kV Fused Switches/Fused Links	1009	63	1072
11kV Load Break Switches	49	166	215
11kV Reclosers	136	1	137
11kV RTE Integrated Transformer Switches	-	71	71
11kV Sectionalisers	62	-	62
11kV Solid Links	569	-	569
11kV Transformer Fuses	5,004	1	5005
11kV Tap-off Fuses	633	-	633
Total	**8,137**	**474**	**8,611**

Condition profile



Age profile



Notes

1) The switches that are contained within the Ring Main Units are counted in the other switch categories above.
2) For ease of visualisation, the age and condition profiles above do not show the fuse, fuse links and solid links which are high-volume common connection assets.
3) Condition assessment of switchgear falls into two groups. The first groups (sectionalisers, air break switches, pole mount fuse switches, pole mounted load break switches, solid links, RTE switch and tap off fuses) receive visual inspections during routine maintenance and are replaced as required. For high impact installations these may be inspected more regularly. The second group are devices that have active control relays that need to be tested to prove they still work. A subset of these have oil which needs to be changed periodically. In both cases assessment during the inspection cycle determines any replacement or maintenance actions if required, and the assets are not specifically profiled to maintain a condition level.

Switchgear risks and issues

The risks associated with distribution vary by the type of switch and operational controls are required to manage most of them. Some of our key risks are:

- Magnefix RMUs are starting to show signs of premature aging. This is being picked up by our partial discharge monitoring programme. These are now being replaced with more modern equivalents.
- Certain types of pole-mounted fuses present fire risks when installed in dry areas as they can potentially cause sparks should the fuse operate.
- Our corrosive coastal areas cause overhead ABS assets to age prematurely.

Switchgear expenditure plan

$000	2024	2025	2026	2027	2028
Substation Switchgear	3,590	100	600	1,371	-
Distribution Switchgear	431	515	965	835	455

7.6 Secondary assets

Secondary systems are crucial for the safe and reliable operation of our electricity network, as they allow for control and operation of most primary equipment such as switchgear.

While their replacement cost is usually lower than the primary equipment that they control or monitor, they generally have shorter service lives. Some are technically complex and require a high degree of strategic direction and careful design to operate effectively.

Protection assets ensure the safe and correct operation of the network. They detect and allow us to rectify network faults that may otherwise harm the public and our field staff, or damage network assets. Our SCADA and communications assets provide network visibility and remote control, allowing our operators to efficiently and effectively manage the network. Table 7.9 provides a summary of our secondary assets.

Table 7.35: Secondary Assets Summary

Secondary Assets	
Regulators	TLC has 74 voltage regulators across 38 sites. The majority of the sites have two relatively new single-phase regulators operating in open delta to give +10% regulation.
Protection Relays	Older style electromechanical relays are being changed out to electronic relays where required with switchgear upgrades. Where possible arc flash detection is included.
Ripple Injection Systems	TLC operates two generations of ripple systems, one in the southern part of the network (317Hz Decabit) and a combination of new (317Hz Decabit) and old (725Hz Semagyr) in the north. The 725 Hz system is being phased out as meters around the network are replaced with smart meters that have internal ripple control capabilities. The 725 Hz ripple control transmitters are decommissioned as the meter installation programme is concluded in each 11kV zone in the northern network.
SCADA System	TLC network uses a Lester Abbey central control system and RTUs to automate our zone substations, and other assets essential to maintaining network performance.
Data Communication	The UHF data communication system consists of a head end and 12 repeater sites (excluding individual RTU radios) using both analogue and digital technology, operating on two channels.
Voice Radio Equipment	A frequency modulated voice communication system consisting of six repeaters, linking equipment and radios in the mobile fleet is owned and operated by TLC.
Mobile Emergency Generator and Injection Transformer	TLC owns a mobile generator, protection transformer, and circuit breaker capable of injecting into the 11kV network under emergency or shutdown conditions.
Capacitor Banks	TLC has an 11kV mobile capacitor bank and 10 fixed capacitor banks across eight sites that are rated at 1MVAr or above.
Metering Assets	TLC, through a subsidiary company (Influx), owns the majority of customer meters and relays. It also owns interconnection metering assets at Whakamaru, Mōkai and Tangiwai.

Secondary assets risks and issues

A significant risk that secondary systems face is from a third-party gaining control of switchgear through a cyber-attack on secondary systems. The increasing potential of a cyber-attack on our network is driving us to invest in improving our communication and control systems as well as building redundancy into our controls.

Another safety risk for the protection fleet is maloperation of relays during faults which can put the public or service provider in danger, can cause network equipment failure, extended outages, or overload. For these reasons, protection systems are designed with cascading backups, but these are designed to take longer to clear the fault to ensure protection discrimination and, being further upstream in the network, generally result in a larger outage area. As longer fault clearance times stress the network more, these can sometimes result in equipment damage, live power lines on the ground or fires.

Secondary systems expenditure plan

$000	2024	2025	2026	2027	2028
Secondary Systems	115	115	115	365	115

7.7 Asset data accuracy

Data accuracy varies across the asset base and is steadily being refined and improved as both inspections and work are completed on the network.

It is estimated that accurate distribution and sub transmission line condition data is held for around 85% of the network, with this information having been gathered as part of the line inspection programme which has been running for the past 15 years. The level of accuracy held on low voltage lines remains low as the focus remains on gathering information on and improving the performance of the distribution and sub-transmission networks, however we realise the importance of this data going forward as the need for visibility of the low voltage network increases.

Age related data is uncertain across a number of asset classes, largely as a result of the various changes in ownership over time and consequently a number of assets have a default commissioning date (typically 1980). TLC has an ongoing data cleansing programme to increase accuracy of age and condition related data for these assets.

08

Capital Expenditure

8. Capital Expenditure

This section discusses our non-network capital expenditure, summarises our overall Capex plan, and outlines the key assumption in developing the AMP forecasts.

8.1 Non-network asset investment

Non-network capital investment includes work that is not specifically related to network assets, but is required for business support, efficiency, or business improvement.

In our forecasts, all expenditure is presented as constant values, meaning that it is not adjusted for Consumer Price Index (CPI) in future years.

Key projects

Non-Network capital expenditure is focused in the following areas:

- **Office Building**
  Currently TLC staff are located across two different sites in Te Kūiti, each requiring significant renewals. This investment is centred on bringing staff from both sites together into a purpose-built space. The investment will allow for greater efficiency by collocating asset management and field staff and provide greater resilience and security in our operationally critical control room. Secondary benefits will be the creation of a modern working environment that will assist in attracting and retaining high calibre staff.

- **Vehicles**
  We own a small fleet of pool vehicles and staff vehicles that requires ongoing replacement.

- **Data Systems**
  The Digital Utility Programme will be focussed upon several key areas of our systems, SCADA, Enterprise Resource Planning (Business Central), Customer data management and GIS and Asset Management. The integration of data from these key systems provides the basis for a fully functioning ADMS.

  The current systems within TLC providing these functions are in many areas coming to end of service or require upgrading to enable the data to be utilised. The SCADA system, asset management system and GIS in particular are all currently inadequate for an ADMS.

  The upgrade of these systems will be managed through the DUP to ensure that systems are selected which provide the greatest benefit to the organisation, it is anticipated that this programme will be delivered across five years with an approximate cost of $6m.

- **Plant and Equipment**
  Covers the replacement and acquisition of new inspection and testing equipment.

Table 8.36: Summary of Total Non-Network Capital Investment

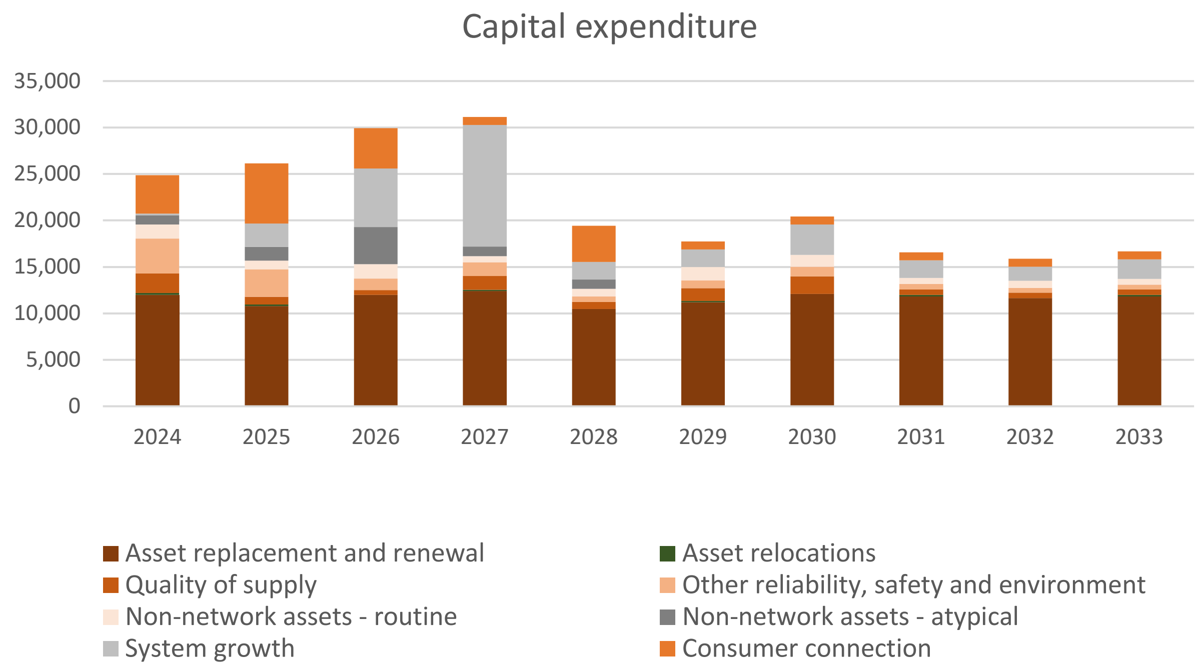
$ 000’s	2024	2025	2026	2027	2028
Office Building	500	3,000	0	0	0
Data Systems	188	188	188	188	188
Vehicles, Plant and Equipment	138	33	33	33	37

8.2 Total capital expenditure

Table 8.37: Summary of Total Capital Investment – 10 years

$ 000’s	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Network										
Asset renewals	11,985	10,797	11,971	12,389	10,466	11,181	12,101	11,831	11,631	11,831
Network growth and development	6,215	6,433	8,090	16,199	3,260	4,265	6,150	3,220	2,600	3,350
Customer required	4,124	6,465	4,365	865	3,865	865	865	865	865	865
Non-Network										
Non-network routine	1,528	938	1,517	683	825	1,433	1,304	646	773	623
Non-network atypical	1,000	1,500	4,000	1,000	1,000	-	-	-	-	-
Total										
All capital expenditure	24,851	26,133	29,943	31,136	19,416	17,744	20,420	16,562	15,869	16,669
Less capital contributions from customers	(3,759)	(5,600)	(3,500)	0	(3,000)	0	0	0	0	0
Total expenditure	21,092	20,533	26,443	31,136	16,416	17,744	20,420	16,562	15,869	16,669

