2021 Asset Management Plan

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TOP ENERGY®
Te Puna Hihiko

Introduction

It gives me great pleasure to present Top Energy's 2021 Network Asset Management Plan (AMP). It has been prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and is the core asset management and operations plan for our electricity transmission and distribution network. It sets out our planned asset inspection, maintenance, development and replacement strategies, and the targeted service levels that we are planning to provide our consumers, over the period 1 April 2021 to 31 March 2031. It replaces our 2019 AMP and our 2020 AMP Update.

This is an exciting time for the Top Energy Group. The fourth generating unit (OEC4) at our Ngawha geothermal power station has recently been commissioned and the unit is now in commercial operation. We also have resource consent to construct a fifth unit (OEC5) and, should we decide to proceed, it could be commissioned by late 2025. If this expansion is completed, the generating capacity of the power station will increase from its current 57MW to 89MW and all the electricity requirements for the Far North would be generated within our supply area. This would enable us to develop a more sustainable, cost-efficient infrastructure that provides higher-value services to our consumers. It should protect our consumers from the impact of rising transmission charges since, with the expansion of Ngawha, our transmission connection will primarily be used to export energy south and we expect the cost of this connection to be paid by the users of this exported energy.

Our Board has approved a Strategy Map for the Top Energy Group, which sets out the Group's mission, vision and values, and underpins everything that we do. Each operating division within the Group has developed its own strategic vision, which interprets the Group's mission and vision for the business unit's activities and delivers on the Group's core values and high-level corporate objectives.

Top Energy Network's mission is: *To provide a safe, secure, reliable, and fairly-priced supply of electricity to consumers in the Far North.* Its vision is to: *Enable consumers to take greater control over their business and home energy supply needs by developing secure; two-way energy flow; load information and management solutions.*

Our ten-year asset management strategy through to FYE 2031 has been developed in accordance with this mission and vision and, being mindful of our corporate values and objectives, has addressed a range of strategic challenges. These include:

- *Providing a secure supply to the North*. We have installed sufficient diesel generation in the Kaitaia area to supply all small-use consumers during maintenance shutdowns of the 110kV Kaikohe-Kaitaia line. This is an interim solution as diesel generators have high greenhouse gas emissions, high maintenance requirements and a limited life. When construction of our new 110kV circuit between Wiroa and Kaitaia is completed in FYE 2030, supply to the north will become fully secure and we will be able to supply consumers in the Far North with renewable energy sourced from Ngawha under all reasonable network contingencies.

- *Relieving localised network capacity constraints*. While overall load growth across our network has been modest, growth in the Kerikeri and Whangaroa area continues. If one of the two 33kV circuits supplying this area is out of service at times of peak demand, we will soon reach a point where the supply voltage in the Kaeo and Waipapa areas may not meet regulatory requirements. To address this, we are planning to construct a 110kV substation on the site of our Wiroa switching station by FYE2024. When this is commissioned, electricity generated by OEC4 at Ngawha will be injected into our network at both Kaikohe and Wiroa. This coming year (FYE2022) we will also construct a second 11kV feeder to supply the Russell peninsula in order to improve the security of supply to the area.

- *Improvement in supply reliability.* Our network development plan, which we initiated in FYE2010, has significantly improved the reliability of the supply we provide our consumers. Apart from the new 110kV line into Kaitaia and the new Wiroa 110kV substation, development of our transmission and subtransmission network is now complete. Our reliability improvement initiatives are now focusing on our 11kV distribution network. Our new zone substations at Kerikeri and Kaeo have improved the reliability of the 11kV network in these area by enabling shorter feeders with fewer connected consumers. Much of the remainder of our network is characterised by long 11kV feeders. Significant reliability improvements to this part of our network would require the construction of more zone substations, so that individual feeders would be shorter, and less fault exposed. Such investment is difficult to justify, especially in areas where the network is already uneconomic. Going forward, our reliability improvement plan is therefore focused on incremental improvements to our existing 11kV infrastructure, without radically changing its architecture. While we expect this investment to further improve the reliability of supply we provide, the rate at which this improvement can be achieved is likely to reduce. Our reliability improvement targets reflect this.

- *Maintenance.* We have transitioned from a largely age-based process for prioritising maintenance and asset renewals to one based on the use of industry-standard asset health indicators. Asset health is a function of asset condition, determined by our asset inspection programme. In developing the defect management and asset replacement plans set out in the AMP, we also consider asset criticality, which reflects the consequences of an in-service asset failure. This leads to better targeting of our maintenance expenditure.
- *Meeting the challenges of new technology.* We have installed an Advanced Distribution Management System (ADMS) that uses the latest available technology. This will significantly increase the level of automation in our management of network outages and increase worker and public safety by reducing the risk of operator error. It will also be used to optimise the use of the diesel generation that we have added to our network. Over time, the system is capable of being further developed to ensure that we are well positioned to embrace emerging technologies that are starting to change the face of our industry, for the benefit of all our stakeholders.
- *Utility-scale photovoltaic generation.* We have recently received applications for the connection of 67MW of utility scale generation in the Kaitaia and Pukenui areas and are currently investigating the impact of connecting this amount of intermittent generation on the operation of our network. The limited capacity of our 110kV circuit between Kaitaia and Kaikohe, and Transpower's 110kV circuits between Kaikohe and Maungatapere, is likely to constrain the amount of generation we can connect.

Our response to these and other challenges is further described in our corporate video, *Top Energy – Energy of the Future* which can be viewed on our website http://www.topenergy.co.nz.

The Commerce Commission's price-quality path for the FYE 2021-25 regulatory period imposes a revenue cap, rather than a price cap, which provides us with more certainty that we will have the resources to implement our asset management plans. It has also relaxed constraints on the impact of planned interruptions, which gives us more flexibility in planning maintenance work on the 11kV network. While we are now at the point where we do not need to interrupt supply to undertake maintenance work on our 33kV networks, we still need to interrupt supply to localised areas when undertaking 11kV network maintenance. Consumers have advance warning of planned interruptions and in our consumer surveys they have indicated tolerance of an increased number of planned interruptions in return for the development of a more reliable network.

Uncertainty remains in other components of the regulatory environment. In particular:

- The Electricity Authority has granted an exemption from the cross-ownership requirements of the Electricity Industry Act 2010, which allows us to run the installed generation across the northern part of our network. However, this exemption is only for 365 days and requires us to seek proposals for the provision of equivalent network support from external providers, before the exemption expires. We have gone out to tender for the provision of this support and will seriously consider any proposals that meet our requirements.
- The Electricity Authority has finalized its review of transmission pricing. When implemented in 2023, transmission prices for consumers in the north of the country will increase significantly. The expanded Ngawha power station will reduce the extent that electricity consumed in our supply area is generated south of Auckland and we expect that this should protect our consumers from much of this increase.
- The Electricity Authority is also requiring electricity distribution businesses to develop more cost reflective pricing policies. We have introduced time-of-use tariffs, but these are not being passed on to consumer by retailers. On 1 April 2021 we will also introduce a new tariff of 0.5 cents per kWh of power injected into the low voltage network by small-scale photovoltaic generators to enable us to understand and mitigate the technical problems we anticipate will emerge as the penetration of this generation increases. This is a significant problem in Australia. We already have the highest penetration of small-scale photovoltaic generation of any New Zealand EDB and this penetration is increasing faster than anywhere else in the country. The concentration of this generation along our eastern seaboard exacerbates this issue.

- Industry response to the challenge of emerging technologies remains a source of debate, focused largely on the extent to which EDBs can recover the costs on implementing new technologies from regulated revenue. The FYE 2021-25 price-quality path decision has done little to clarify this issue.

We will keep a watching brief on these developments and their potential impact on our consumers and provide updates in subsequent AMPs.

Since FYE2010 we have put significant investment into the network and the value of our regulatory asset base (RAB), which was approximately $128 million in 2010, exceeded $280 million by the end of FYE 2020 . Over this period our annual capital expenditure has been significantly greater than depreciation. Since FYE 2015 our depreciation has averaged $8.5 million per annum while our average annual capex has exceeded $17.7 million. During FYE 2020 our capital expenditure, which included the construction of a new 110kV line to connect the expanded Ngawha power station to our network, the installation of additional diesel generation in the Kaitaia area and the rebuilding of the Omanaia substation, was almost $38 million. The difference between capital expenditure and depreciation has been funded by increasing prices to the limit allowed by our regulatory price path and significantly increasing debt. This investment has allowed us to resolve the security of supply issue on our 110kV and 33kV networks and significantly improve the resilience of our network. Looking forward over the period FYE 2022 to FYE 2031, we plan to continue to invest; however, we cannot increase prices above the new price path, and we have no further debt capacity, so we have capital constraints. Nevertheless, implementation of the plans set out in this AMP will still see us invest approximately $174 million on network capital expenditure and $60 million in network maintenance expenditure over the ten-year FYE2022-31 planning period.

In addition to the management of our network assets, we continue to develop the safety and asset management culture within Top Energy. We actively participate in industry safety initiatives, which require staff engagement at all levels and have the added benefit of sharing participants' experiences from across the industry. To succeed, the Company and all staff must maintain a proactive role in training, competency, peer support and guidance, and monitoring industry issues.

We hope that you find that this AMP shows that we are responsibly exercising our stewardship of our network assets for the long-term benefit of all our stakeholders and, in particular, the electricity consumers who rely on our network. We welcome your feedback on these asset management plans, or on any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website at http://www.topenergy.co.nz/contact-us-feedback.shtml or emailed to info@topenergy.co.nz.

Russell Shaw

Chief Executive, Top Energy Ltd

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Section 1 Executive Summary

1 Executive Summary

1.1 Overview

Top Energy Network (TEN) is the electricity distribution business (EDB) that distributes electricity to more than 33,000 electricity consumers in the Far North District Council's territorial area, covering the mid- and far-north of the Northland region. We are a division of the Top Energy Group, which is wholly owned for the benefit of our consumers by the Top Energy Consumer Trust (Trust). The Group, which employs around 150 people and is one of the biggest employers in our supply area, has three divisions:

- *Ngawha Generation Ltd (NGL)*, which operates the Ngawha geothermal power plant, with a current capacity of 57MW.
- *Top Energy Networks (TEN)*, which manages the electricity distribution network.
- *Top Energy Contracting Services (TECS)*, which provides contracting services to TEN.

As a large electricity lines business, TEN is subject to regulation by the Commerce Commission in accordance with the requirements of Part 4A of the Commerce Act, 1986. Therefore, we must publicly disclose information on the performance of our network assets in accordance with the Commission's Electricity Distribution Information Disclosure Determination 2012. Furthermore, the reliability of the supply that we provide our consumers, and the prices that we charge for providing electricity distribution services, are regulated by the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2020.

This Asset Management Plan (AMP) is the defining strategic and business planning document for the management of our network. It describes how we plan to develop and manage our network assets for the benefit of our consumers over the period 1 April 2021 to 31 March 2031. It sets out the ten-year capital and maintenance expenditures that we estimate will be needed to manage the network in a sustainable way. It lies at the heart of the management of our network assets and is the primary tool for planning the long-term development and maintenance of our network.

While the primary purpose of this AMP is to inform our consumers and other stakeholders of our asset management intentions, it has been prepared in accordance with the Commission's Information Disclosure Determination. It covers only our network assets and does not cover the assets of other divisions of the Top Energy Group. It also does not cover privately-owned assets beyond the consumers' connection to our network.

1.2 Asset Management Policy

Our formal network asset management policy sits below the overarching Group asset management policy in our quality system and has been developed in accordance with Top Energy's strategic objectives:

- To operate a successful business that optimises the long-term value of the Group for its shareholder.
- To operate a safety and organisational culture where all employees take responsibility for themselves and others to minimise the risk of injuries to consumers, staff, contractors and the public.
- To achieve network quality standards that are acceptable to consumers.
- To operate in an environmentally sustainable manner, and to be responsive to the cultural and social needs of our community.
- To minimise the total delivered cost of electricity to our consumers.

Within this overarching strategic framework, Top Energy's mission is:

> *From generation to the light switch, providing energy solutions to customers and optimising long term value for our consumers today and tomorrow.*

TEN's goal is to provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in our supply area. To this end, we will manage our network assets for the long-term benefit of our existing and future consumers. We will achieve this by acting with integrity, in compliance with our legal obligations, and by developing and maintaining the assets in a manner that is sustainable over time, minimises environmental impacts, meets the reasonable expectations of our consumers in respect of the quality and reliability of the supply that we provide, and underpins the economic development of our supply area.

Safety

Safety is our highest priority. We will act at all times in accordance with industry standard safe working practices and, in consultation with our employees and contractors, we will develop and adopt systems and procedures in accordance with the *Health and Safety at Work (General Risk and Workplace Management) Regulations 2016* that minimise the risk of harm to people or property. We will consider the impact of all that we do on our employees, contractors, consumers, and the public.

Security

We will develop a network that is resilient to high impact, low probability events, by building in asset redundancy where this is appropriate, and by developing plans and procedures for responding to events that have a high impact on our consumers.

Reliability

We will manage our assets to improve the reliability of supply that we provide meets the expectations of our consumers. We will achieve this using a range of strategies including targeted network development, more effective maintenance, and improved response to supply interruptions that do occur.

Fair Pricing

We will achieve improvements to the security and reliability of our network at a rate that is financially sustainable and affordable to our consumers. We will also strive to continually improve the efficiency and cost effectiveness of our asset stewardship to increase the value we provide to our stakeholders.

New Technologies

We live in a time of technological change that has the potential to radically alter the way in which our consumers use the services we provide. We will monitor these developments, and their impact, and modify our asset management strategies as necessary so that we remain relevant to the consumers that we serve.

The strategies, objectives and plans set out in this AMP are consistent with, and evolve from, this asset management policy.

1.3 Network Description

Our electricity network stretches from Hukerenui, approximately 25km north of Whangarei, to Te Paki, 20km south of Cape Reinga. It supplies one of the more economically depressed areas of the country; an area that is sparsely populated and contains no dominant urban centre. Our network is predominantly rural, characterised by a low consumer density and an average consumption per consumer that is the second lowest in the country. Table 1.1 lists the key network parameters.

DESCRIPTION	QUANTITY
Area Covered	6,822km^2
Consumer connection points	32,537[(1)]
Grid Exit Point	Kaikohe
Network Peak Demand (FYE2020)	71MW[(2)]
Electricity Delivered to Consumers (FYE2020)	329GWh
Number of Distribution Feeders	60
Distribution Transformer Capacity	272MVA[(3,4)]
Transmission Lines (operating at 110 kV)	64km[(3)]
Subtransmission Cables (33kV)	21km[(3)]
Subtransmission Lines (33kV)[5]	328km[(3)]

DESCRIPTION	QUANTITY
HV Distribution Cables (22, 11 and 6.35kV)	231km(3)
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,597km(3)

Note 1: Average number of active connections FYE2020.
Note 2: Metered load as disclosed to the Commerce Commission.
Note 3: As at December 2020.
Note 4: Does not include 22/11 kV or SWER isolating transformers.
Note 5: Includes the Kaikohe-Wiroa line, which is constructed to 110kV, but currently operating at 33kV.

Table 1.1: Network parameters (FYE2020 unless otherwise shown)

We have a significant amount of embedded and distributed generation connected within our network, as shown in Table 1.2. Of note is the connection of small-scale, roof-top photovoltaic generation. Not only is the penetration[1] of small-scale generation higher than that of any other New Zealand EDB; it is also increasing at a faster rate than elsewhere.

TYPE OF GENERATION	NO OF INJECTION POINTS	CAPACITY (MW)
Geothermal	2[1]	57
Diesel	5[2]	17.2
Photovoltaic	1,115	5.65

Note 1. All geothermal generation is located at Ngawha. However, OEC1-3 connect to the network at 33kV while OEC4 connects at 110kV.
Note 2: This includes a 1MW generator at Pukenui, scheduled for connection by 31 March 2021.

Table 1.2: Embedded and Distributed Generation (as at 31 December 2020)

1.4 Value of Network

The regulatory value of our fixed network assets, calculated in accordance with the Commerce Commission's Information Disclosure Requirements was $280 million as at 31 March 2020, an increase of $18.6 million since 31 March 2019.

This increase in asset value was derived as shown in Table 1.3. The increase has largely been driven by the commissioning of new assets in accordance with our network development plan. The value shown in Table 1.3 is the regulatory asset value, which is different from the corresponding asset value shown in Top Energy's financial accounts, as the valuation methodologies differ.

	$000
Asset Value as at 31 March 2019	**261,426**
Add:	
New assets commissioned	22,856
Indexed inflation adjustment	6,589
Less:	
Depreciation	9,683
Asset disposals	990
Asset allocation adjustment	193
Asset value as at 31 March 2020	**280,006**

Table 1.3: Value of System Fixed Assets

1 In this context, penetration is the ratio of the number of small-scale photovoltaic connections to the total number of consumers connected to our network.

1.5 Economics of Supply

Many of our distribution lines were built using subsidies provided by the Rural Electrical Reticulation Council (RERC). These were provided to assist with post-war farming productivity growth in remote areas and provide an electricity supply to consumers in sparsely populated rural areas that would have otherwise been uneconomic to service. Many of these lines are now reaching the stage where extensive rebuilding and refurbishment is required. We are obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers currently supplied from existing lines, although this continuing supply does not need to be a grid connection.

In 2009, prior to the passing of this Act, the Electricity Networks Association (ENA) created a working party to review the implications of this obligation. The working party defined lines as uneconomic if there were less than three connected low consumption consumers per km. Low consumption was defined either by the volume of energy delivered per year (less than 6,500kWh per consumer) or by the installed distribution transformer capacity (less than 20kVA per consumer); these criteria were based on an independent analysis of network costs undertaken by the then Ministry of Economic Development (now MBIE). Approximately 35% by length of our 11kV distribution network is uneconomic if the MBIE cost of supply criteria is applied. These lines supply just 9% of our consumers.

In 2018 we investigated this issue in more detail by developing a Cost-to Serve model that looked at the costs we incur in supplying consumers in different parts of the network. Our modelling shows that the revenue received from consumers in the remote segments of our network is enough to cover the operating costs of the assets used to provide their supply but makes only a marginal contribution to the capital costs of these assets. Consumers connected to the more economic parts of our network therefore subsidise the capital costs we incur in maintaining supply to these consumers.

We keep abreast of the economics of using remote area power supplies instead of a network connection to service consumers in the most remote parts of our network, but have found this difficult to justify, primarily because line assets tend to be renewed incrementally as individual poles and pole top hardware fail.

1.6 Network Development

1.6.1 Introduction

The main objectives of our network development plan were to:

- Increase the capacity of network to meet the growing demand for electricity in the Kerikeri area.
- Improve supply security in the north of our supply area, which is supplied from Kaikohe over a single 110kV circuit and experiences extended supply interruptions when this line is taken out of service for maintenance.
- Improve the reliability of supply to consumers by developing our subtransmission and distribution networks to be more resilient to weather equipment failures.

Since the plan was initiated, we have invested over $185 million in capital expenditure on network improvement. This has allowed us to:

- Increase the capacity of our network in the Kerikeri area through the construction of a new 110kV line from Kaikohe, a new switching station at Wiroa and a new zone substation within Kerikeri town.
- Improve the fault resilience of our 33kV subtransmission network by upgrading the protection to form 33kV rings, so that faults affecting our larger zone substations no longer cause interruptions to supply.
- Install a new zone substation in Kaeo to improve the reliability of supply to consumers in the Whangaroa area.
- Constructed a new double circuit 110kV transmission line to connect the new 32MW generator at Ngawha to the grid at Kaikohe.
- Install over 17MW of diesel generation at Kaitaia, Taipa Omanaia and Pukenui to increase the resilience of the network to high impact events and improve the reliability of the supply we provide to our consumers.

- Replace assets that have reached the end of their economic life and rebuild the Kawakawa, Moerewa and Omanaia substations.
- Increase our ability to remotely control the distribution network, so that supply can be restored more quickly to consumers not directly affected by a fault.

These investments have been effective. They have enabled us to reduce the number of minutes the average consumer is without power due to unplanned supply interruptions (unplanned SAIDI) in a year of average weather conditions by 25%. Similarly, we have also reduced the number of unplanned supply interruptions a consumer can expect in an average year (unplanned SAIFI) by 25%. These improvements are shown in Figures 1.1 and 1.2. The values shown in the figures are normalised, using the methodology approved by the Commerce Commission, to reduce the impact of extreme events that are outside our reasonable control and better reflect the performance of the network under average weather conditions.

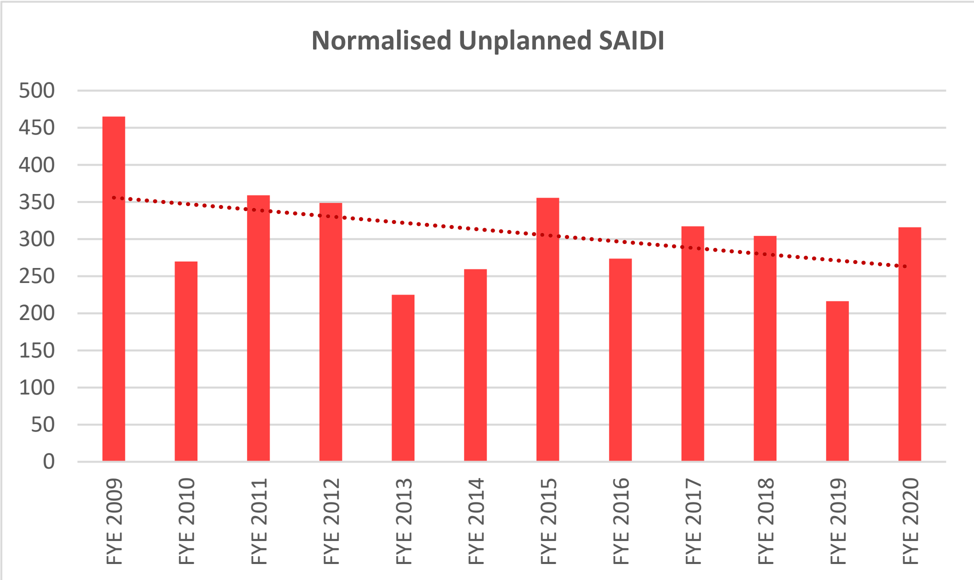


Figure 1.1: Normalised Unplanned SAIDI FYE 2009-20

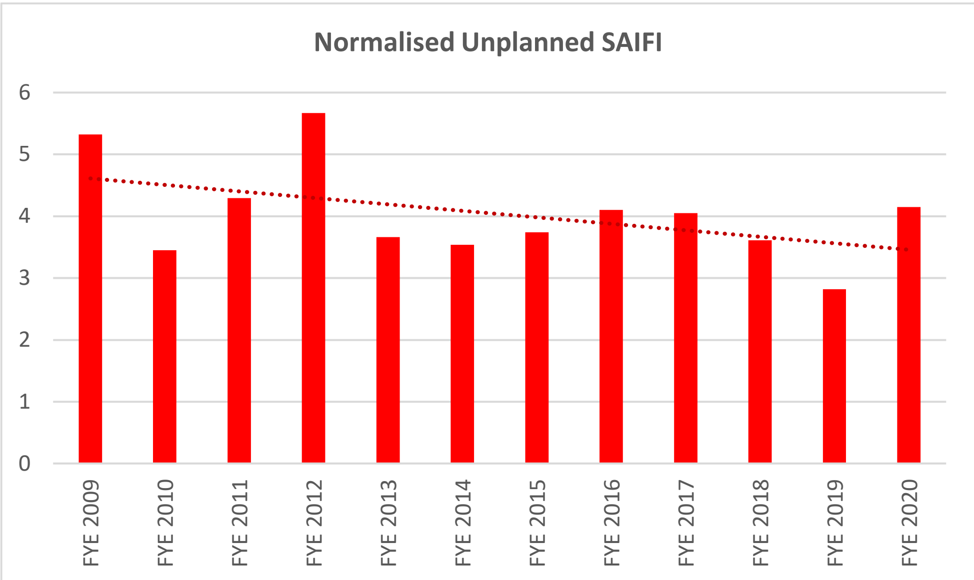


Figure 1.2: Normalised Unplanned SAIFI FYE 2009-20

In FYE2021 Top Energy commissioned a 4th unit, known as OEC4, at Ngawha power station, increasing its generation output to 57MW. It has resource consent to install a 5th unit, which would increase the generating capacity of the power station further to 89MW. If this increase proceeds, all electricity consumed in our supply area will be generated locally and almost 50% of the electricity generated at Ngawha will be exported south. We anticipate this will benefit consumers through a reduction in transmission charges, since consumers should not have to pay the cost of transmitting electricity from a point of generation south of Auckland to the Kaikohe substation if the electricity they consume is locally generated.

1.6.2 Challenges

In developing our network through strategies to improve the reliability of supply to consumers, we have had to address a several unique challenges.

- We have only one point of connection to the national transmission grid through a single radial transmission line; most other rural EDBs have more than one GXP and are not reliant on a single radial connection. For example, Northpower has two grid connections, a 220KV line to Marsden and a 110kV line over a separate route to Maungatapere.
- Our grid exit point (GXP) at Kaikohe was constructed at a time when Kaikohe and Kaitaia were the economic centres of our supply area. Over the last twenty years, there has been a steady decline in the growth of Kaikohe and other inland towns, which have lost population and become economically depressed. At the same time, there has been significant growth and economic development in Kerikeri, the Bay of Islands and the eastern coastal peninsulas. Zone substations supplying the eastern seaboard now account for 70% of our southern area demand and our GXP is poorly located.
- We have a dispersed population with no dominant urban centre and our average consumption per consumer is the second lowest in the country. The less affluent south and west of our supply area continues to be served by long 11kV feeders, with a high number of connected consumers on each. Typically, over 50% of our unplanned distribution network SAIDI and over 30% of our 11kV faults originate on only 10% of our 11kV feeders.

To meet these challenges and further improve the reliability of our network, we are forecasting capital expenditure of $184 million over the ten-year period of this AMP. This expenditure will be used to:

- Construct a new 110/33kV substation on the site of our 33kV switching station at Wiroa. While growth in the demand for electricity across the network over the last ten years has been subdued, there has been localised growth in the Kerikeri, Waipapa and Whangaroa areas. We expect this growth to continue, to the point where, at times of peak demand, we would not be able to provide a quality of supply that meets regulatory requirements following a fault on one of the two 33kV circuits supplying the area.
- Upgrade the supply to the Russell peninsula by installing a new 11kV cable between Okiato and the tee-off point of the Rawhiti spur. Currently, while there are two submarine cables supplying the peninsula, almost all the load is supplied by the one cable and the second cable provides a backup. The new 11kV cable will allow the load to share between the two submarine cables. This project will also increase the security of the supply to the peninsula, since one submarine cable will be supplied from the Kawakawa substation and the second from Haruru.
- Continue to replace assets that are approaching the end of their economic life. This will include the replacement of a 110/33kV transformer and circuit breaker at Kaitaia and the rebuilding of our Waipapa substation.
- Construct the new 110kV circuit between Wiroa and Kaitaia. One of our biggest challenges has been to secure a route for this line. Negotiations with affected landowners commenced in FYE2012 and, while most of the route has now been secured, we are still awaiting the result of an appeal to the Supreme Court by three landowners before the route can be confirmed. This new line will provide a second incoming circuit to our northern area and provide a secure, high-capacity ring capable of serving all the main load centres within our supply area. It will also supply our northern area when reconductoring of the existing 110kV line is required, sometime after 2030. In the meantime, we have installed diesel generation in the Kaitaia area to avoid extended maintenance interruptions and reduce the time required to restore supply following an unplanned interruption to the existing 110kV incoming supply.
- Improve the reliability of our 11kV distribution network though increased asset replacement and renewal, improved protection coordination, additional interconnections between adjacent feeders, and additional network automation and remote control.

1.7 Emerging Technologies

Ten years ago, the only generation embedded within our network was the 25MW Ngawha geothermal plant; now we have 5.7MW of solar generation injecting power into our network from over 1,115 injection points. Over the last twelve months we have also had applications to connect 67MW of utility scale photovoltaic generation in the Kaitaia area. Our network will therefore need to transition from an electricity distribution system designed to transfer electricity in one direction from a centralised source to multiple consumers to a technology enabled distributed energy system that allows multi-directional energy transfers between small generators and users. We will also need to adapt to the connection of batteries, the charging of electric vehicles, and potentially the emergence of home area networks, demand response and peer-to-peer energy markets.

The impact of these technologies and the rate at which they will emerge is unclear. Nevertheless, we need to be open to the application of these technologies by consumers connected to our network and we also need to identify opportunities where the use of these technologies will enable us to develop and manage our network more cost effectively for the benefit of our consumers. We have recently installed a new advanced distribution management system that provides the capability needs to efficiently manage two-way power flows in a more complex network. Our policy on the introduction of new and emerging technologies is to closely monitor developments with the objective of being a fast follower, open to the introduction of technologies once we are confident that they will benefit our consumers.

1.8 Reliability of Supply

We measure the reliability of our network for internal management purposes using the normalised measures of SAIDI and SAIFI that the Commerce Commission uses to monitor the reliability of the networks under its price-quality control regime. Our internal targets are more challenging than the thresholds set by the Commission, as we use them to measure the effectiveness of our investment programme. The indicators we use to measure reliability are:

- SAIDI (System Average Consumer Interruption Duration Index), which is the number of minutes that the average consumer connected to our network is without supply. We measure reliability of supply over our standard financial year, which ends on 31 March, rather than a calendar year.
- SAIFI (System Average Interruption Frequency Index) is the number of times the average consumer's supply is interrupted over the measurement period. While an individual consumer can only be interrupted a whole number of times, SAIFI is measured as a real number to allow for averaging.

The normalisation of the raw performance measure, as applied by the Commission is designed to limit the impact of events that are outside our reasonable control. We believe that setting targets using normalised measures provides a better indication of the success of our asset management strategies, by limiting the extent to which events outside our control and response capacity impact the measured performance.

The impact of this normalisation process is to:

- Exclude interruptions originating from events outside our network.
- Limit the impact of unplanned interruptions occurring on "major event days" to a boundary value, which reduces the impact of an extreme event on the overall measure. The SAIDI and SAIFI boundary values were determined by the Commission using a statistical analysis of the historic performance of our network.

We have set internal targets for both planned and unplanned interruptions for each year of the planning period in this AMP. Our targets for the impact of unplanned interruption assume that:

- Weather conditions will be average for the area. The reliability of an overhead distribution network is strongly influenced by the weather, so targets are unlikely to be met in years where storm activity is significantly greater than normal.
- There are no unplanned outages of the 110kV Kaikohe-Kaitaia transmission lines. The measured reliability of our network is sensitive to the performance of this line, as an outage will affect all consumers in the northern region. While the installation of generation will limit the duration of any unplanned line interruption, supply will nevertheless be interrupted while the generators are started and connected to the network. There will still be a significant impact on both SAIDI and SAIFI because of the number of consumers affected.

Our internal reliability targets for each year of the planning period are shown Table 1.4.

FYE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Unplanned Interruptions										
SAIDI	245	240	235	230	230	230	230	230	230	230
SAIFI	2.98	2.97	2.96	2.95	2.95	2.95	2.95	2.95	2.95	2.95
Planned Interruptions										
SAIDI	125	125	125	125	125	125	125	125	125	125
SAIFI	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Table 1.4: Reliability Targets

Our targets for the impact of unplanned interruptions are shown in Figures 1.3 and 1.4 below, where they are also compared with the historic reliability of our network. In these figures we have normalised our historic performance using the Commission's currently approved normalisation methodology to provide a valid comparison between historic and targeted performance.

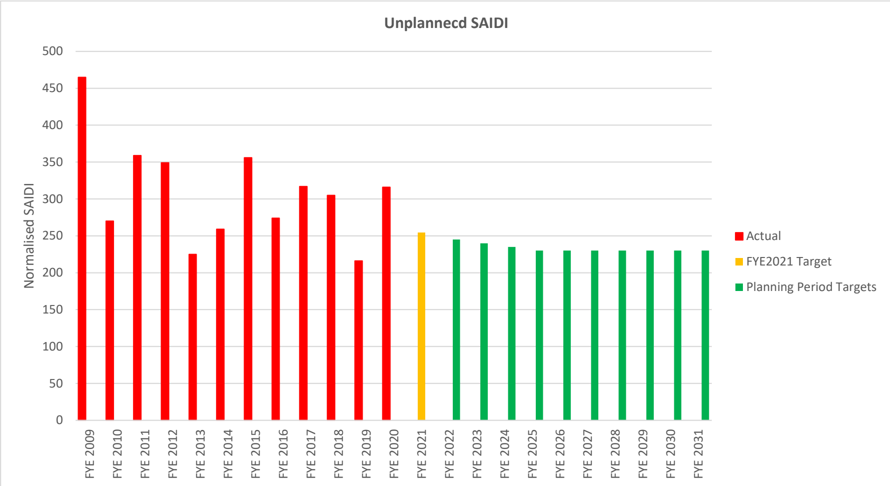


Figure 1.3: Historical and Target Normalised Unplanned SAIDI

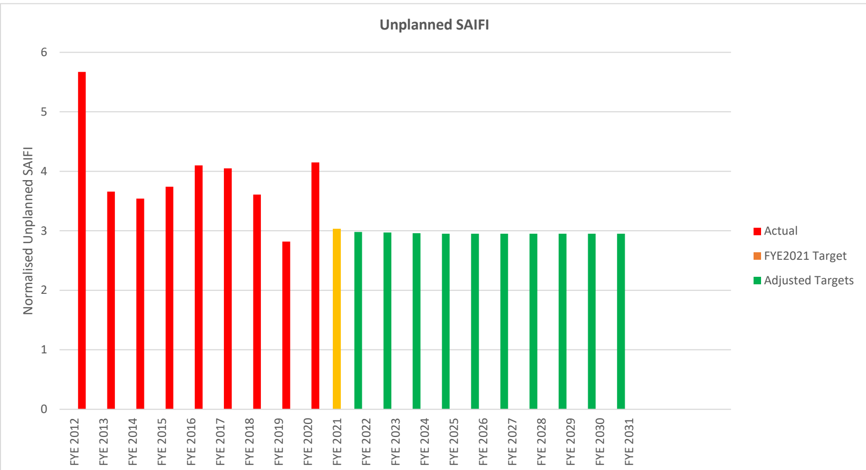


Figure 1.4: Historical and Target Normalised Unplanned SAIFI

We note the following in respect of these targets:

- Our internal SAIDI and SAIFI targets of around 230 and 2.95 are substantially lower than the Commission's corresponding regulatory thresholds of 380 and 5.07. Should we beach a regulatory threshold we would be subject to an investigation and possible sanction by the Commission, but failure to meet our internal targets will not trigger an external investigation.