Figure 8.44: Total capital expenditure

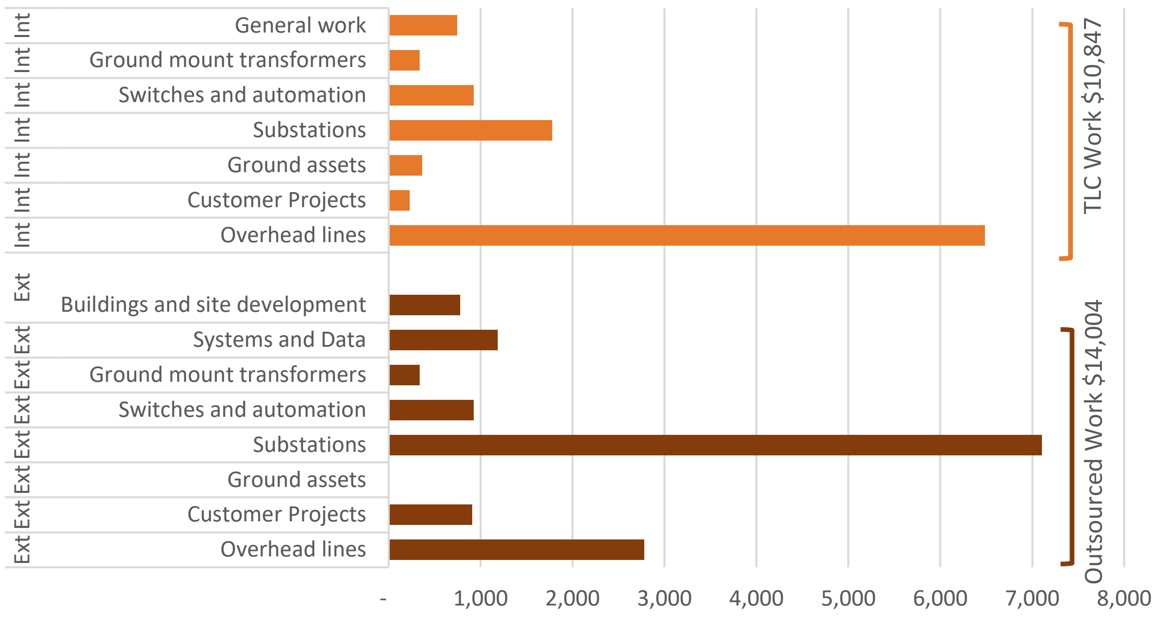


8.3 Deliverability

We are confident that our BAU Capex plan (i.e., all except large customer required projects) for FY2024 is achievable because it is consistent with the Capex volume delivered in FY2019 and FY2020 (prior to the impact of COVID-19 in FY2021).

We intend to outsource most of the work associated with major customer projects. These projects are in commercial negotiation at the time of writing and consequently the timing of these projects remains subject to confirmation by our customers. The key components of our Capex plan outlined in Figure 8.2.

Figure 8.45: Allocation of internal and external work



8.4 Key assumptions

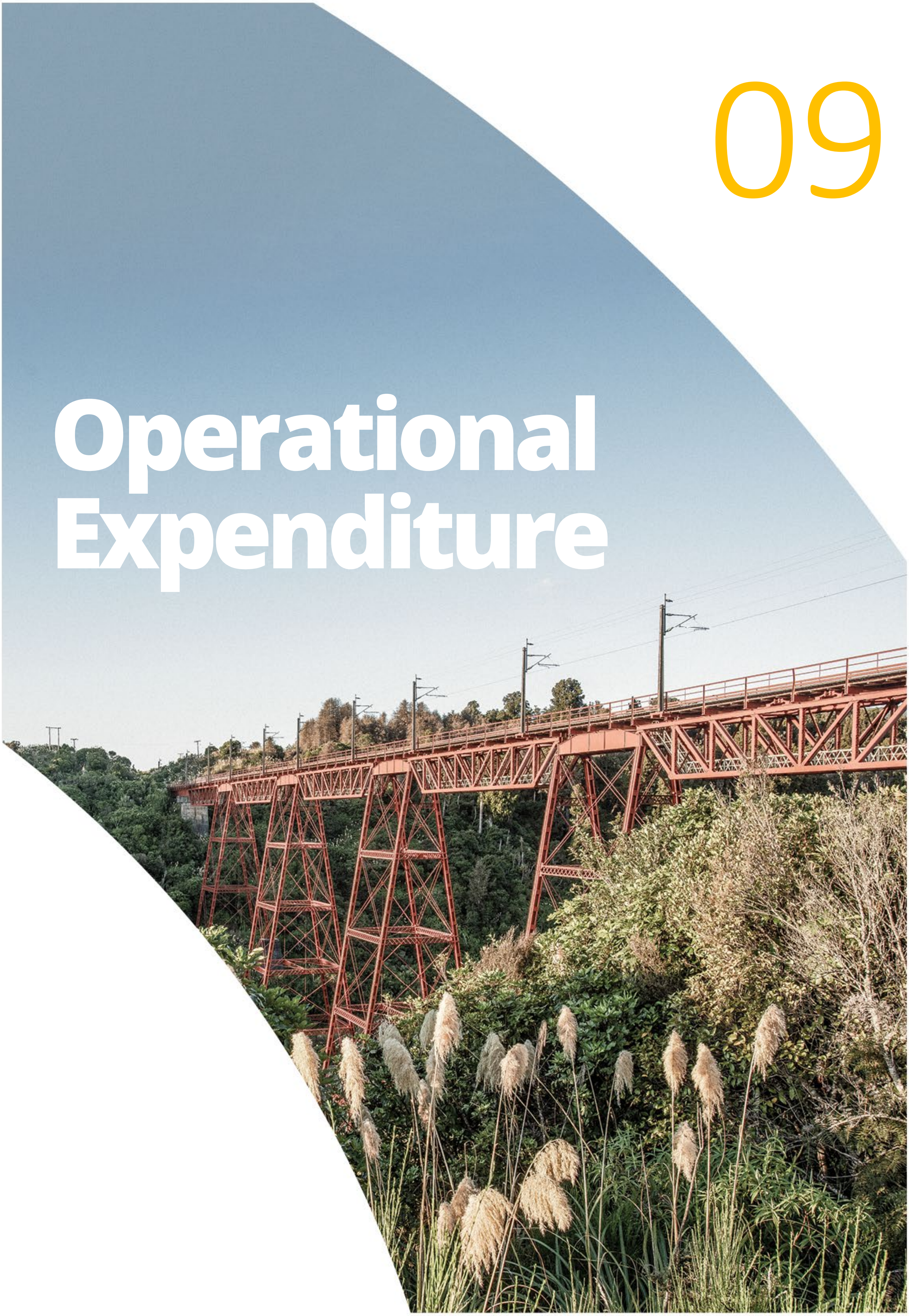
The key assumptions that may materially impact this plan are outlined below:

Table 8.38: Key Assumptions

Asset Renewals	
Line renewal programme	Data quality for line renewal is continually being improved but remains aged or absent in some cases. As we embark on our Aerial Inspections programme, we will understand the condition of our network better and it may result in a significant departure from our line renewal expenditure plan.
Zone substation renewals	Finalisation of designs for remedial substation development to meet seismic regulations does not result in a significant departure from our expenditure plan.
Network Development	
Whakamaru Zone Substation	There are no material constraints in implementing the planned zone substation to supply Whakamaru (i.e., access to land and any required easements) resulting in significant changes from our expenditure plan.
Ohakune alternative supply (220kV)	An alternative supply point for Ohakune is agreed with Transpower and remains within our planned cost envelope.
Customer Projects	Customer initiated projects to support industrial growth and large generation are at various stages of finalization. These represent $15m of forecast expenditure. Material uncertainties may arise from formalisation of a design and developing customer needs.
All Capex Projects	Delivery of this AMP assumes availability of resource, equipment and capital is consistent with current market experience, i.e., not materially impacted by a pandemic or other natural or un-natural disaster. This includes: • Availability of internal and contracted resources required for project delivery. • Costs and availability of equipment supply • Finance being accessible and at rates that are not inconsistent with the current market at the time of writing.

09

Operational Expenditure



9. Operational Expenditure

This chapter explains the operation and maintenance of our electricity assets. It aims to ensure the safe and reliable performance of our assets over their expected lives. It outlines the planning process for maintenance, vegetation management and system operations and support activities; how we establish our budgets and describes how we deliver our operations and maintenance tasks.

9.1 Introduction

Operations and maintenance are an essential part of the asset management process. Operational expenditure covers maintenance and business support activities rather than asset investment (which is capital expenditure covered in Section 5).

In this forecast, all expenditure is presented as constant values, meaning that it is not adjusted for Consumer Price Index (CPI) in future years.

Operations and maintenance portfolio – key objectives

TLC continually seeks to improve the approach taken to delivering work across the network. This includes:

- Assurance that the preventive maintenance strategy continues to provide essential information about the health of the assets, manage down preventable defects and meet all statutory obligations.
- Minimisation of breakdown rates of the assets, and adjustment of the services delivery or recommendations on asset renewal where the condition of the assets represents a high probability of failure.
- Assurance of timeliness of response to urgent work.
- Optimisation of scheduled work, including balancing resource commitments between capital projects, preventative maintenance programmes and faults.
- Assurance that the personnel delivering services are suitably trained and experienced to be safe in their work and assure high quality for each job.
- Assurance that systems remain appropriate to enabling efficient work management and reporting.

How this section is structured

Here we outline our investment across five key categories. These are:

Section		Purpose
6.2	Preventative Maintenance	Covers the activities that we undertake to maintain our assets. It includes details on: • Scheduling inspections of assets. • Scheduled repairs and improvement work. • Scheduled corrective maintenance to repair defects as they emerge.
6.3	Reactive Maintenance	Outlines how we respond to faults and interruptions to supply.
6.4	Vegetation Management	Outlines how we manage the vegetation that grows near our distribution lines to prevent tree-related outages.
6.5	Business, System Operation and Network Support (SONS)	Outlines the expenditure used for our business support functions and network operations, including staff, IT, and office costs.
6.6	Expenditure Summary	Summarises our total operational expenditure plan.

9.2 Preventative maintenance

The intent of planned maintenance is to prevent or minimise risk of failure by removing or reducing failure causes before they accumulate to create fault. Preventative maintenance includes inspections of assets, repairs, and correction of known defects.

Planned maintenance begins at the annual planning stage, where an inspection schedule is renewed or developed, and the work costed for budgetary approval. Following approval of the expenditure, work packs are developed that include detailed instructions for field staff to carry out the planned inspections or maintenance work. Resources are then scheduled to ensure the work can be carried out within the planning year.