- Our targeted SAIDI improvement over the next three years reflects the impact of the generation we have recently installed. As this has only just been commissioned, its impact is not reflected in our current performance. While the installation of generation can be expected to improve unplanned SAIDI due to shorter interruption durations, it will have no impact on SAIFI, since supply will still be interrupted while the generation is connected to the network.
- Our past investment in the network has developed the subtransmission network to the point where significant further improvement in the performance of this part of the network is unlikely. Most (but not all) feeders on the eastern seaboard, which is served by substations at Kaeo, Waipapa, Kerikeri, Haruru and Kawakawa are short and have limited fault exposure.
- The balance of the network is characterised by long 11kV feeders with a high fault exposure. We will continue to make incremental improvements to the reliability of this part of the network through vegetation management, protection improvements, and the installation of more feeder interconnections and remote-controlled switches. However more significant improvements will likely require investment in additional zone substations to shorten the length and fault exposure of individual feeders. The investment needed to achieve this is difficult to justify, given that much of this part of the network is already uneconomic.
- We have set our planned interruption targets equal to our average annual SAIDI and SAIFI impacts resulting from planned interruptions over the period FYE2010-20. Our planned SAIDI targets equate to an aggregated SAIDI of 625 minutes over the five-year FYE2021-25 regulatory period, well below the Commission's threshold of 1,905 minutes. The Commission has not set a planned SAIFI threshold. In setting its planned SAIDI threshold the Commission indicated that an overly restrictive planned interruption threshold would not be in the interests of consumers if it resulted in essential network maintenance not being undertaken. We agree and have set our internal targets accordingly.

1.9 Capital Expenditure

The focus of our capital expenditure forecast is asset renewal and network development. To better reflect these drivers, we have disaggregated our capital expenditure forecast into the following priority areas.

- *Priority 1 – Asset Life Cycle Renewals.* Our first priority is to maintain the existing network in a condition that is fit for purpose. To do this, we need to replace existing assets as they reach the end of their economic service life. We have increased our forecast expenditure on asset renewals and replacements and have introduced the asset health assessment process developed by the Electricity Engineers Association (EEA) as a basis for assessing asset condition and prioritizing assets for replacement.
- *Priority 2 – Capacity Augmentation.* Our second priority is the construction of new assets to meet any growth in demand for network services while ensuring that the technical parameters (e.g., voltage) of the supply we provide meets regulatory requirements and the reliability of supply does not fall below its current level.
- *Priority 3 – Reliability Improvement.* Capital expenditure on reliability improvement initiatives is our third priority. Expenditure on projects, such as our new 110KV line into Kaitaia, where the main driver is reliability improvement falls into this category even if an expansion of network capacity is a secondary outcome. Expenditure focused on improving the safety of the network is also categorized as reliability improvement, consistent with the categorization used by the Commerce Commission.
- *Priority 4 – Emerging Technology.* This expenditure relates to the development of network information systems and expenditure on pilot projects designed to trial the application of technologies likely to impact our future network developments. Consistent with our decision to be a fast follower rather than an innovator in the introduction of new technologies, our expenditure forecast no longer includes provision for trial projects. It includes a provision for gathering additional data on our network assets so that we can fully utilise the potential of our new ADMS.

Our forecast total capital expenditure over the ten-year AMP planning period is $174 million. Figure 1.5 shows how this forecast is allocated over the four priority areas and Table 1.5 quantifies this expenditure over the planning period. Consistent with our expenditure prioritisation, expenditure on asset renewal is higher than on the other categories. Expenditure on reliability improvement is dominated by the construction of the new 110kV line in the final years of the planning period, while the lower expenditure on capacity expansion and customer connections reflects our relatively low forecast rate of growth in demand and the spare capacity already available in the subtransmission network.

As our forecast expenditure on emerging technology is small, we have included it in the reliability of supply forecast. This is consistent with the approach of the Commerce Commission.

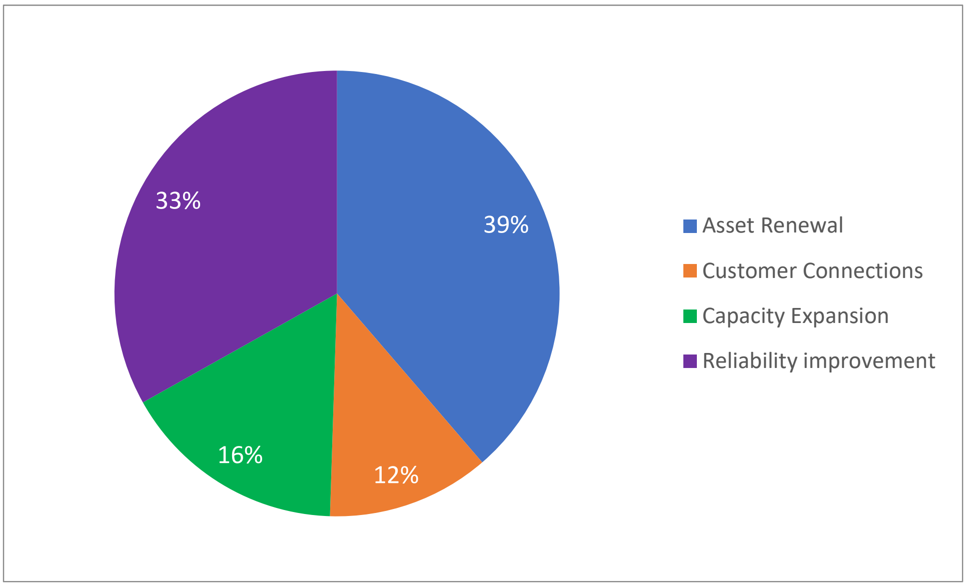


Figure 1.5: Allocation of Capital Expenditure by Priority

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31	Average Annual
Asset renewal	6,888	6,244	5,946	6,682	6,414	35,862	6,804
Customer connections	4,113	2,257	1,889	1,889	1,889	8,751	2,079
Capacity expansion	1,263	3,813	5,083	3,676	1,750	13,195	2,878
Reliability improvement	2,116	2,978	1,783	2,812	5,795	42,778	5,826
Total	**14,379**	**15,293**	**14,701**	**15,059**	**15,847**	**100,586**	**17,586**

Table 1.5: Network Capital Expenditure Forecast

1.10 Life Cycle Asset Management

We continue to develop and refine our business processes for the management of assets after they have been commissioned through to replacement at the end of their economic life. Our overall objective is to target our maintenance expenditure on critical assets and assets identified as potentially showing signs of end-of life deterioration.

We have adopted the asset health indicators developed by the EEA as a basis for assessing the condition of our various asset fleets and the need for asset renewal or replacement. Our assessments of asset heath are based on our regular asset inspections but where it is not possible to determine the condition of an asset by visual inspection or by non-invasive testing of in service asset, we use age as a proxy for condition. The asset renewal forecast in this AMP includes for the first time a separate provision for crossarm replacements, as we have found that crossarm failures are a significant cause of faults due to equipment failure.

Vegetation remains a significant cause of supply unreliability and our vegetation management efforts continue. Both the Far North District Council and the New Zealand Transport Authority have no interest in trees growing within rural road reserves, which allows us to remove any trees within these road reserves that could grow into our lines. We are also adopting a more aggressive approach to the cutting of trees that are already touching our lines and have initiated a campaign to remove bamboo hedges growing under our lines. We are also negotiating vegetation management agreements with commercial plantation owners where their operations could impact our lines. We look forward the review of the tree regulations that the Ministry of Business, Industry and Employment are planning.

Our forecast total maintenance expenditure over the ten-year planning period is $62 million. Figure 1.6 shows how our maintenance expenditure forecast is allocated over the four maintenance categories and Table 1.6 quantifies this expenditure over the planning period.

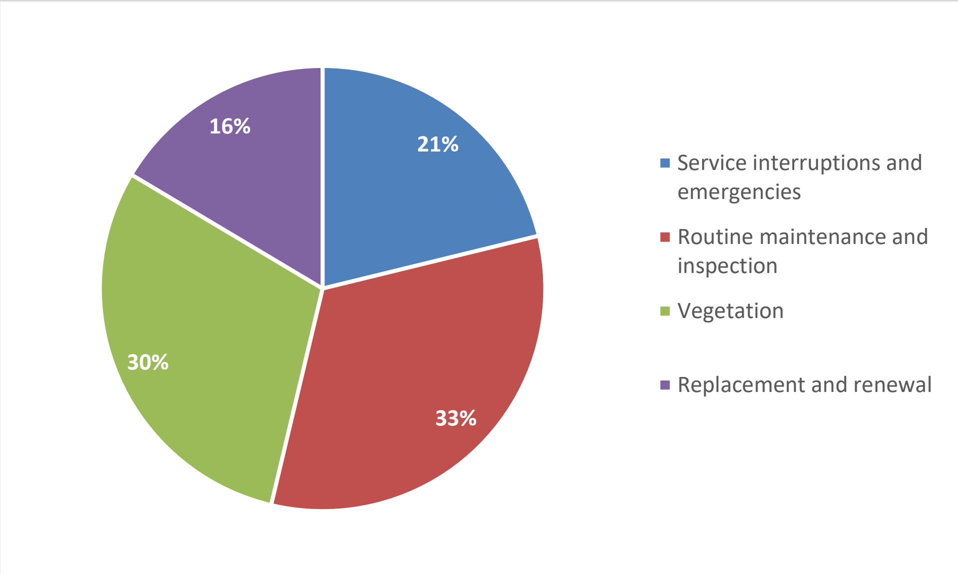


Figure 1.6: Allocation of Maintenance Expenditure by Category

$000 (in constant prices)	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31	Average Annual
Service interruptions and emergencies	1,313	1,313	1,313	1,313	1,313	6,566	1,313
Routine maintenance and inspection	2,120	1,976	1,942	1,989	2,001	10,134	2,016
Vegetation	1,850	1,850	1,850	1,850	1,850	9,250	1,850
Replacement and renewal	1,019	1,019	1,019	1,019	1,019	5,095	1,019
Total	**6,303**	**6,159**	**6,125**	**6,171**	**6,184**	**31,048**	**6,199**

Table 1.6: Maintenance Expenditure Forecast

Section 2 Background and Objectives

2 Background and Objectives

2.1 Overview

Top Energy Ltd was formed in 1993 and is an electricity generation and distribution business located in New Zealand's Far North District Council's geographical area. The business comprises three divisions:

- **Ngawha Generation Ltd (NGL)**, which operates the 57MW Ngawha geothermal power plant.
- **Top Energy Network (TEN)**, which distributes electricity throughout the Far North; and
- **Top Energy Contracting Services (TECS)**, which provides construction and maintenance services to TEN.

The Top Energy Group is 100% owned by the Top Energy Consumer Trust (Trust), which holds the shares of the business for the benefit of electricity consumers connected to our electricity distribution network. The Group is a major contributor to the Far North community's financial well-being and employs approximately 150 staff. It is one of the largest employers in the region and is uniquely placed to act as a catalyst for developing the region's economic potential.

TEN's assets comprise a network of lines interconnecting approximately 33,000 electricity consumers within our supply area together with recently installed backup diesel generation to provide network support. The network was constructed to supply these consumers from electricity sourced from the national transmission grid and, more recently, the Ngawha geothermal power station. However, recent development in small scale photovoltaic generation technologies has resulted in approximately 5.7MW of localised generation dispersed across more than 1,100 injection points now being connected to our network.

This Asset Management Plan (AMP) covers the management of TEN's assets, which had a regulatory asset value of more than $280 million as at 31 March 2020. This figure does not include assets owned by Top Energy's other operating divisions, which are not covered by this AMP.

TEN's role has traditionally been to manage, on behalf of retailers, the one-way flow of electricity from the national grid and the Ngawha geothermal plant to our consumer stakeholders. However, with the installation of localised generation expected to accelerate, electricity flows within our network are becoming increasingly bidirectional. Furthermore, the emergence of new technologies is rapidly changing the use and management of electricity by our consumers, and consequently the demand for the services that we can provide. If we are to meet these challenges and remain relevant in a changing environment, we must transition from a traditional electricity distributor to a network service provider with the innovation and flexibility required to meet the evolving needs of an increasingly diverse consumer base. This AMP sets out our strategy for managing this transition.

Table 2.1 below shows the key parameters of our network and Table 2.2 overviews the current level of embedded generation.

DESCRIPTION	QUANTITY
Area Covered	6,822km^2
Consumer connection points	32,537[(1)]
Grid Exit Point	Kaikohe
Network Peak Demand (FYE2020)	71MW[(2)]
Electricity Delivered to Consumers (FYE2020)	329GWh
Number of Distribution Feeders	60
Distribution Transformer Capacity	272MVA[(3,4)]
Transmission Lines (operating at 110 kV)	64km[(3)]
Subtransmission Cables (33kV)	21km[(3)]
Subtransmission Lines (33kV)[5]	328km[(3)]
HV Distribution Cables (22, 11 and 6.35kV)	231km[(3)]
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,597km[(3)]

Note 1: Average number of active connections FYE2020.
Note 2: Metered load as disclosed to the Commerce Commission.
Note 3: As at December 2020.
Note 4: Does not include 22/11 kV or SWER isolating transformers.
Note 5: Includes the Kaikohe-Wiroa line, which is constructed to 110kV, but currently operating at 33kV.

Table 2.1: Network parameters (FYE2020 unless otherwise shown)

TYPE OF GENERATION	NO OF INJECTION POINTS	CAPACITY (MW)
Geothermal	2[1]	57
Diesel	5[2]	17.2
Photovoltaic	1,115	5.65

Note 1. All geothermal generation is located at Ngawha. However, OEC1-3 connect to the network at 33kV while OEC4 connects at 110kV.
Note 2: This includes a 1MW generator at Pukenui, scheduled for connection by 31 March 2021.

Table 2.2: Embedded and Distributed Generation (as at 31 December 2020)

2.2 Mission and Values

2.2.1 Group

The Board has approved a Strategy Map for the Group, which sets out the Group's mission, vision, and values and underpins everything that we do. This is shown in Figure 2.1. Each operating division within the Group has developed its own strategic vision, which interprets the Group's mission and vision in the context of the business unit's core activity while maintaining the Group's core values and high-level corporate objectives.

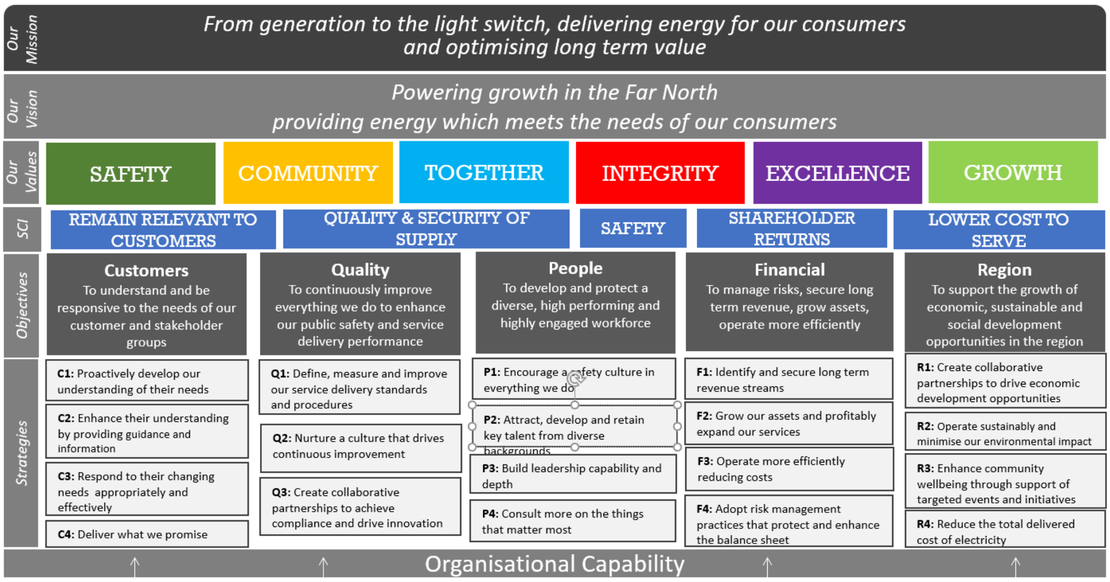


Figure 2.1 Group Strategy Map

2.2.2 Top Energy Network

TEN, as one of the Group's three business units, has developed the following mission and vision:

2.2.2.1 Goal

Our goal is to:

- *provide a safe, secure, reliable, and fairly-priced supply of electricity to consumers in the Far North.*

Since the Trust exists for the benefit of our consumers, our goal is well aligned with the mission of the Group. While safety is not negotiable, our biggest challenges in delivering on our network goal are finding the appropriate balance between security, reliability, and price for the services that we provide, and adapting to the challenges of emerging technologies in order to remain relevant to the consumers we serve.

2.2.2.2 Vision

Our vision:

- *enabling two-way power flow to deliver our consumers evolving energy needs.*

Electricity distribution has long been considered a natural monopoly as consumers have historically had little choice other than to source electricity from the grid. However, the reducing cost of photovoltaic generation and the rapid development and improving economics of battery storage technologies are making self-generation by small consumers increasingly viable, both technically and economically. Disconnection from the grid is becoming a realistic possibility for domestic consumers. Alternatively, the advent of electronic time-of-use metering, coupled with continuing developments in communications and power control technologies, is making it possible for small consumers to also become energy traders, selling their surplus electricity to retailers, to other users through peer-to-peer trading arrangements, or even to us for network support. We think that, while some consumers may disconnect from the grid, most will remain connected; many of these will want to use the grid very differently from the way they have in the past.

It follows that the emergence of these disruptive technologies is challenging the relevance of the monopolistic business and regulatory models that underpin our industry. We recognise this and are committed to adapting to emerging technologies and changing consumer behaviour, while at the same time improving our service to consumers. We welcome consumers and external parties introducing distributed generation on our network and apply short and medium-term development solutions where traditional long-life network assets are expected to become obsolete or redundant before their end-of-life.

2.2.2.3 Asset Management Challenges

In developing our AMP for the planning period FYE2022-31 in accordance with our mission and vision, and mindful of our corporate values and objectives, we have addressed a number of asset management challenges. In particular:

- There has been a strong community desire that we provide a higher level of supply security for the approximately 10,000 consumers in the north of our supply area, who have been dependent on a single 110kV transmission circuit that requires an annual maintenance outage lasting up to nine hours. Unplanned interruptions of this line were also a risk – while these are relatively infrequent, they can last an indeterminate period. While the line is currently in good condition, sometime after 2030 the conductor will have deteriorated to the point where replacement will be necessary. This will require the line to be taken out of service for extended periods.

  Our original plan to address this major network vulnerability was the installation of a second 110kV line, routed closer to the eastern seaboard, to secure the supply to Kaitaia. While this would meet all future requirements using proven technology, it is a high-cost solution with a long lead time. We commenced the design of this line in 2012 but have still not secured property rights over the full line route and are awaiting a Court decision in respect of property rights over three properties.

  When it became clear that completion of the line would be significantly delayed, we adopted an alternative strategy whereby northern area customers, apart from Juken New Zealand Ltd (JNL), would be suppled from local diesel generation when the 110kV line was not available. To this end our existing generators at the Taipa substation have been augmented by generators located at our Kaitaia field service depot, a new generator farm 2km west of Kaitaia in Bonnetts Rd, and at our Pukenui substation. We have negotiated a special arrangement with JNL that provides it with enough energy to ensure an orderly process shutdown following an unplanned interruption, but otherwise allows us to interrupt its supply when the 110kV line is not available.

  While this has allowed us to avoid the extended supply interruptions our northern consumers used to experience, it is not an optimal solution. Firstly, diesel generation is inefficient, expensive and runs counter to the Government's policy objective of minimising reliance on thermal generation because of its high carbon emissions. Secondly, consumers will still experience an interruption following an unplanned line outage while the diesel generators are started and pick up load. Finally, the capacity of the existing 110kV line is an emerging constraint that could limit the connection of utility scale intermittent renewable generation projects in our northern region. Top Energy has recently fielded three firm enquiries from proponents wanting to connect up to 67MW of utility scale solar generation in the Kaitaia and Pukenui areas.

- While there has been significant improvement in our reliability of supply in recent years, our most recent customer satisfaction survey found that we are just below our target. This is due to our fringe location on the transmission grid, the dispersed population and lack of a dominant urban centre within our supply area, and the architecture of our distribution network, where many rural and remote consumers are still supplied by long, radial feeders.

  Our reliability improvement plan has focused on the development of our transmission and subtransmission assets. Protection upgrades have improved the reliability of our subtransmission system to the point where the load on most of these circuits is now seamlessly transferred to an alternative circuit in the event of a fault. The completion of our Kaeo zone substation at the end of FYE 2018 has improved the reliability of supply in the Whangaroa area by introducing shorter feeders and reducing the number of consumers affected by an 11kV fault.

  We are now implementing incremental improvements to the 11kV network that reduce the number of consumers interrupted following a fault and allow supply to be restored more quickly to consumers not directly affected. These include the installation of new protective devices with improved discrimination in the core network, the installation of additional interconnections between neighbouring feeders, and the installation of fault indicators to help locate a fault after it has occurred.

- WorkSafe New Zealand now requires lines companies to avoid the use of live line maintenance except under exceptional circumstances. Due to a lack of clarity as to what might constitute exceptional circumstances, we now only allow our staff and contractors to work on deenergised lines. This has increased the number of planned supply interruptions, although we continue to develop and implement strategies to minimise these impacts where practicable.

  The Commerce Commission's new price-quality path for the FYE2021-25 regulatory period has mitigated this issue because it allows us to increase the number of planned network interruptions without risking a threshold breach. This is making it easier for us to plan maintenance work on the 11kV network.

- Electricity volumes supplied to consumers peaked in FYE2012 following a period of relatively strong growth and have since declined from a peak of 333GWh to a low of 325GWh in FYE2020. While there has been some subsequent recovery, delivery volumes remain below the FYE2012 peak. This lack of growth, which may be only temporary, is attributed to flat consumption by our large industrial consumers, an increasing number of consumers installing photovoltaic generation behind the meter, and energy efficiency initiatives implemented by our consumers. The flat industrial consumption is a function of the depressed economic climate in our supply area, while energy efficiencies and the installation of photovoltaic generation are likely driven by a response to the price increases that we introduced to fund our network development programme and the increased community awareness of the environmental impacts of excessive electricity consumption.

- The rate at which we can improve the security and reliability of our network is limited by the need to restrict our capital expenditure so that we maintain a prudent debt management strategy and keep within the price path determined by the Commerce Commission.

- We have also developed our network to accommodate the increased capacity of the Ngawha Power Station. While this expansion has limited the available funding for investment in network reliability improvement, our Board, with the agreement of the Trust, considers this investment to be aligned with Top Energy's mission and vision, largely because it will increase energy self-sufficiency within our supply area and limit our consumers' exposure to transmission price increases being proposed by the Electricity Authority.

Overall, this document reflects our current view on how we should respond to these challenges and contribute to Top Energy's corporate mission, given our forecast revenues and the expected availability of debt funding under what we consider the most likely energy demand scenario.

2.3 Purpose of this Plan

Top Energy's Statement of Corporate Intent (SCI) describes this AMP as the defining document for TEN, which sets out ten-year capital and maintenance expenditure levels estimated to be required to ensure that the network is managed in a sustainable way. This AMP lies at the heart of our asset management process and is the primary tool for planning the long-term development and maintenance of our electricity network.

This AMP documents our planned processes and activities to develop, maintain and operate our electricity network so that it meets required levels of safety, service, and quality in a cost-effective manner.

In this context, the purpose of this AMP is to:

- Communicate to stakeholders our asset management strategies and action plans for the network, within the context of Top Energy's mission statement and corporate strategy.
- Define the services that we plan to provide, the measures used to monitor the quality of these services and the target performance levels for these services over the AMP planning period.

- Describe the capital and maintenance works programmes planned to meet the target service levels (including reliability of supply), provide for future growth in electricity demand, and estimate the cost of delivering these programmes.
- Demonstrate responsible management of the network infrastructure and show that funds are optimally applied to deliver cost-effective services that meet consumer expectations.
- Comply with clause 2.6.1 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012.

2.4 Asset Management Policy

This AMP is guided by our network asset management policy. In summary, this policy requires us to develop an asset management plan that:

- Gives safety our highest priority. We must act at all times in accordance with industry standard safe working practices and, in consultation with our employees and contractors, develop and adopt systems and procedures in accordance with the *Health and Safety at Work (General Risk and Workplace Management) Regulations 2016* that minimize the risk of harm to people and property. We must consider the impact of all that we do on our employees, contractors, consumers, and the general public.

- Develops a network that is resilient to high impact, low probability events. We do this by building in asset redundancy where this is appropriate, and by developing and improving plans and procedures for effectively responding to events that exceed our normal response capacity.

- Improves our network's security and reliability at a rate that is both financially sustainable to the business and affordable to our consumers. We must also strive to continually improve the efficiency and cost-effectiveness of our asset stewardship to increase the value that we provide to our stakeholders.

- Monitors the technological changes affecting our industry and is ready to modify our asset management strategies to remain relevant to the consumers that we serve.

We use the Commerce Commission's asset management maturity assessment tool (AMMAT) to assess the quality of the systems and processes that we use to implement this policy. Our current AMMAT assessment is shown in Schedule 13 in Appendix A. Our aim is to improve our processes to achieve a minimum score of 3 for all indicators.

2.5 Asset Management Objectives

Our asset management objectives are grouped into five separate focus areas to align with the Top Energy Group's corporate objectives shown in Figure 2.1. In the sections below, we show how these corporate objectives are reflected in TEN's operation and the way that we manage our physical network assets.

2.5.1 Consumers and other Stakeholders

Our corporate objective is to:

understand and be responsive to the needs of our customer and stakeholder groups.

We do this by:

- Proactively developing our understanding of our consumer and stakeholder needs. We do this formally through regular consumer surveys and informally though less structured interactions with stakeholders in the normal course of business. These stakeholder interactions are becoming increasingly important as we seek to better understand the impact of emerging technologies on consumer behaviour and the impact that this could have on the future demand for our electricity distribution services and the way in which our network assets will be used.

- Responding to stakeholder needs appropriately and effectively.
- Increasing stakeholder understanding by providing guidance and information. We are also increasing the amount and timeliness of information to stakeholders through our website and other social media including a real-time outage map. We have also communicated our asset management strategy and rationale through a video that has been positively received by our stakeholders.

Sections 2.8.3 and 2.8.4 identify our stakeholders, their interests, how we aim to accommodate those interests and how we attempt to resolve any stakeholder conflict that may occur.

2.5.2 Quality

Our corporate objective is to:

> *continuously improve everything we do to enhance public safety and our service delivery performance.*

We do this by:

- Better defining, measuring, and improving our service delivery standards and procedures. We have successfully implemented an ISO 9001 certified quality management system. We have initiatives underway to implement safety-by-design across all our projects and to implement an integrated safety process and performance auditing programme. We are developing an integrated management system across the business, which will incorporate all our safety, quality, and risk management systems.
- Nurturing a culture that drives continuous improvement.
- Creating and maintaining collaborative partnerships to achieve compliance and drive innovation. We are actively involved with industry groups such and the Electricity Networks Association (ENA), the Electricity Engineers' Association (EEA), WorkSafe New Zealand, and the Business Health and Safety Forum to better understand our regulatory and legislative environment and work collaboratively towards the achievement of shared objectives. We also engage with other lines companies and digital technology providers where this helps us better serve our consumers.

2.5.3 People

Our corporate objective is to:

> *develop and protect a high performing and highly engaged workforce.*

We do this through:

- Our processes for the recruitment and retention of key talent.
- Building leadership capability and depth.
- Consulting more on the things that matter most, through the deployment of an annual employee culture survey and the provision of increased support and accountability on managers and supervisors to run consultative team meetings; and
- Investing in the development and training of our people by increasing our training budgets to a level above industry and national averages and establishing strategic training plans to meet our operational needs.

2.5.4 Financial

Our corporate objective is to:

> *manage risks, secure long-term revenue, grow assets and operate more efficiently.*

We do this by:

- Securing our long-term revenue stream by implementing a pricing strategy designed to increase the certainty of our revenue levels.
- By delivering the key network projects identified in this AMP and being open to the investment in non-network alternatives, where these provide cost effective outcomes that better meet consumer needs.
- Operating more efficiently to reduce costs through the development and implementation of a standardized project management delivery framework, identifying procurement and cost saving opportunities and providing operations and financial management training to managers to enhance financial decision making.

2.5.5 Region

Our corporate objective is to:

> *support the growth of economic, employment and social development opportunities in the region.*

We do this by:

- Providing network and non-network solutions that will underpin economic development by assisting investors, developers and industry to fulfil their growth ambitions.
- Providing holiday work experience to tertiary students in accordance with our recruitment strategy.
- Participating in community events.
- Encouraging and supporting employees to volunteer for community emergency services.

2.6 Strategic Issues

2.6.1 Embedded Generation

The expansion of the Ngawha Geothermal Power Station to its current capacity of 57MW has shifted the centre of electricity supply to our consumers from remote generation located south of Auckland, to generation located close to our network. More than 95% of the electricity consumption in our supply area is now locally generated, although our consumers are still reliant on the grid for generation operational purposes. The primary function of the connection to Maungatapere is now to export electricity generated at Ngawha south for use by consumers outside our area.

Top Energy has resource consent to for the installation of a further 32MW generating unit at Ngawha, which would increase its maximum output to 89MW. As noted in Section 2.2.2.3, we also have firm enquiries from proponents planning to connect up to 67MW of utility scale solar generation in the Kaitaia and Pukenui areas (this is further explained in 2.6.5. Clearly, there are sufficient local renewable generation resources available for our supply area to be fully self-sufficient and there is potential to further develop the local economy by exporting energy generated within our supply area.

Overall, the New Zealand power system will benefit from increased generation located north of Auckland as it will reduce the amount of energy that needs to be transmitted through the congested Auckland isthmus. However, the amount of electricity that can be exported south will be constrained by the capacity of our single circuit 110kV line between Kaikohe and Kaitaia and Transpower’s double circuit 110kV line connecting our Kaikohe substation to the Transpower grid at Maungatapere. These constraints are quantified and discussed further in Section 5.11.2.1 and 5.11.2.2.

Management of utility scale generation in the Kaitaia area will be a challenge because of the potential impact of rapidly changing generation output on the technical performance of our network. We have engaged a consulting engineer to undertake dynamic studies of our network so we can better understand this issue.

2.6.2 Tourism

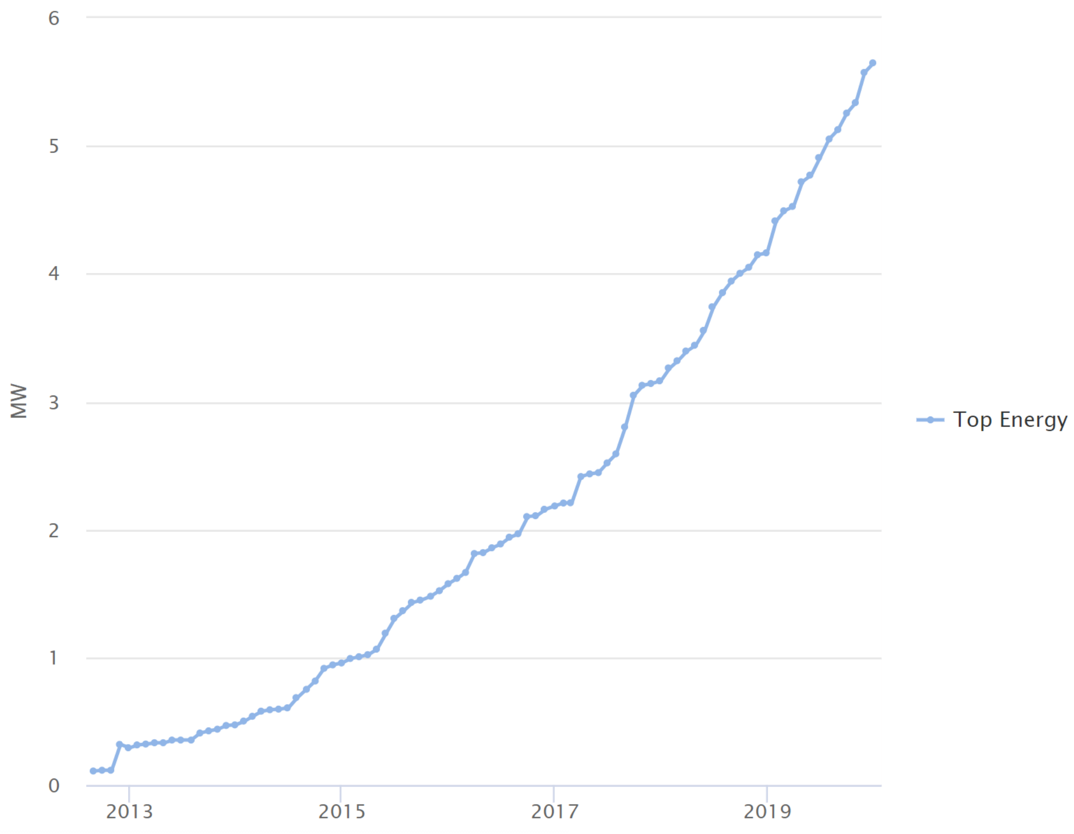
The beaches within our supply area are popular tourist spots where the population swells over the summer period. This creates high levels of demand that persist for only a short time. Furthermore, the catering, accommodation, and other ventures associated with the tourism sector are sensitive to losses of supply. Many of these developing tourist areas are located away from our subtransmission network. This makes the economic provision of a secure supply challenging. Significant tourist areas still supplied from long 11kV distribution feeders include the Russell and Karikari peninsulas, Opononi/Omapere and Purerua.