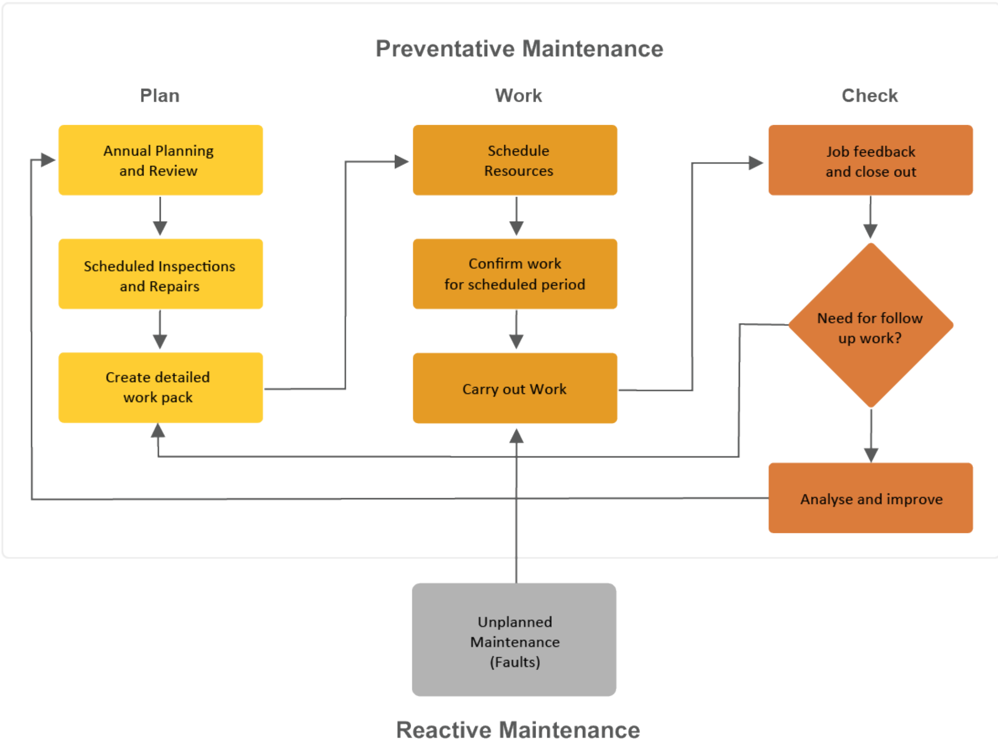
When complete, each job is reviewed and assessed to consider what additional improvements or changes can be made to the maintenance plan, to further minimise risk of failure in the future.

Preventative maintenance activities are scheduled annually based on the current understanding of asset condition and performance requirements for the planning period. These activities are incorporated into the annual works plan. Planned maintenance activities are scheduled to avoid resource constraints during peak work times, which often results in this work being carried out during winter when land access for renewal work is constrained.

The preventative maintenance plan outlines the inspection requirements for overhead lines, distribution switches, ground mounted transformers and zone substations. It is also used to monitor the condition of power transformers with regular condition tests. Currently our pole inspections are time driven rather than condition or risk driven, which presents an opportunity for improvement in the pole inspection regime.

Our vegetation management programme also links to preventative maintenance with all of the sub-transmission and a third of the distribution network inspected every year via helicopter. This allows targeted trimming of trees before they encroach on the regulatory growth limits.

Figure 9.46: Maintenance Workflow



Preventative maintenance schedule

The objective of the preventive maintenance schedule is to ensure that routine work is scheduled so that our assets remain safe, reliable, and compliant. The maintenance schedule also seeks to achieve a time-relevant understanding of the asset condition in order to enable renewal or improvement works at the optimal time. TLC's preventative maintenance schedule is outlined here.

Overhead structure and conductors

Key Risks

Key risks for overhead structure and conductors include:

- Public safety risk caused from vehicles colliding with the poles, resulting in uncontrolled exposure to live conductors
- Insulator failures
- Flashover and earth faults caused from animals (birds, opossums etc)
- Flashover caused by contact with trees or wind-blown debris
- Public or staff injury from pole collapse, caused by rotten pole structure or loss of pole stay wires
- Pole, insulator, or conductor damage caused by lightning strike.

Maintenance Undertaken

Maintenance is centered on conducting visual inspections to identify existing or potential problems which may cause future failures.

Asset Class	Frequency	Scope of Work
Sub-transmission Lines	12 Monthly	Helicopter patrols
11 kV and Low Voltage Lines	18 Monthly 3 Yearly	Drive or foot patrol Helicopter patrols - Hazard
11 kV Structure and Conductors	15 Yearly	A full inspection programme including pole testing

Cables

Key Risks

Key risks for cables are:

- For Mount Ruapehu ski-field cables, public safety and reliability risk caused by rock and snow groomer damage
- Mechanical damage from third party excavations
- Cable joint failures.

Maintenance Undertaken

Maintenance includes visual inspections of over-ground cables, and repairs as issues are identified.

Asset Class	Frequency	Scope of Work
Cables (ski-field areas)	12 Monthly	Foot patrols through the low valley areas, stream beds, rock movement areas, in/around tracks and high hazard areas.
Other Cables	3 Yearly	Foot patrols of cables and visual inspections of till box integrity.
Pillar box terminations	5 Yearly	Inspection.

Pole mounted distribution switches

Key Risks

Key risks for pole mounted distribution switches are:

- Staff injury from flashover caused by failed switch mechanisms
- In service failure resulting in an outage.

Maintenance Undertaken

Asset Class	Frequency	Scope of Work
Remote switchgear operation	12 Monthly	Operational check of remote-controlled switchgear overhead.
Overhead Remote Switch Battery change	3 Yearly	Change the battery on all remote switch control units. Check alarms. Visual inspection.
Oil Recloser oil change	3 Yearly Operation Count	Recloser refurbishment at workshop.

Ground mounted distribution transformers and switches:

Key Risks

Key risks for ground mounted distribution transformers and switches are:

- Staff injury from flashover or explosion caused by failed switch mechanisms
- Electrocution risk when working on ground mount transformers with exposed conductors (in tin sheds)
- Environmental damage caused by uncontained oil spills
- Operational failure caused by deterioration of paper insulation of the windings.

Maintenance Undertaken

Asset Class	Frequency	Scope of Work
Transformers	5 Yearly	Inspection.
Distribution substations	2 Monthly	Visual Inspection, Check, record value and reset MDIs at selected distribution substations.
Ground Mount Oil filled HV switch service	12 Monthly	Service Oil Switches and check operation.

Voltage regulators

Key Risks

Key risks for voltage regulators are:

- Environmental risk caused by fire damage or uncontained oil spills
- Public safety risk caused by compromised fencing and barriers
- Injury to staff and public from flashover and explosion caused by faulty equipment.

Maintenance Undertaken

Maintenance Type	Frequency	Scope of Work
Regulator Inspection	12 Monthly	Visual inspection.
Regulator Thermal Image Survey	12 Monthly	Thermal image survey of regulator and all associated equipment and connections.
Regulator Controller Test	12 Monthly	Operation and alarm test.
Regulator Internal Inspection	200,000 Operations	Internal inspection and change oil in regulators.

Zone substation buildings and grounds

Key Risks

Key risks for zone substation buildings and grounds are:

- Substation and environmental risk caused by fire damage or uncontained oil spills
- Public safety risk caused by compromised fencing and barriers
- Water and condensation damage to control circuitry.

Maintenance Undertaken

Asset Class	Frequency	Scope of Work
Buildings and Grounds	2 Monthly	Inspection and minor repairs without requiring outage

Zone substation power transformers

Key Risks

Key risks for zone substation power transformers are:

- Environmental damage caused by uncontained oil spills
- Operational failure caused by deterioration of paper insulation of the windings, or manufacturing defects
- Flashover caused by wind-blown debris
- Failure caused by windings and packing become loose and wet with age
- Failure caused by fault currents that cause movement and localised heating
- Failure caused by movement which can deform windings and create localised heating, resulting in ionisation of moisture in the transformer windings.

Maintenance Undertaken

Maintenance Type	Frequency	Scope of Work
Visual Inspection	2 Monthly	Routine visual equipment inspections and checks.
Thermal Imaging	12 Monthly	Thermal imaging.
Transformer oil test	2 Yearly	Test oil for acidity, power factor, breakdown voltage, moisture content, interfacial tension, colour and dissolved gas analysis. Furan reading for insulating paper analysis.
Tap changer service	5 Yearly	Clean out tap changer to ensure free of arc products and deposits. Replace insulating oil. Check contact alignment and correct operation of tap changer.

Transformer maintenance	5 Yearly	Close visual inspection, insulation resistance, impedance and Winding Capacitance and power factor test, Buchholz and pressure relief operational test, temperature gauge check, Neutral Earth Resistor test.
Test Zone substation earthing system	15 Years	Test zone substation earth mats. Test bonding of equipment and structure.

Zone substation 33kV switchgear

Key Risks

Key risks for zone substation 33kV switchgear are:

- Injury to staff and public from flashover and explosion caused by faulty equipment
- Injury to staff from inadvertent operation of unsafe-to-operate SDAF switchgear
- Injury to staff from incorrect identification and operation of switchgear.

Maintenance Undertaken

Maintenance Type	Frequency	Scope of Work
Inspection	12 Monthly	Routine visual equipment inspections and checks, including thermal imaging.
Outdoor 33kV Vacuum and SF6 Circuit Breaker servicing	5 Yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Outdoor Oil Circuit Breaker major servicing	5 Yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service Oil change, inspect contact.
Indoor Switches	2 Monthly	Routine visual equipment inspections and checks.
Thermal Image and Partial Discharge testing	2 Monthly	Thermal imaging and partial discharge diagnostic tests.
Indoor 11kV Oil Circuit Breaker major servicing	3 Yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service Oil change, inspect contact.
Indoor 11kV Vacuum and SF6 Circuit Breaker servicing	5 Yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.

Field 33kV Switchgear

Key Risks

Key risks for field 33kV switchgear are:

- Injury to staff and public from flashover and explosion caused by faulty equipment
- Injury to staff from incorrect identification and operation of switchgear
- In service failure resulting in outage.

Maintenance Undertaken

Maintenance Type	Frequency	Scope of Work
Routine equipment inspections	12 Monthly	Routine visual equipment inspections and checks, including thermal imaging.
Outdoor 33kV Vacuum and SF6 Circuit Breaker servicing	5 Yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Outdoor Oil Circuit Breaker major servicing	3 Yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service Oil change, inspect contact.

Outdoor current and voltage transformers

Key Risks

Key risks for outdoor current and voltage transformers are:

- Arc flash and / or failure caused by wind-blown debris
- Failure or environmental damage caused from oil leaks.

Maintenance Undertaken

Maintenance Type	Frequency	Scope of Work
Routine inspections and checks	12 Monthly	Routine visual equipment inspections and checks, including thermal imaging.
33kV oil filled VT's & CT's	3 Yearly	Insulation resistance test, oil change.

Other assets

Maintenance Undertaken		
Asset Class	Frequency	Scope of Work
SCADA and communications		
Radio site checks	3 Yearly	Visual inspection, battery charger and battery impedance tests.
Auxiliary supplies		
Battery maintenance	12 Monthly	Battery impedance test and charger test. Visual inspection.
Protection Relays		
Routine inspections and checks	12 Monthly	Routine visual equipment inspections and checks.
Protection testing for electromechanical/static Relays	5 yearly	Secondary injection tests and check operation.
Protection testing for numerical Relays	5 yearly	Secondary injection tests and check operation.
Protection review		Relay attributes check including settings, standards, discrimination, and records checks. Check for the impact of any changes in the Network.

9.3 Reactive maintenance

Reactive maintenance refers to the repair of faults, as well as urgent unplanned work that may be required to avoid a safety or environmental issue or prevent an imminent failure.

Reactive maintenance cannot usually be scheduled and is highly dependent on weather events such as storms or high winds, which create conditions that can lead to a failure, e.g., wind loading, treefall, lightning, and car-hits-pole events. Reactive maintenance uses the same engineering and field staff as planned maintenance and capital works. When it occurs, it necessarily breaks into and takes priority of the work schedule. As such work scheduling continually changes to cater for these unplanned events.

9.4 Vegetation management

Introduction

Our network crosses through dense vegetation and forested areas. As such, TLC has a high exposure to faults resulting from tree fall, particularly during storm events. To counter this, we invest significantly in vegetation management to maintain reliable supply to our rural customers.

Vegetation management involves tree trimming and removal, inspections to determine the amount of work required, and liaising with tree owners regarding the work needed on their property.