2.6.3 Resilience of our Grid Connection

We are located at the most remote end of the transmission grid, well away from most connected generation. Our network is remotely connected to the grid via a single, long transmission spur. Hence the security of our connection to the transmission grid is much lower than it would be if our supply area was in the middle of the power system. Increasing the capacity of the Ngawha power station has not mitigated this concern as, for technical reasons, the power station is unable to operate without a grid connection.

2.6.4 Small Scale Photovoltaics

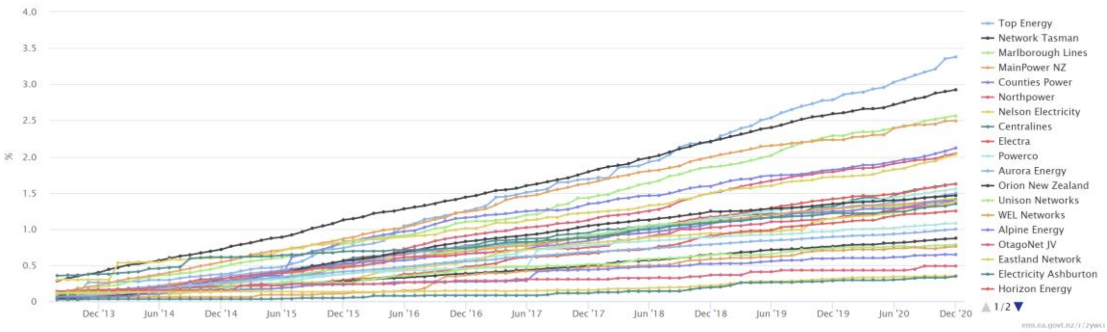
Over the past five years the penetration of domestic solar panels has increased with recent larger installations on commercial premises giving the trend an upward trajectory, as shown in Figure 2.2. As of 31 December 2020, there was a total of 5.65MW of solar generation installed within our network, spread across 1,115 injection points. This is an increase of almost 1.5MW (36%) in just 12 months.



Source: Electricity Authority

Figure 2.2: Growth in Photovoltaic Generation Connected to our Network

An installed distributed generation capacity of 5.7 MW is not inconsequential and contributes both to the reduction of imported energy from the grid and potential energy export at times when our demand is low. We also have the largest penetration of distributed generation injection points as a percentage of the total number of connection points on the network of any New Zealand EDB and, as can be seen from Figure 2.3 below, this penetration rate is currently increasing significantly faster than any other EDB.



Source: Electricity Authority

Figure 2.3: Solar Penetration by EDB

We do not consider congestion on the 11kV distribution network due to the aggregation of small-scale solar panels within a localised area likely to cause problems in the medium term. Nevertheless, in Australia, management of voltages on low voltage networks with a high number of consumers with rooftop photovoltaic generation has become a significant issue. The location of small-scale photovoltaic generation is concentrated along the wealthier eastern seaboard of our supply area and the penetration in these areas will be higher than shown in Figure 2.3. While no issues have emerged to date, as this penetration increases further the management of localised over-voltages on the low voltage network where a number of installations are connected to the same transformer could become an issue. This is discussed further in Section 5.11.1.1.

2.6.5 Utility Scale Photovoltaics

The technology for large solar arrays for bulk power generation has been around for a long time, and has been implemented with success overseas, particularly where there are generous government incentives to install them. The introduction of solar farms into New Zealand however has been slow, and it is only very recently that we have been fielding enquiries from solar farm developers.

The connection of large solar arrays is an emerging issue that will potentially impact how our network is configured and operates. The capacity of our 110kV network between Kaitaia and Kaikohe and our grid connection to Maungatapere will place an upper limit on the amount of utility scale generation that can be connected. These factors will be carefully evaluated when proposals are assessed and are discussed further in Sections 5.11.2.1 and 5.11.2.2. There are also technical challenges due to the highly dynamic and unpredictable power output of solar arrays. Voltage changes on the transmission network as a result of these output variations could filter through to consumers. These transient effects will largely be managed at source through invertor control, but some additional network voltage control may be required.

Nevertheless, the work undertaken over the past 10 years or so to reinforce the subtransmission network, build new and upgrade old substations, undertake the first stage of the 110kV line build and install generation at strategic sites has placed us in a strong position to accommodate future load growth including the installation of utility scale embedded generation and the development of distributed generation in its various forms.

2.6.6 Electric Vehicles

The Government is strongly promoting the introduction of electric vehicles, because of New Zealand's high proportion of electricity generation from renewable resources. As shown in Section 3.1.12, there are currently 179 pure electric and plug-in hybrid vehicles registered in our supply area, an increase of 77% over the last 12 months. Approximately 72% of these are pure electric. Increased penetration of electric vehicles should increase our delivery volumes but has the potential to cause localised overloads if several vehicles in the same area are charged together at times of peak demand. Consumer education and time of use tariffs may be needed to mitigate this. In the longer term the use of electric vehicle batteries as energy storage devices has the potential to assist with the management of potential network overload and voltage issues.

We have planned a data capture programme to fully determine the configuration and connectivity of the low voltage network. This will enable us to better understand the potential impact of both electric vehicle charging and small-scale solar generation.

2.6.7 Developing a Platform for New Services and Markets

We have an organisational challenge to build the operational knowledge and technical capability to transition from a distribution network operator to a distributed energy system operator. Our operations and the services we provide will become increasingly automated and software driven. The installation of our new advanced distribution and management system (ADMS) is a first step in this direction.

2.7 Rationale for Asset Ownership

Our rationale for asset ownership is derived from our mission statement, which as noted in Section 2.2.2, is to:

> *provide a safe, secure, reliable, and fairly-priced supply of electricity to consumers in the Far North.*

Our intention is to own only the assets needed to deliver on this mission with the lowest long-term cost.

Until recently, the economies of scale in electricity generation were substantial, the demand for electricity was growing exponentially and technologies for storing large quantities of electricity were not available. In this situation, the most economic approach to providing an electricity supply to individual consumer premises was to use a network of conductors and transformers to deliver electricity, sourced from a relatively small number of large generators and interconnected by a centralised transmission grid. This industry paradigm is now changing to the extent the installation of traditional network assets may not always be the most cost-effective solution. Traditional network assets are expensive to install and have lives of forty years or more. It is only cost-effective to use such assets to meet today's distribution requirements if we can be confident that the installed network capacity is likely to be required for the life of the asset, or if there is no suitable lower-cost alternative that will fully meet consumer requirements.

While we know that our industry will be significantly affected by the introduction of emerging technologies, the timing and nature of these impacts is far from clear. In this environment, the risk of asset stranding, where an asset becomes redundant part way through its life, can be reduced through the installation of lower-cost alternatives with a relatively short life, on the basis that by the end of their life, the future of the industry should be clearer. We can then replace these assets with solutions that better meet our stakeholders' long-term requirements.

We are open to the use of non-network solutions to meet the needs of our consumers. This approach has already involved the installation of diesel generation to provide supply security to our northern area in the absence of a second incoming 110kV circuit and at zone substations supplied by a single incoming 33kV circuit.

As emerging technologies become more mature, we expect our consumers to become less reliant on traditional network assets to meet their energy requirements. As we transition to a distributed energy services operator the nature of our asset base will change, and we will not necessarily own all of the assets that we manage. Some will be owned by our consumers and some will be provided on a competitive basis by third parties.

2.8 Asset Management Planning

The key internal planning documents with a direct link to this AMP are our:

- Statement of Corporate Intent (SCI), which outlines our overarching corporate objectives and strategic performance targets for the coming year. It incorporates the outcome of an annual strategic business review and formally documents an agreement between the Top Energy Board and the shareholder, and so requires the approval of the Trust.
- Annual Plans, which are short-term operating documents that detail how the funds will be used within the budget set out in this AMP and approved by the Board. Annual Plans are prepared for maintenance, vegetation management and capital works delivery. They provide more detail than described in this AMP on how budget funding will be used. For example, the vegetation management plan identifies the feeders that will be the focus of the vegetation management effort in a particular year. Annual Plans are approved by our executive management team, but do not require Board approval.
- Business Cases, which are prepared for all projects or programmes with an estimated cost of more than $500,000. These are prepared throughout the year and require Board approval before a project or programme can commence.

In addition, there are a range of internal and external documents and systems that influence the content of the AMP. Internal documents and systems include our:

- Quality System, which is certified as compliant with ISO 9001 and externally audited on a regular basis. It includes the policies, procedures and work instructions that underpin all that we do.
- Risk Register, which identifies key risks that our business faces, given the architecture and condition of our network fixed assets. Mitigation of these risks is a key driver of our capital expenditure (capex), and operations and maintenance expenditure (opex) on network assets.
- Emergency Preparedness Plan, which details the plans and procedures we have in place to ensure electricity supply is maintained or restored as quickly as possible, following emergency circumstances and events that the network is not designed to withstand.
- Safety Management System, which details the processes and procedures in place to ensure the safety of our employees and contractors working on the network.
- Public Safety Management System, which specifies the processes and procedures in place to ensure that our assets do not present a risk or hazard to the general public.
- Northland Region Civil Defence Emergency Group Plan (NRCDEGP), which describes procedures for the response to a Civil Defence emergency in the Northland region. It identifies interdependence issues between our network and other lifelines and the role of Top Energy in response to a Civil Defence emergency. The response procedures include the operation of injection equipment and support delivery to ensure the functioning of the MEERKAT community warning system.

The external documents that influence the strategies and action plans described in this AMP include the Commerce Commission's price-quality path that applies to the operation of the network. This is defined in the Commission's *Electricity Distribution Services Default Price-Quality Path Determination 2020.* The development of the asset management strategies and action plans described in the AMP is also restricted by the requirements of the different legal and regulatory instruments that govern our operations. These include technical standards relating to electricity supply, public safety, employee and contractor health and safety, and environmental protection.

2.8.1 Preparation of the AMP

This AMP is both a strategic and an operational document. It is strategic, as it sets out our current plans for the management of our network assets over a ten-year planning period. It is operational, as the plans and budgets within the AMP for the first year of the ten-year planning period form the basis for the Annual Plans, which control our asset management expenditure for FYE2022. In subsequent years, the content becomes progressively more strategic.

The SCI provides the context for the AMP, which in turn provides the context for the Annual Plans. All documents are interdependent and prepared in parallel using a largely iterative process.

At a strategic level, the SCI details the funding available to resource the action plans and strategies set out in the AMP. These funds are reliant on the revenue that we expect to earn, the return that the shareholder requires, and the need to maintain a prudent debt-equity ratio. The SCI also sets out the target levels of service for the first three years of the planning period. These are an outcome of the strategies and plans detailed in the AMP.

The AMP strategies and plans are prioritised within the available funding. They are also influenced by factors that impact our operation, including:

- The capacity of the existing network assets to accommodate localised growth in demand.
- The needs of consumers and other network stakeholders.
- The cost of meeting legal and regulatory requirements.
- The assessment of potential risks to the smooth operation of the network, and the need to plan for and mitigate these risks.

The AMP takes account of our ability to deliver planned outcomes and maximise the investment of funds and other available resources in a way that optimises benefits to stakeholders.

Preparation of these key planning documents commences more than six months prior to the start of each financial year. The process begins with a reassessment of the environment in which the business operates and how this might influence our strategic corporate objectives. It also includes a review of our forecast of the demand for electricity and the performance of the existing network asset base. As a result of this review, we prioritise our capex and opex requirements. These activities lead to the development of initial plans that consider operational constraints at a high level.

The process then enters an iterative refinement phase, where the impact of constraints on the deliverability of these initial plans is analysed in more detail. The AMP is refined, and the impacts that these refinements may have on our SCI and Annual Plans are considered, which may result in further adjustments. The iterative process continues until a set of plans result that are consistent with one another, align with our mission and accommodate all key constraints.

The final plans are subject to review and approval by our executive management team. The SCI and the AMP are formally approved by the Board in March, prior to the commencement of each financial year.

2.8.2 Planning Periods Adopted

This AMP is dated 1 April 2021 and relates to the period from 1 April 2021 to 31 March 2031. It was approved by the Board on 30 March 2021 and replaces all previously published AMPs and AMP Updates.

2.8.3 Key Stakeholders

Engagement with stakeholders is ongoing and the outcomes of this engagement provide critical inputs to the development of asset management plans at all levels. We engage with stakeholders through the following forums:

- Meetings and informal discussions.
- Discussions with major consumers.
- Industrial seminars and conferences.
- Consumer surveys.
- Enquiries and/or complaints.
- Discussions with the Trust.
- Reviews of major events such as storms.
- Specific project consultation (e.g. large capital projects such as the installation of diesel generation and construction of the 110kV line between Wiroa and Kaitaia).
- Meetings with suppliers.

- Performance review and management for internal and external contractors.
- Papers and submissions.
- Website and social media.
- Local media.

Table 2.3 below indicates how the AMP incorporates the expectations of stakeholders. Each year, the published AMP is made available to all stakeholders for their information. Feedback is welcomed.

Where conflict arises between our asset management requirements and stakeholder expectations, we engage with the affected stakeholders and attempt to achieve an acceptable outcome. In these situations, the following considerations apply:

- Safety is always our highest priority.
- The needs of all affected stakeholders are considered.
- Alignment with the Trust objectives as published in the SCI.

Our approach is to work with all parties involved to ensure there is a complete understanding of all the issues and to seek alignment, or at least common ground, and work towards a mutually acceptable solution. Our experience is that this will usually resolve the issue. However, if agreement cannot be reached, we will proceed in a manner that we believe is fair to all affected parties and is consistent with Top Energy's group values and objectives.

2.8.4 Stakeholder Interests

Table 2.3 below identifies our key stakeholders and their individual interests and summarises the process that Top Energy has in place to accommodate their expectations.

STAKEHOLDER	EXPECTATIONS	ACTIONS
NETWORK USERS	Fair price	• We set prices at the price threshold determined by the Commerce Commission in applying its price-quality regulatory framework. • We continually strive to improve our operating efficiency in the expectation that, over time, network users will benefit through lower prices for the services we provide. • Network losses are a cost to consumers. We measure these losses and expect they will reduce over time as our network development plan is implemented. We calculate loss factors for different parts of the network in accordance with the methodology approved by the Electricity Authority. • We actively manage GXP demand using our water heater control system to ensure transmission connection costs are minimised without adversely impacting the quality of supply as perceived by consumers. • We minimize the cost of improvements to the reliability and capacity of our network by using new technologies and non-network alternatives, such as embedded generation, where this is practicable.
	Reliability	• We continually measure and review reliability against the SAIDI and SAIFI targets detailed in the AMP. We target higher reliability than the benchmarks set by the Commerce Commission in applying its price-quality framework, to reflect the planned outcomes of our network development and maintenance initiatives.
	Quality	• We identify areas within the network where the quality of supply does not meet technical standards through internal modelling and monitoring of consumer complaints, and we implement improvement projects as a result.
	Resilience	• We set security standards for the transmission and subtransmission networks and have implemented augmentations to ensure these standards are met or exceeded. • We have a documented Emergency Preparedness Plan that sets out the procedures we will follow if an emergency arises due to a low probability event that exceeds our normal response capacity.
	Flexibility	• We are flexible and endeavour to meet the requirements of individual consumers to the extent that this is cost-effective using a shared network.
	Emerging technologies	• We facilitate the application of emerging technologies that provide opportunities for consumers to use our network in new and innovative ways.
	Communications	• An external call centre has been contracted to ensure consumers are directed to the appropriate point of contact for quick and efficient service. • We closely monitor consumer expectations through regular surveys and other communication channels and endeavour to meet these expectations in the planning and operation of the network. • We communicate with our consumers through our interactive outage app., website, social media and local media.
	Embedded generation	• We welcome the connection of embedded generation and will negotiate with proponents to achieve an outcome that meets their requirements, where this does not reduce the level of service that we provide to other network users. •

STAKEHOLDER	EXPECTATIONS	ACTIONS
RETAILERS	Communications	• We share information on network outages and other relevant issues with retailers in accordance with standard industry protocols.
	Use of system agreements	• We negotiate use of system agreements with retailers in good faith and in accordance with the requirements of the Electricity Authority.
	Simple tariff	• Our tariff structure is developed in conjunction with retailers and reflects the business needs of all parties. • We coordinate the timing of any tariff changes with retailers.
	Allocation of losses	• We calculate loss factors for different parts of the network in accordance with the methodology approved by the Electricity Authority.
	Metering and billing	• We rely on retailers' systems to reconcile revenue.
BOARD AND TRUST	Safety	• Safety is our highest priority. We operate a safety management system that has been developed in accordance with the requirements of the Health and Safety at Work Act 2015, the expectations of WorkSafe New Zealand and industry guidelines and practices. • We cultivate a culture of safety within the business and actively participate in industry safety initiatives. • We actively monitor safety outcomes and report these monthly to the Board.
	Return on investment	• Our asset management activities are consistent with a corporate strategic plan designed to ensure that our operations are financially sustainable. • We report financial outcomes monthly to the Board. This report includes a comparison against the budgets in this AMP.
	Economic development	• Consistent with the objective of supporting economic development within our supply area, we negotiate with potential new industrial and commercial consumers to identify an economic supply solution that meets their specific requirements without disadvantaging consumers already connected to our network.
	Reliability	• Our reliability improvement expenditure is targeted at initiatives that are expected to improve reliability of supply. • We report the reliability of our network monthly to the Board. This includes a comparison of actual reliability against the reliability targets in this AMP.
	Accountability	• Our employees' key performance indicators are linked to the achievement of asset management service levels.
	Legal and regulatory compliance	• Our internal standards, policies and procedures ensure compliance with all legal and regulatory requirements. • We monitor changes to the legal and regulatory regime within which we operate and modify our asset management plans, processes and procedures as necessary to maintain compliance.
	Asset management	• We manage our assets in accordance with this AMP, which is prepared in accordance with the corporate strategy agreed with the Trust by the Board and reflected in the SCI.
	Social responsibility	• Our capital contribution scheme is designed to ensure equitable sharing of the costs of new construction installed for the benefit of individual consumers.

STAKEHOLDER	EXPECTATIONS	ACTIONS
COMMERCE COMMISSION	Price	• We set our prices in accordance with the price path set by the Commission under its price-quality regulatory regime and confirm compliance annually through our audited regulatory compliance statement.
	Quality	• We set internal reliability targets that are higher than the standards set by the Commission under its price-quality regulatory regime and monitor our performance against these targets monthly through our Board reports. • We confirm that our reliability of supply is better than the standard set by the Commission under its price-quality regulatory regime annually through our audited regulatory compliance statement.
	Information disclosure	• We keep records of our financial performance and the performance of our network assets, and we disclose this information annually in accordance with the Commission's requirements.
ELECTRICITY AUTHORITY	Price	• We are transitioning over time to a more cost reflective pricing structure and are currently preparing a formalized plan to guide this transition.
	Legal compliance	• We manage our business in accordance with the Electricity Industry Participation Code and provide the Electricity Authority with information required under the Code.
	Retail competition	• We provide the installation control point (ICP) and metering data required for the operation of the competitive retail electricity market. • We treat all retailers using our network on a similar basis to ensure that the market operates in our area across a level playing field.
MBIE	Energy monitoring	• We provide the Ministry of Business, Industry and Employment (MBIE) with the statistical data and other information it requires to undertake its role of monitoring and regulating the use of energy in New Zealand.
TRANSPOWER	Grid management	• We cooperate with Transpower to facilitate the management of its assets that are located within our 110kV substations. • We regularly provide Transpower with updated information on our forecast peak demand and our connection point requirements. • We use Transpower's standards as the benchmark for determining the maintenance requirements of our 110kV assets.
WORKSAFE NEW ZEALAND	Safety	• We manage all work in our network in accordance with the industry standard safety requirements approved by WorkSafe. • We participate in industry forums on the development of safety standards to protect industry workers and the general public. • We cooperate with WorkSafe in its accident reporting and investigation requirements.
STAFF	Health and safety	• We have a safety management plan in place to ensure the safety of our staff. This complies with industry standards and requirements and is regularly reviewed.
	Job security and satisfaction	• We strive for a motivated staff with high levels of job satisfaction that can meet stakeholder expectations. We regularly survey staff to monitor satisfaction with their work and working environment and undertake improvement initiatives if needed. • We have training and development, and recruitment plans in place so that relevant skill sets will be available when required.

STAKEHOLDER	EXPECTATIONS	ACTIONS
	Training	• We regularly survey staff to monitor satisfaction with their work and working environment and to identifying areas where skill development or support may be necessary. • This AMP reflects the skill set required of our work force, which inputs to our Training and Development Plan. We monitor staff training hours both individually and collectively.
PUBLIC	Vegetation control is fair	• We implement our vegetation management programme in accordance with the Electricity (Hazards from Trees) Regulations 2003. • We target expenditure on vegetation to achieve improvements in reliability of supply.
	Safety	• We implement an NZS 7901 compliant public safety management system to ensure that operation of our network assets does not pose reasonably avoidable risk or hazard to the public. This is subject to regular audit.
	Land access rights upheld	• We comply with relevant regulations and consult with landowners and occupiers as appropriate before undertaking work that requires access to private property.

Table 2.3: Accommodation of Stakeholder Interests

2.8.5 Accountabilities and Responsibilities for Asset Management

The Trust is the sole shareholder of Top Energy Ltd, which holds its shares on behalf of electricity consumers connected to the Top Energy network. The Trust appoints the Top Energy Board of Directors (Board) to govern Top Energy and protect the shareholder's interests.

The Board governs our asset management effort through the development of Top Energy's strategy, approval of this AMP and of individual project business cases for projects with an estimated cost of $500,000 or more. It also actively monitors the ongoing operation of TEN and TECS, and provides input into development of the strategic performance targets in the SCI.

The Top Energy Group structure is shown in Figure 2.4.

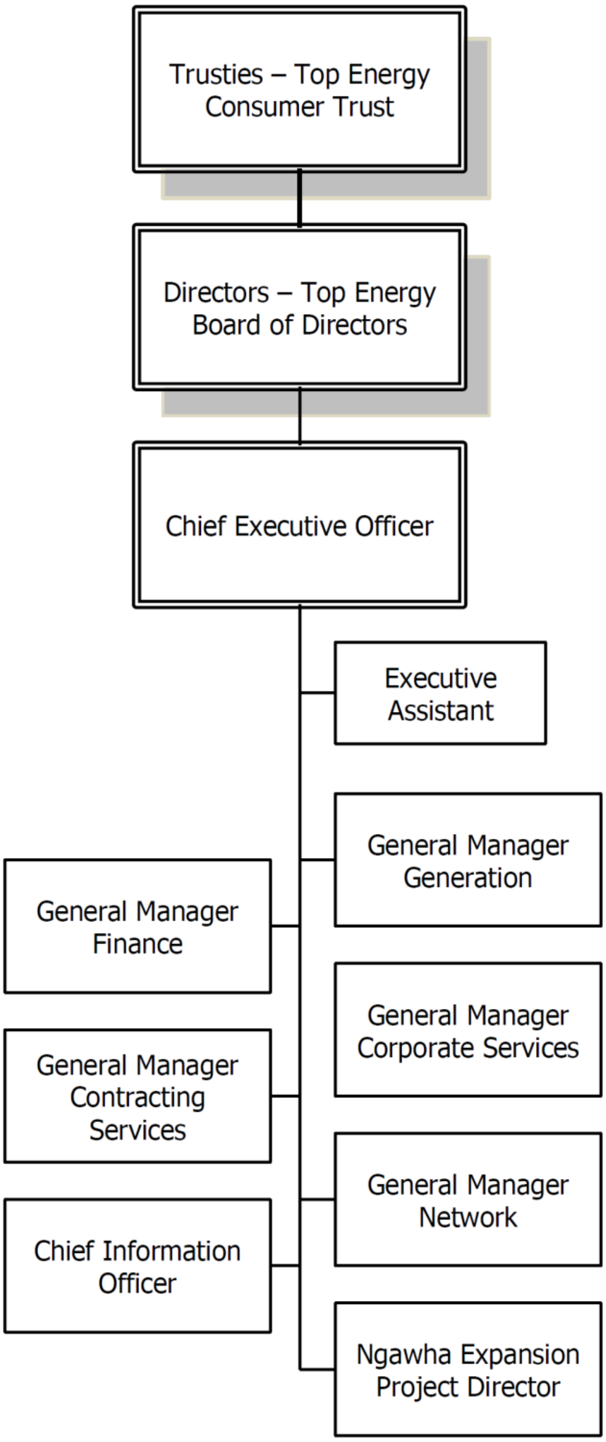


Figure 2.4: Top Energy Structure

BACKGROUND AND OBJECTIVES

At the executive level, the Chief Executive Officer (CEO) is appointed by the Board and has overall responsibility for our network asset management effort. TEN is responsible for managing the network assets covered by this AMP and is managed by the General Manager Network, who reports to the CEO and follows the strategies and policies approved by the Board. The General Manager Network is a member of Top Energy's executive management team and presents a monthly report on our network operations directly to the Board.

TEN is responsible for ensuring that the network assets are developed, maintained, renewed and operated for long-term sustainability. This includes:

- Determining expenditure requirements.
- Maintaining asset records, developing and setting standards.
- Operating the network in a safe manner to minimise outages.
- Monitoring performance.
- Making investment recommendations.
- Managing risk.
- The ongoing management of the network assets within approved renewal, maintenance, capital and operational expenditure budgets.

TEN is responsible for preparing this AMP and implementing the network budgets. We are required to report any material variances from the budgets in terms of both scope and finance to the Board monthly, including variances related to projects with an approved budget of more than $500,000. Variances related to projects with an approved budget of $500,000 or less are discussed and agreed between the General Manager Network and the CEO and may be raised for Board approval if they are considered significant.

Apart from specialist maintenance activities and major construction projects subject to competitive tender, work on the distribution network is undertaken by TECS, which employs approximately 65 staff including supervisors, technicians, and line mechanics.

TECS operates from purpose-built depots in Kaitaia and Puketona. While TECS is also a division of Top Energy, work contracted-out to TECS is managed by TEN as if TECS was an external contractor operating under an arms-length relationship. The nature of the formal relationship between TEN and TECS is discussed further in Section 2.15.4 and is regularly reviewed. The cost of field work is comparatively benchmarked against current industry costs to ensure the efficiency of works delivery is maintained. The Trust and the Board believe that this arrangement is in the best interest of the shareholder since, with this model, the interest of the asset manager and service provider are aligned.

Specialist work outside the skill set of TECS staff is outsourced to external contractors and supervised directly by relevant TEN maintenance, planning or programme delivery managers.

Maintenance work on the transmission network, including the 110kV transmission line, the 110kV substation assets, and the 33kV assets at Kaikohe and Wiroa substations, is undertaken by Northpower under a maintenance contract that requires maintenance standards equivalent to those required by Transpower.

TEN has overall responsibility for the safety of all personnel working on the network, including contractors. Consistent with industry safety standards, we implement an Authorisation Holders Certificate (AHC) assessment process to ensure the competence of field staff (both internal and external) is compliant with company and industry requirements. Employees and contractors' staff are required to be reassessed every 12 months and hold an AHC to work on the network.

Staff must provide relevant training records, workplace audits and operational evidence to prove their competency in undertaking specific tasks. AHC holders are only allowed to perform tasks to the level permitted by their AHC. The assessment and approval for issuing an AHC to an individual is by recommendation of the Network Operations Manager and with the consent of the General Manager Network.

BACKGROUND AND OBJECTIVES

TEN currently has a staffing establishment of 40 full-time equivalents and is structured as outlined in Figure 2.5 below.

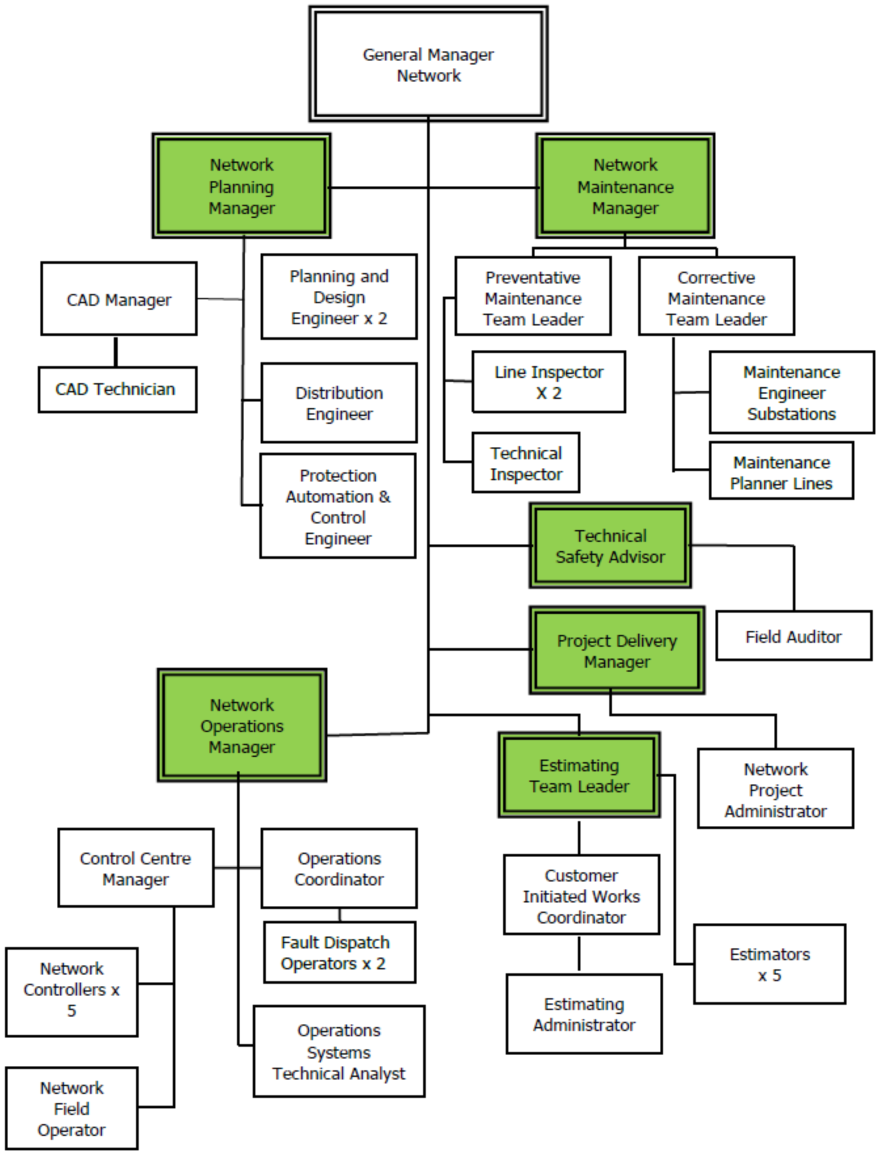


Figure 2.5: Top Energy Networks – Structure

The key responsibilities of our Networks management team are:

Position	Accountability
General Manager Network	To control the network budget that governs TEN's activities.
Maintenance Manager	To control the maintenance and renewal budget.
Planning Manager	To control the capital budget.
Project Delivery Manager	To manage the delivery of the capital investment programme budgets individually assigned for each project.
Technical Safety Advisor	To ensure compliance with regulations and to minimise the safety risk to staff, contractors, and the public.
Operations Manager	To manage the control centre and fault budget, and to monitor network performance.
Engineers	Delegated authority to manage projects to individual budgets.

Table 2.4: Top Energy Networks Division Responsibilities

Individual order approval levels are:

Position	Delegated Approval Level
CEO	$1 million
General Manager Network	$100,000
Section Managers	$50,000

Table 2.5: Top Energy Order Approval Levels

2.9 Asset Management Systems

We use a range of information and telecommunications systems critical to the asset management process. This section outlines our present and future development plans for information systems.

2.9.1 System Control and Data Acquisition

We went live with our new Advanced Distribution Management System (ADMS) in January 2020. The ADMS currently delivers;

- Supervisory Control And Data Acquisition (SCADA) of applicable Network assets
- Outage Management System (OMS)

The OMS combines real time inputs on the state of the network from our SCADA system with the customer connectivity information in our Geographic Information System (GIS) to predict the location of faults and to automatically calculate the SAIDI and SAIFI impact of supply interruptions. This has resulted in improved management reporting. The OMS also provides the data for our web based Outage Centre, where customers can view current planned and unplanned outages, as well as subscribe for future outage notifications.

Our operational groups are continuously adapting existing and developing new processes to take advantage of the ADMS functionality and capability.

The ADMS has significant additional functionality and capability that is planned to be implemented over the next five years. These are commonly referred to as the Distribution Management System (DMS) components. This functionality will be added progressively as the software is customised to our network and our operators are familiarised with each new function as it is brought online;

- Advanced Meter Interface (AMI). Utilises the data and capability of smart meters to improve the OMS outage status, coverage and prediction accuracy and performance.
- Distribution Power Flow Analysis (DPF). This provides a real-time capacity and constraints model of the network, using inputs from SCADA, the GIS and our potentially SAP Asset Management System (AMS). It supports management and predictive modelling function for planning purposes for the operation of the network by making real-time information on network status available to operators.
- Switching Advisor (SA). Delivers enhanced shutdown planning services and workflow management to optimise the operation and management of the network.
- Automated Planned Restoration Service (APRS). Leverages DPF to minimise outage impact and improve response and recovery times.
- Adaptive Network Management (ANM). Leverages DPF to provide automated control of embedded generation plants based on current network conditions and constraints. The need for this capability will be driven by customer demand.

We expect the ADMS to be a key tool in developing a network that is open to the use of new technologies and in facilitating our transition from a distributor of electricity to a manager of a distributed energy system. The system we plan to install has been future-proofed and modules to support Distributed Energy Resource Management (DERM) and Demand Response Management (DRM) are being developed by our ADMS vendor. These will be added as required.

2.9.2 Accounting/Financial Systems

The Group uses SAP for the management of expenditure, capital accounts, estimating capital jobs, inventory, orders, accounts payable and accounts receivable, and uses Payglobal for processing all salaries.

We report actual versus budget performance monthly by general ledger category and individual projects. The senior management team also receives monthly reports of:

- Profit and loss reconciliation by division.
- Consolidated profit and loss.
- Consolidated balance sheet.
- Consolidated cash flow.
- Capital and maintenance expenditure.

We also use ancillary electronic databases and spreadsheets to analyse the performance of the company.

2.9.3 GIS System

The Intergraph Geographic Information System (GIS) is an engineering asset register and provides a spatial representation of assets, their connectivity and relationship with one another, consumers, and vegetation. This information is merged with the Terralink database and overlaid with raster images from aerial photography.

Our GIS data includes several integrated critical business applications that are used to manage and report on assets. These are:

ICP Application

This application is integrated into the national registry to manage and report on consumers' Installation Control Points (ICPs). Supplementary information is included to facilitate the management of consumer connections, including safety and pre-connection status.

Permission Application

We use this for storing details and agreements relating to easements and general property access rights.

Incidents/Faults Management System

Where the location of a fault is noted against an asset that has failed, the application provides electrical traces to be run to ascertain the areas, roads and numbers of consumers affected under different switching configurations.

2.9.4 Network Analysis System

We use the DigSilent power systems analysis package for load flow, voltage profile and protection design.

2.9.5 Consumer Management System

We contract an external call centre to handle consumer calls. The call centre uses its customer management system to provide details about consumer calls and call statistics.

2.9.6 Drawing Management System

We use Autodesk AutoCAD to generate construction drawings for subdivisions and new capital works.

These drawings include:

- Standard line construction drawings.
- Zone substation building and site plans.

- Specialised equipment drawings.
- Procedures manual diagrams.
- Control, circuit and wiring diagrams.

2.9.7 Maintenance Management System

We use the SAP asset management software modules as a repository for asset condition data and the basis for our maintenance planning and management. Each individual asset is assigned to a maintenance and inspection plan detailed within SAP, according to the type of asset, the required inspection frequency, and the asset location. Asset inspections are undertaken both internally by TEN and externally with contractors; our asset inspectors work systematically through each inspection plan and, as each asset is inspected, asset condition and other relevant data (such as defects requiring remediation) are downloaded directly into the SAP database using hand-held data input devices.

The first inspection cycle for all asset categories is now complete apart from a small number of service pillars due to be inspected in FYE2022. Assets are inspected according to a time-based inspection regime. The frequency of inspection under this programme is based on the expected rate of asset deterioration and a risk-based assessment of the consequences of an asset's failure. When an asset is assessed as potentially requiring replacement before its next scheduled inspection, it is transitioned into our defects management system and inspected more frequently until the asset is replaced. Our inspection and defects management regimes are discussed further in Section 6.1.2.

2.10 Asset Data Accuracy

Top Energy maintains a dedicated GIS team responsible for ensuring that asset data is accurately recorded and maintained.

GIS data is considered accurate in the following areas:

- 11kV Lines and associated equipment.
- Transformers (overhead and ground mount).
- Line switchgear and equipment.
- 33kV zone substations.
- 33kV lines.
- 33kV switchgear.
- Transmission assets transferred from Transpower.
- Other technical equipment, including SCADA.
- 11kV cable and related equipment, including switchgear.
- 33kV cable and related equipment, including switchgear.

For these asset types, individual assets down to mother/child connectivity levels are identified, and attributes and capacity are recorded.

Data gaps and errors still exist with:

- Low voltage systems; and
- Consumer points of connection (i.e. three-phase, single phase, underground or overhead).

These issues arose because the data on approximately 30% of the low voltage network was not collected during the data gathering exercise that was undertaken to initially populate the GIS database. Data on the low voltage network will be updated as part of our planned extension of the new ADMS functionality to include management of the low voltage network (see Section 5.12.4).

2.11 Asset Management Processes

2.11.1 Asset Inspections and Maintenance Management

The asset inspection programme described in Section 2.9.7 is uploaded into, and managed through, SAP. Our visual asset inspections are complemented by a structured, non-invasive condition assessment programme that targets key assets (e.g. power transformers) as well as items that are prone to failure (e.g. cable terminations). A more detailed description of the maintenance policies for specific asset types is provided in Section 6.

Defects are prioritised and packaged into work orders by TEN staff. These maintenance work packages are designed to ensure that all defects in a particular area that require a maintenance intervention are remedied at the same time and are passed to TECS for implementation. Quality and efficiency of defect remediation by TECS are monitored through selective auditing and monthly reporting. Defect management is discussed further in Section 6.1.2.3.

We receive regular reports from TECS on maintenance work completed. These are used as the basis for Board reporting on maintenance completion and expenditure against the maintenance budget.

We also operate a 24-hour emergency maintenance service to provide prompt repair of network faults and to attend to defects that pose an immediate threat to public safety.

2.11.2 Network Development Planning and Implementation

Our network development plan is strategic in nature and requires a level of expenditure relative to our expected annual income. It is reviewed annually at both a strategic and detailed planning level.

At the strategic level, the development plan is reviewed for continuing alignment with the Board's mission and values, and also with consumer expectations, taking due account of the dynamic environment in which we operate, and our ability to fund the substantial investment required. Given the current low rate of growth in incremental demand, our strategic focus is on improving the security and reliability of supply and accommodating any new block loads seeking connection to the network.

DigSilent analysis is used to reassess the current plan against any revised assumptions to ensure the plan efficiently and effectively addresses security, reliability, and capacity issues. Our network development plan, load forecasting and the development of the network capital investment strategies are discussed in greater detail in Section 5.

2.11.3 Network Performance Measurement

We use our ADMS to automatically calculate the SAIDI and SAIFI impact of supply interruptions caused by network faults occurring at 11kV and above. An interruption starts when the operation of protection equipment is time-stamped by the system. If the protection operation is not automatically timestamped, it is assumed to start when we are first advised of the outage. The ADMS subsequently tracks and timestamps the operation of all switching/protection equipment until supply is restored to all affected consumers. It then traces sections of the network that are disconnected from supply or reconnected by each switching operation and counts the ICPs affected by each operation. This allows the system to calculate the customer interruption minutes for each step of each event. THE ADMS uses this information to automatically determine total SAIDI and SAIFI for the interruption, based on the actual switching record created in response to the event. The Network Operations team performs daily checks of the system and reviews each event to ensure quality and accuracy of reporting is maintained.

Annual audits of interruption impacts are also carried out by an external auditor, as required by the Commerce Commission.

Network performance measurement and tracking is the responsibility of the Network Operations Manager. Monthly fault statistics, together with SAIDI, and SAIFI performance, are prepared for inclusion in the General Manager Network's monthly Board report.

2.12 Assumptions and Uncertainties

The network development plan and other asset management strategies described in this AMP are strategic and Top Energy's Board and executive management have endeavoured to ensure that, not only are they consistent with stakeholder expectations, but also that they are affordable and deliverable. A funding plan has been prepared and debt funding has been secured to ensure that Top Energy will be able to complete the investment programme described in this AMP.

Notwithstanding this, the strategies and action plans are predicated on a range of assumptions and, as with all major investment programmes, there are risks and uncertainties that may impact the timely completion of the action plans in the manner described in this AMP. These are discussed in Table 2.6 below.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
ELECTRICITY SALES	This AMP assumes that the forecast volume of energy delivered will materialise. The network development plan has been prepared on the basis that the cost of developing the network can be partly financed by revenue from electricity volumes delivered. If forecasts of delivery volumes are not met, then the funding available for new capital works will reduce.	We have developed a funding plan based on a combination of increased bank borrowings and revenues from electricity volumes delivered. This funding strategy is designed to keep increases in line charges as low as possible and ensure the costs are shared with future consumers, who will also benefit from our current investments.	The rate at which the plan is implemented may need to be adjusted if the revenues we assumed in developing the funding plan do not materialise. The connection of new block loads that are not provided for in this AMP may also change our network development plans. We will work with proponents seeking to connect new block loads to our network to meet their requirements in a cost-effective manner. Current indications are that the decline in electricity volumes delivered is now stabilising and we anticipate volumes will increase when the Ngapuhi Waitangi Tribunal claim is settled, and local iwi invest in initiatives that create employment opportunities for their whanau. Increased penetration of electric vehicles should also drive growth in delivery volumes although this could be offset by the installation of more small-scale photovoltaic generation
REGULATORY CONTROL	Regulatory controls will continue to encourage investment in infrastructure, asset replacement and maintenance of existing assets to provide target service levels and an adequate return on the investment.	The assumption aligns with the government's energy policy to encourage efficient investment in infrastructure.	Our network development plan can only be implemented in accordance with the schedule in this AMP if the line charge increases required to fund the investment are permitted by the Commerce Commission. The Commission has been supportive of our network development plan and we expect this support to continue.
110kV LINE PROPERTY RIGHTS	The property disputes will be resolved enabling the 110kV line between Wiroa and Kaitaia to be completed	The court will rule in Top Energy's favour.	Without a positive ruling the line build will be significantly delayed.
DIESEL GENERATION	The Electricity Authority will continue to allow us to own our diesel generation.	The Authority's exemption allowing us to own our diesel generation expires after 365 days and an extension is not guaranteed.	As required by the Authority, we have gone to tender for an external provider of network support services. If the tender is unsuccessful and our exemption is not extended, then the reliability of supply to our northern area will be significantly lower than indicated in this AMP. We think such an outcome is unlikely.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
DEMAND SIDE MANAGEMENT AND PEAK CONTROL	The industry and its regulators will continue to recognise the importance of demand side management and peak demand control, and retailers will offer pricing structures that penalise low power factor loads and discourage the use of electricity during times of peak demand.	Power systems must be designed to meet peak demand. Increased power system efficiency and minimisation of investment comes largely from minimising demand. Control of power factor is directly related to power system efficiency and is a demand side management tool. Losses and investment are minimised if power factors are close to unity and demands are controlled. Hence an industry structure that does not incentivise demand management will increase the required network capacity.	If our ability to effectively control peak load is reduced, we may need to increase the capacity of the parts of the distribution network to address voltage issues on long rural feeders. This would utilise funds currently budgeted for other activities. This medium-term risk is largely related to the uptake of electric vehicles. There will need to be incentives in place to encourage the charging of vehicles at times when the demand for electricity is low, if investment in the distribution network to accommodate new electric vehicle load is to be minimised.
ASSET CONDITION	Assumptions have been made in forecasting asset replacement and renewal expenditure beyond the first five years of the planning window. These forecasts have a high level of uncertainty.	The forecasts are largely based on defect rates gathered during routine asset inspections, together with adjustments as necessary to accommodate estimated changes in failure rates with changes in the age profile of assets in a specific category. Our adoption of the asset health indicators recommended by the Electricity Engineers' Association has improved our knowledge of the condition of our assets. This has been supported by the introduction of SAP, which has permitted the collection of more useful information on the condition of individual assets and has also allowed asset maintenance (including replacement and renewal) expenditure to be better targeted at assets known to require renewal or replacement.	Equipment failures cause approximately one third of our unplanned supply interruptions and 25% of our unplanned SAIDI. However, it is a fault cause that is difficult to target through a reliability improvement programme, since these faults occur anywhere on the network in a largely random fashion. Implementation of our network development plan and our reliability improvement initiatives has been designed to reduce the SAIDI impact of network faults and the installation of generators will result in further reductions. However, if renewal and reliability expenditure is insufficient to ensure that assets are renewed or replaced before they reach the end of their economic life, the fault frequency will increase, and these measures will be less effective in improving overall network reliability. That said, we are confident that the forecast asset replacement expenditure in this AMP is sufficient to prevent a deterioration in the overall health of our asset base.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
FAULT AND EMERGENCY MANAGEMENT	The weather is the biggest factor in fault and emergency maintenance. Storms that involve wind speeds greater than 75km/hr have been shown through post-fault analysis to have a significant effect on our network.	Post-fault analysis following major storm events.	Variability of weather conditions inevitability means there is volatility in the annually reported SAIDI and SAIFI. SAIDI and SAIFI targets presented in the AMP represent a trend line and year-on-year volatility around the trend is to be expected. Network reliability that was consistently worse than the target over a period of 3-5 years will indicate that further management intervention may be needed.
ELECTRIC VEHICLE CHARGING STATIONS	There is sufficient capacity in the existing network to accommodate installation of electric vehicle charging stations over the AMP planning period.	The network has spare capacity available and the uptake of electric vehicles over the AMP planning period is unclear.	We are not planning investment in charging stations. However, if uptake in electric vehicles is higher than anticipated, then some localised network augmentation may be needed to accommodate the additional load.
INFLATION	Except where otherwise shown, cost estimates in the AMP are presented in real New Zealand dollars in FYE2022. Where these cost estimates are expressed in nominal New Zealand dollars, an annual inflation rate of 2% is assumed for the whole of the planning period.	This is the mid-point of the Reserve Bank's long-term target consumer price index (CPI) inflation rate of 1-3%. Network cost increases are driven by increases in the cost of the labour skills required (which are generally in short supply) as well as changes in the cost of copper and aluminium. Historically, changes in network costs have not mirrored CPI and can be significantly higher, due to the highly skilled workforce required. Nevertheless, we see little point in attempting to develop a more accurate forecast, given the length of the planning period and the high levels of uncertainty in other elements of the AMP.	

Table 2.6: AMP Assumptions and Uncertainties

2.13 Asset Management Strategy and Delivery

2.13.1 Asset Management Strategy

The key objective of our asset management strategy is to provide reliability of supply expected by our consumers and to develop a network that meets the needs of network users when technologies that are currently emerging become mature. This is being done by:

- Securing a route for a second 110kV transmission circuit between Kaikohe and Kaitaia to increase the security of supply to consumers in the northern part of our supply area. Completion of a second circuit is still the only identified option using currently available technology that will fully meet the aspirations of network users over the longer term.
- Replacement of assets that require renewal as they near the end of their economic life.
- Incremental upgrades to the distribution network targeted at reducing the time required to locate a fault and then to restore supply to consumers not directly affected.
- Targeting vegetation management at trees that are a safety hazard and on those parts of the network where vegetation has the most impact on supply reliability.
- improving the efficiency of the maintenance effort by focusing on high SAIDI impact assets that are nearing the end of their economic lives and are therefore most likely to fail in service.

The detailed network development and lifecycle asset management plans in Sections 5 and 6 of this AMP describe how we are implementing this strategy.

Our strategy is consistent with the overarching corporate mission statement described in Section 2.2 and underpins the longer-term development of the economically depressed Far North region. While the bulk of the asset management capital expenditure has historically been on network development, our focus is now changing and expenditure on maintenance and, most particularly, asset renewal is increasing. Our maintenance management system is described in Section 2.9.7 and programmes for the proactive replacement of assets at risk of premature failure, due to accelerated deterioration or systemic design weaknesses, are described in Section 6.

2.13.2 Contingency Planning

Our control room staff are developing plans that document the optimal response to potential faults that would have a high SAIDI impact.

We also have a documented Emergency Preparedness Plan setting out processes for the response and management of serious incidents and events. We proactively anticipate and plan for foreseeable emergencies and this planning has resulted, for example, in the construction of a mobile substation and the installation of diesel generators.

2.13.3 Asset Management Implementation

The General Manager Network has overall responsibility for asset management implementation and controlling expenditure on network development and maintenance. Asset management procedures are documented in our ISO 9001 certified quality system and our NZS 7901 certified public safety management system.

Apart from 110kV asset maintenance and major zone substation construction, most work on the network is undertaken by TECS. A documented Service Level Agreement, discussed further in Section 2.15.4 and based on the asset manager-service provider model, define the roles and responsibilities of TEN and TECS. Project work is managed directly by TEN staff using standard project management processes while maintenance work is aggregated by TEN into maintenance work packages and passed to TECS for implementation. Asset inspections are undertaken by both internal and external resources.

2.13.4 Corrective and Preventive Action

Our ISO 9001 certified quality management system process defines the business processes in place for determining preventive and corrective actions. When an unexpected asset problem is identified the process owner undertakes a root cause analysis, determines appropriate corrective actions, and tracks these through to close-out. The process works well when a major incident arises. We continue to develop a culture that encourages our staff to proactively identify issues and implement incremental process improvements.

2.14 Information and Data Management

A mature process is in place for the management of GIS data, described in some detail in Section 2.10. Processes for the management of maintenance data in SAP have matured and we have specified measurement points and asset condition criteria for the different asset types. The quality of the data set is improving over time as assets are progressively inspected and data input specifications are refined and improved.

2.15 Asset Management Documentation, Controls and Review

We use the following documents and processes to control our asset management activities:

2.15.1 Asset Management Policy

Our documented network asset management policy, which is discussed in Section 2.4, underpins all our asset management effort. This network-specific policy is a component our ISO 9001 certified quality system and sits below the more generic asset management policy that relates to all assets managed by the Top Energy Group. The policy, while it has existed for some years, has only recently been integrated into our formal quality system.

2.15.2 Asset Management Plan

This AMP is the document central to the implementation of our asset management system and meets the requirement of ISO 55000 for an organisation to have documented asset management plans. The AMP is also consistent with the structure of the standard, in that Section 2 covers strategic issues in some detail and Sections 5 and 6 provide the detailed action plans derived from these strategies.

We have qualitative objectives derived from the corporate mission statement and these are discussed in detail in Section 2.5, but we still need to develop a formal process for evaluating how well we are achieving these. This could mean developing quantified measures that we can use to track the progress we are making towards those objectives described in Section 2.5 that we consider most critical to achieving our corporate mission.

The quantified supply reliability indicators set out in Section 4 of this AMP are central to our overarching asset management strategy, in that all our asset management activities are designed to ensure that our consumers receive a quality of supply that matches their needs and expectations. We have also developed quantified measures to cover performance in other areas, including health and safety. In addition, we have developed leading indicators of our asset management performance – these include indicators relating to the completion of planned asset inspections and defect management backlogs.

2.15.3 Annual Plans

Annual plans are prepared for maintenance, vegetation management and capital works delivery. These describe the work programmes and budgets for the first year of the AMP planning period. These are based on the approved budget in the AMP but include more detail. For example, the vegetation management plan identifies the actual feeders that will be targeted by the vegetation management effort in a particular year.

2.15.4 Service Level Agreement

The service level agreement (SLA) between TEN and TECS is integral to the implementation of the action plans set out in this AMP. The SLA, which was updated in February 2020:

- Defines the relationship between the two business units, based on an asset manager–service provider model.

- Specifies the different responsibilities of the two parties.
- Defines key performance indicators that measure the extent that each party fulfils its obligations.
- Specifies the information that TEN must provide to TECS and when it is to be provided.
- Details the TECS service response to cover the delivery of the annual work programme in accordance with agreed targets.

All planning of capital works, asset inspections and maintenance requirements is undertaken by TEN. The resulting design and delivery documentation from TEN enables TECS to develop an annual work programme and to ensure that it the appropriate resources are available to efficiently undertake the required work.

2.15.5 Documentation of the Asset Management System

Our quality management system was certified as compliant with ISO 9001 early in FYE2016. This system documents many processes and procedures relevant to asset management and in particular the implementation of this AMP.

2.15.6 Legal Compliance Database

The General Manager, Corporate Services is responsible for ensuring Top Energy meets its legal obligation and maintains relevant records through a database that can automatically email staff responsible for legal compliance. The database does not capture changes to technically focused regulations, such as the Safety Rules, but the General Manager Network and his staff monitor such changes through their membership and engagement with relevant industry bodies and respond as necessary. Our decision to suspend live-line work is an example of this. We are confident that any change in a law or regulation that impacts the way we manage our network assets will be identified and actioned in a timely manner.

2.15.7 Audit

Our NZS 7901 certified public safety management system and an ISO 9001 certified quality system both require independent external audit. These systems strengthen our internal auditing of our asset management activities and the field activities undertaken by TECS and our contractors.

2.15.8 Continual Improvement

There is a commitment to continual improvement within TEN and the wider Top Energy Group. The successful introduction of our public safety management system, and the ISO certified quality management system that we are not required by regulation to introduce, is testimony to our ongoing improvement culture. This is driven by our Board and executive management team.

The preparation and ongoing improvement of this AMP is accorded a high priority with input from the Board to provide the strategic direction at an early stage of its development. We have engaged an external consultant with a good knowledge of our network to help prepare this AMP. This enables us to prepare and fully update a comprehensive document.

2.16 Communication and Participation Processes

2.16.1 Communication of the AMP to Stakeholders

Our SCI identifies this AMP as the defining document for the management of our network and all senior managers within TEN are involved in its preparation.

We actively encourage external stakeholders to review and comment on the content of the AMP. We distribute the final AMP widely within the organisation, publish the AMP online at our website, and provide a copy in the reception of our head office in Kerikeri for anyone to view. We are also happy to provide a printed copy on request.

2.16.2 Management Communication and Support

Our executive management has undertaken a formal engagement process consulting both internal and external stakeholders and through this process, we have gained an understanding of stakeholder expectations regarding the reliability of their electricity supply. We sought feedback on our network development plan and communicated the need for increased line charges to fund network improvements. We have gained broad acceptance of the network development plan described in this AMP from those involved in the consultation.

External communication of our asset management plan has largely focused on vegetation management and the total cost of our network investment programme. Vegetation management is easily understood by consumers, as it is visible and its impact on improving reliability is well known. Communicating the cost of our network investment programme signals to stakeholders the improved service delivery that is to be expected over time and the reason for our price increases.

Going forward, the Board and senior management have committed to communicating more openly about other elements of our asset management and in particular our maintenance initiatives.

2.16.3 Communication, Participation and Consultation

Ongoing communication of asset management issues with external stakeholders, by the CEO and TEN's senior managers, continues to support our operational and organisational objectives. Top Energy has also upgraded its website to include a video on the future of energy in our supply area and real time information on planned and unplanned interruptions to supply.

Communication with Top Energy employees occurs regularly through CEO presentations to staff at head office and depots, as well as in team meetings. The CEO also presents to stakeholders, community organisations and media to convey key information, including our network investment and asset management programme.

2.17 Capability to Deliver

The investment programme described in this AMP continues to be strategic. We developed this programme in consultation with our local community and with the full support of the Trust, the Board of Directors and the Executive Management Team. Top Energy and its shareholder have demonstrated an ability to successfully undertake challenging projects for the benefit of our stakeholders. The successful construction, commissioning and operation of OEC4 at Ngawha Power Station with the involvement of local iwi is testimony to this.

In addition, much has already been achieved in the delivery of our network development programme. In particular:

- We have constructed a double circuit 110kV line between Kaikohe and Wiroa (which currently operates at 33kV), a new 33kV switching station at Wiroa, and new zone substations at Kerikeri and Kaeo. A section of one of the circuits of this line now operates at 110kV and forms part of the connection between OEC4 at Ngawha and the grid
- We have replaced several structures on the 110kV line between Kaikohe and Kaitaia and installed a new 110/33KV power transformer at Kaitaia.
- We have rebuilt or upgraded older zone substations at Moerewa, Kawakawa and Omanaia, and installed a new 33kV indoor switchboard at Kaikohe.
- We have installed and commissioned 17.2MW of diesel generation at Taipa, our Kaitaia construction and maintenance depot, a new generator farm in Bonnetts Rd, Kaitaia and at Omanaia and Pukenui substations to increase the resilience and reliability of our network.
- We have upgraded the protection systems on the core 33kV subtransmission network, so that subtransmission assets can be operated in parallel, which allows supply to be seamlessly routed around faulted subtransmission network assets with no impact on consumers. This seamless N-1 redundancy is now provided at Okahu Rd, NPL, Kaikohe, Kerikeri, Waipapa, Haruru, Kawakawa and Moerewa zone substations.

- We have installed a new, largely underground 11kV feeder between Paihia and Opua to provide an alternative 11kV supply to the Russell peninsula, should a fault occur between Kawakawa and Okiato Point on the Russell Express feeder.
- We have installed new 33/11kV zone substation at Kerikeri and Kaeo to accommodate load growth in the fastest developing part or our supply area and improve reliability by reducing the length and number of connected consumers on each distribution feeder.

The challenges in delivering the additional projects and programmes described in the AMP include:

- Financing.
- The ability to secure line routes.
- Engineering.
- Construction.

These are each discussed in the following sections.

2.17.1 Financing

As result of our investment in network assets through the implementation of our network development plan, the disclosed regulatory value of our network assets has increased from $97 million on 31 March 2004 to $280 million on 31 March 2020.

With the help of external consultants, Top Energy maintains a financing plan to fund our ongoing investment programme. This includes:

- revenues from line charges; and
- increased bank borrowings.

There is a fine balance between the ability to increase line charges so that they are affordable to our consumers and the level of debt that represents sustainable long term borrowing. A limiting constraint can be when the actual financing rate received from lenders is higher than the regulatory WACC inputs, especially in this low interest rate environment.

2.17.2 Engineering

The design of the network development works within this AMP requires specialist engineering skills and resources, which are outsourced where these are not available internally. These costs are included in our estimated project costs.

2.17.3 Construction

Construction of the works described in this AMP is undertaken by TECS where it has the skills and resources available. In general, line construction and cable laying is undertaken internally, while the construction of new substations is outsourced.

2.18 Public Safety Management Issues

The passing of the Health and Safety at Work Act 2015 has raised awareness of the risk that the operation of an electricity network can create for the general public and the liability of the company and its directors if they fail to take reasonable precautions to mitigate these risks. We have reviewed the safety of our network in response to the Act and identified two significant issues that are discussed below.

2.18.1 Single Wire Earth Return Lines

The single wire earth return (SWER) system was invented by Lloyd Mandeno, who was the consulting electrical engineer engaged by the Bay of Islands Electric Power Board to set up the original electricity supply system in our area. Consequently, SWER lines were used extensively in the original reticulation of our area and many such lines remain. However, the load is now getting too high for SWER lines in some areas.

SWER lines also pose a public safety risk because, unlike two and three wire lines, the earth system carries the full load current. If the earth resistance is too high, the earth potential can rise to hazardous levels creating a risk of shock and possibly death to persons and stock that come into contact with our primary assets. While we design and install SWER earthing systems to mitigate these risks, for example by ensuring the resistance is low when an earth connection is installed and encasing earth wires in conduit where they are accessible from the ground, such precautions cannot be relied on to provide complete protection. We have undertaken an inventory of our SWER lines to identify those lines that pose an excessively high public safety risk and should be upgraded to two- or three-wire. Funding to commence this work has been provided for in our expenditure forecast. We now also require any new consumer wanting to connect to our SWER network must install a two-wire line so that when we upgrade, we do not have to fund the cost of upgrading that consumer's private line.

2.18.2 Private Lines

Many of the private lines in our area are in poor condition. These lines are not regularly inspected and there are no systems in place for ensuring they are maintained in a safe condition. The Commission's view is that this is not our role and we are therefore unable to fund such inspections. It is the line owner's responsibility to ensure that they are maintained in a safe condition.

Top Energy's preference is to assume ownership of newly installed 11kV service lines to prevent the situation in the future. Existing service lines are progressively fused and labelled when the opportunity arises.

Section 3 Assets Covered

3 Asset Description

3.1 Overview

3.1.1 Distribution area

Top Energy owns and manages the northern-most electricity distribution network in New Zealand, covering an area of 6,822km^2. The area is bounded by both the east and west coasts, and the territorial local authority boundary of the Far North District Council in the south.

Most of our supply area is rural. There is no single dominant urban area, and urban development is spread amongst several small towns with populations between 1,000-7,000 people and numerous smaller settlements. Coastal settlements, especially on the eastern and north-eastern coasts, are growing at a faster rate than the district average. Most inland towns, including Kawakawa, Moerewa and Kaikohe, have relatively static or, in some instances, declining populations.

Our supply area is separated by the Maungataniwha Range into two distinct geographic areas. The northern area, which includes Kaitaia, Taipa and the Cape Reinga peninsula, is supplied from our 110kV Kaitaia substation located at Pamapuria, approximately 10km east of Kaitaia. The larger and more populous southern area, which includes Rawene, Kaikohe, Kawakawa, Moerewa and the coastal towns of Kaeo, Kerikeri, Paihia and Russell, is supplied from the 110kV Kaikohe substation and grid exit point (GXP). A single circuit 110kV line owned by Top Energy connects the two substations; there is currently no other 110kV or 33kV interconnection between the two areas.

Compared to New Zealand as a whole, our distribution area is notable for the high proportion of people who are unemployed or on low incomes. The average quantity of electricity supplied to each active connection point is the second lowest in the country.

3.1.2 Network Characteristics

Electricity from the national transmission grid is delivered to our Kaikohe substation through a double circuit 110kV Transpower-owned transmission line supplied from Maungatapere. Electricity from our 57MW Ngawha geothermal power station, situated about 7km Southeast of Kaikohe, is also delivered to Kaikohe though one 110KV and two 33kV subtransmission circuits. We supply our northern area from Kaikohe through our 110kV Kaikohe-Kaitaia line.

A 33kV subtransmission network delivers electricity from our Kaikohe and Kaitaia 110kV substations to 13 zone substations - four in the northern area and nine in the southern. These zone substations supply 60 distribution feeders that operate at 11kV (except for a section of the Rangiahua feeder that has been uprated to 22kV). In rural areas, many spur lines fed from the three-phase distribution feeder backbones are two wire single phase or single wire earth return (SWER).

The distribution feeds supply distribution transformers that convert the electricity to the low voltage (LV) for supply to consumers. Our LV distribution is at 400V three-phase, 460/230V two-phase and 230V single phase.

We have now installed a total of 17.2MW of diesel generation to increase our network resilience. This can supply all small use consumers in our northern area when the incoming 110kV circuit from Kaikohe is out of service.

We purchased our Kaikohe and Kaitaia 110kV substations, and the 110kV interconnecting line between the two substations from Transpower on 1 April 2012. As these assets are no longer part of the national grid, we can incorporate them into an integrated development plan that will more efficiently meet the long-term needs of our consumers. Our double circuit 33kV line between Kaikohe and Wiroa has been built to 110kV construction to form part of a 110kV ring, which will provide a high-capacity network backbone interconnecting the Kaikohe, Kaitaia and Kerikeri load centres. A section of one circuit of this line has already been energised at 110kV to provide a connection between the newly commissioned OEC4 generator at Ngawha and the Kaikohe 110kV switchyard.

During FYE2020, we supplied an average 32,537 active connections. The maximum demand on our network was 71MW and the total energy delivered to consumers was 329GWh.

3.1.3 Grid Exit Point

Our one GXP is the termination of the Transpower 110kV Maungatapere-Kaikohe double circuit line. Transpower retains ownership of the two 110kV circuit breakers at Kaikohe that terminate these circuits. Each incoming 110kV circuit has a winter rating of 77MVA. Generation from Ngawha reduces the loading on these circuits.

3.1.4 110kV System

There are two single-phase 110/33kV transformer banks at Kaikohe: one rated at 30MVA and the other at 50MVA. At current loads, support from our Ngawha geothermal power station would be required should the larger of these transformer banks be out of service at times of peak demand.

The 110kV circuit between Kaikohe and Kaitaia has a winter rating of 68MVA, which is sufficient to supply the foreseeable Kaitaia load, so the existing network constraint between Kaikohe and Kaitaia is one of security rather than capacity. However, as discussed in Section 5.11.2.2, we have recently had applications to connect utility scale solar farms in the Kaitaia area to our network and the 55MVA summer rating of this line will constrain the amount of electricity from these developments that can be exported south.

At Kaitaia, there is a newly installed three-phase transformer rated at 40/60 MVA. There is also an older transformer bank of single-phase units with a rating of 22MVA, which is insufficient to supply the total load at times of peak demand. Should the larger transformer fail, which is unlikely as it is new and lightly loaded, we will use our diesel generation to ensure that the smaller transformer bank is not overloaded at times of peak demand.

3.1.5 33kV Subtransmission System

We have two 33kV subtransmission networks, one serving our northern area and the second serving the south, supplied from our Kaitaia and Kaikohe 110kV substations respectively. The outdoor 33kV switchyard at Kaikohe was replaced in FYE2015 with a new indoor switchboard.

Our 33kV subtransmission networks and the locations of the zone substations they supply are shown geographically in Figures 3.1 and 3.2 below. Approximately 94% of our subtransmission system is overhead. Underground cable is used within substations or on new circuits when an overhead line route is not available.