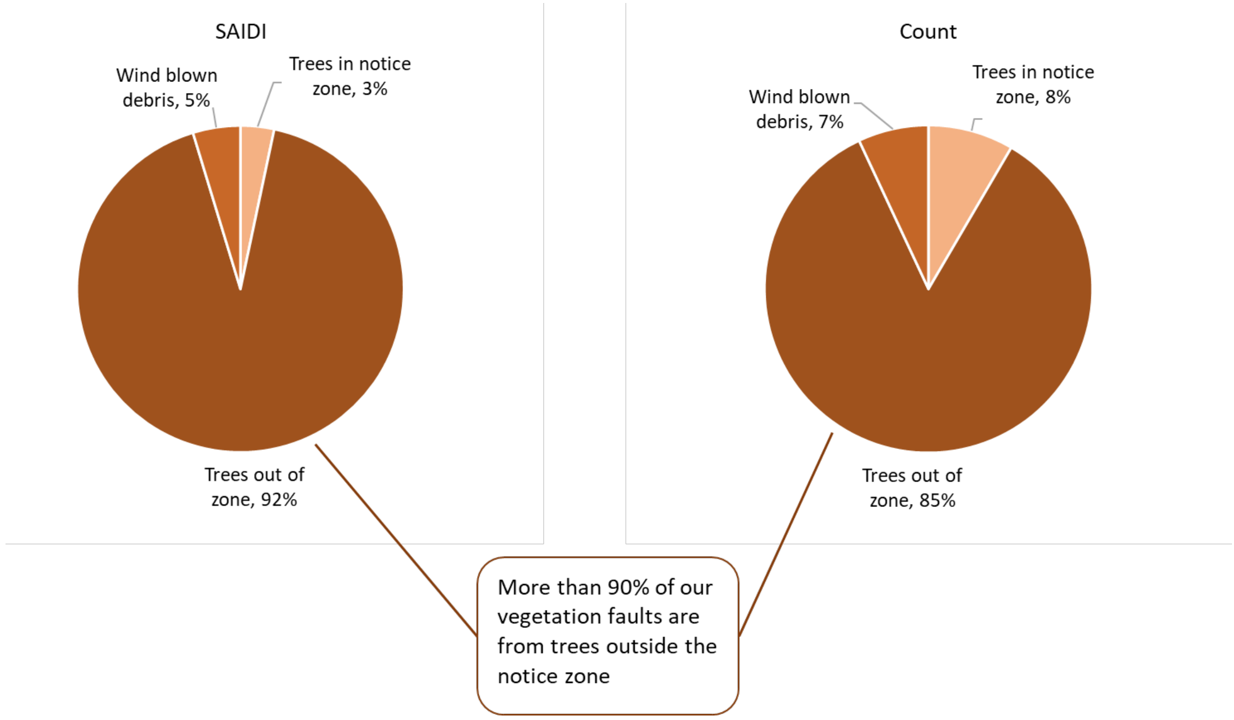
The issues and solutions associated with our vegetation management are summarised in the table below:

Issues	**Steps to Address**
Landowners planting under lines.	3 yearly patrols following up on new plantings.
Trees that breach the fall distance.	Charging landowners for problems caused by trees that breach the fall distance if the tree does fall through lines.
Landowners not complying with Tree Regulations.	Strict follow up on notices. Account follow up on any invoiced charges.
Legacy issues.	Issues are addressed one at a time when problems occur. They are mostly associated with plantation owners and their desire to maximise forest production.
Forest fires started by trees falling through lines.	Where a heightened risk of forest fire is known, inspection regimes of lines, trees and associated equipment are increased to assist in reducing the probability that a line fault could start a fire.

Vegetation management performance

In 2020 we restructured our fault reporting to categorize vegetation faults by their cause. The insights of this work are now emerging and have revealed that most of our faults are from trees falling onto the lines from outside the notice zone or by windblown debris, and this accounts for around 97% of our vegetation SAIDI. Figure 9.2 shows the proportion of vegetation faults against each man cause.

Figure 9.47: Vegetation Faults by Main Cause



Notwithstanding this, we have chosen to maintain consistency in our vegetation remediation program and associated expenditure (which reduces trees from growing under our lines) to ensure we are effectively managing faults and public safety risk that can occur if they are not maintained.

9.5 Business support, system operation and network support

Business support, system operation and network support or SONS relates mainly to our people and business that provide the supporting functions for our operations and control functions. This includes personnel expenses, professional fees for network support and supporting expenditure.

Annual business support budget planning is based on a combination of historical costs and trends supplemented to reflect the future effort associated with projected network growth and renewal.

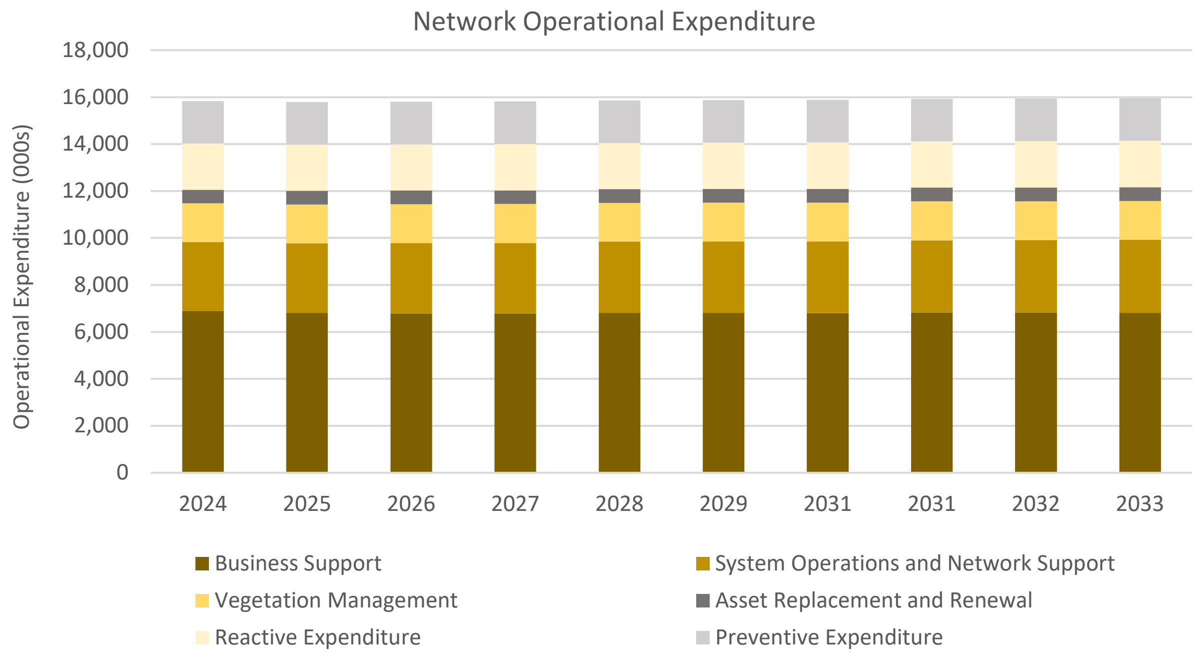
9.6 Total forecasted operational and maintenance expenditure

The 10-year maintenance expenditure forecast is provided in the table below.

Table 9.39: Summary of all Operational and Maintenance Expenditure – 10 years

$ 000's	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Maintenance										
Preventive Expenditure	1,812	1,814	1,813	1,814	1,815	1,815	1,816	1,817	1,818	1,818
Reactive Expenditure	1,968	1,968	1,968	1,969	1,970	1,970	1,971	1,972	1,973	1,973
Asset Replacement and Renewal										
Expenditure	584	584	584	584	584	585	585	585	585	586
Vegetation Management										
Expenditure	1,650	1,651	1,651	1,651	1,652	1,653	1,653	1,654	1,655	1,655
System Operations and Network Support										
Expenditure	2,930	2,965	2,992	3,008	3,023	3,038	3,054	3,070	3,087	3,104
Business Support										
Expenditure	6,893	6,811	6,793	6,787	6,820	6,812	6,805	6,832	6,825	6,818
Total	15,118	15,838	15,793	15,802	15,813	15,863	15,874	15,884	15,930	15,942

Figure 9.48: Summary of All Operational Expenditure



Appendices

10. Appendix A: Glossary

ABBREVIATION	DESCRIPTION
ABS	Air Break Switch
AHI	Asset Health Index
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
CB	Circuit Breaker
DGA	Dissolved Gas Analysis
DNO	Distribution Network Operators
DER	Distributed Energy Resources (Solar and Batteries)
EDB	Electricity Distribution Business
EV	Electric Vehicle
GIS	Geographic Information System
GWh	Gigawatt Hour
GXP	Grid Exit Point
HI	Health Index
HILP	High Impact Low Probability
HV	High Voltage
ICP	Installation Control Point
IT	Information Technology
kV	Kilovolts
kW	Kilowatt
LTI	Lost-time Injury
LTIFR	Lost-time Injury Frequency Rates
LV	Low Voltage

ABBREVIATION	DESCRIPTION
MVA	Mega Volt Ampere
MW	Megawatt
N	N system security means that the system is not able to tolerate the failure of any single component in the network. Any failure will result in a loss of supply
N-1	N-1 means that the system must be able to tolerate the failure of any single component in the network without affecting the supply of electricity
OH	Overhead Lines
PD	Partial Discharge
PoF	Probability of Failure
PoS	Point of Supply
PV	Photovoltaic
RCA	Root Cause Analysis
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SF6	Sulphur Hexafluoride
SONS	System Operation and Network Support
TLC	The Lines Company
TRIFR	Total Recordable Injury Frequency Rate
XLPE	Cross Linked Polythene

11. Appendix B: Information Disclosure Compliance

REFERENCE	REQUIREMENT	REF
Summary		
3.1	The AMP must include a summary that provides a brief overview of the contents and highlights information that the EDB considers significant.	1.2
Background and Objectives		
3.2	The AMP must include details of the background and objectives of the EDB's asset management and planning processes.	3.1, 3.2, 3.3, 3.4, 5.5
Purpose Statement		
3.3	The AMP must include a purpose statement that:	
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.	1.1
3.3.2	States the corporate mission or vision as it relates to asset management.	3.1
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB.	5.1
3.3.4	States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management.	3.2, 5.1

3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans.	3.2, 5.1
AMP Period		
3.4	The AMP must state that the period covered by the plan is 10 years or more from the commencement of the financial year.	1.1
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	1.1
Stakeholder Interests		
3.6	The AMP must include a description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates:	
3.6.1	How the interests of stakeholders are identified.	2.3
3.6.2	What these interests are.	2.3
3.6.3	How these interests are accommodated in asset management practices.	3.1, 3.2, 3.3, 3.4
3.6.4	How conflicting interests are managed.	2.3
Accountabilities and Responsibilities		
3.7	The AMP must include 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.	5.1, 5.2, 5.3
3.7.2	Executive - an indication of how the in-house asset management and planning organisation is structured.	2.1