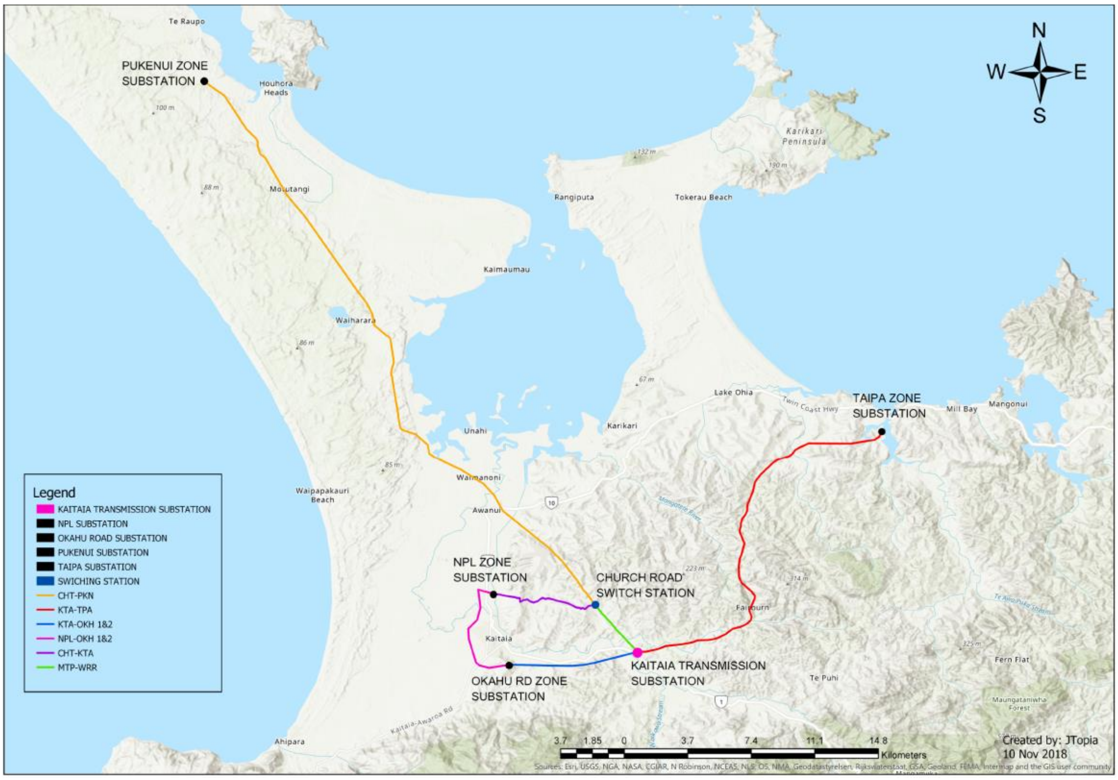


Figure 3.1: Subtransmission Network – Northern Area

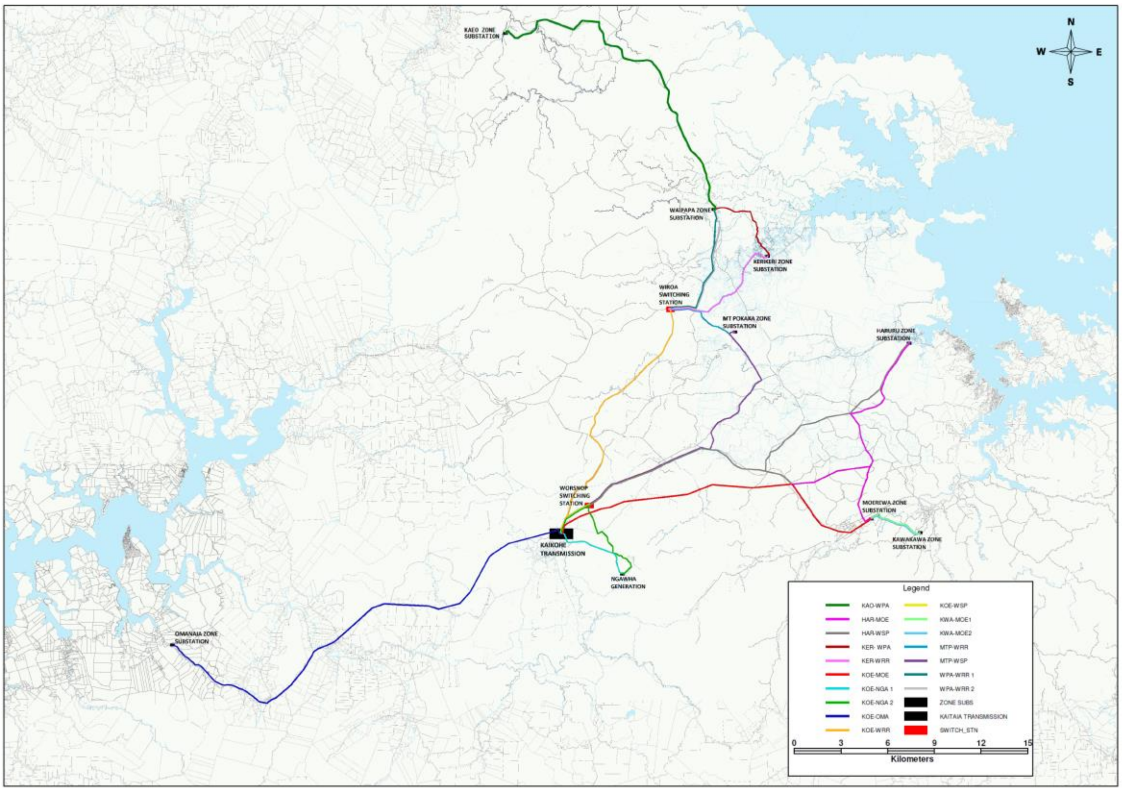


Figure 3.2: Subtransmission Network – Southern Area

Table 3.1 below shows the transformer capacity at each zone substation. The limiting factor that determines transformer capacity is the temperature of the transformer oil. Most transformers are fitted with radiators for air cooling; the capacity of a transformer is increased if the transformer is fitted with fans to force air through the coolers (air forced or AF) or with pumps to pump oil through the radiators (oil forced or OF), rather than rely on natural circulation. Most transformers, therefore, have two ratings, one for natural cooling and a higher one if forced cooling is used.

SUBSTATION	UNIT	NOMINAL RATING (MVA)	MAXIMUM CAPACITY (MVA)
Southern Area			
Kaikohe	T1	11.5/23	17[1]
	T2	11.5/23	17[1]
Kawakawa	T1	5/6.25	6.25
	T2	5/6.25	6.25
Moerewa	T1	3/5	5
	T2	3/5	5
Waipapa	T1	11.5/23	23
	T2	11.5/23	23
Omanaia	T1	3/5	5
Haruru	T1	11.5/23	23
	T2	11.5/23	23
Mt Pokaka	T1	3/5	5
Kerikeri	T1	11.5/23	23
	T2	11.5/23	23
Kaeo	T1	5/10	10
	T2	5/10	10
Northern Area			
Okahu Rd	T1	11.5	11.5
	T2	11.5	11.5
Taipa	T1	5/6.25	6.25
Pukenui	T1	5	5
NPL	T1	11.5/23	23
	T2	11.5/23	23

Note 1: The transformer would need to be fitted with oil pumps to deliver its full force-cooled rating. These are not required to supply the current peak demand.

Table 3.1: Zone Substation Security

Now that we have diesel generation available to provide network support in addition to our feeder transfer capability, we have developed our transmission and subtransmission networks to the point where, following a single element interruption, we can restore supply to all but two large consumers, either uninterrupted or after a short interruption of less than one hour. The two consumers where this does not apply have accepted a lower level of security. The security level we now provide at individual substations is discussed in detail in Section 5.1.2.

We also have a 33/11kV, 7.5MVA mobile substation that can be relocated within 12 hours, in the event of a transformer failure at one of our single transformer substations. While we now have diesel generation available at all but one of these substations, the availability of the mobile substation avoids the need for this generation to be run for extended periods. The mobile substation is current located at Mt Pokaka, where it provides backup to the permanent transformer.

3.1.6 Diesel Generation

The locations and capacities of the diesel generation connected to our network are shown in Table 3.2.

Location	No of Units	Rated Capacity (MW)	Comment
Pukenui substation	1	1	Provides support to the northern area when the 110kV line is out of service, and also provides local substation support when the transformer or incoming line is out of service.
Bonnetts Rd	8	8	Bonnetts Rd is a standalone generator farm 2km west of Kaitaia. These generators provide support to the northern areas when the 110kV line is out of service.
Kaitaia depot	3	3	Provide support to the northern area when the 110kV line is out of service.
Taipa substation	2	3.2	These unit were installed in FYE2014 to provide local support when the transformer or incoming line is out of service. They also provide support to the northern area when the 110kV line is out of service.
Omanaia substation	2	2	These are the only diesel generators in our southern area. They provide local support when the incoming 33kV line or transformer is out of service.
Total	**16**	**17.2**	

Table 3.2: Diesel Generation Installed for Network Support

3.1.7 Distribution Network

Our distribution system consists of 60 predominantly rural feeders which are 93% overhead. Underground cable is used in commercial areas and newer subdivisions. The system operates at 11kV, except for 20km of the Rangiahua feeder, which has been upgraded to 22kV. Figures 3.3 to 3.15 show the extent of the distribution system supplied from each of our zone substations.

The distribution network supplies approximately 6,100 transformers, which are of three types:

- Distribution transformers, which provide the low voltage supplied to consumers.
- Step-up transformers, which form the interface between the 22kV section of the Rangiahua feeder and the 11kV distribution network.
- Isolating transformers, which connect SWER lines to the core 11kV distribution network.

Notwithstanding our extensive LV cabling, 83% of distribution transformers are pole mounted, although pole mounting of transformers is now limited to ratings up to 100kVA due to seismic limitations. Ground mounted transformers are generally enclosed in steel cabinets, which may also house 11kV switches depending on the application. Only five distribution transformers, which are not installed within consumer premises, are located within purpose-built substation buildings.

Figures 3.3 – 3.15 below show the coverage of the distribution feeders supplied from each of our zone substations. Not shown are four feeders supplying the Juken Nissho tri-board mill from the NPL substation.