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.	2.1, 5.5
Assumptions		
3.8	The AMP must include all significant assumptions.	1.3
3.8.1	All significant assumptions must be quantified where possible.	1.3
3.8.2	All significant assumption must be clearly identified in a manner that makes their significance understandable to interested persons.	1.2.2, 5.10, 6.2, 6.3, 6.4, 6.5, 6.7, 7.1 7.2, 7.7, 8.4
3.8.3	The identification of significant assumptions must include a description of changes proposed where the information is not based on the EDB's existing business.	1.3, 8.4
3.8.4	The identification of significant assumptions must include a description of the sources of uncertainty and the potential effect of the uncertainty on the prospective information.	1.3, 8.4 ???
3.8.5	The identification of significant assumptions must include a description of 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.	6.1, 7.1, 8.1, 9.1
Material Difference in Information		
3.9	The AMP must include 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.	1.3, 8.4
Asset Management Strategy and Delivery		

3.10	The AMP must include an overview of asset management strategy and delivery.	3.1, 3.2, 3.3, 3.4, 5
Systems and Information Management Data		
3.11	The AMP must include an overview of systems and information management data. (a) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; (b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; (c) the systems and controls to ensure the quality and accuracy of asset management information; (d) the extent to which these systems, processes and controls are integrated; (e) how asset management data informs the models that an EDB develops and uses to assess asset health; and (f) how the outputs of these models are used in developing capital expenditure projections.	5.6
3.12	The AMP must include a statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data.	4.2, 4.4, 4.5, 4.6, 4.7, 7.1, 7.7
Asset Management Process		
3.13	The AMP must include a description of the processes used within the EDB for:	
3.13.1	Managing routine asset inspections and network maintenance.	5.1, 5.5, 9.2
3.13.2	Planning and implementing network development projects.	4.2, 5.5, 6.1, 6.2, 6.3, 6.4, 6.5, 6.6, 6.7
3.13.3	Measuring network performance.	4.4

3.14	The AMP must include an overview of asset management documentation, controls, and review processes.	5.2, 5.3, 5.5
Communication Processes		
3.15	The AMP must include an overview of communication and participation processes.	5.2, 5.3, 5.5, **Error! Reference source not found.**
Financial Values		
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	Throughout the document
Disclosure Requirements		
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 the document
Assets Covered		
4	The AMP must provide detail 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:	2.2, 2.3, 6
4.1.1	The region(s) covered.	2.2
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities.	2.3
4.1.3	Description of the load characteristics for different parts of the network.	2.3
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	6.2

Network Configuration		
4.2	The AMP must provide 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.	2.4, 6.2
4.2.2	A description of the sub-transmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the sub-transmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x sub-transmission security or by providing alternative security class ratings.	6.1, 6.2, 6.3, 6.4, 6.5
4.2.3	A description of the distribution system, including the extent to which it is underground.	2.4
4.2.4	A brief description of the network's distribution substation arrangements	6.1
4.2.5	A description of the low voltage network including the extent to which it is underground.	2.4
4.2.6	An overview of secondary assets such as protection relays, ripple injection systems, SCADA, and telecommunications systems.	2.4
Sub-Networks		
4.3	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	N/A
Network Asset Information		
4.4	The AMP must describe the network assets by providing the following information for each asset category:	

4.4.1	Voltage levels.	2.4, 7
4.4.2	Description and quantity of assets.	2.4, 7
4.4.3	Age profile.	2.4, 7
4.4.4	A discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	7
Network Asset Information by Asset Category		
4.5	The asset categories discussed in clause 4.4 should include at least the following asset categories:	
4.5.1	The categories listed in the Report on Forecast Capital Expenditure in Schedule 11(a).	8.2
4.5.2	Assets owned by the EDB but installed at bulk electricity supply points owned by others.	2.4
4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand.	7.6
4.5.4	Other generation plant owned by the EDB.	Not applicable
Service Levels		
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	3.5

6	The AMP must include performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next five disclosure years.	3.5
7	The AMP must include performance indicators for which targets have been defined in clause 5 above should also include:	
7.1	Consumer oriented indicators that preferably differentiate between different consumer types.	3.5
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.	3.5
8	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	3.5
9	Targets should be compared to historic values where available to provide context and scale to the reader.	3.5, 3.6
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.	
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.	4, 6
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based	3.4, 4, 6

	planning techniques are used, this should be indicated, and the methodology briefly described.	
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.	3.4, 4.5
11.4	The use of standardised designs.	5.5
Network Efficient Operation		
11.5	The AMP must include 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.	3.4, 4.5
Equipment Capacity		
11.6	The AMP must include description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network.	6.8
Project Prioritisation		
11.7	The AMP must include 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	5.1, 5.2, 5.3
Demand Forecasts		
11.8	The AMP must provide 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.	6.2, 6.3, 6.4, 6.5
11.8.1	The AMP must explain the load forecasting methodology and indicate all the factors used in preparing the load estimates	6.2, 6.3, 6.4, 6.5
11.8.2	The AMP must 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	6.3, 6.4, 6.5

	are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts.	
11.8.3	The AMP must identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period.	6.2, 6.3, 6.4, 6.5
11.8.4	The AMP must 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.	4.2
Network Development Options		
11.9	The AMP must provide an analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including:	
11.9.1	The reasons for choosing a selected option for projects where decisions have been made.	6.2, 6.3, 6.4, 6.5
11.9.2	The alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described.	6.2, 6.3, 6.4, 6.5
11.9.3	The consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	4.4, 4.5, 4.6
Network Development Programme		
11.10	The AMP must provide a description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include:	
11.10.1	A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next twelve months.	6.2, 6.3, 6.4, 6.5

11.10.2	A summary description of the programmes and projects planned for the following four years (where known)	6.2, 6.3, 6.4, 6.5
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period.	6.2, 6.3, 6.4, 6.5
Distributed Generation		
11.11	The AMP must provide 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.	4.2
Non-Network Solutions		
11.12	The AMP must provide 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.	5.5
11.12.2	The potential for non-network solutions to address network problems or constraints.	4.2
Lifecycle Asset Management Planning (Maintenance and Renewals)		
12	The AMP must provide a detailed description of the lifecycle asset management processes, including:	
12.1	The key drivers for maintenance planning and assumptions.	4.4, 9.1, 9.2, 9.3, 9.4
Maintenance Programme		
12.2	The AMP must provide identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each	9

	asset category, including associated expenditure projections. This must include:	
12.2.1	The approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done.	9.2
12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems.	3.4, 7
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period.	0
Renewal Programme		
12.3	The AMP must include 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.	3.3, 3.4, 5.5, 4, 7
12.3.2	A description of innovations that have deferred asset replacements.	5.5
12.3.3	A description of the projects currently underway or planned for the next twelve months.	7.2, 7.3, 7.4, 0, 7.6
12.3.4	A summary of the projects planned for the following four years (where known).	7.2, 7.3, 7.4, 0, 7.6
12.3.5	An overview of other work being considered for the remainder of the AMP planning period.	7.2, 7.3, 7.4, 0, 7.6
12.4	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	7.2, 7.3, 7.4, 0, 7.6, 8.2

12.5	Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of:	
12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	7.1
12.5.2	the rationale for using the approach for each asset category.	7.2, 7.3, 7.4, 0, 7.6
12.6	Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	4.4
12.7	The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	4.3
Non-Network Development, Maintenance and Renewal		
13	The AMP must provide a summary description of material non-network development, maintenance, and renewal plans, including:	
13.1	A description of non-network assets.	2.4, 5.6
13.2	Development, maintenance, and renewal policies that cover them.	3.3, 5.6
13.3	A description of material capital expenditure projects (where known) planned for the next five years.	8.1
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	7, 9
Risk Management		
14	The AMP must provide details of risk policies, assessment, and mitigation, including:	
14.1	Methods, details, and conclusions of risk analysis.	4.4, 5.4

14.2	Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events.	4.4, 5.7
14.3	A description of the policies to mitigate or manage the risks of events identified in clause 14.2.	3.3, 5.7
14.4	Details of emergency response and contingency plans.	5.7
Evaluation of Performance		
15	The AMP must provide details of performance measurement, evaluation, and improvement, including:	
15.1	A review of progress against plan, both physical and financial.	3.6
15.2	An evaluation and comparison of actual service level performance against targeted performance.	3.5, 3.6
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.	4.8
15.4	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	3.6
Capability to Deliver		
16	The AMP must describe the processes used by the EDB to ensure that:	
16.1	It is realistic and the objectives set out in the plan can be achieved.	5.9
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1, 5.2, 8.3, 8.4

Tranche 1 Amendment Determination 2022: Qualitative Information in Narrative Form

REFERENCE	REQUIREMENT	REF
Notice of planned and unplanned interruptions		
17.1	A description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions	4.6
Voltage quality		
17.2	A description of the EDB's practices for monitoring voltage, including:	
17.2.1	The EDB's practices for monitoring voltage quality on its low voltage network;	4.6
17.2.2	Work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	4.6
17.2.3	How the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	4.6
17.2.4	How the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	4.6
17.2.5	Any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above;	4.6
Customer service practices		
17.3	A description of the EDB's customer service practices, including:	
17.3.1	The EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	4.6

17.3.2	The EDB's approach to planning and managing customer complaint resolution;	4.6
Practices for connecting new consumers and altering existing connections		
17.4	A description of the EDB's practices for connecting consumers, including:	
17.4.1	The EDB's approach to planning and management of- (a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and (b) alterations to existing connections (offtake and injection connections);	4.6
17.4.2	How the EDB is seeking to minimise the cost to consumers of new or altered connections;	4.6
17.4.3	The EDB's approach to planning and managing communication with consumers about new or altered connections; and	4.6
17.4.4	Commonly encountered delays and potential timeframes for different connections.	4.6
New connections		
17.5	A description of the following:	
17.5.1	How the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, e.g., the network location of new demand, generation, or storage capacity; and	4.2

17.5.2	How the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	4.2
Innovation practices		
17.6	A description of the following:	
17.6.1	Any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	4.7
17.6.2	The EDB’s desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	4.7
17.6.3	How the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;	4.7
17.6.4	How the EDB’s decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	4.7
17.6.5	The types of information the EDB uses to inform or enable any innovation practices, and the EDB’s approach to seeking that information.	4.7

12. Appendix C: Information Disclosure Asset Management Plan Schedules

Number	Report Name
11a	Forecast Capital Expenditure
11b	Forecast Operational Expenditure
12a	Asset Condition
12b	Forecast Capacity
12c	Forecast Network Demand
12d	Interruptions and Duration
13	Asset Management Maturity
14a	Mandatory Explanatory Notes on Forecast Information