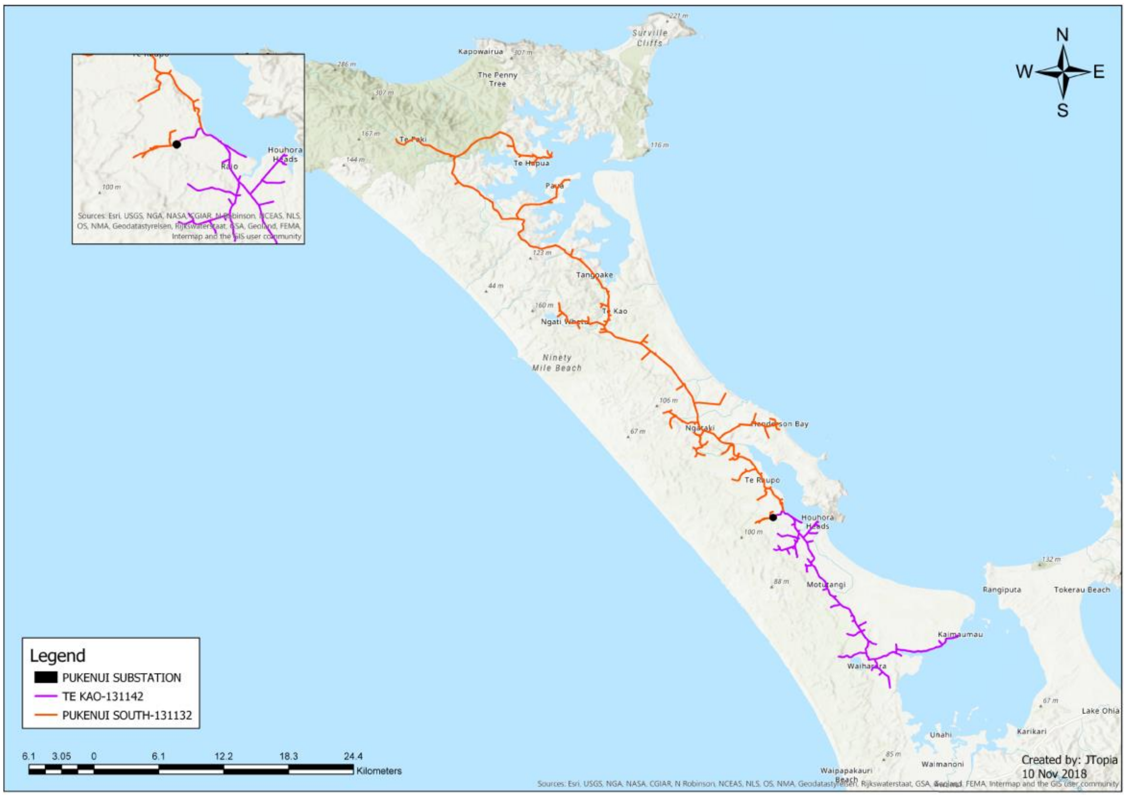


Figure 3.3: **Geographic diagram of the Pukenui zone substation**

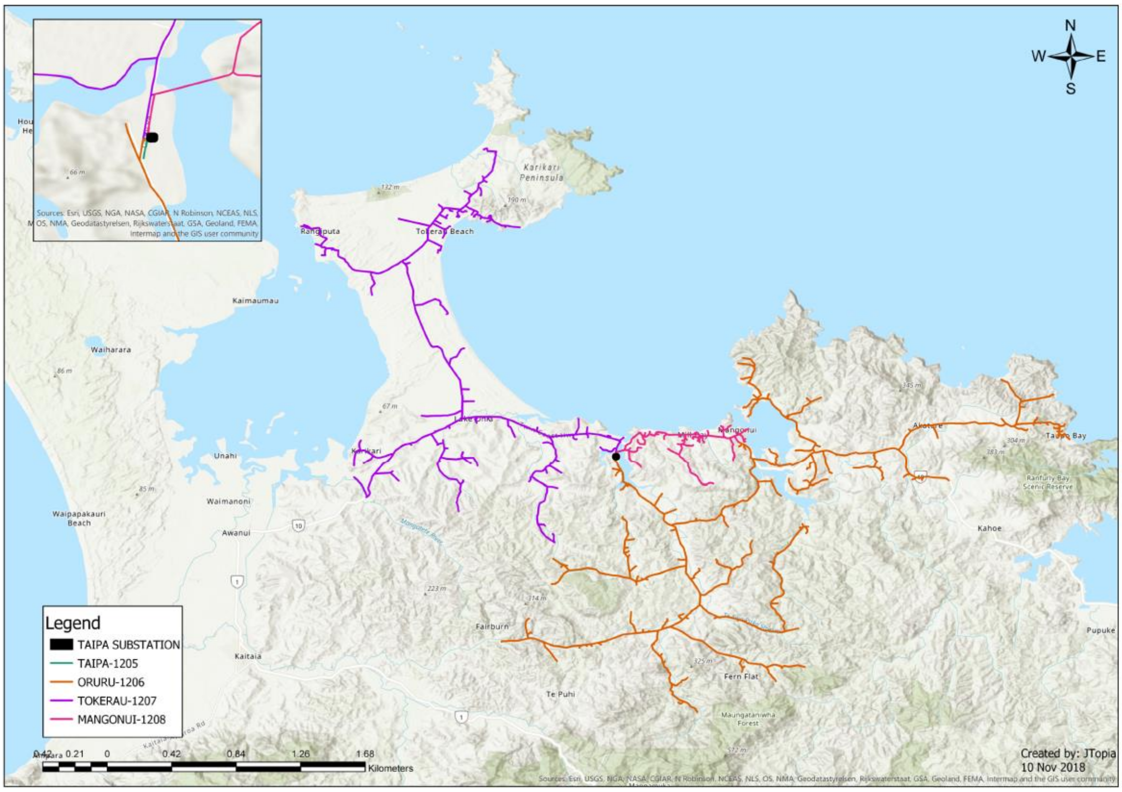


Figure 3.4: **Geographic diagram of the Taipa zone substation**

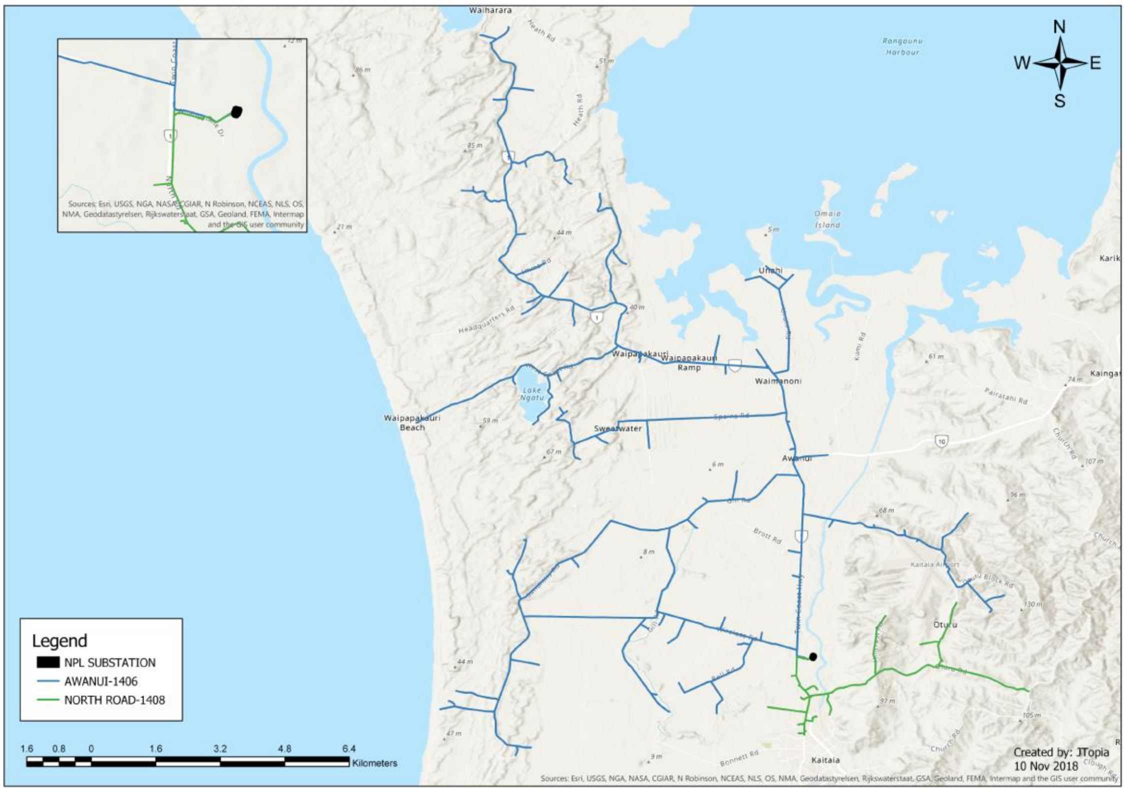


Figure 3.5: **Geographic diagram of the NPL zone substation**

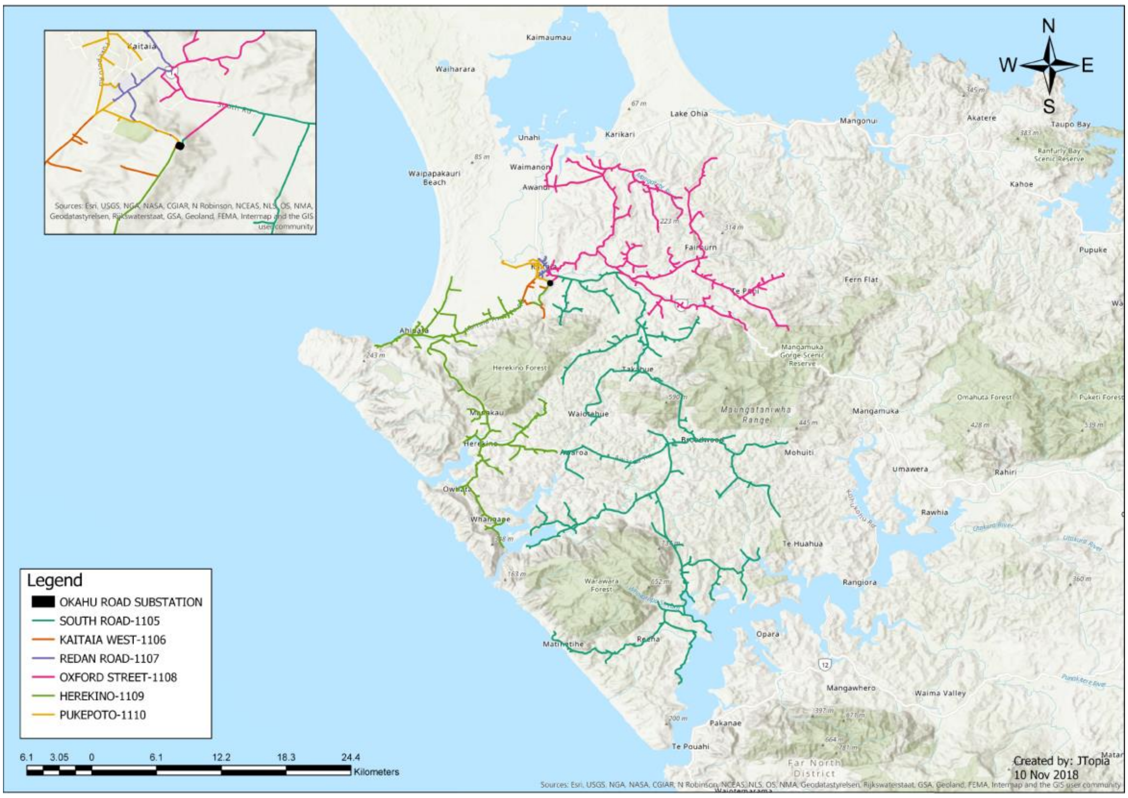


Figure 3.6: **Geographic diagram of the Okahu Road zone substation**

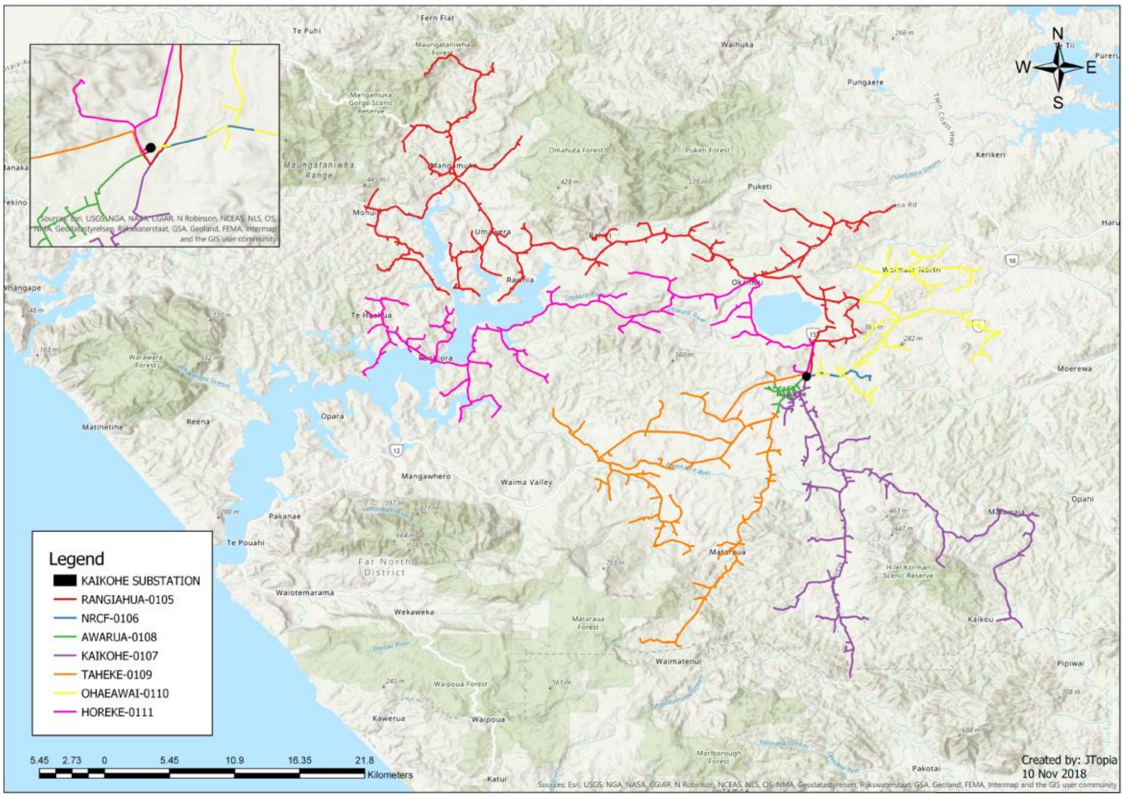


Figure 3.7: Geographic diagram of the Kaikohe zone substation

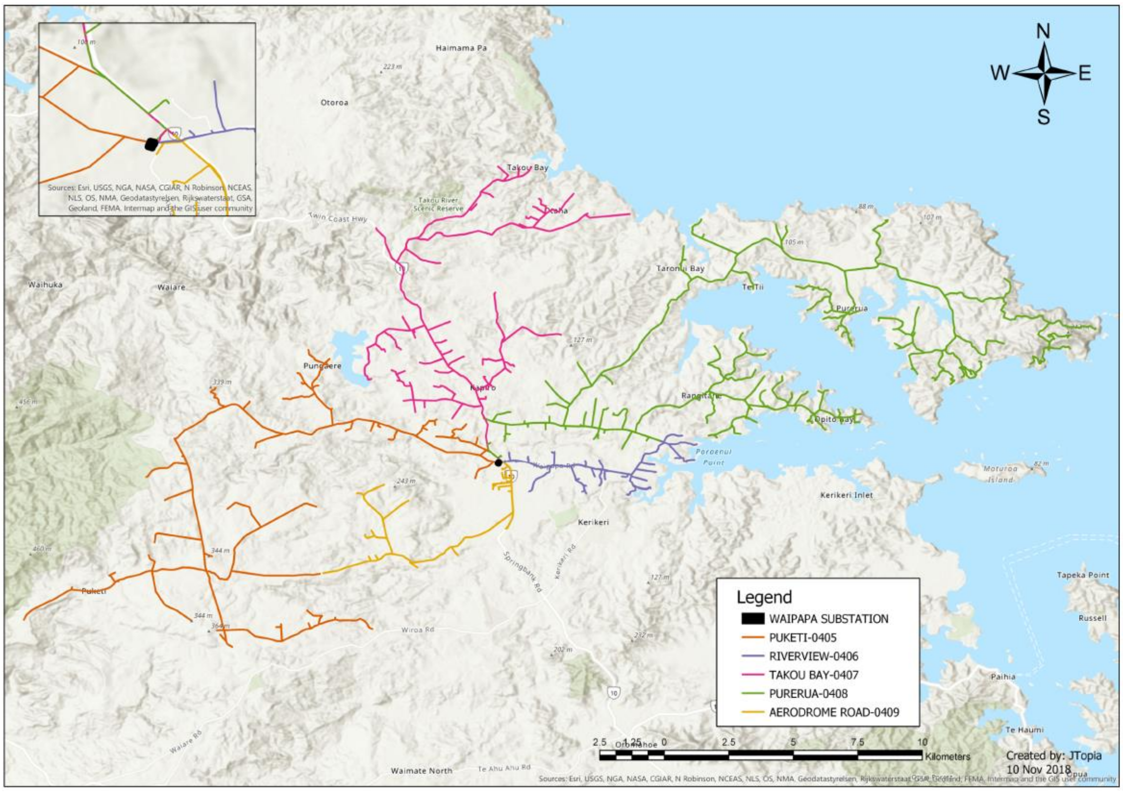


Figure 3.8: Geographic diagram of the Waipapa zone substation

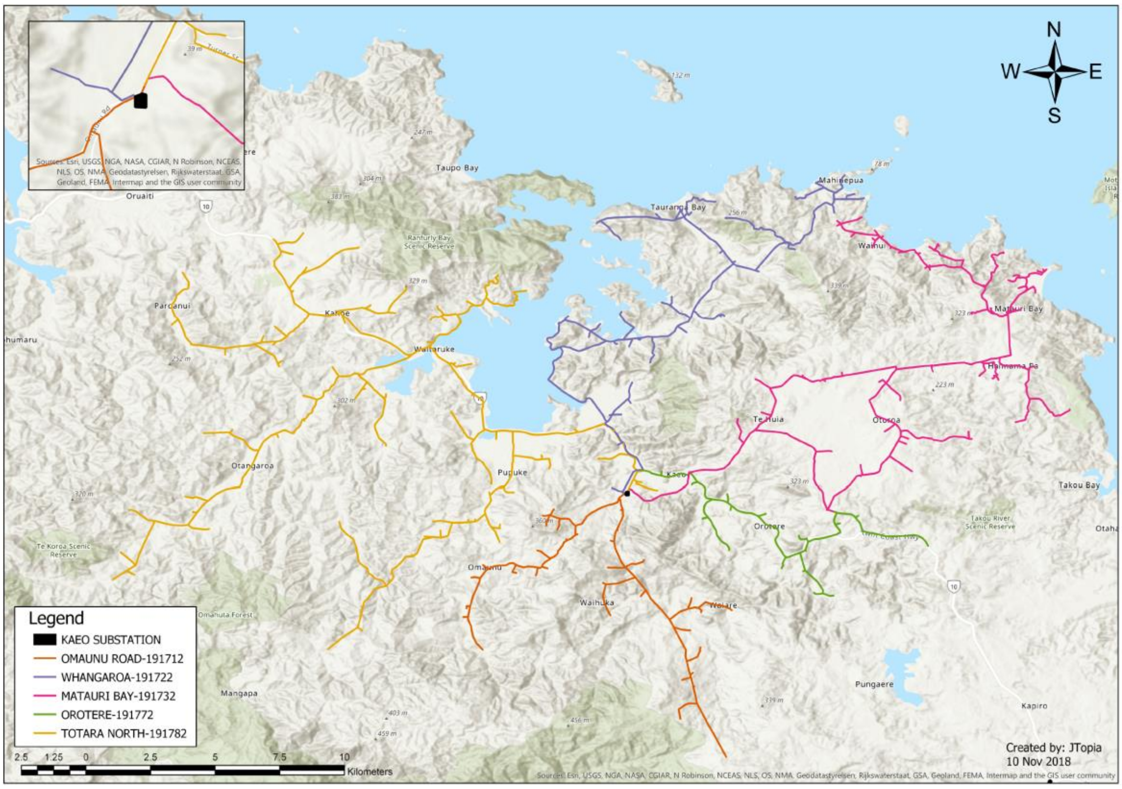


Figure 3.9: **Geographic Diagram of the Kaeo Substation**

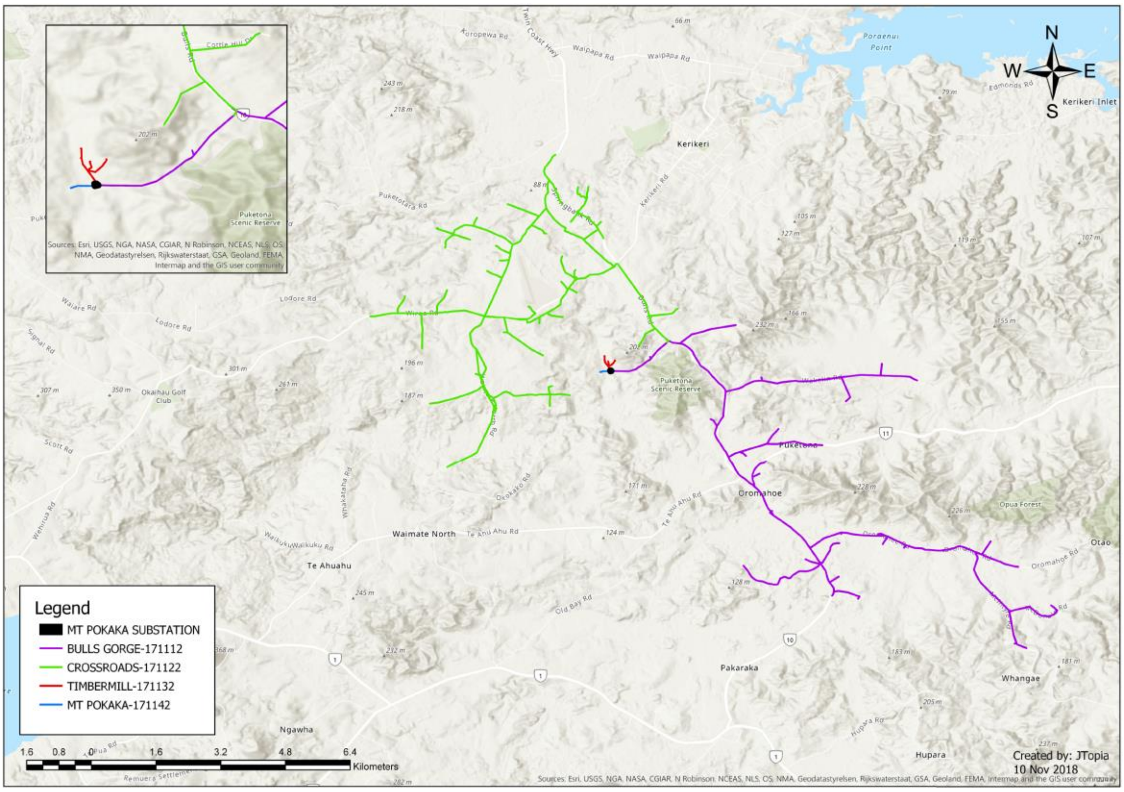


Figure 3.10: **Geographic diagram of the Mt Pokaka zone substation**

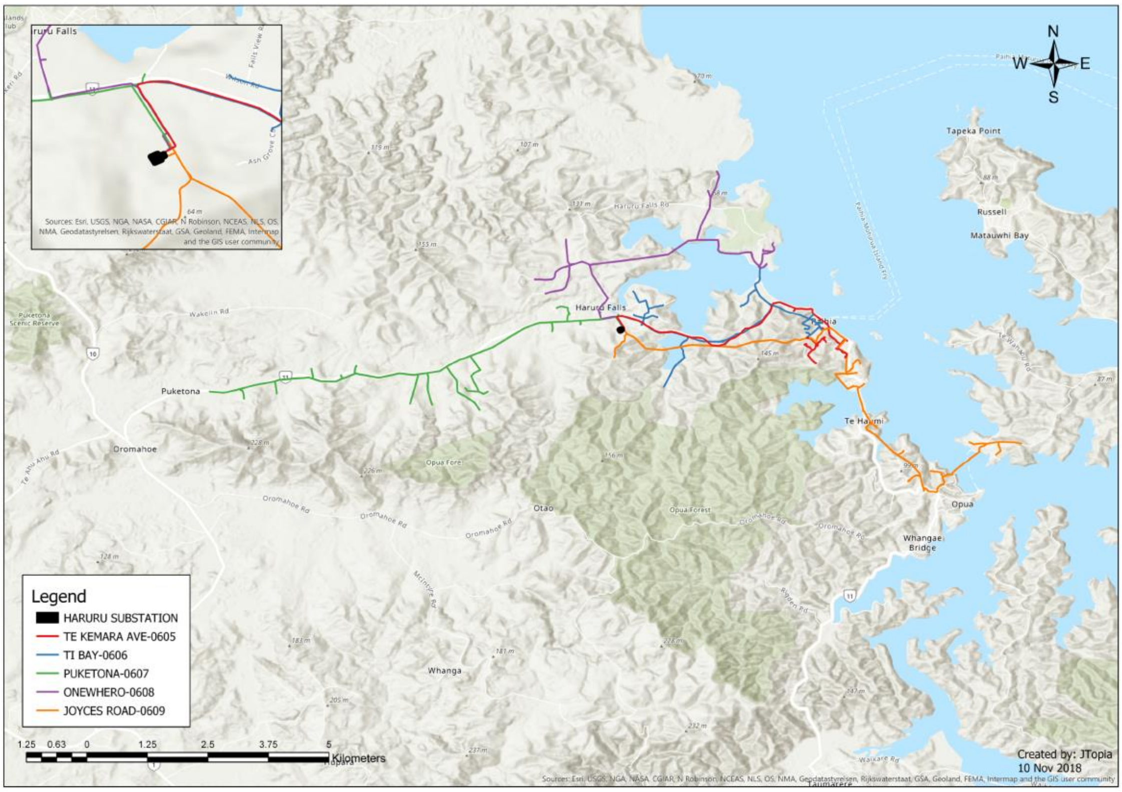


Figure 3.11: Geographic diagram of the Haruru zone substation

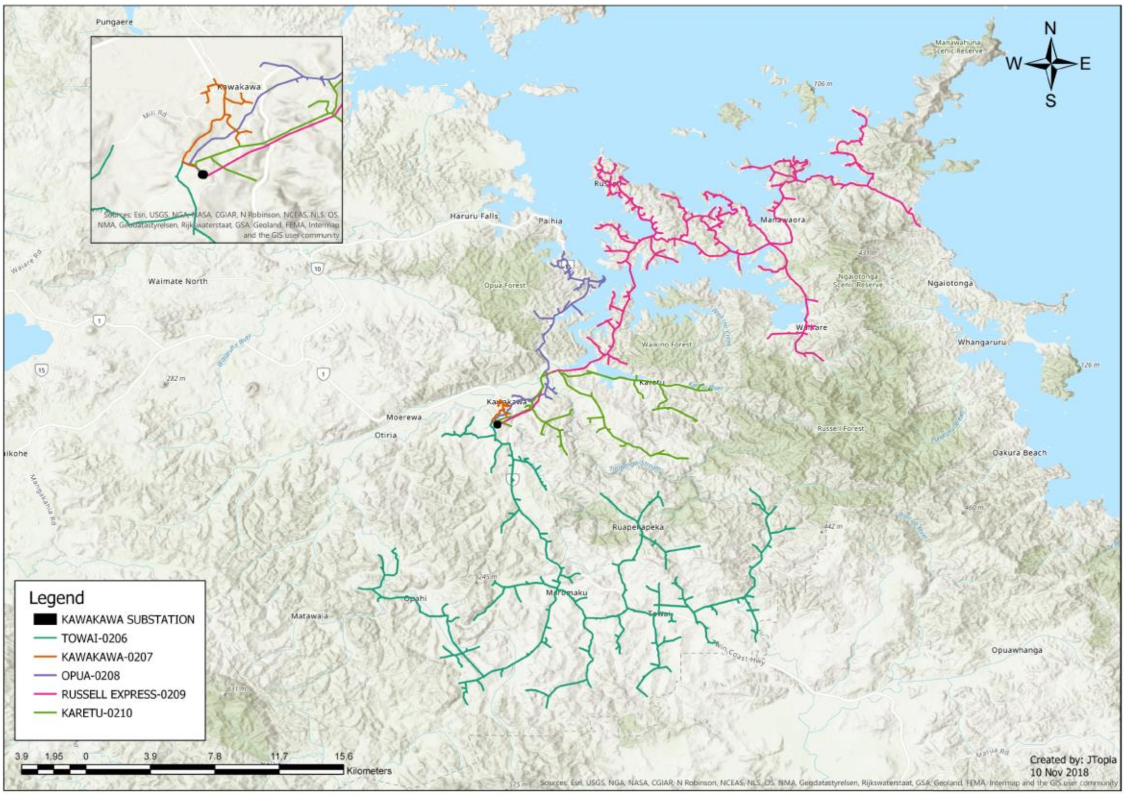


Figure 3.12: Geographic diagram of the Kawakawa zone substation

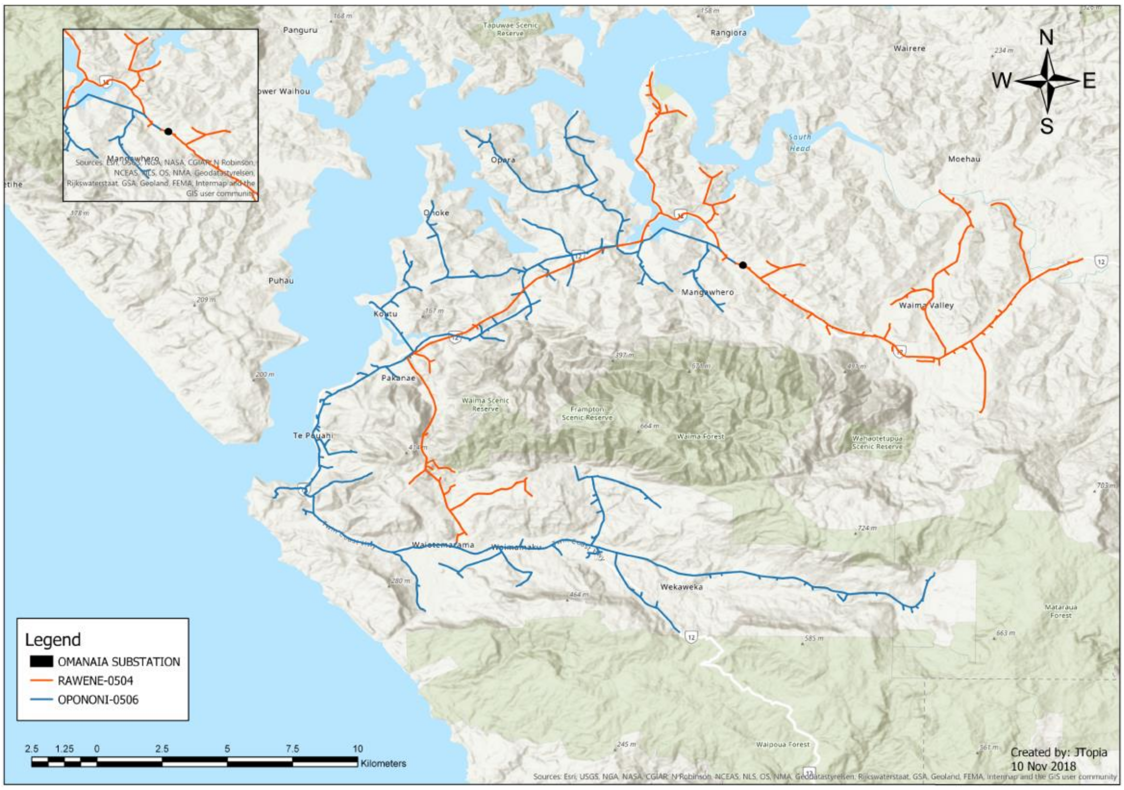


Figure 3.13: Geographic diagram of the Omanaia zone substation

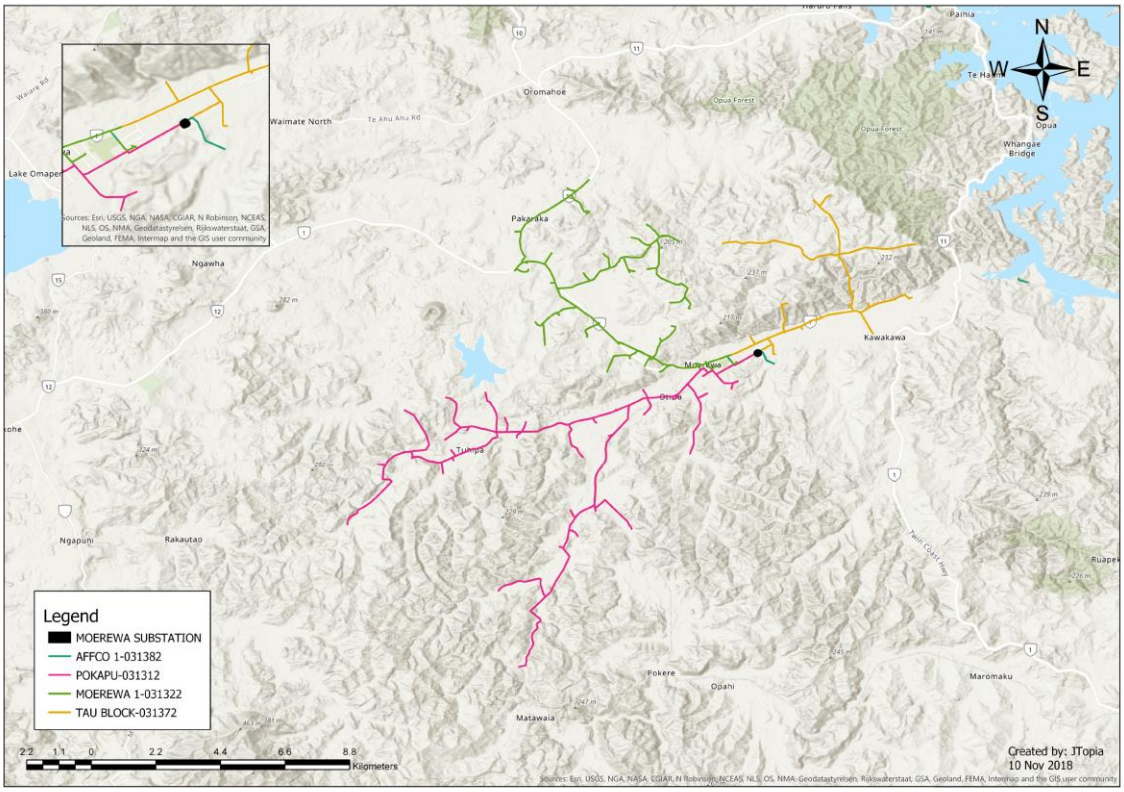


Figure 3.14: Geographic diagram of the Moerewa zone substation

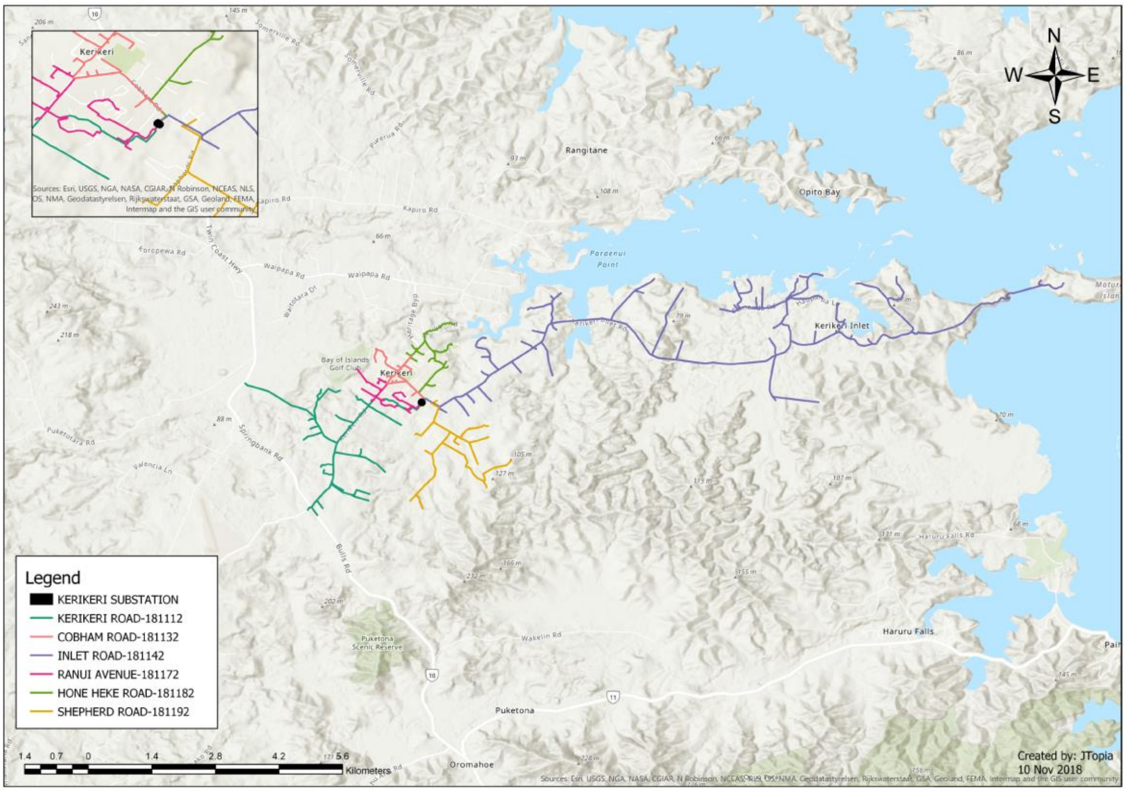


Figure 3.15: Geographic Diagram of the Kerikeri Zone Substation

3.1.7.1 Submarine Cables

Or distribution network includes two 11kV submarine cables, both feeding the Russell Peninsula. The first cable is laid across the Waikare Inlet and is a three-core, 70 mm^2 copper cable around 1.5 km long and was livened in 1975. It has been through 45 years of its nominal 70-year economic life.

The second cable is across the Veronica Channel between Opua and Okiato Point and is a single circuit three core, 150 mm^2 copper cable, livened in 2007.

There are also two consumer-owned 11kV submarine cables supplying islands within the Bay of Islands.

3.1.8 Low Voltage

Low voltage can be supplied at 400V three phase, 460/230V two phase or 230V single phase, although three-phase is not available to consumers supplied from a two-wire 11kV spur line or a SWER line.

For more than 40 years, we have required new developments and subdivisions to be underground, which has resulted in a high percentage of underground distribution at LV level and a corresponding low level of LV faults. Most LV road crossings are also underground. Our preferred LV arrangement in urban areas is looping between network pillars. This allows for the rapid identification and sectionalisation of the system in the event of localised network faults. There are limited interconnections available between transformers at low voltage (LV) level, except in the Kaikohe, Kaitaia, Kerikeri, Russell and Paihia urban areas.

3.1.9 Protection Assets

We use a mixture of protective devices including:

- Electromechanical and electronic relays.
- Numerical relays.
- Integrated protective devices such as fuses, pole top reclosers and sectionalisers.
- Indoor and outdoor circuit breakers with either local or remote-control functionality.

These devices are used to detect and isolate a fault as quickly as possible to maintain public safety and ensure that damage is minimised. Protective devices that carry the full load current (including fuses, reclosers and circuit breakers) are considered primary assets, whereas protection relays, which function using measured values of current and voltage, are classified as secondary assets.

Our network is on the fringe of the transmission grid and is characterised by very low fault currents. This affects the reliability of protection; particularly where traditional electromechanical protection relays are used. We have replaced the electromechanical protection relays in most zone substations and have also installed fibre-optic cable on most 33kV subtransmission lines, so that these lines now have differential protection, which continuously compares the current entering and leaving a circuit and is more effective in situations where the fault current is low. This allows the subtransmission lines and transformers at a substation to be operated in parallel, so that a single subtransmission fault will not result in a supply interruption.

3.1.10 SCADA and Communications

We use a GE PowerOn Advanced Distribution Management System (ADMS) to monitor the state of our network in real time and allow key network assets including 110kV and 33kV circuit breakers as well as sectionalisers and reclosers located in the field to be remotely controlled from our network control room in Kerikeri. This also incorporates an outage management system that combines real time inputs on the state of the system with connectivity data from our GIS to predict the location of faults and automatically calculate the SAIDI and SAIFI impact of supply interruptions. It also generates switching schedules to support the control room operators in the management of network outages.

The architecture consists of distributed data collection and operation via an Ethernet wide area network (WAN). Communication is usually direct with protection and measurement transducers in zone substations, and high voltage switching device locations. The systems include:

- Microwave link equipment operating at speeds from 256kB up to 10MB from each control or monitoring point to either Maungataniwha (northern GXP network) or Mt Hikurangi (southern GXP network).
- A leased 2MB link from Maungataniwha to Mt Hikurangi.
- Fibre-optic cable along subtransmission line routes.
- A front end in the control centre comprising of an iPower HMI system and backup servers at Ngawha Power Station, connected via the Ethernet WAN.

We have also installed a standby control room at the Ngawha power station.

The existing radio communications system is reaching the end of its useful life and is not capable of providing some functions (e.g. protection signalling), which the network now requires. It is being progressively replaced by a modern system.

3.1.11 Load control system

Our load control system operates by injecting a control signal onto the electricity supply, which is detected by control relays located at the controlled load. We own and operate three Zellweger static ripple injection plants and injection is at 317Hz onto our 33kV subtransmission system. The plants are located at our Kaikohe and Okahu Road substations, with a standby plant at Waipapa substation. These are operated from the network control room via our SCADA system. The Kaikohe plant was commissioned in 2007 and is rated at 80MVA, while the Okahu Rd plant (commissioned in 1991) is rated at 30MVA. The standby Waipapa plant was commissioned in 1981 and is also rated at 30MVA.

The load control plants are used to manage demand by allowing the control of a range of load types (particularly water heating) to actively manage our peak transmission charges and potentially defer capital investment on the network. The control relays installed in the field at the points where the controllable load is connected are owned by energy retailers, so we are reliant on retailers continuing to support the system in order to capture the benefit of demand management.

3.1.12 Load characteristics and large users

We have five large consumers:

- Juken Nissho Mill near Kaitaia (≈ 10MVA)
- AFFCo Meat Works near Moerewa (≈ 2MVA)
- Mt Pokaka Timber Products Ltd, south of Kerikeri (≈ 1MVA)
- Immery's Tableware near Matauri Bay (≈ 1MVA)
- Northern Regional Corrections Facility (NRCF) at Ngawha (≈ 0.6MVA)

Juken Nissho, AFFCo and Mt Pokaka all have dedicated distribution feeders from zone substations located at, or close to, their sites. Immery's Tableware is supplied from its local distribution feeder, while NRCF has a dedicated 11 kV feeder from the Kaikohe zone substation. Almost 20% of the energy delivered through our network supplies these five largest consumers.

Our other consumers are predominantly residential or rural, with dairy sheds comprising a significant proportion of the rural load. There is no predominant urban centre in our supply area, and light commercial and industrial loads are generally concentrated within small towns and settlements dispersed throughout our supply area.

We currently supply ten public electric vehicle charging stations dispersed across our network as shown in Figure 3.16 below.

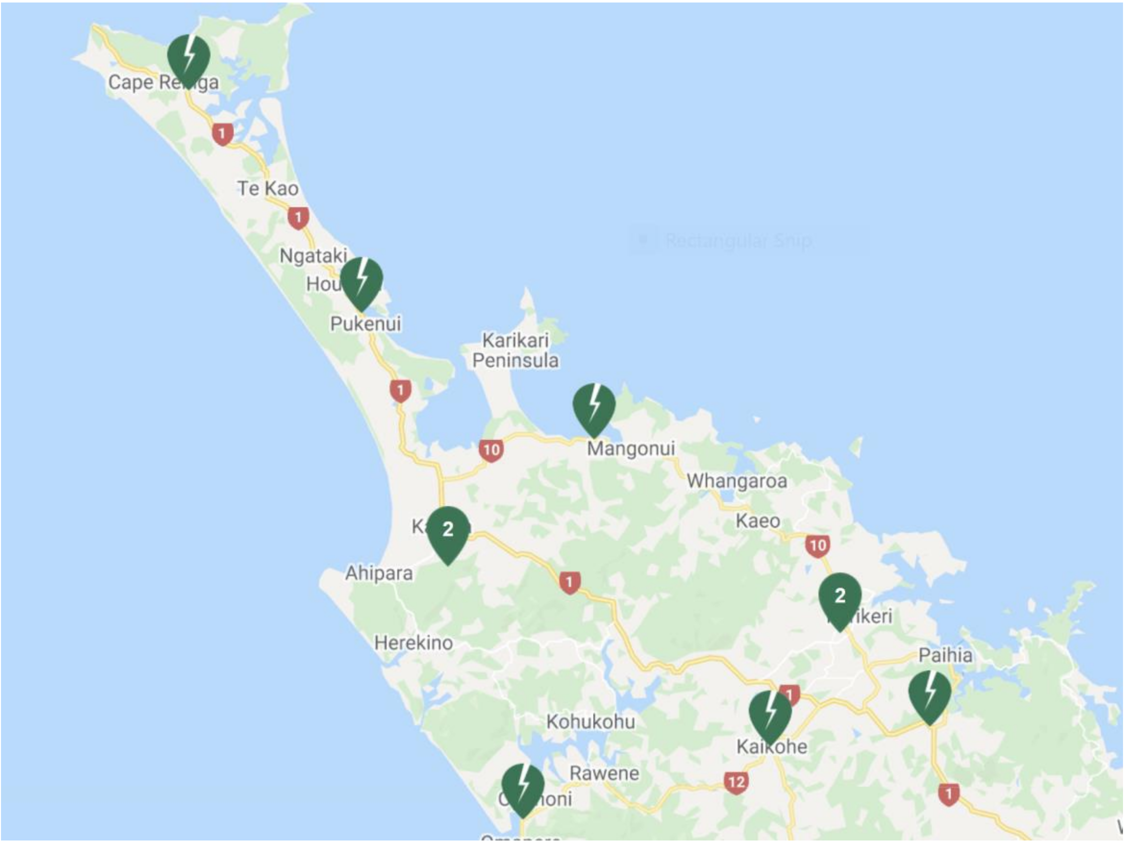


Figure 3.16: Public Electric Vehicle Charging Station Locations

As of December 2020, there were 179 pure electric and plug-in hybrid vehicles registered within our supply area, as shown in Table 3.3 below. This is a 73% increase in the number of pure electric and 88% increase in the number of plug-in hybrid vehicles in the two years since December 2018.

	Pure Electric	Plug-in Hybrid	Total
Ahipara	1	-	1
Awanui	2	5	7
Bay of Islands	-	1	1
Cable Bay	2	1	3
Haruru	1	1	2
Hokianga	1	-	1
Kaeo	2	1	3
Kaikohe	10	-	10
Kaitaia	7	6	13
Kawakawa	2	2	4
Kerikeri	61	20	81
Kohukohu	2	-	2
Manganui	4	2	6
Moerewa	1	1	2
Ohaeawai	1	-	1
Omapere	1	-	1
Opua	7	-	7
Paihia	8	3	11
Rawene	3	1	4
Russell	12	6	18
Waipapa	-	1	1
Total	**128**	**51**	**179**

Table 3.3: Plug-in Electric and Hybrid Vehicles Registered in Top Energy's Supply Area

3.1.13 Economics of Supply

Many of our distribution lines were built using subsidies provided by the Rural Electrical Reticulation Council (RERC). These were provided to assist with post-war farming productivity growth in remote areas and provide an electricity supply to consumers in sparsely populated rural areas that would have otherwise been uneconomic to service. Many of these lines are now reaching the stage where extensive rebuilding and refurbishment is required. We are obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers currently supplied from existing lines, although this continuing supply does not need to be a grid connection.

In 2009, prior to the passing of this Act, the Electricity Networks Association (ENA) created a working party to review the implications of this obligation. The working party defined lines as uneconomic if there were less than three connected low consumption consumers per km. Low consumption was defined either by the volume of energy delivered per year (less than 6,500kWh per consumer) or by the installed distribution transformer capacity (less than 20kVA per consumer); these criteria were based on an independent analysis of network costs undertaken by the then Ministry of Economic Development (now MBIE). Approximately 35% by length of our 11kV distribution network is uneconomic if the MBIE cost of supply criteria is applied. These lines supply just 9% of our consumers.

In 2018 we investigated this issue in more detail by developing a Cost-to Serve model that looked at the costs we incur in supplying consumers in different parts of the network. Our modelling shows that the revenue received from consumers in the remote segments of our network is enough to cover the operating costs of the assets used to provide their supply but makes only a marginal contribution to the capital costs of these assets. Consumers connected to the more economic parts of our network therefore subsidise the capital costs we incur in maintaining supply to these consumers.

We keep abreast of the economics of using remote area power supplies instead of a network connection to service consumers in the most remote parts of our network, but have found this difficult to justify, primarily because line assets tend to be renewed incrementally as individual poles and pole top hardware fails. This is discussed in Section 5.7.3.

3.2 Asset Quantities

The quantities and average age of our network assets are shown in the tables below. Age profiles, asset health assessments and asset maintenance strategies are detailed in Section 6.

3.2.1 Poles and Structures

Asset	Quantity (No.)	Average Age (yr)	Expected Life (yr)
Steel			
110kV towers	13	55	60-80
110kV poles	76	3	
33kV	83	16	
Subtotal	**172**	**13**	-
Concrete			
110kV[1]	198	25	60-80
33kV	2,953	30	
Distribution -excluding SWER	26,969	36	
SWER	3,270	34	
Low voltage	1,385	36	
Subtotal	**34,775**	**35**	-
Wood			
110kV[1]	89	38	35-45
33kV	58	40	
Distribution – excluding SWER	393	44	
Distribution - SWER	319	37	
Low voltage	259	46	
Subtotal	**1,118**	41	-
TOTAL	**36,065**	**35**	

Note 1: Two pole structures on the Kaikohe-Kaitaia line. (Excludes concrete poles on the Kaikohe Wiroa line, which is currently energised at 33kV.)

Table 3.4: Network Pole and Structure Quantities

3.2.2 Overhead Conductor

Asset	Quantity (cct-km)	Average Age (yr)	Expected Life (yr)
Aluminium			
110kV Kaikohe-Kaitaia line	56	45	50-60
110kV Kaikohe-Wiroa line[1]	36	9	
110kV Ngawha-Worsnops line	8	1	
33kV	328	30	
Distribution (excluding SWER)	2,046	36	
SWER	384	44	
LV	91	29	
Subtotal	**2,949**	**36**	**-**
Copper			
Distribution (excluding SWER)	88	49	60
SWER	57	58	
LV	123	33	
Subtotal	**268**	**44**	**-**
Galvanized Steel			
SWER	22	68	50
Subtotal	**22**	**68**	**-**
Unknown			
All voltages	27	-	-
TOTAL	**4,064**	**37**	**-**

Note 1: Currently operating at 33kV

Table 3.5: Network Overhead Conductor Quantities

3.2.3 Underground Cable

Asset	Quantity (cct-km)	Average Age (yr)	Expected Life (yr)
33kV	21	8	55
Distribution	231	9	45-70
LV (excluding streetlight)	684	28	45-55
Streetlight	326	29	45-55
TOTAL	**1,262**	**24**	**-**

Table 3.6: Network Underground Cable Quantities

3.2.4 Other Assets

Asset	Quantity (No)	Average Age (yr)	Expected Life (yr)
Pole-mounted distribution transformers	5,079 (130MVA)	25	45
Ground-mounted distribution transformers	847 (142MVA)	18	45
Voltage regulators	27	7	45-55
Zone substation buildings	34	35	50+
Power transformers	30	29	45-60
Outdoor 110kV circuit breakers	10	23	40
Indoor 33kV circuit breakers	38	6	60
Outdoor 33kV circuit breakers	39	17	40
Indoor 11kV circuit breakers	84	35	45-60
Outdoor 11kV circuit breakers	24	10	40
Outdoor 33kV switches	183	20	35
Outdoor distribution switches	822	26	35
Sectionalisers	250	12	40
Reclosers	114	23	40
Ring main units	307	13	40
Distribution fuses	5,649	24	35
Underground service fuse boxes	12,224	25	45
Protection relays	400	11	20-40
Capacitors	45	46	40

Table 3.7: Other Network Asset Quantities

3.3 Regulated Asset Value

In accordance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, Top Energy disclosed that its regulated asset base was valued at $280.0 million as at 31 March 2020, an increase of $18.6 million since 31 March 2019. This total was derived as shown in Table 3.8 and reflects the value of the assets commissioned in FYE2020 as part of our network development programme.

	$000
Asset Value as at 31 March 2019	**261,426**
Add:	
New assets commissioned	22,856
Indexed inflation adjustment	6,589
Less:	
Depreciation	9,683
Asset disposals	990
Asset allocation adjustment	193
Asset value as at 31 March 2020	**280,006**

Table 3.8: Value of System Fixed Assets

The asset value shown in Table 3.8 is the value of our regulatory asset base, as measured for in accordance with the Commerce Commission's information disclosure requirements. It differs from the value of our distribution assets as shown in our annual report for two reasons: firstly, the valuation rules for information disclosure differ from those for financial accounts; and secondly, the regulatory asset base includes assets such as the land and buildings (e.g. substation control buildings), which form an integral part of the network, but are recorded under other asset categories in the Group financial accounts. Neither value includes works that are under construction, but have yet to be commissioned, which had a disclosed regulatory asset value of $20.7 million as at 31 March 2018. This cost largely related to the 110kV Ngawha line.

Table 3.9 disaggregates the value system fixed assets shown in Table 3.8 into its main asset categories.

	$000
Transmission and subtransmission lines	70,392
Subtransmission cables	9,676
Zone substations	36,952
Distribution and low voltage lines	54,706
Distribution and low voltage cables	38,663
Distribution substations and transformers	30,002
Distribution switchgear	26,971
Other network assets	5,787
Non-network assets	6,856
Total	**280,006**

Table 3.9: Disaggregated Value of System Fixed Assets as at 31 March 2020

Section 4 Level of Service

4 Level of Service

4.1 Introduction

When regulatory control over EDBs was introduced, the reliability of our network was low compared to other New Zealand EDBs supplying primarily rural areas. In part, this was a consequence of our fringe location at the end of the grid, where we remain reliant on a single double circuit radial connection to a mesh node of the Transpower network. A rural network of similar size located within the meshed core of the transmission system would have more grid connections and backup options. Our other disadvantage has been our highly dispersed population, spread over a large supply area with no dominant urban centre.

Our grid connection at Kaikohe and the 110kV transmission line route over the Maungataniwha range are no longer optimally located to serve our present load. They were constructed during an era when Kaikohe and Kaitaia were the hub of both economic and population growth within our supply area. Over the last thirty years, there has been a steady decline in the growth of both towns, whilst there has been significant growth in Kerikeri, the Bay of Islands and the eastern coastal peninsulas.

Accordingly, we have concentrated our development on the redesign of our subtransmission network to match the shift in the centre of our load away from the GXP. We have also improved the level of security on the 33kV subtransmission system to make the assets that serve larger load centres tolerant to one contingent outage event without any supply interruption (the N-1 security standard). This development, which together with the installation of diesel generation at Kaitaia and Taipa has driven a significant improvement in the supply reliability experienced by our consumers, is now largely complete.

At the 11kV distribution level, much of our network remains characterised by long distribution feeders supplying sparsely populated rural areas and small pockets of fringe development with limited subtransmission support. To address these legacy issues and further improve our network resilience, we plan to invest a further $175 million capital expenditure on the network during the ten-year planning period of this AMP. This will focus on the replacement of assets that have reached the end of their economic life, the construction of the new 110kV line into Kaitaia to complete a resilient high-capacity network backbone and improving the reliability of the 11kV network. This will include the construction of additional feeder interconnections, improved automation, the introduction of advanced distribution management technology, and the integration of distributed energy resources, such as photovoltaic and battery storage (including electric vehicles) as they connect to our network.

Our diesel generation has allowed us to improve the reliability of the supply we provide to our consumers and increase our resilience to high impact events. As diesel generation is now used to supply our northern area when the 110kV circuit from Kaikohe is out of service, our consumers no longer experience regular supply interruptions lasting up to nine hours to enable maintenance of the existing line. Our generation is also used to reduce the impact of supply interruptions following an unexpected fault on this line.

Not all our reliability gains have come from improvements to our network architecture. Improved maintenance has also increased our network reliability. Our reliability improvement plan also includes more effective vegetation management, more efficient maintenance strategies and increased expenditure on asset renewal. We will also improve our supply reliability through improvements in our operational practices, including our organisational capability and the skill set of our staff, coupled with the introduction of new technology to support our decision making.

This investment in network resilience and reliability improvement has been effective. The indicators that we use for measuring the reliability of our network are:

- SAIDI: System Average Interruption Duration Index. This is the accumulated total time that the average consumer connected to our network is without supply in any measurement year due to faults or planned outages within the network. The units are minutes.
- SAIFI: System Average Interruption Frequency Index. This is the total number of supply interruptions that the average consumer connected to our network will experience in a

measurement year due to faults and planned outages within the network. The units are outages per consumer per year. While an individual consumer can only experience a whole number of outages, the target is set as a real number to allow for the effect of averaging.

We now record the SAIDI and SAIFI impact of unplanned and planned interruptions separately.