		Company Name	The Lines Company
		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	1,524	4,124	6,724	4,676	945	4,304	982	1,001	1,021	1,041	1,062
11	System growth	411	150	2,600	6,749	14,309	2,116	2,157	3,763	2,243	1,805	2,577
12	Asset replacement and renewal	10,061	11,985	12,009	13,358	14,078	11,878	12,923	14,010	13,966	13,999	14,519
13	Asset relocations	23	203	156	-	164	-	170	-	177	-	184
14	Reliability, safety and environment:											
15	Quality of supply	2,422	2,102	874	589	1,615	846	1,550	2,165	708	722	736
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	7,624	3,760	2,281	793	1,059	445	738	1,193	673	602	614
18	**Total reliability, safety and environment**	10,046	5,862	3,155	1,382	2,675	1,292	2,288	3,358	1,381	1,324	1,350
19	**Expenditure on network assets**	22,065	22,324	24,643	26,165	32,170	19,590	18,521	22,132	18,789	18,170	19,692
20	Expenditure on non-network assets	2,900	2,528	2,438	5,517	1,683	1,825	1,433	1,304	646	773	623
21	**Expenditure on assets**	24,965	24,851	27,081	31,682	33,854	21,415	19,954	23,436	19,434	18,943	20,315
22												
23	*plus* Cost of financing	499	489	514	589	612	382	349	402	326	312	328
24	*less* Value of capital contributions	750	3,759	5,600	3,500	-	3,000	-	-	-	-	-
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	24,714	21,581	21,995	28,771	34,466	18,797	20,303	23,837	19,760	19,255	20,643
28												
29	Assets commissioned	23,407	23,901	23,545	28,221	36,766	19,097	20,603	23,337	19,260	18,755	20,143
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	1,524	4,124	6,465	4,365	865	3,865	865	865	865	865	865
34	System growth	411	150	2,500	6,300	13,100	1,900	1,900	3,250	1,900	1,500	2,100
35	Asset replacement and renewal	10,061	11,985	11,547	12,471	12,889	10,666	11,381	12,101	11,831	11,631	11,831
36	Asset relocations	23	203	150	-	150	-	150	-	150	-	150
37	Reliability, safety and environment:											
38	Quality of supply	2,422	2,102	840	550	1,479	760	1,365	1,870	600	600	600
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	7,624	3,760	2,193	740	970	400	650	1,030	570	500	500
41	**Total reliability, safety and environment**	10,046	5,862	3,033	1,290	2,449	1,160	2,015	2,900	1,170	1,100	1,100
42	**Expenditure on network assets**	22,065	22,324	23,695	24,426	29,453	17,591	16,311	19,116	15,916	15,096	16,046
43	Expenditure on non-network assets	2,900	2,528	2,438	5,517	1,683	1,825	1,433	1,304	646	773	623
44	**Expenditure on assets**	24,965	24,851	26,133	29,943	31,136	19,416	17,744	20,420	16,562	15,869	16,669
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												

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 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
Difference between nominal and constant price forecasts		$000										
Consumer connection		-	-	259	311	80	439	117	136	156	176	197
System growth		-	-	100	449	1,209	216	257	513	343	305	477
Asset replacement and renewal		-	-	462	888	1,189	1,212	1,542	1,909	2,135	2,368	2,688
Asset relocations		-	-	6	-	14	-	20	-	27	-	34
Reliability, safety and environment:												
Quality of supply		-	-	34	39	136	86	185	295	108	122	136
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment		-	-	88	53	89	45	88	163	103	102	114
Total reliability, safety and environment		-	-	121	92	226	132	273	458	211	224	250
Expenditure on network assets		-	-	948	1,739	2,717	2,000	2,210	3,016	2,873	3,074	3,646
Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
Expenditure on assets		-	-	948	1,739	2,717	2,000	2,210	3,016	2,873	3,074	3,646

11a(ii): Consumer Connection

		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
*Consumer types defined by EDB**		$000 (in constant prices)					
NXC: 1 - Standard Connection - High Density		291	292	692	692	692	692
NXC: 2 - Standard Connection - Low Density		73	73	173	173	173	173
NXC: 3 - Non-standard connection		1,160	3,759	5,600	3,500	-	3,000
		-					
		-					
**include additional rows if needed*							
Consumer connection expenditure		1,524	4,124	6,465	4,365	865	3,865
less Capital contributions funding consumer connection		750	3,759	5,600	3,500	-	3,000
Consumer connection less capital contributions		774	365	865	865	865	865

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	-	-	-	-	-
Zone substations	376	150	2,100	2,500	10,900	1,500
Distribution and LV lines	35	-	400	3,800	2,200	400
Distribution and LV cables	-	-	-	-	-	-
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	411	150	2,500	6,300	13,100	1,900
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	411	150	2,500	6,300	13,100	1,900

11a(iv): Asset Replacement and Renewal

	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**
	$000 (in constant prices)					
Subtransmission	900					
Zone substations	2,240	4,428	100	600	1,721	
Distribution and LV lines	6,164	6,076	8,396	9,324	8,751	8,929
Distribution and LV cables	385					
Distribution substations and transformers	53	910	1,440	986	986	986
Distribution switchgear	269	475	1,265	1,465	1,335	655
Other network assets	50	96	346	96	96	96
Asset replacement and renewal expenditure	10,061	11,985	11,547	12,471	12,889	10,666
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	10,061	11,985	11,547	12,471	12,889	10,666

11a(v): Asset Relocations

	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**
*Project or programme**	**$000 (in constant prices)**					
NXL: 1 - Miscellaneous	23	203	150		150	
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	23	203	150		150	
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	23	203	150		150	

11a(vi): Quality of Supply

	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**
*Project or programme**	**$000 (in constant prices)**					
NXEQ: 1 - 11kV Fdr Development - Feeders	115	655	100	100	1,124	100
NXEQ: 2 - Network sectionalisation and automation	760	285	740	315	215	510
NXEQ: 3 - Security of supply improvement	1,342	1,032				
NXEQ: 4 - Zone substation improvement	50	100		75	140	150
NXEQ: 5 - Scada and Radio improvement	155	30		60		
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	2,422	2,102	840	550	1,479	760
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	2,422	2,102	840	550	1,479	760

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28

11a(vii): Legislative and Regulatory

*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure						
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions						

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28

11a(viii): Other Reliability, Safety and Environment

*Project or programme**	$000 (in constant prices)					
NXEO: 1 - 11kV Fdr Dev - Switchgear, Cables	219	1,200	850	700	300	400
NXEO: 2 - Sub and 33kV Dev - Substations	2,166	2,500	1,303		630	
NXEO: 3 - Sub and 33kVDev -Supply Points	200					
NXEO: 4 - Tx & Service Boxes - GMT, 2 Pole Structures	5,039					
NXEO: 5 - SCADA, Radio, Data Systems, Other		60	40	40	40	
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	7,624	3,760	2,193	740	970	400
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	7,624	3,760	2,193	740	970	400

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28

11a(ix): Non-Network Assets

Routine expenditure						
*Project or programme**	$000 (in constant prices)					
NXNR: 1 - Eng & Asset Capital - Data and Data Systems	11	760	180	1,010	160	180
NXNR: 2 - Eng & Asset Capital - Office Area	22	24	24	24	24	24
NXNR: 3 - Eng & Asset Capital - Miscellaneous Equipment		622	612	362	378	500
NXNR: 4 - Eng & Asset Capital - Vehicles	122	122	122	122	122	122
NXNR: 5 - General business support	835					
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	990	1,528	938	1,517	683	825
Atypical expenditure						
*Project or programme**						
NXNA: 1 - Eng & Asset Capital - Building Re-structure	910		500	3,000		
NXNA: 2 - Eng & Asset Capital - Data and Data Systems	1,000	1,000	1,000	1,000	1,000	1,000
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	1,910	1,000	1,500	4,000	1,000	1,000
Expenditure on non-network assets	2,900	2,528	2,438	5,517	1,683	1,825

Company Name	The Lines Company
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		1,559	1,968	2,047	2,108	2,150	2,193	2,237	2,282	2,328	2,374	2,422
11	Vegetation management		1,516	1,650	1,717	1,768	1,804	1,840	1,877	1,914	1,952	1,991	2,031
12	Routine and corrective maintenance and inspection		1,555	1,812	1,886	1,942	1,981	2,021	2,061	2,103	2,145	2,188	2,231
13	Asset replacement and renewal		584	584	607	626	638	651	664	677	691	705	719
14	**Network Opex**		5,213	6,014	6,257	6,445	6,574	6,705	6,839	6,976	7,116	7,258	7,403
15	System operations and network support		2,611	2,930	3,084	3,205	3,285	3,366	3,450	3,536	3,624	3,716	3,810
16	Business support		5,875	6,893	7,083	7,277	7,413	7,595	7,736	7,879	8,065	8,214	8,367
17	**Non-network opex**		8,486	9,824	10,167	10,482	10,698	10,961	11,185	11,415	11,690	11,930	12,176
18	**Operational expenditure**		13,699	15,838	16,425	16,927	17,271	17,667	18,025	18,391	18,805	19,188	19,579
19			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20		for year ended	**31 Mar 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		1,559	1,968	1,968	1,968	1,969	1,970	1,970	1,971	1,972	1,973	1,973
23	Vegetation management		1,516	1,650	1,651	1,651	1,651	1,652	1,653	1,653	1,654	1,655	1,655
24	Routine and corrective maintenance and inspection		1,555	1,812	1,814	1,813	1,814	1,815	1,815	1,816	1,817	1,818	1,818
25	Asset replacement and renewal		584	584	584	584	584	584	585	585	585	585	586
26	**Network Opex**		5,213	6,014	6,017	6,016	6,018	6,021	6,023	6,025	6,028	6,030	6,032
27	System operations and network support		2,611	2,930	2,965	2,992	3,008	3,023	3,038	3,054	3,070	3,087	3,104
28	Business support		5,875	6,893	6,811	6,793	6,787	6,820	6,812	6,805	6,832	6,825	6,818
29	**Non-network opex**		8,486	9,824	9,776	9,786	9,794	9,843	9,850	9,859	9,902	9,912	9,922
30	**Operational expenditure**		13,699	15,838	15,793	15,802	15,813	15,863	15,874	15,884	15,930	15,942	15,954
31	**Subcomponents of operational expenditure (where known)**												
32	Energy efficiency and demand side management, reduction of												
33	energy losses		-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*		637	-	-	-	-	-	-	-	-	-	-
35	Research and Development		-	-	-	-	-	-	-	-	-	-	-
36	Insurance		-	451	476	508	522	537	553	569	585	602	620
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
38													
39			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40		for year ended	**31 Mar 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		-	-	79	140	182	224	267	311	356	402	448
43	Vegetation management		-	-	66	118	152	188	224	261	298	337	376
44	Routine and corrective maintenance and inspection		-	-	73	129	167	206	246	287	328	370	413
45	Asset replacement and renewal		-	-	23	42	54	66	79	92	106	119	133
46	**Network Opex**		-	-	241	428	555	684	816	951	1,088	1,228	1,371
47	System operations and network support		-	-	119	213	277	344	412	482	554	629	705
48	Business support		-	-	272	484	626	775	923	1,074	1,233	1,390	1,549
49	**Non-network opex**		-	-	391	697	904	1,119	1,335	1,556	1,787	2,018	2,255
50	**Operational expenditure**		-	-	632	1,125	1,459	1,803	2,151	2,506	2,875	3,246	3,625

Company Name	**The Lines Company**
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					Asset condition at start of planning period (percentage of units by grade)							
7												
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.28%	1.49%	24.09%	39.34%	34.22%	0.59%	3	6.59%
11	All	Overhead Line	Wood poles	No.	7.77%	5.54%	16.05%	45.27%	19.20%	6.17%	2	13.31%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	32.65%	59.56%	7.79%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	2.43%	12.02%	85.56%	-	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	-	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	60.87%	39.13%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	1.69%	-	-	13.56%	84.75%	-	3	1.69%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	13.79%	5.42%	7.88%	20.69%	52.22%	-	3	13.79%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	100.00%	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	100.00%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	31.43%	-	-	24.29%	44.29%	-	3	31.43%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	12.00%	-	66.00%	22.00%	-	3	-
35												