Figures 4.1 and 4.2 illustrate how we have reduced the SAIDI and SAIFI impact of unplanned interruptions since FYE 2009. The measures shown in the figures have been normalised, in accordance with the methodology approved by the Commerce Commission, to reduce the impact of severe weather on the measures. Normalisation is discussed in Section 4.2 below. As the normalised measures reduce the impact of volatile weather on the numbers, they better reflect the reliability improvements driven by our investment in the network.[2]

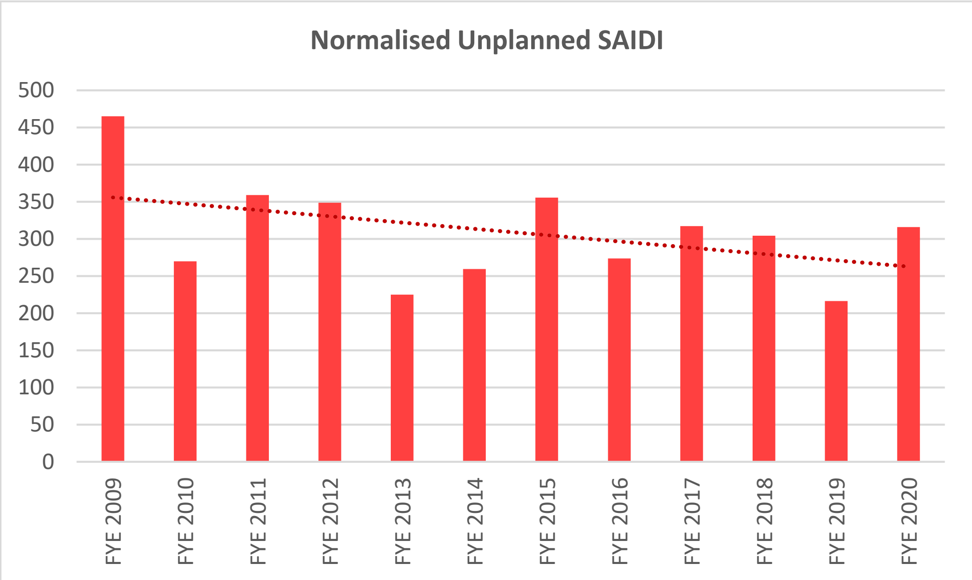


Figure 4.1: Normalised Unplanned SAIDI FYE 2009-20

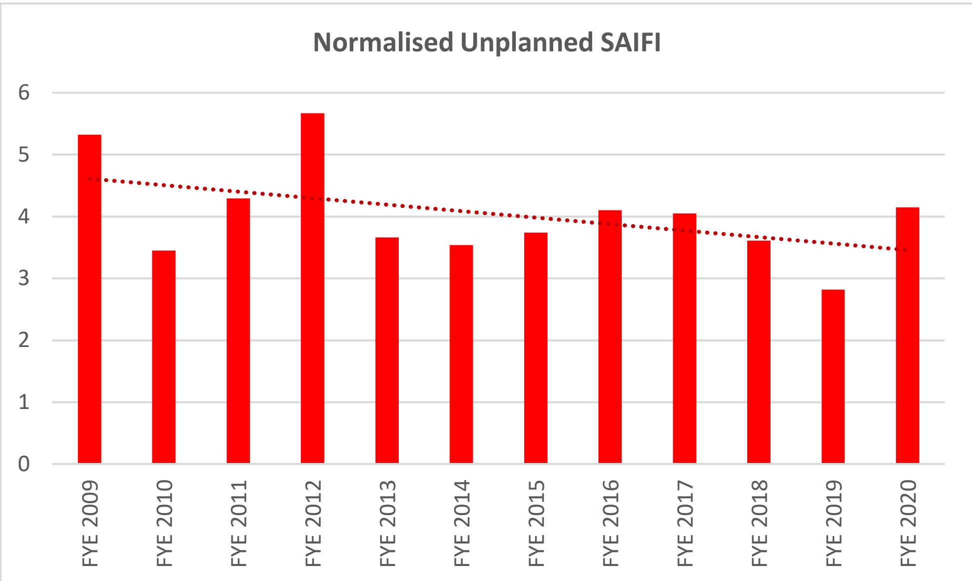


Figure 4.2: Normalised Unplanned SAIFI FYE 2009-20

[2] While the normalization process described in this AMP only came into effect for FYE 2021, for the purpose of this analysis we have normalised our historic reliability as if it did apply. Thus, the measures shown will be different from the corresponding measures reported in previous AMPs.

We do not expect to be able to maintain this rate of improvement in network reliability going forward. We have now reached the point where most faults on our subtransmission network will not result in a supply interruption. Where this is not the case, we have configured the system to enable supply to be restored after a short interruption, without waiting for the fault to be repaired. Hence any improvements in the reliability of this part of the network will be limited, at least in the short to medium term.

Further improvements in supply reliability will therefore need to come from investment in the distribution network. This is almost seven times the length of the transmission and subtransmission network and therefore much more fault exposed. Furthermore, due to its radial design (which is typical of such networks, particularly in rural areas) all distribution network faults will cause a supply interruption to one or more consumers. Investments in improving distribution network reliability will focus on reducing both the frequency of faults and the time taken to restore supply to consumers once a fault has occurred. Improvements in reliability as a result of this investment will be incremental due to the larger number of faults, the size and geographic spread of the network, and the smaller number of consumers affected by an individual fault.

We perform regular consumer research, including formal consumer surveys, to educate and seek feedback from consumers on what is an appropriate level of service. The results of these consumer interactions have been incorporated in the strategies discussed in this AMP and have guided development of the service level targets proposed within this chapter.

4.2 Consumer Orientated Service Levels

4.2.1 Unplanned Interruptions

The consumer service targets included in this AMP are limited to the normalised SAIDI and SAIFI measures used by the Commerce Commission to monitor the reliability of our network under its price-quality regime. The Commission has chosen these measures because it believes they are effective indicators of how well an EDB provides a reliable electricity supply to consumers. We have set ourselves more challenging targets than the benchmark service levels used by the Commission in monitoring our supply reliability, to ensure that our targets capture the benefits of our network investment. The Commission’s benchmarks are based solely on historic performance and therefore do not reflect our targeted service level improvements.

In measuring our performance for internal management purposes and setting our own targets, we use the normalising approach taken by the Commerce Commission in measuring the reliability of supply provided by all the EDBs that it regulates under the default price-quality path regime[3]. Normalisation of the raw performance measure is designed to limit the impact on the measure of network reliability of events that are outside our reasonable control. As noted in Section 4.1, we believe that setting targets using normalised measures provides a better indication of the success of our asset management strategies, because normalisation limits the extent to which events outside our control and response capacity impact the measured performance.

In the normalisation process, any rolling 24-hour period where the aggregate unplanned network SAIDI or SAIFI from all supply interruptions that commence during the period exceeds a predetermined boundary value is categorised a SAIDI or SAIFI major event. The SAIDI or SAIFI impact of all interruptions during a major event is normalised back to $^{1}/_{48}$ of the boundary value (unless the SAIDI or SAIFI impact of the individual interruption is lower than this).[4] The normalisation process is designed so that the aggregate normalised SAIDI or SAIFI over any rolling 24-hour period cannot exceed the boundary value. Furthermore, SAIDI and SAIFI are normalised independently so you can have a SAIDI major event without a corresponding SAIFI event and vice-versa.

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3 Trust owned EDBs that do not operate generation are exempt from regulation under the default price-quality path but must disclose details of their operations in accordance with the information disclosure requirements.

4 Periods are rolled forward in half hourly increments starting on the hour and half-hour. Interruptions that occur within the same half-hour period are aggregated and treated as a single interruption for normalization purposes.

The normalisation process can have a significant impact on the reported reliability in years where reliability is poor due to a large number of abnormally severe storms. For example, in FYE2015 our raw SAIDI of 1,837 minutes, primarily due to a major weather event. This was reduced to 356 minutes after normalisation.

Under its price-quality regime, the Commission also sets a normalised SAIDI and SAIFI threshold for each regulated EDB. Our thresholds reflect the average normalised reliability of our network in the ten years preceding the start of the current FYE2021-25 regulatory period, but also include a margin to provide for volatility. Should we breach a threshold in any year, the Commission will investigate our management of the network and has the power to impose a civil penalty. Our normalised SAIDI and SAIFI thresholds and boundary values are shown in Table 4.1.

	Threshold	Boundary Values
SAIDI	380.24	27.92
SAIFI	5.0732	0.2284

Table 4.1: Current Unplanned Interruption Reliability Limits and Boundary Values

As noted above, we set ourselves more challenging reliability targets than the Commission's thresholds to reflect the impact of our reliability improvement investment. While we met our internal targets in FYE2013 and FYE 2019, years in which very benign weather conditions were experienced over most of the country, in other years we have not met our targets due to the impact of the weather typically experienced in our supply area.

In a significant change from previous years, we have also reset our internal reliability targets to separate planned and unplanned interruptions. This is consistent with the approach taken by the Commission in resetting our price-quality path for the FYE2021-25 regulatory period.

The indicators measure only interruptions that originate within our network. Interruptions that originate outside the network, such as automatic, under-frequency, load shedding event or loss of the grid connection to Maungatapere, are not included. Interruptions lasting less than one minute are also excluded irrespective of cause. These interruptions are generally caused by a transient event, such as a lightning strike or debris blown across a line and supply is restored by an automatic system reclosure without the need for operator intervention.

Our internal SAIDI and SAIFI targets for each year of the planning period are shown in Table 4.2. The unplanned interruption targets over the planning period are shown graphically in Figures 4.3 and 4.4 below, which also compare the targets with the historical reliability.

FYE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Unplanned SAIDI	245	240	235	230	230	230	230	230	230	230
Unplanned SAIFI	2.98	2.97	2.96	2.95	2.95	2.95	2.95	2.95	2.95	2.95

Note: Targets are raw performance normalised in accordance with the Commerce Commission's 2015-20 DPP normalisation methodology.

Table 4.2: Consumer Service Level Targets

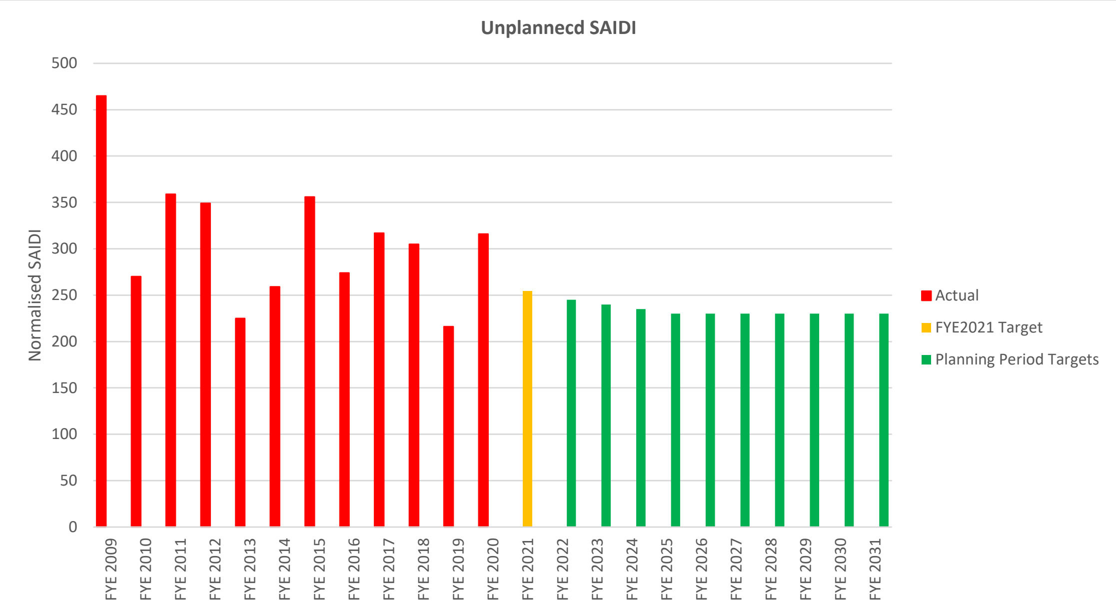

Figure 4.3: Historical and Target Unplanned SAIDI

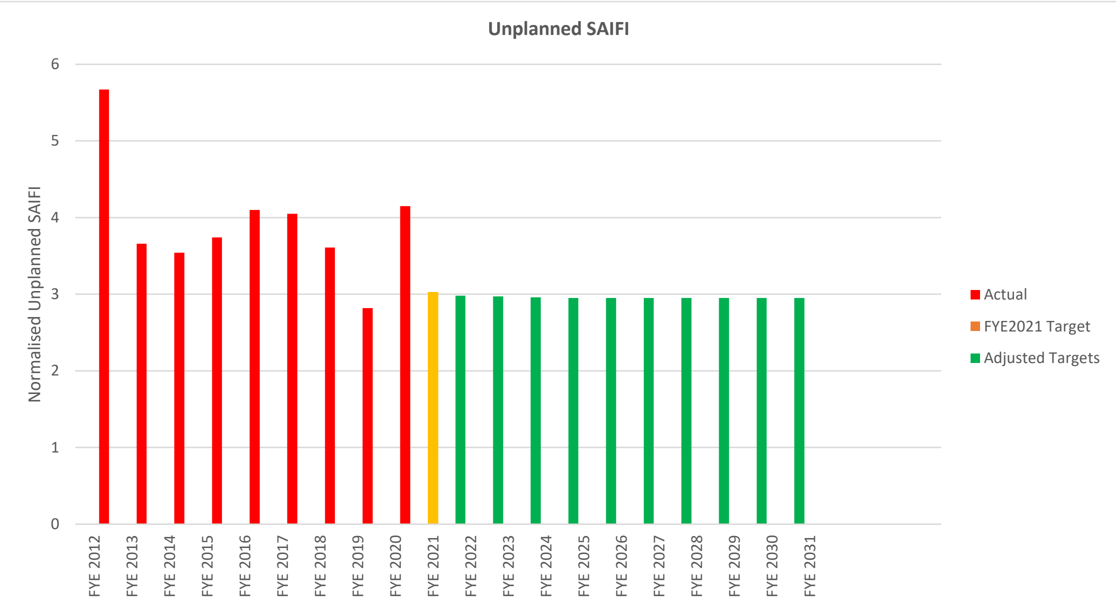

Figure 4.4: Historical and Target Unplanned SAIFI

4.2.2 Planned Interruptions

While planned interruptions are disruptive to consumers, they are less so than unplanned interruptions, because consumers are given advance notice of the outage and can plan accordingly. With generation installed at Kaitaia, Omanaia, Pukenui and Taipa, planned interruptions should now normally only be required for work on the 11kV distribution network[5].

For DPP3, the Commission has not set an annual limit for the impact of planned interruptions but has set aggregated planned SAIDI and SAIFI limits for the whole regulatory period. As compliance will only be assessed at the end of the period, EDBs are free to use up this allowance at any time over the period.

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5 The one exception to this is the Juken Nissho mill. Insufficient generation has been installed at Kaitaia to supply the mill during an outage of the 110kV Kaikohe-Kaitaia line. An arrangement is in place with the customer to ensure the mill is shut down during a planned interruption of this line.

Our limit is 1,905.36 SAIDI minutes and 7.63 interruptions (SAIFI), which is calculated as three times our average annual planned SAIDI and SAIFI over the FY 2010-19 period aggregated for five years.

For internal management purposes we have set rounded annual planned SAIDI and SAIFI targets equal to our average performance over the FY 2010-19 period[6]. Given that there should be little need for planned interruptions on our transmission and subtransmission network, this will allow us to increase our level of maintenance on the 11kV network without increasing our consumers' exposure to planned interruptions above historic levels. These targets are shown in Table 4.3. Assuming the SAIDI target is met, the aggregate SAIDI impact of planned interruptions over the DPP3 regulatory period will be 625 minutes, less than one third of the 1,905.36 minutes set by the Commission.

FYE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Planned SAIDI	125	125	125	125	125	125	125	125	125	125
Planned SAIFI	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Table 4.3: Targets for the Impact of Planned Interruptions

4.3 Asset Performance and Efficiency Targets

We have developed targets to reflect our asset performance and efficiency to ensure that our asset management strategies result in effective utilisation of our asset base.

The targets for loss ratio and the ratio of operational expenditure to total regulatory income are based on indicators that reflect the effectiveness of our management of the network assets for the benefit of electricity consumers in our supply area.

4.3.1 Loss ratio

Network losses are a function of network length and load. We have a high loss ratio (defined as the ratio of energy losses to the energy flowing into the network), as is typical in a rural network.

Energy losses are measured as the difference between the energy flowing into the network and the energy sold out. They include both technical network losses, due to the loss of energy flowing though the physical network and non-technical losses, due to factors such as incorrect metering installations, meter errors and theft. In our case, the relatively poor loss ratio is primarily driven by technical losses, which result from the high network loading and rural nature of the network.

From 1996 to 2001, our network loss ratio was approximately 10%. In subsequent years, the loss ratio improved to between 8% and 9%. However, in FYE2013, there was a step increase to 9.5%, as losses in the transmission assets were included for the first time. Over time, distribution losses should decrease incrementally as we continue our investment in network development. Nevertheless, there is a limit to the extent the losses can be mitigated, as a large proportion of losses are on the low voltage network and these losses cannot easily be reduced.

We can expect losses to reduce with the completion of our 110kV ring. The transition to a distributed energy system may also reduce losses because the power flows within the network are the net balance between generation and consumption, and the generation is closer to the load.

We have reduced our loss ratio target through to FYE2030 from 9.3% to 9.0% to reflect the improvements we have seen since FYE2015. In FYE2031, we have further reduced the target to 7.5% to reflect the expected reduction in losses once the second 110kV line is commissioned. The targets for the planning period are shown in Table 4.3 and Figure 4.5 compares these targets with the recent historical performance.

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6 These are rounded down values. The reliability incentive scheme has a planned SAIDI component with a target SAIDI of 127.02. This is the neutral level, for which no reward or payment will apply.

FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031
9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	7.5%

Table 4.4: Target Loss Ratios

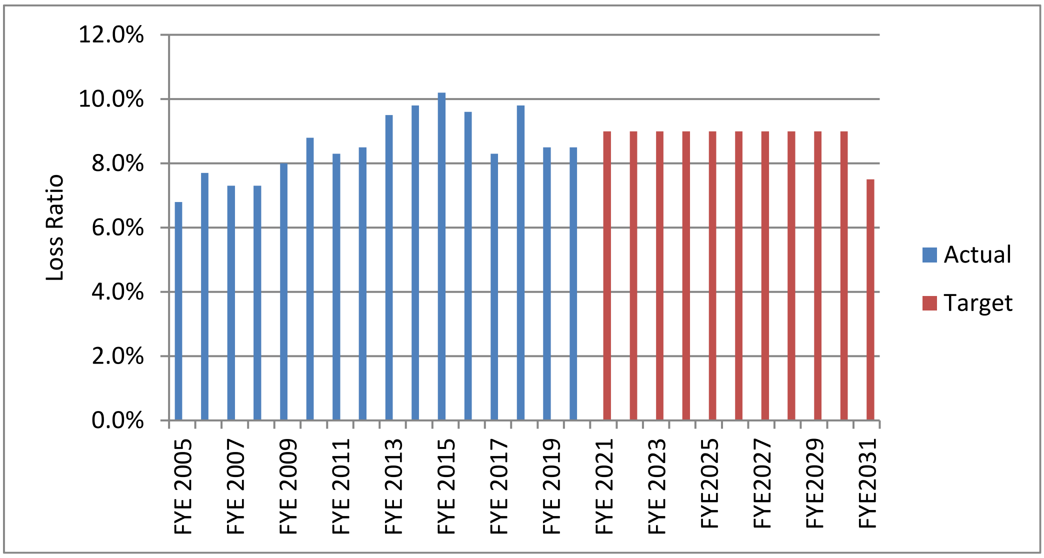

Figure 4.5: Loss Ratios of Top Energy since FYE2004

4.3.2 Cost Performance

Ideally, any financial performance indicator should be directly measurable for performance against a specific target and independent of the annual effects of inflation. We use the ratio of total operational expenditure to total regulatory income since this metric is independent of inflation as both numerator and denominator are financial measures. It is therefore preferred over other, possibly more relevant, alternatives, such as the ratio of operational expenditure to circuit length, where the impact of inflation would need to be considered in setting forward targets. The disadvantage of this measure is that total regulatory income is not a direct measure of the size of the asset base and therefore it could be argued that the ratio is not a direct measure of asset management efficiency. Nevertheless, regulatory income is indirectly related to the size of the asset base and the measure reflects the portion of the revenue from the provision of distribution line services that is allocated to operating expenditure, which is directly relevant to consumers. All else being equal, a smaller ratio reflects greater efficiency in the day-to-day management of assets.

We believe that metrics related to capital expenditure are not good indicators of asset management efficiency at a time when we are implementing an extensive network development programme, because of the potential variability of capital expenditure from year to year.

Our targets for the ratio of total operational expenditure to total regulatory income are shown in Table 4.5.

FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031
33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%

Table 4.5: Targets for Ratio of Total Operating Expenditure to Total Regulatory Income

Figure 4.6 compares these targets with our actual performance against this measure since 2008. The increase in operational expenditure for the three years from FYE2011 is apparent as we implemented our vegetation management and reliability improvement programme. Operational expenditure has now reverted to more normal and sustainable levels, and this is reflected in the forward targets.

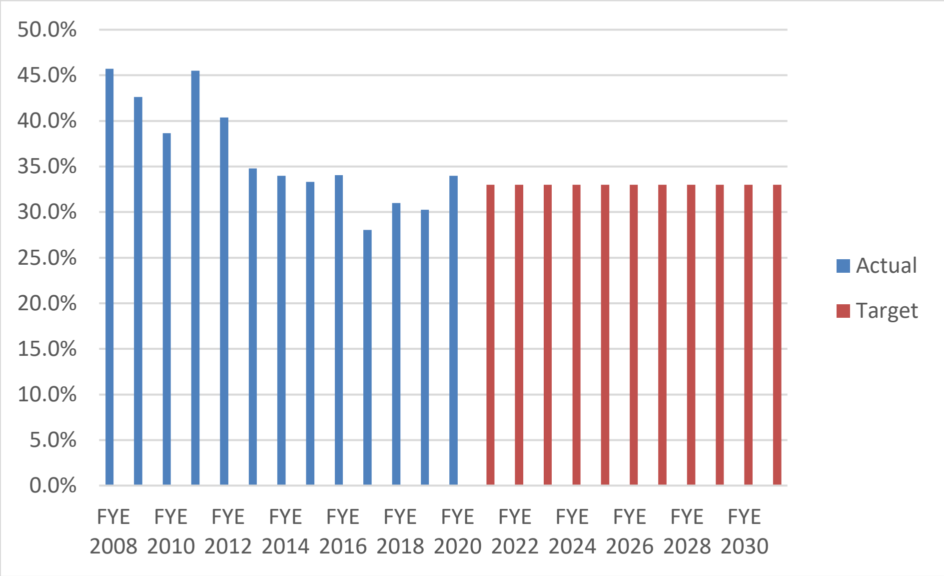

Figure 4.6: Ratio of Total Operating Expenditure to Total Regulatory Income since FYE2008.

4.4 Justification for Service Level Targets

4.4.1 Supply Reliability Targets

The SAIDI and SAIFI service level targets measure the effectiveness of our asset management strategies, which have been developed to reflect the outcome of our stakeholder consultation process and other internal business drivers. They reflect our current normalised reliability, as shown in Tables 4.1 and 4.2 and have been derived as follows.

4.4.1.1 Unplanned SAIDI

We have assumed no planned or unplanned 110kV interruptions. The Kaitaia generation is designed to eliminate planned 110kV interruptions. Unplanned 110kV interruptions are relatively rare and have not been included in our previous targets.

The starting point for the unplanned SAIDI target is the 2020 AMP Update target of 246 minutes for FYE2022. We think there will be further improvement over the short term as our diesel generation has only just been commissioned and its impact on supply reliability has still to be reflected in our measured network performance. After that, any reliability improvement will be driven by incremental investment in the 11kV distribution network rather than by development of a more resilient network architecture. This improvement will be more difficult to observe given the volatile weather conditions that we experience.

4.4.1.2 Unplanned SAIFI

The starting point for the unplanned SAIFI target is the 2020 AMP Update target of 2.98 for FYE2022. Unlike SAIDI, which is a measure of interruption length, installation of diesel generation is unlikely to impact unplanned SAIFI. This is because, when a fault occurs, there will still be a supply interruption before the diesel generation is started and brought online. We also note that the current target is well below the unplanned SAIFI we currently achieve, on average, as shown by the trend line in Figure 4.2. This suggests that, notwithstanding our performance in FYE2019, we are unlikely to better our existing target level on a regular basis. Therefore, our projected unplanned SAIFI targets reflect only a very modest improvement over the planning period.

4.4.1.3 Planned Interruptions

As discussed in Section 4.2.2, we have set our targets for planned interruptions based on our average historic performance. As we no longer work on live assets, we are reliant on planned interruptions to maintain our existing 11kV network assets. Therefore, we do not think targets that severely limit our ability to arrange planned interruptions are in the long-term interest of our consumers.

4.4.2 Justification for Asset Performance and Efficiency Targets

4.4.2.1 Loss Ratio

Our loss ratio targets reflect the current performance of the network and include the losses on the 110kV transmission system. The commissioning of the second 110kV line to Kaitaia was expected to result in a material improvement to the measured loss ratio, but this has now been deferred until FYE2030. The commissioning of the Kaeo substation will result in some reduction in line losses due to lower 11kV currents, but this will be largely offset by the losses on the new substation transformers. While continuing investment in the network over the planning period may result in an incremental reduction in network losses, we suspect that these will not be sufficient to reduce the loss ratio to a level significantly below the target we have set.

4.4.2.2 Ratio of Total Operational Expenditure to Total Regulatory Income

The level of operational expenditure on the network is actively managed and it is expected that the ratio of total operational expenditure to total regulatory income will remain around current levels throughout the planning period. The growth in our asset base over the planning period will necessarily increase our operations and maintenance expenditure by around the same proportion as the growth in the asset base, so the measurement ration should not be materially affected.

Section 5 Network Development Planning

5 Network Development Planning

5.1 Planning Criteria

Planning criteria for our network development projects are governed by legislative and internal requirements, such as voltage compliance, security of supply and technical constraints, such as maximum current ratings. While load growth and the need to meet maintain network resilience are the main factors that drive these requirements, network development is also driven by our response to the strategic issues discussed in Section 2.6.

5.1.1 Voltage Criteria

We use the following design voltage limits.

- 33kV subtransmission: +4.5%, -10% of nominal voltage.
- 11kV distribution: +2%, -5% of nominal voltage.
- LV network: ±4% of nominal voltage up to legal point of supply.

The voltage limits defined above allow our voltage control equipment, such as on-load tap changers in zone substation power transformers, voltage regulators and capacitors on distribution feeders, to keep voltages within statutory limits at all levels of demand.

Our voltage compliance related projects are mainly justified by the following benefits from improved voltage levels or voltage control:

- The ability to meet statutory voltage limit requirements.
- Improvement in distribution circuit capacity.
- Improvement in back-feed ability to other distribution circuits in a contingency situation.
- Reduction of power losses.

Because of the length of our feeders, low voltage is generally the first indicator of an emerging network capacity issue and therefore the most common driver for augmentation projects on our 11kV and LV networks.

5.1.2 Security of Supply

The level of security that we provide in the event of an unplanned single-element fault on our transmission or subtransmission networks is summarised in Table 5.1. Our overarching objective is to restore supply to all affected consumers within one hour following such an incident, unless otherwise agreed with a consumer.

Substation	Target Restoration Time	Comment
Kaitaia	1 hour	Supply restored using diesel generators at Kaitaia depot, Bonnetts Rd, Taipa and Pukenui. Supply to JNL will be restored to allow an orderly plant shutdown and then disconnected until the fault is repaired.
Kaikohe Kawakawa Kerikeri Moerewa NPL Okahu Rd Waipapa	-	No interruption. These substations all have two transformers and two incoming lines.
Omanaia Pukenui Taipa	1 hour	These substations have a single transformer and single incoming line. Supply restored using diesel generators located at the substation. There is insufficient generation capacity at Taipa to supply the full substation load at time of peak demand, but supply can be restored by transferring some load to adjacent substations.
Kaeo	1 hour	This substation has two transformers but only one incoming line. In the event of an incoming line fault, load can be transferred to adjacent substations
Mt Pokaka	1 hour	This substation has one incoming line and one transformer. In the event of either a transformer or line fault, supply can be restored to all small use consumers by transferring them to adjacent feeders. We have an agreement with the Mt Pokaka mill that supply will not be fully restored until the mobile transformer is put into service. This could take up to 12 hours. However, now that security at our other small substations has been increased through the installation of diesel generation, our mobile substation is based at Mt Pokaka. This means that, unless the mobile substation is deployed elsewhere, there will be no supply interruption in the event of a transformer failure.

Table 5.1 Transmission and Subtransmission System Security

We own and operate a 7.5MVA 33/11kV mobile substation, which limits the maximum total outage duration should all transformer and generation capacity be lost at any substation. This will be used in the event of a transformer failure at any of our four single-transformer zone substations to avoid the need to run generators continuously for extended periods of time and to restore system security to normal levels until the fault is repaired. The time required to relocate this unit from its present location to provide backup at another substation is up to 12 hours. This includes the time required for packing, travelling from one zone substation to another, and the time required for assembling and connecting the unit at its new location. Transformer failures are relatively rare but, if one occurs, the repair time is potentially several months.

The 11kV distribution network is operated in a radial configuration, which means that there will be a supply interruption every time there is a fault. The number of consumers affected by a fault will depend on the network location. We also have interconnections between feeders which that allow us to reroute supply around a fault to restore supply before the fault is repaired to consumers not directly affected. The availability of an alternative supply route depends on network location but, in general, the likelihood reduces as the distance from a zone substation increases. Supply cannot be restored to consumers in remote locations or on the edge of the network until a fault is repaired.

5.1.3 Asset Capacity Constraints

For design purposes, we consider the different capacity constraint levels on primary assets for normal operation and contingent operation and apply the more restrictive of the two. These are shown in Table 5.2.

ASSET TYPE	CONDITION	PERCENT OF NOMINAL CURRENT RATING	
		Normal operation	Contingent operation
Transformers	Nominal	100	125 for one hour
Overhead Conductors	Still Air 30 degrees	75	100
Underground cables	In Duct	75	100
Circuit Breakers	Nominal	75	100

Table 5.2: Design Capacity Limits

5.1.4 New Equipment Standards

To maximise cost efficiencies and reduce the required number of spares, we have adopted equipment supply standards for the capacity and rating of stock issue equipment, such as power transformers, conductors, cables and poles.

Distribution transformers follow the ISO standard sizing. Pole mounting of new transformers is now limited to those rated 100kVA and below for seismic reasons. Transformers may be one, two, or three-phase according to consumer or load requirements. Appropriately rated isolating transformers are used to isolate SWER circuits from the rest of the network. Pad (berm) mounted transformers are steel cabinet enclosed units and may include switch units (total pad type) depending on the application.

XLPE cables are now used as standard for all voltages. HV cables and larger LV cables are aluminium and 33kV cables are single core for flexibility and ease of installation. LV copper cables in the smaller sizes are used for consumer connections.

Wood poles are being progressively phased out of the network. New concrete poles are all pre-stressed 'I' section poles and are generally used at subtransmission voltage and below. Steel poles are now used for 110kV transmission lines[7] and will also be used for new subtransmission lines in locations where our standard concrete poles do not meet the design requirements.

Overhead conductors are generally all aluminium conductor (AAC), except where long spans demand higher tensions. For these applications, the equivalent steel reinforced aluminium (ACSR) conductor is used. However, all aluminium alloy conductor (AAAC) has now been adopted as standard for new lines rated at 11kV and above, while new low voltage overhead lines use 95mm^2 covered aerial bundled conductor (ABC).

Zone substation transformers have been standardised as 11.5/23MVA units, except for small sites where this capacity is not warranted, and 5/10MVA and 3/5MVA transformers are used. Transmission transformers with a 110kV primary winding are standardised at 40/60MVA. In our view, given the small number of power transformers in the fleet, this relatively small number of standard power transformer ratings is justified as it ensures that assets are interchangeable between sites.

Network development is planned around our standard asset sizes. In selecting the appropriate size, the forecast peak load under contingency conditions at the end of what we consider a reasonable planning period is used as the basis for design. In situations where the appropriate asset size is unclear, or where there is a high level of uncertainty in the demand forecasts, we prefer to install a higher capacity asset on the basis that the incremental cost of the additional capacity is much smaller than the cost of installing a new asset, should the smaller asset become fully loaded.

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7 The Kaikohe-Hariru section of the 110kV Kaikohe-Wiroa line uses concrete poles. This section was constructed before the decision was made to use steel poles for 110kV construction.

5.2 Energy Efficiency

Given the current electricity industry structure, we are not responsible for the cost of losses on our network. Nevertheless, as a responsible service provider, we recognise that the energy efficient operation of our network is in the long-term interest of all stakeholders. The following initiatives are in place to promote energy efficiency:

- Our network losses increased after the acquisition of the Transpower assets since the losses from these 110kV assets had to be included in the measure. While loss minimization is not the primary objective of our network development plan, we expect a reduction of network losses will be a positive outcome from the implementation of this plan.
- Our distribution network was constructed with long feeders, with augmentation generally being triggered by a need to reduce voltage drop. We have reduced the feeder length and the load on some feeders with the construction of new zone substations at Kerikeri and Kaeo. Nevertheless, long distribution feeders with high losses remain on many parts of the network.
- With the recent commissioning of OEC4, the Ngawha geothermal power station provides more than 95% of the energy requirements of our consumers. The power station displaces generation located south of Auckland and eliminates most of the losses that would be incurred in transmitting this power from the alternative point of generation to the grid exit point at Kaikohe.
- We actively control consumers' hot water heating and other load at times of peak demand to ensure more efficient use of the available network capacity. Load control is estimated to reduce our network maximum demand by more than 10MW. In the longer term our generators may be integrated into the load management system giving us more firm control capacity.
- Our standard specification for power and distribution transformers includes industry standard clauses relating to the minimization of transformer losses and the cost of losses is considered during tender evaluation.

5.3 Policy on Acquisition of New Assets

We maintain a system of procurement authorisation for individuals within the overall approved business plan. A job authority system controls authorisation of expenditure on major projects.

5.4 Project Prioritisation Methodology

Capital expenditure is broadly prioritised as follows:

Priority 1: Asset Replacement and Renewal

Our stakeholders expect us to maintain a network that is fit for purpose – both safe and reliable. We apply the industry best practice of monitoring asset condition using asset health indicators and apply management strategies appropriate for their position in their lifecycle. As an asset approaches the end of its service life, we assess its criticality in respect of the safety risk and the outage impact of an in-service failure. Asset replacement and renewal programmes are prioritised by risk, which is a function of both the probability of failure and the consequences of such failure.

Priority 2: Network Development

Projects that are designed to maintain or increase the capacity of the network or sustain the standards to which the network is developed are categorised as "development". For internal budgeting and prioritisation purposes, we also categorise network capacity upgrades and network extensions to enable the connection of new consumers as "network development". This expenditure is driven by growth and is differentiated from new build funded by consumers.