					Asset condition at start of planning period (percentage of units by grade)							
36												
37												
38	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
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	2.56%	25.64%	51.28%	20.51%	-	4	7.69%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.15%	0.80%	10.64%	74.53%	13.88%	-	2	0.96%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	0.28%	0.10%	26.95%	64.97%	7.70%	-	2	0.38%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.43%	0.08%	7.74%	37.20%	54.55%	-	2	0.43%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	-	-	-	N/A	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	18.33%	1.25%	3.75%	8.75%	67.92%	-	3	18.33%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	100.00%	-	3	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5.83%	2.43%	7.57%	44.01%	40.16%	-	2	5.83%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	2.63%	19.74%	77.63%	-	3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.98%	5.40%	3.41%	10.51%	76.70%	-	3	3.98%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.86%	1.22%	11.05%	58.35%	28.51%	-	2	0.86%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.93%	4.67%	4.49%	61.87%	28.04%	-	3	0.93%
53	HV	Distribution Transformer	Voltage regulators	No.	2.47%	-	-	24.69%	72.84%	-	3	2.47%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	0.34%	0.62%	14.34%	71.99%	12.70%	-	2	0.97%
56	LV	LV Cable	LV UG Cable	km	1.83%	0.06%	3.35%	76.67%	18.09%	-	2	1.83%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	8.31%	84.20%	7.49%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.43%	0.62%	4.86%	9.49%	7.12%	77.48%	2	0.43%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	6.38%	12.77%	-	73.76%	6.74%	0.35%	3	6.38%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	9.08%	8.50%	0.10%	48.63%	32.62%	1.07%	3	9.08%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.00%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	30.77%	-	53.85%	15.38%	-	3	-
63	All	Load Control	Relays	No.	-	-	-	62.41%	11.38%	26.21%	3	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Company Name	**The Lines Company**
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	Arohena	3.6	-	N	0.8	-	-	-	No constraint within +5 years	
10	Atiamuri	11.4	-	N	10.0	-	-	-	Transformer	Scheduled upgrade to Atiamuri planned in next 5 yrs
11	Awamate	1.4	-	N	1.3	-	-	-	No constraint within +5 years	
12	Borough	7.8	10.0	N - 1	2.5	78%	10.0	0.8	No constraint within +5 years	
13	Gadsby Road	5.3	-	N	5.7	-	-	-	Transformer	
14	Hangatiki	3.6	-	N	1.3	-	-	-	No constraint within +5 years	
15	Kaahu Tee	2.2	-	N	1.0	-	-	-	No constraint within +5 years	
16	Kiko Road	1.7	-	N	-	-	-	-	No constraint within +5 years	Transformer out of service. Site currently operating as a switching station.
17	Kuratau	2.4	-	N	0.1	-	3.0	0.8	No constraint within +5 years	
18	Mahoenui	3.3	-	N	0.5	-	-	-	No constraint within +5 years	
19	Manunui	3.3	-	N	1.2	-	-	-	No constraint within +5 years	
20	Maraetai	5.4	-	N	0.5	-	-	-	No constraint within +5 years	
21	Marotiri	3.6	-	N	1.3	-	-	-	No constraint within +5 years	
22	Mokai	5.0	-	N	1.0	-	-	-	No constraint within +5 years	
23	National Park	2.8	-	N	1.2	-	-	-	No constraint within +5 years	
24	Nihoniho	1.2	-	N	0.7	-	-	-	No constraint within +5 years	
25	Oparure	1.8	-	N	1.1	-	-	-	No constraint within +5 years	
26	Otukou	0.3	-	N	-	-	-	-	No constraint within +5 years	
27	Piripiri	1.4	2.4	N-1	2.4	59%	-	-	No constraint within +5 years	-
28	Taharoa	17.2	10.0	N - 1	-	172%	10.0	1.5	Transformer	Constraint managed through agreement with major customer
29	Taharoa Village	0.3	-	N	-	-	-	-	No constraint within +5 years	
30	Tawhai	4.8	-	N	0.7	-	-	-	No constraint within +5 years	
31	Te Anga	2.3	2.4	N-1	2.4	96%	-	-	No constraint within +5 years	
32	Te Waireka	11.1	15.0	N - 1	2.7	74%	15.0	0.9	No constraint within +5 years	
33	Tokaanu	0.2	-	N	-	-	-	-	No constraint within +5 years	
34	Tuhua	1.4	-	N	0.7	-	-	-	No constraint within +5 years	
35	Turangi	4.8	5.0	N - 1	1.9	96%	5.0	1.0	No constraint within +5 years	
36	Waiotaka	2.2	-	N	0.5	-	-	-	No constraint within +5 years	
37	Wairere	3.0	2.5	N - 1	1.1		2.5	1.2	No constraint within +5 years	
38	Waitete	9.0	15.0	N - 1	3.8	60%	10.0	0.9	No constraint within +5 years	

39

Company Name	**The Lines Company**
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

12c(i): Consumer Connections

sch ref			Number of connections					
8	*Number of ICPs connected in year by consumer type*							
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: Service Level Urban		68	89	90	91	92	93
13	Standard: Service Level Rural		122	161	163	164	166	167
14	Standard: Service Level Remote		9	12	12	12	12	12
15	Non standard connection		-	1	-	1	-	-
16								
17	**Connections total**		199	264	265	268	270	272
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		34	42	53	66	82	103
21	Capacity of distributed generation installed in year (MVA)		0.084	0.105	0.132	0.165	0.206	0.257

12c(ii) System Demand

sch ref									
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		68	75	82	91	97	101
26	*plus*	Distributed generation output at HV and above		13	13	13	14	14	15
27		**Maximum coincident system demand**		81	88	95	105	111	116
28	*less*	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**		81	88	95	105	111	116
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		319	321	323	325	328	330
32	*less*	Electricity exports to GXPs		5	5	5	5	5	5
33	*plus*	Electricity supplied from distributed generation		67	68	69	70	71	72
34	*less*	Net electricity supplied to (from) other EDBs		(12)	(13)	(13)	(13)	(13)	(13)
35		**Electricity entering system for supply to ICPs**		393	396	400	403	406	410
36	*less*	Total energy delivered to ICPs		366	369	372	375	378	381
37		**Losses**		27	28	28	28	28	28
38									
39		**Load factor**		55%	51%	48%	44%	42%	41%
40		**Loss ratio**		6.8%	6.9%	6.9%	6.9%	6.9%	6.9%

Company Name	**The Lines Company**
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)	88.0	113.6	113.6	113.6	113.6	113.6
12	Class C (unplanned interruptions on the network)	152.4	179.7	167.9	156.8	146.2	136.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.00	0.7	0.7	0.7	0.7	0.7
15	Class C (unplanned interruptions on the network)	2.60	2.9	2.8	2.7	2.5	2.4

Company Name	**The Lines Company**
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
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Documented evidence indicates that TLC's AM Policy was reviewed and re-approved by its Asset Management Committee in 2022. The authorised AM Policy is documented in TLC's AMP 2023 and is effectively communicated to the senior management team. However, there is no strong evidence that shows the AM Policy has been broadly communicated with all relevant employees and external stakeholders.	3b AMP Policy Review 2023 Asset Management Plan_Master_ Draft for RAM Review
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?	3.5	TLC has revised its AM objectives for this 2023 AMP to reflect the changes in its business goals and the broader needs of its customers and stakeholders. The AM strategy is consistent with risk management policy. TLC's AM strategy is also reflecting the changes in its approach to customer and community engagement. TLC has identified its key stakeholders and reviewed their main interests with established engagement processes.	2023 Asset Management Plan_Master_ Draft for RAM Review - TLC's business strategic themes - The relationship between business strategy, AM
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?	3.5	TLC has defined five AM objectives that guide its asset management decision-making. For each AM objective, the initiatives are set out and the key targets are defined. The strategic asset management plans are developed for the defined asset classes (categorised based on an asset system, e.g., OH Line, substation, etc.) and interconnected with the AM objectives and initiatives. This approach takes account of the lifecycle management of the assets from their creation through operations and maintenance to eventual disposal.	2023 Asset Management Plan_Master_ Draft for RAM Review - Life Cycle Management - Renewal our network - Preventative Maintenance
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?	3.5	TLC has made two key changes in approach in developing the 2023 AMP. With the established asset class strategies, a master programme of work is formed from the individual asset class plans. The network hygiene projects are separated from other capex to adjust for risk. The AMP covers lifecycle management of its assets. The AMPs are documented, implemented, and maintained to achieve TLC's AM objectives. The new features in TLC's 2023 AM Planning are: - 10-year Capex forecast and Opex forecast chart - The significant projects in TLC 2023 AMP - Capex plan deliverability analysis	RAM Information Memorandum - 2023 Asset Management Plan – Update 2023 Asset Management Plan_Master_ Draft for RAM Review 2023 AMP RAM Paper4 V5

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
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?	3.15	TLC communicates its AMPs to all relevant parties to a level of detail appropriate to their needs. While a summary of the 10-year expenditure forecast with the core drivers represented in a chart gives a glance at the key Capex and Opex expenditure categories, a Project Description Sheet (PDS) provides detailed information including the scope of work, budget, work sequence, outage plan, photos and drawings to support implementing a project. TLC holds regular meetings with set agendas processing standard reports so everyone knows what to expect. TLC has a good culture of an open-door approach to communication and teamwork within the organisation.	Meeting Minutes - AMC 30 August 2022 Minutes of Meeting held with Treescape 22 Nov 2022 2023 Asset Management Plan_Master_ Draft for RAM Review PDS Kuratau Feeder split_TH
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3.15	TLC documents the designated responsibilities of the asset management related roles across the business in its AMPs. A project manager is assigned to each project. Asset engineers are assigned to the maintenance programme. TLC Position Description provides key responsibilities and key relationships with internal and external stakeholders. TLC reviewed and amended its organisation structure and key functions in 2022 to ensure that designated responsibility and authority for the achievement of asset plan actions are appropriate.	2023 Asset Management Plan_Master_ Draft for RAM Review TLC Organisation Chart TLC Position Description
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)	3.15	TLC has assessed the deliverability of the Capex plan. With an understanding of the deliverability of its own service delivery team, TLC has outlined the key components of its Capex plan and allocated the work between internal and external resources. Complex work including substations, complex switchgear, and some line renewals is outsourced. The AM strategic plan gives visibility to the projects in the longer term. The improved certainty helps TLC to make its plan on resource needs on the engineering and project management as well as field staff.	2023 Asset Management Plan_Master_ Draft for RAM Review Proposed team - 17 Jan 2023
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	TLC manages business continuity risk through the implementation of its Incident Management framework. The framework is based on Civil Defence Coordinated Incident Management System (CIMS) and uses the Four Rs of Emergency Preparedness Reduction, Readiness, Response, and Recovery. TLC has Incident Management Plan (IMP) as part of its Business Continuity framework in place to provide guidance for managing any incident that may occur during the course of TLC's day to day operations.	Incident Management Plan

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
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)?	3.15	TLC reviewed and updated its organisation structure and key functions, and adjusted its AM team in the organisation chart. TLC has assigned accountabilities to relevant asset management roles across the business. TLC's Asset Management Committee is responsible for monitoring the implementation of the AM Policy and Objectives. TLC has also established four additional operational governance groups in the past few years. Each group has its designated responsibilities in making decisions and monitoring the performance in its focused operational area. It has helped TLC to strengthen its oversight of operational delivery and risk.	2023 Asset Management Plan_Master_ Draft for RAM Review TLC Organisation Chart - Nov 2022
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	TLC reviewed its organisation structure and adjusted key functions. With an established asset management team structure, TLC is continuously developing its asset management capacity and capability by hiring personnel with the required expertise and relocating the existing resources. The deliverability analysis of the Capex plan allows TLC to plan the required resources within the company and outsource the work with much-increased certainty.	2023 Asset Management Plan_Master_ Draft for RAM Review TLC Organisation Chart - Nov 2022 2023 AMP RAM Paper 4 V5
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3.15	TLC has used a range of strategies to communicate the importance of meeting asset management requirements. The company holds regular Asset Management Committee meetings, Network monthly report meetings, and Project monthly meetings. TLC developed a project management process (Typical TLC Project Lifecycle) in 2022. The process is represented in a chart which will help people who are involved in project delivery improve their understanding of the workflow and the requirements.	AMP Memo Network Monthly Report Meeting minutes Emails TLC Position Description Typical TLC Project Lifecycle
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	2.75	TLC has a Master Service Agreement in place to ensure quality delivery of outsourced asset management activities from design to construction. All outsourced works are managed through the internal project managers. Work Pack for each work is prepared to specify scope of work, deliverables, task details and work instruction. TLC sets out the requirements for the contractor on induction training and switching competence assessment.	Master Service Agreement

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.75	TLC's AM leadership team defines the required human resources to undertake asset management activities. Asset Management Roles and Accountabilities are detailed in its APM. The required key competencies are documented in Position Descriptions. TLC has been continually hiring personnel with the required expertise to increase the capacity of the human resources as required.	Organisation Chart Position description
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.5	TLC has identified core competencies in the job design process and includes the requirements in Position Descriptions. Training requirements are identified/discussed through an interactive communication approach which can be either from the managers who arrange on the job training for the personnel or from the personnel who reach the managers to discuss appropriate training opportunities for continual professional improvement. A structured means is not currently in place for identifying training requirements, planning and recording training for all core asset management related competencies.	Organisation Chart Position description
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.5	TLC has specified in detail about the required qualifications, experience and skills for the designated asset management positions. TLC also provides support for training requirements when identified. These approaches help the company to ensure that persons under its direct control have an appropriate level of competence to undertake asset management related activities. There is however no evidence that TLC has documented the processes for developing training and development plans.	Organisation Chart Position description

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
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?	3.15	TLC uses both formal and informal communication strategies to facilitate effective communication with its staff. The different types of asset management information are communicated with different stakeholders. Board meetings are held to review long-term Capex and Opex to ensure the plans are aligned with the AM objectives. The monthly meetings on network reports and project management communicate information on all aspects of asset management activities focusing on project delivery including outsourced capex work. The development of a Typical TLC Project Lifecycle in 2022 will improve communication through the "do" phase.	Board memo Typical TLC Project Lifecycle PDS Approval Process
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?	3	In 2022, TLC improved its Asset Management System (AMS) by revising the AM objectives and set out the initiatives and measurable targets. A flow chart with a set of high-level processes indicating the main elements of the system with the interrelations/interactions between elements. The AMS information is documented in its AMP. With the established AM structure, TLC has established additional governance functions including AMC, VMC, DRG, OMC, and PSG to monitor the planning and implementation of its AM objectives and strengthen its oversight of the operational delivery and risk.	2023 Asset Management Plan_Master_ Draft for RAM Review 2023 AMP RAM Paper 4 V5 AMC - Asset Management Committee VMC - Vegetation Management Committee DRG - Design Review Group OMC - Outage Management Committee PSG - Public Safety Review Group
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?	3	TLC has four core information systems associated with asset management functions. The company has been developing processes including Dashboard and Asset Altitude to process the raw data to a ready-to-use form to assist stakeholder decision-making. The development of the decision-making support tools provides great help to determine what its asset management information systems should contain to meet the asset management requirement.	Dashboards Asset Altitude
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?	3.25	TLC has reviewed data accuracy across the asset base and identified data quality issues in relation to the asset classes. Data accuracy is steadily being refined and improved as both inspections and work are completed on the network. In 2022, TLC changed its OH line inspection approach to provide more accurate condition data by combining a LiDAR scan, poletop photography, and ground inspection. TLC has now largely automated its inspection processes using tablets in the field to reduce the subjectivity of condition assessment and streamline data entry.	3d Changing our Line Inspection Approach Business case for spatial analytics - Final 2023 Asset Management Plan_Master_ Draft for RAM Review

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3.25	In 2022, TLC conducted a review of its core asset systems and business capabilities. The review resulted in a proposed system upgrade roadmap. TLC's focus in the next three years will be in developing an Advanced Distribution Management System. That will enable TLC's information systems to integrate together and allow them to more deeply analyse their network, and to be more efficient and responsive. TLC has allocated funds over a five-year period to upgrade its key systems.	2023 Asset Management Plan_Master_ Draft for RAM Review Asset Information System Roadmap (Digital Compass - Roadmap)
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?	3	TLC has documented its processes and procedures for the identification and assessment of asset and asset management-related risks in its AMP. AM-related risks are regularly assessed in association with the delivery of asset management objectives by the senior leadership team as the Tier 1 risk. Asset risk assessment methodology on likelihood, consequences, detectability, and mitigation are detailed in its AMP. TLC has implemented Asset Altitude which is an asset condition and risk modelling database to support long-term asset renewal planning. The key risks for the relevant asset classes are documented under the section Preventative Maintenance in its AMP.	2023 Asset Management Plan_Master_ Draft for RAM Review 3c Change to AMC Work Plan
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.5	While there is evidence that risks are being identified, and mitigated, there is no evidence that mitigating actions are being comprehensively linked to resourcing, competencies, and training plans. It is noted in an incident report that mentioned that the event coordinator needs further training for the role to - improve a better understanding of his powers, roles, and responsibilities - have full situational awareness of what assets were available and where they were, and where priority calls needed to be made. This kind of information provides valuable input into competency and training needs.	Incident Report – Mokau Outage Event - 20th May 2022
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2.75	Statutory and regulatory risks are included in TLC's Tier 1 risks and are monitored and reported to the Board Audit, Risk and Finance Committee on a bi-annual basis. TLC's regulatory compliance is managed by its Customer and Community Engagement team. Project-related legal requirements are reviewed and advised by contracted lawyers on a project basis. TLC has incorporated the statutory and regulatory requirements into its asset lifecycle management to ensure that network performance is within statutory limits and preventative maintenance strategy meets all statutory obligations.	

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
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	TLC has the AMP(s) in place to provide visibility of Capex and Opex planning for the main investment categories for the 10 years period. A detailed description of TLC's asset lifecycle management provided in its AMP. In 2022, TLC completed the DS26 Works Management System which defines the processes from job identification to closeout. TLC has a suite of operating procedures in place covering asset operations. TLC has Master Service Agreement and Work Pack in place to provide detailed requirements for external suppliers. TLC has been continually building operational governance groups including VMC, OMC, DRG, and PSG which have enhanced its oversight of operational delivery and risk.	DS26 Works Management System Asset amendment form Typical TLC Project Lifecycle Business Process for Project Closeout
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	2.9	TLC has started to assess and document the current process which is followed by the network engineering, design, and project delivery team to perform the overhead asset renewal/replacement work and to make decisions in case of a Red Tag Pole being identified. When scheduling preventative maintenance activities TLC considers avoiding resource constraints, seasonal related land access issues, the primary working season for renewal work. TLC intends to establish Maintenance Governance Committee.	OH Line Renewal Process Current State Analysis Red Tag Pole management Current State Analysis Basix Database PDS Approval Process
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3.15	The performance of the assets is measured by SAIDI and SAIFI. Defective equipment is the top driver of TLC's unplanned interruptions by both SAIDI and count. Further analysis indicates that around half of defective equipment faults are related to the pole top. TLC has changed its OH line Inspection Approach to improve condition monitoring of its OH line assets. TLC has implemented an Asset Altitude modelling database to analyse asset health and remaining life to support asset renewal planning.	LiDAR scan, drone inspection and pole base inspection AMP, Basix Database, ICAM report, Asset Altitude
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.9	TLC's Outage Management Committee (OMC) is to assess the outage performance and generate initiatives for the ongoing prevention and mitigation. Asset related incidents where the SAIDI minutes exceed 2 minutes are fully investigated to find the root causes and communicated in the Network Quality Performance Analysis report. TLC's ICAM reports provide comprehensive information about the incident, the causes, the environmental conditions, the organisational factors, and the recommendations. TLC's IMP has a placeholder for network event including significant asset failure and need to be incorporated.	Incident Management Plan ICAM Incident Report

Company Name	**The Lines Company**
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	Score	Evidence—Summary	User Guidance
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2.75	TLC takes actions to periodically review its overall asset management system and capability. Evidence includes an annual AMMAT review by an independent party in the past 5 years.	AMMAT review report
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.9	TLC identifies the causes of interruptions on its network and applies different strategies to the main drivers. To address the defective equipment issues (the key contributor is the pole top elements), TLC has changed its OH line inspection approach to provide more accurate and timely data to support asset planning on corrective actions. When dealing with the increased vegetation risk due to tree encroachment TLC established the VMC and developed the strategy to apply Spatial Analytics to support vegetation risk management and operational performance. TLC's Incident Report provides event descriptions, causes of faults, and recommendations for further actions.	2023 Asset Management Plan_Master_ Draft for RAM Review Business case for spatial analytics ICAM Incident Report - Lake Taupo 33_AB 3d Changing our Line Inspection Approach Vegetation Management Committee Meeting Minutes Treescape Monthly Meeting Minutes
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	TLC has made continual improvement in an optimal combination of costs, asset-related risks, and performance across the asset life cycle in the following areas: - Revised its AM objectives and developed a Strategic AM plan at the asset class level with interconnection to AM objectives - Changed OH line Inspection Approach - Used Asset Altitude to estimate the long-term asset renewal expenditure - Commenced a data cleansing programme - Undertaken innovations that defer asset replacements to ease network constraints.	2023 Asset Management Plan_Master_ Draft for RAM Review Business case for spatial analytics - Final 3d Changing our Line Inspection Approach FMEA analysis and
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?	3.15	TLC's AM strategy support the organisation t seek and acquire knowledge and new technology for evolving its AM practice. As a result, TLC actively engages with industry peers to share new practices and technologies, works with NiWA to develop a storm forecasting model, participates in industry groups such as EEA and ENA, etc. The senior leadership team who is responsible for monitoring changes in the company's business operating environment, reviewing new technology opportunities and implement where appropriate.	2023 Asset Management Plan_Master_ Draft for RAM Review - TLC's business strategy themes and AM objectives. Business case for spatial analytics - Final

SCHEDULE 14A: MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. 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).

3. 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:

Inflation has been applied to nominal forecasts as follows:

- 4% in RY2025
- 3% in RY 2026
- 2% in RY's 2027 to 2033

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a).

4. 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:

Inflation has been applied to nominal forecasts as follows:

- 4% in RY2025
- 3% in RY 2026
- 2% in RY's 2027 to 2033

SCHEDULE 15: VOLUNTARY EXPLANATORY NOTES

1. This Schedule enables an EDB to provide, should it wish to –

    1.1. Additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2 and 2.6.6;

    1.2. information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

We have identified non-material errors in Schedules 11a and 11b in disclosure years 2020, 2021 and 2022.

13. Appendix D: Director Certification

SCHEDULE 17: CERTIFICATION FOR YEAR-BEGINNING DISCLOSURE

Clause 2.9.1

We, **Mike Underhill and Todd Spencer**, being Directors of The Lines Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of [name of EDB] 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 The Lines Company's corporate vision and strategy and are documented in retained records.

DIRECTOR	**DIRECTOR**
Date: 30 March 2023	**Date:** 30 March 2023

The Lines Company Limited

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31 March 2023