Priority 3: Reliability Safety and Environment

Projects targeting an improvement in the reliability of the 11kV network, as measured by unplanned SAIDI impact, comprise most of the projects categorised as reliability safety and environment. We have also included the upgrade of our Waipapa substation in this category, as this upgrade is primarily driven by safety and the design (outdoor feeders with low ground clearance) of this very old substation, rather than by the consequences of an asset failure. In previous asset management plans, we categorised line refurbishment projects as reliability improvement on the basis that these were targeted at more critical assets where a reduction in faults would result in a material SAIDI improvement. These have now been recategorized as renewal, since this better describes the main driver for the work.

We are now categorising the construction of the planned 110kV line between Wiroa and Kaitaia as reliability, safety and environment the implementation of a long-term solution to improving the reliability of supply to consumers in the north of our supply area is the primary driver for this initiative.

Priority 4: New Technology

We have adjusted our strategy towards the implementation of new technology to one of being a fast follower rather than a leader. Therefore, while we will continue to monitor the development of these technologies and their potential application to our network, we are no longer forecasting expenditure on experimental projects designed to test different approaches to new technology implementation. Expenditure in this category is now limited to data collection projects that will enable us to fully capture the efficiencies available from utilisation of our new ADMS system. Information technology projects such as the ADMS installation are classified as non-system expenditures.

Within this broad prioritisation framework, our capital expenditure is further categorised into major projects and capital upgrades. Major projects are one-off, individually designed, major augmentations or upgrades to the network. These projects are allocated individual budgets and generally have long lead times. Capital upgrades are smaller, have shorter lead times and are managed within budget envelopes.

As budgets for network development and augmentation are limited, project prioritisation is one of the key functions of asset management planning. Prioritisation determines the ranking of one project compared to another in the most practical and feasible way possible. It also determines whether a project is included in the AMP and the timing of its implementation.

This system of prioritisation ensures that the network's fitness for purpose is sustained in the face of growth, service improvement and development, which results in underlying performance decline if not kept in focus.

5.4.1 Major Projects

Major projects are prioritised by the Network Planning Manager and his staff, with the objective of meeting the strategic objectives approved by the Board (and set out in this AMP) with the least lifecycle cost. They generally involve augmentations to our transmission and subtransmission networks with the objective of providing a resilient network backbone that provides the security of supply our consumers require and has sufficient capacity to meet the demand for network services in an uncertain network environment. Distribution network upgrades specific to parts of the network are also scoped and managed as major projects.

5.4.2 Renewal and Upgrade Capital Programmes

These capital expenditure programmes generally have shorter lead-times and are managed within budget envelopes. They include:

- Asset replacement or refurbishment programmes, which are targeted at assets that have deteriorated to the stage where their reliability cannot be assured and where their failure could have significant consequences for our consumers. Priorities are based on asset health, life cycle, criticality, defect, risk and safety management processes, performance, and gap analysis.
- Reliability improvement initiatives, such as the installation of remote-controlled switches or interconnections between feeders. These are prioritised by assessing the improvement to SAIDI that they will deliver for the expenditure required.

5.5 Demand Forecasting Methodology

5.5.1 Overview

Load forecasting is performed to provide an estimate of future demand, which is essential for prudent planning. Electricity demand is largely dependent on:

- Economic conditions.
- Weather patterns.
- Technology release and adaptation into society (e.g. photovoltaic cells, heat pumps etc.).

5.5.2 Forecast Methodology

We use our SCADA system data that provides the average current in each feeder for each half-hourly period as the base data for the forecast. This enables us to determine the maximum half-hourly demand at each zone substation. Peaks, due to the network not being in its normal operating state, are identified and removed. The forecast incremental growth rates at each substation are based on historic trends for the substation, which in some cases are modified to take account of econometric or other factors that could be expected to impact the demand for electricity in a localised area. We then overlay on this base forecast major new block loads that have been consented and are likely to proceed within a firm timeframe.

Our forecast includes adjustments for load transfers between zone substations that are likely to occur during the planning period. In our current forecast, this is limited to a 1.5MW load transfer from Kawakawa to Haruru substation in FYE2023, following completion of the second feeder to supply the Russell peninsula, and a similar 1.5MW from the Kaikohe, Mt Pokaka, Waipapa and Kerikeri substations to the new 11kV injection point planned for Wiroa at the end of the planning period in FYE2031.

Block loads that are speculative or may not proceed are not included in the forecast but may be taken into account when planning the development of the network, provided that the cost does not burden other consumers.

5.6 Demand Forecasts

5.6.1 Forecast peak demand over planning period

Using the methodology described above, the winter peak demand forecast for each zone substation is shown in Table 5.3 below. The peak demands shown in the tables are net of the peak demand reductions that we can achieve though the operation of our load control system. At present, apart from household photovoltaic systems, there is no embedded generation within our network that supplies an internal consumer load and therefore has the potential to reduce peak network demand. Apart from Pukenui, all our zone substations have winter peaks, so photovoltaics are unlikely to have a material impact on our peak demand until the penetration of battery storage systems in domestic consumer installations becomes significant.

	Actual FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029	FYE 2030	FYE 2031
SOUTHERN AREA											
Kaikohe	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.4
Kawakawa	6.8	6.8	5.4	5.4	5.5	5.5	5.6	5.6	5.7	5.7	5.8
Moerewa	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Waipapa	9.7	9.8	9.9	10.1	10.2	10.3	10.5	10.6	10.8	10.9	10.8
Omanaia	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Haruru	5.7	5.8	7.4	7.6	7.7	7.8	7.9	8.0	8.2	8.3	8.4

	Actual FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029	FYE 2030	FYE 2031
Mt Pokaka	2.5	2.5	3.0	3.1	3.1	3.1	3.1	3.1	3.2	3.2	2.8
Kerikeri	7.7	7.9	8.0	8.1	8.3	8.4	8.6	8.7	8.8	9.0	8.5
Kaeo	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.1	4.2	4.3
Wiroa	-	-	-	-	-	-	-	-	-	-	1.5
NORTHERN AREA											
Okahu Rd	8.4	8.5	8.6	8.7	8.8	8.9	8.9	9.0	9.1	9.2	9.3
Taipa	6.3	6.3	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.5	6.5
NPL	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1
Pukenui	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9

Table 5.3: Zone Substation Demand Forecast (MVA)

The demand forecasts for the transmission substations and for the total network are shown in Table 5.4 below.

	Actual FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029	FYE 2030	FYE 2031
Kaikohe	48	48	49	49	24	24	25	25	26	26	27
Wiroa	-	-	-	-	23	24	25	26	27	28	29
Kaitaia	24	24	24	25	25	25	25	25	25	26	26
NETWORK	71[1]	71	71	71	72	72	72	72	73	73	74

Note 1: Estimated from SCADA data. May not correspond to disclosed demand in FYE2020 information disclosure, which is derived from metered data.

Table 5.4: 110kV Transmission Substation and Network Demand Forecast – Winter (MVA)

5.6.2 Uncertainties in the demand forecast

The load forecasts in Tables 5.3 and 5.4 form the basis of our network development expenditure forecast and exclude all potential block loads that may not proceed or where the timing is uncertain.

There are possible new block loads in our supply area that have already been consented or are close to being consented. However, we have not received any formal applications to provide supply and it is still uncertain if these will go ahead. If they do proceed, the timing and magnitude of the additional demand still needs to be confirmed. Because of this, the demand and capital expenditure forecasts in this AMP have made no explicit provision for these loads. Our existing transmission and subtransmission networks now have the capacity to accommodate these additional block loads. The new lines to connect these developments to our existing, and augmentations to 11kV feeder capacity would be funded by a developer capital contribution.

These potential loads are shown in Table 5.5.

Load	MW	Comment
Awanui solar farm[1]	23	This will require a new 33kV feeder connection to the NPL substation. It will only have a small impact on network peak demand as maximum generation will be at times of low load.
Pukenui solar farm[1]	20	This is across the road from the Pukenui substation and will be connected into the substation by a 33kV line. The maximum capacity will be limited by the 20MVA rating of the 33kV line supplying Pukenui.

Load	MW	Comment
Pamapuria solar farm[1]	24	This will be connected directly to the 33kV bus at our Kaitaia 110kV substation though a dedicated new 33kV feeder.
Kaikohe irrigation	2-3	This would require an upgrade to the 11kV Ohaeawai feeder.
Kaitaia irrigation	2-3	This would require a new 11kV feeder from the NPL substation due to the location of the pumping stations.
Tokerau resort	5	This would require an upgrade of the Tokerau feeder to 22kV or a new 33kV substation. However, this development is now unlikely to proceed.
Ngawha energy park	5	The tenants that have already signed up have only a small energy requirement and can be supplied from the Ohaeawai feeder. As the load grows a dedicated 11kV feeder or a 33kV substation could be required. The 33kV substation would be connected into one of the existing lines between the Ngawha Power Station 33kV switchyard and Kaikohe.

Note 1. Utility scale solar generation will require the provision of network capacity but will not impact the demand forecasts shown in Tables 5.3 and 5.4.

Table 5.5: Potential Block Loads

The Northland iwi have yet to negotiate a treaty settlement with the Government that, when finalised, could inject well over $200 million into the Northland economy. As the negotiations are still ongoing and firm plans for development are not available, our forecast makes no provision for the economic stimulus that an eventual treaty settlement could provide to our supply area.

We have also not made any provision for the impact of emerging technologies on electricity demand since the impact of these technologies, which are discussed in Section 5.7 is still highly uncertain.

5.7 New Technologies and Non-Network Solutions

5.7.1 Introduction

EDBs have traditionally relied on poles and wires to distribute electrical energy and assumed power flow would be in one direction – from generator to the customer. However, with generation becoming more widely distributed across and within the network, and disconnection from the network becoming a viable alternative, these assumptions do not necessarily hold true any longer. Consequently, we are closely monitoring and assessing the application of non-network alternatives to supply customers with power. Equally, the impacts of these technologies on the network are also being monitored.

5.7.2 Long Range Wireless Transmission Technology

This technology, although in its infancy, is currently being developed in New Zealand. The technology uses electromagnetic waves (microwave beams) to transmit energy through the air between “antennae. We will keep abreast of the development of this technology in a bid to better understand it and the applications to which it might be suited.

5.7.3 Remote Area Power Supplies:

More traditional remote area power supplies (RAPS) consist of a solar array, battery bank and a diesel or gas generator. They are viewed as a potential solution for customers who are supplied via a long line that is in a deteriorated condition and uneconomic to replace. The intent would be to install a RAPS and remove the uneconomic line.

We have studied the applicability of this technology to our network in a number of applications. These studies have applied various criteria to determine a project’s viability including:

- Customer location (end of a line).

- Line length potentially to be removed.
- Condition of the line to be removed.
- Line route environmental factors.
- Number of connected consumers.
- Reliability and/or where a single supply circuit is prone to interruption.
- Location specific risks (e.g. vegetation and/or forestry).
- Access.

Finally, we have tested the viability of a potential project using a financial model that compares the lifecycle cost of the project with the cost of replacing and maintaining the existing line, including into account any asset replacement and refurbishment already undertaken on the line as a reactive measure in the recent past.

We have found that this last factor, where lines typically have already had a degree of replacement and refurbishment undertaken as a reactive measure, continues to tip the balance away from adopting RAPS as an economic alternative to lines. To date, no potential site has been identified that stands up to this level of scrutiny. This is before customer consultation has commenced. Apart from a small number of enthusiastic adopters of new technologies, consumer acceptance of non-line alternatives is unlikely to be positively received unless suitable inducements are offered. This will reduce the viability of RAPS even further. We estimate the standard residential install cost of a RAPS to be close to $100,000, and the ongoing maintenance costs of a RAPS are not insignificant. The economic lives of RAPS assets are also much shorter than that of an upgraded distribution line, further reducing the economic potential of RAPS when assessed on a lifecycle cost analysis.

Nevertheless, we will continue to evaluate on a case-by-case basis situations where a RAPS could be a viable and economic alternative.

5.7.4 Batteries

Battery storage, particularly when coupled with photovoltaics, is not entirely new, as small DC systems have been commonly used for many years. However, use of battery storage in the world of AC power is relatively new, being driven largely by reductions in battery costs and solar panels, and improvements in battery efficiency and inverter technology. Battery storage transforms the way in which solar (or wind) power generation can be used, enabling generated power to be made available when it is needed, rather than when it is generated (depending on the capacity of the batteries installed). Batteries behind the meter, to store energy generated during the day for use in the evening when demand is higher, have become more prevalent in domestic photovoltaic installations in recent months.

Batteries open up all sorts of opportunities for EDBs because of their potential to:

- Reduce system peak demand.
- Morph generation profiles to suit load requirements.
- Smooth peaks and troughs in generation due to cloud cover (solar) or gusts (wind).
- Reduce the network impact of EV charging.
- Provide ride through inertia during system faults.
- Provide backup supply during outages.

We currently have few network constraints where batteries could provide a potential solution. However, there is potential for batteries to be used to manage transients where utility scale photovoltaic generation is connected to our network. In this situation we would require the battery or alternative mitigation technology to be provided by the developer.

While the cost of battery storage is reducing rapidly, cost is still the inhibiting factor to the widespread and large-scale uptake of battery installations. For example, with an installed battery cost currently about $1.2 million per MWh, the installation of a 30MWh battery in the Kaitaia region would cost $36m. This is comparable to the capital cost of our planned new 110kV line, but the battery would provide only two hours of peak backup.

As the volumes and capacities of energy sources connected to our network increase, controlling the dispatch of these installations could be required on some parts of the network. Our newly installed ADMS will facilitate this. It would require real time information (possibly through access to smart metering data) and the ability to remotely or automatically constrain or move load through a contractual arrangement with the distributed generation owners. This will be a requirement of the connection agreement, should any of the proposed utility-scale solar farms in the northern part of our supply area proceed.

5.7.5 Other Energy Storage Options

Other forms of energy storage, such as pumped hydro, compressed gas, flywheel etc, exist and some of these are mature in their development. However, they are all variously expensive to implement or narrow in their application and have little applicability to the management of distribution networks.

5.7.6 Network Access

Distributed generation and new technology applications can provide investors with a source of revenue and our network is available to investors wanting to connect such equipment to the electricity system. The network has capacity to accommodate the connections of wind and photovoltaic generation at a commercial scale. We can, in general, support the connection of 3-5MW generation to our 11kV distribution network and 15-30MW to our 33kV subtransmission network. Our 110kV network currently has a capacity of 50MW, but we will not be able to provide N-1 security until our new 110kV line is completed in FYE2030. Access to this network capacity will be on a first-come, first-served basis. Our northern area demand currently varies between 7MW and 23MW, but excess generation can be exported south through our 110kV circuit. Our policies for the connection of embedded generation to our network are described in Section 5.8.

5.7.7 Network Support

If privately owned generation or other equipment such as battery storage seeks to connect to the network and has a network benefit, we will negotiate on a case-by-case basis to find a commercial solution that recognises the network benefit of the connection. We are open to negotiating with investors where such generation would improve supply reliability or defer the need for network augmentation to meet localised incremental load growth. This could be an opportunity for a business considering the installation of generation as a backup in the event of an interruption to the network supply. Areas where such generation or utility scale battery storage could potentially provide distribution network support include:

- The north-east coast, including the Karikari and Purerua peninsulas, where holiday and tourism ventures are driving development.
- North of Kaitaia, where irrigation-driven load growth is occurring.
- The Russell peninsula, where the summer peak demand is approaching the limits of 11kV distribution.
- Both North and South Hokianga.

5.7.8 Other Fuels

Two further technical developments which may have an impact on electricity networks are the manufacture and use of methanol and hydrogen for the transport industry. Methanol is likely to only be an interim fuel while electric and hydrogen powered vehicle technology matures. The future of hydrogen is convoluted and may be entirely determined by how quickly and aggressively electric vehicles are able to be placed in the hands of the average consumer. It would however provide a solution for heavy and long haulage transport, where electric vehicle technology has limitations. In any event both fuels are electricity intensive in their manufacture which will be good for network and energy companies in the localities where they are made and used.

5.7.9 Electricity Distribution Business Technologies

In essence, electricity and its distribution has not changed since its inception. Poles, wires, and cables still carry electricity from generator to consumer, as they always have. However, the technologies used by EDBs to manage this function have changed and continue to change rapidly. Drones now make possible faster and more accurate capture of asset information using aerial photography and can also be used to locate faults. Sophisticated protection systems isolate faults quickly and safely and pinpoint their location. Smart grids enable automatic recovery from faults and restore power to customers in shorter periods of time. Digital maps and digital data entry have replaced their paper equivalents, and control and monitoring via the internet is becoming the norm.

We have already adopted many of these technologies and are assessing others for their suitability and relevance to our day-to day network management. Our ADMS is being bedded into our real time network control, fibre-optic communication is in use universally for both voice and data communication, sophisticated protection systems utilising fibreoptics are now standard, electronic field devices are now used to remotely access and enter asset data and our paper records are steadily being replaced by digital equivalents.

5.8 Distributed and Embedded Generation Policies

As noted in Section 5.7.6, we welcome users wanting to connect larger generating units to our network. Our approach to the connection of such generation by external parties is based on the following principles.

- Distributed generation can connect to our network on fair and equitable terms that do not discriminate between different distributed generation schemes. We will ensure that these are as clear and straightforward as possible, subject to our obligation to maintain a secure and safe distribution network.
- We will process all distributed generation applications as quickly as possible and in full consultation with the proponent.
- Distributed generation must comply with industry-standard technical and safety requirements, and all relevant legislation and regulation.
- We may need to limit the capacity of distributed generation that can connect to different parts of our network, such as a distribution feeder. In such a situation, access to existing spare capacity will be given on a first come-first served basis and the cost of any capacity upgrade needed to overcome a capacity limitation shall be funded by the proponent.

Our policy and requirements for the connection of distributed generation are available on our website. Nevertheless, proponents seeking to connect generators larger than 10kW to our network should contact us to discuss their specific requirements.

5.9 Demand Management

Demand side management (DSM) is the management of a consumer's demand to avoid overloading the network. It typically involves shifting a consumer's peak away from the time of the network peak to reduce the magnitude of peak network demand. This can defer the need for capital investment to increase network capacity, and potentially also reduce the transmission charges we pass through to our consumers. DSM can also reduce the need to install diesel generation for network support. Our consideration of the need for a network augmentation incorporates an assessment of any identified DSM opportunities that could defer or reduce the cost of an augmentation.

We use the following DSM options to manage demand in different operating conditions.

- **Direct Load Management:** We routinely control water heating load through our ripple-frequency controlled load management system. Daily peak load shedding is based on the GXP peak load. Under emergency conditions, where network components are out of service, we also use the system to reduce load and maintain supply for as many consumers as possible. Load control relays also delay the restoration of hot water load for a short period after a total loss of supply to reduce switching spikes and avoid equipment overload. We estimate that direct load management reduces the actual peak demand on the network by more than 10MW. Diesel generation can also be applied to load management and has the advantage of being predictable and firm.

- **Under-Frequency Load Shedding:** In order to prevent a total power system collapse following a major grid disturbance, Transpower requires automatic tripping of a percentage of each EDB's network load when an under-frequency event occurs.

  This event, for example, could be the failure of a major generation in-feed or the loss of the HVDC link between the North and South Islands. In order to comply, our network has been configured so that the load to be shed is split into two blocks. These blocks trip after a pre-set delay, dependant on the levels of frequency excursion on the system. Table 5.6 shows the operating arrangements of these two load blocks.

Frequency Excursion	Tripping Time - Seconds	
	Block 1	Block 2
47.8Hz	4	15
47.5Hz	4	4

Table 5.6: Emergency Load Shedding Specification

  Block 1 amounts to approximately 35% of our network maximum demand and Block 2 is approximately a further 20% of our demand.

The development of a market-based system by Transpower to provide load reduction in the event of an emergency loss of generation has provided an opportunity for the use of our ripple control system. As yet, we do not participate in this demand side management opportunity, due to the limited load available to be shed within the required response time. We offer different DSM options to our major industrial consumers but are currently unable to provide a price incentive that is sufficient for them to modify their demand.

5.10 Smart Metering

Smart metering measures consumption over half-hourly periods, permitting the introduction of tariff structures that discourage the consumption of electricity during periods of peak demand. Meter readings are downloaded over a communication link, avoiding the cost of monthly meter reading visits. We have installed a radio frequency (RF) mesh communication network within our supply area to enable smart meter data to be downloaded automatically and Contact Energy (our incumbent retailer) is replacing its mechanical meters with smart meters. Approximately 60% of our consumers have smart meters installed.

Smart meters can be programmed to automatically advise our control room when supply is lost. Our capex forecast provides for a data gathering exercise to enable us to extend our ADMS functionality to include active real time management of the LV network. Access to smart meter data would enhance this capability. The disaggregated demand data available using such meters would also enable more effective management and planning of our network.

However, we do not own the meters and would need to agree terms and condition under which retailers would allow us to access their meter data if we were to use it. This is an issue the industry is currently addressing.

5.11 Network Constraints

5.11.1 Types of Constraints

The three factors that can limit the capacity of our network to provide an acceptable level of service to network users are:

- Voltage.

- Thermal capacity.
- Security.

5.11.1.1 Voltage

Voltage constraints are caused by the dynamic responses of the system to power being taken from, or injected into, the network. Low voltage can occur at the ends of lines when they are heavily loaded and high voltage can occur at times of low load and/or at points of high generation injection. Consumer demand for electricity on our network varies both by season and by time of the day. The network must be capable of maintaining the voltage at consumer points of supply within regulatory limits irrespective of the level of demand. Since voltage drop increases with line length and our rural network is characterised by long lines, low voltage at times of peak demand is usually the first indicator of a network capacity constraint.

To reduce these constraints on 33kV and 11kV systems, voltages are regulated at key points of the network using transformer tap changers at zone substations or voltage regulating transformers strategically located across the network.

Voltage constraints can appear on the LV network due to there being limited facilities to dynamically adjust the voltage at this level. In Australia, management of voltages on LV networks with a high number of consumers with rooftop photovoltaic generation has become a significant issue. In New Zealand this is less of a problem due to the lower penetration of distributed generation and we have not received complaints of significant voltage or capacity problems being experienced by consumers due to the injection of intermittent distributed generation at low voltage. However, we have the highest penetration of small-scale photovoltaic generation of any EDB in the country and these issues will inevitably arise in the future. When they do, we must be ready. On April 1, 2021 we will introduce an energy injection charge of 0.5c per kWh exported into the low voltage network, to ensure recovery of the incremental network costs of investigating and mitigating the impact of uncontrolled intermittent generator connections.

5.11.1.2 Equipment Rating

An equipment rating constraint will occur when the current in a line, cable or item of equipment exceeds its rating. Current ratings can, however, vary according to use or application, environment (hot or cold etc), time (short or long duration), equipment life expectancy, thermal response (heating of conductors causes them to sag) etc.

An equipment rating constraint may manifest itself in several forms and have one or more different causes. Of particular interest are:

- Thermal constraints where exceeding a current rating will cause the equipment to overheat, which will degrade the material and shorten equipment life. An example would be transformer rating constraints, or an underground cable’s thermal capacity.
- Regulatory constraints where the power flow in a line causes the line to perform in a substandard manner. An example would be a line where the conductor sags at high loads so ground clearance is compromised.
- Power transfer constraints, where the ability to transfer power from one feeder to another is compromised because the rating of the interconnection between the two feeders is insufficient.

5.11.1.3 Security

A security constraint relates to the alternative source of supply should a fault on the primary supply occur. It may be a full constraint where no alternative exists, or a partial constraint which limits supply due to capacity or voltage regulation limitations on the alternate supply. Security constraints are of most concern on the transmission and subtransmission networks because faults on these networks can affect large numbers of consumers.

5.11.2 Known Constraints

5.11.2.1 Maungatapere-Kaikohe 110kV line

The double circuit 110kV line between Kaikohe and Maungatapere is owned by Transpower and is the only connection between our network and the national transmission grid. The line will be used to export electricity generated within our supply area at times when this generation exceeds the electricity demand in our supply area. A constraint arises when one of the two circuits is out of service. In this situation there could be times when the amount of generation available for export exceeds the thermal capacity of the remaining circuit. This is shown in Table 5.7.

Period	Line Capacity (MVA)	TE Minimum Demand (MVA)	Maximum Unconstrained Generation (MVA)	Ngawha Generation Capacity OEC1-5 (MW)	% of Time Constraint Exceeded with OEC5 only	% of Time Constraint Exceeded with OEC5 plus 20MW Solar
Summer Anytime	63/65[1]	21	84	88	3%	3%[2]
Winter Anytime	77/80[1]	23.6	100.6	88	0%	0%[3]
Summer Day	63/65[1]	28.3	91.3	88	0%	48%

Note 1: The two ratings are because the two lines have slightly different configurations.
Note 2: The summer anytime minimum demand occurs at night when the solar farm will not be generating.
Note 3: The winter anytime demand occurs in the late evening after dark, so solar farm will not be generating.

Table 5.7: Transmission Constraints Kaikohe-Maungatapere.

Implication

- Assuming OEC5 proceeds, when both circuits are in service there will be a potential constraint during the summer daytime if more than about 35MVA of utility scale solar generation is connected. We have already had connection applications that exceed this level. There would be no constraint of Ngawha dispatch at night as the solar farms will not be generating.
- With one line out of service there could be some constraint on the dispatch of Ngawha generation overnight during the summer. However, during the day generation in the area would be subject to significant constraints.

Likelihood

- The likelihood of a single circuit constraint is very low as the loss of a single circuit is a rare event. Transpower aims for one unplanned interruption every five years.
- This is comparable to the risk of a complete loss of the grid connection, most likely caused by a grid event south of Maungatapere. Ngawha cannot operate without a grid connection and connected photovoltaic generation would also probably have to shut down.
- If OEC5 and the proposed utility scale solar generation in our northern area both proceed, the likelihood of daytime generation constraints is high, particularly over the summer.

Mitigation

- The ability to constrain generators off is being written into new embedded generation contracts.
- We will work with Transpower to coordinate line maintenance outages into winter months.
- Given the very low likelihood of the loss of one circuit and the high cost of a second line (in excess of $100 million), there are no plans to construct a second Kaikohe-Maungatapere line.

5.11.2.2 Kaitaia-Kaikohe 110kV Line

The single circuit 110kV line between Kaikohe and Kaitaia is the only substantive connection between the northern and southern areas of our network. The line will be used to export electricity generated by solar farms connected to our northern area south, to the extent that the amount of electricity generated exceeds the electricity demand in our northern area. A constraint will arise if:

- The line is out of service, in which case the amount of solar generation would theoretically be limited to the northern area demand. However, in this situation it is likely that the solar farms would need to be constrained off, as solar generation is non-dispatchable and speed of response of our diesel generation will be too slow to respond to variations in solar farm output.
- The line is in service, but the amount of solar generation exceeds the sum of the line capacity and local load. This is shown in Table 5.8.

Period	Line Capacity (MVA)	Northern Area Demand Minimum (MVA)	Maximum Unconstrained Generation (MVA)
Winter Day	68	10.6	79
Summer Day	55	10.4	66

Table 5.8: Transmission Constraints KOE – KTA

Likelihood

- This is a potential issue only, since even if all three potential northern area solar farms proceed, the likelihood of the line rating being exceeded is low. It is possible that the amount of solar generation that can be connected to the northern area will be limited by the ability of the network to respond to dynamic changes in generator output fast enough to keep voltages within regulatory limits rather than 110kV line capacity. We have commissioned dynamic studies of our network response to establish this.

Potential Far North Generation

- Three solar farms with a total capacity of 67MVA, Awanui, Pukenui and Pamapuria.
- A consented 30MVA wind farm proposal at Ahipara. While this has been consented, we understand that it is unlikely to proceed.
- A 5MVA wind farm in North Hokianga. This is unconsented and unlikely to proceed.
- 17MW of Top Energy owned diesel generation from Bonnetts Rd, Taipa, Kaitaia Depot and Pukenui. This is backup generation and unlikely to be operated at the same time as the solar generation.

Mitigation

- Constraining generation off.
- Limiting the connected capacity or triggering a network upgrade at generators' cost
- Second 110kV Kaikohe to Kaitaia circuit. This is currently planned for FYE2030.

5.11.2.3 Pukenui 33kV

We have received an application to connect a 20MVA solar farm located close to the Pukenui substation. It will be connected to the Pukenui substation via a new 33kV line and the generation will be exported south via the incoming 33kV Pukenui single circuit line, which has a capacity of only 20MVA. The local Pukenui demand is only 1.8MVA, but the daytime summer demand is likely to be much lower. The likelihood of this project proceeding is high given that a firm connection application has been received. If it does proceed, the line would be fully loaded and it would not be possible to connect any further solar generation to the Pukenui substation.

Likelihood

- Low at this stage as we are not aware of any further interest in the connection of additional generation in this area.

Mitigation

- Connection of additional local load.
- Triggering network upgrade at generator's cost.

5.11.2.4 Kaikohe Transformers

There are two 110/33kV transformers at Kaikohe, one rated at 39MVA and the other at 30MVA. Ngawha generators OEC1-3 inject power directly into the 33kV network, but if these generators are out of service at the same time as one of the transformers is out of service there is a capacity shortfall as all the southern area demand would need to be supplied. This is more severe when the larger unit is out of service as shown in Table 5.9 below.

Period	Transformer T1 Capacity (MVA)	Transformer T2 Capacity (MVA)	Max Southern Demand (MVA)	% half hours demand exceeds T2 capacity
Winter	39	30	47	40%
Summer	39	30	36	15%

Table 5.9: 110kV Transformer Capacity Constraint - Kaikohe

Likelihood

The likelihood of this constraint materialising is very low, provided prudent network management practices are applied. It is an N-2 contingency in that it requires a simultaneous outage of more than one critical plant item at a time of peak demand.

Mitigation

- Ensuring both transformers are well maintained to reduce the risk of failure.
- Ensuring that the transformers are only taken out of service for maintenance when Ngawha is running and at times of low network demand.
- Ensuring that Ngawha is taken out of service at low load times, and for as short a time as possible.
- Ensuring that the Wiroa 110/33kV substation is constructed. This is planned for commissioning in FYE2024 and will fully mitigate the constraint.
- In the unlikely event that this situation arose load control would be needed, either by using our hot water control system or by rationing power to non-essential loads.

5.11.2.5 Voltage Constraint at Waipapa and Kaeo Substation

The Wiroa 33kV switching station is supplied by two incoming 33kV lines – the double circuit 110kV line from Kaikohe, which is currently configured as a single circuit and operated at 33kV, and the older, 33kV Kaikohe-Mt Pokaka-Wiroa circuit. This second line is longer and has smaller conductors. If the 110kV line is out of service at times of peak network demand the load on the Kerikeri, Waipapa and Kaeo substations will all be supplied via Mt Pokaka and the 33kV voltage at Kaeo and potentially Waipapa will fall below acceptable levels. Consumers north and west of Kerikeri will experience low voltage unless load is shed.

Likelihood

- Expected to be a risk through to FYE2024 at current projected levels of demand growth around Kerikeri.
- This risk will be higher when the 110kV line is taken out of service prior to being connected and energized at 110kV for the commissioning of the Wiroa 110/33kV substation.

Mitigation

- Construction of Wiroa 110kV substation – this will fully mitigate the risk and is programmed for FYE2024.
- Ensuring that the existing 110kV line operating at 33kV is uprated to 110kV operation over the summer when the demand on the network is lower.
- In the event of an unplanned outage of the 110kV line at times of peak network demand rotational load shedding may be needed. Supply to critical loads will be maintained.
- Ensuring that maintenance work, such as vegetation management, on the 110kV line is undertaken at times of low network demand.

5.11.2.6 Taipa Generation Constraint

The Taipa substation has a single transformer, a single incoming 33kV line and two diesel generators with a combined capacity of 3.6MVA. Hence, in the event of a loss of the incoming line or the transformer, there is a supply shortfall of up to 1.9MVA.

Likelihood

- There is a medium to high likelihood of this situation arising.
- An N-2 scenario with a medium probability of occurring is an unplanned 33kV line fault when one of the generators fails to start or is out of service.

Mitigation

- It is possible to transfer approximately 3MVA onto adjacent feeders such as Totara North. This will fully mitigate the loss of the incoming 33kV line if both generators are in service.
- If one generator is out of service when there is an incoming 33kV line fault, then there could be a capacity shortfall of up to 0.7MVA. Some load shedding would be required but supply to essential loads would be maintained.
- Plan 33kV line, transformer or generator shutdowns for periods of low demand.
- The construction of a new replacement 110kV substation at Garton Rd will fully mitigate this constraint but has been pushed out beyond the AMP planning period.

5.11.2.7 Taipa Transformer Constraint

As shown in Table 5.3, the FYE2021 peak demand at the Taipa substation measured by our SCADA system was 6.3MVA, close to the rated capacity of the 5/6.5MVA transformer. This was unexpected, as in recent years the growth in the demand at Taipa substation has been limited and in FYE2019, when we prepared the demand forecast for our 2019 AMP, the peak measured demand was only 5.6MVA. There have been no recent developments in the Taipa area we think would be sufficient to trigger a 12% increase in demand in just two years. We plan to investigate further the reason for this apparent demand increase.

The measured peak demand has only occurred for short period in any one day. To date it has not exceeded the transformer's continuous rating and is well within its short-term contingency rating shown ion Table 5.2. Nevertheless, there is a potential for the transformer rating to be exceeded in the short to medium term.

Likelihood

- High. We will monitor the demand at the substation and new connection applications to assess whether the load forecast shown in Table 5.3, which indicates only a small increase in demand over the planning period, is realistic. Given the potential for flooding at the existing site, as discussed in Section 7.6, we have no plans to increase the transformer capacity at the substation. Furthermore, any new transformer will become a stranded asset if we build our planned 110/11kV substation soon after the end of this AMP planning period.

Mitigation

- Move the mobile substation from Mt Pokaka to Taipa. This is the solution assumed in our substation capacity forecast in Appendix 1, Schedule 12b.

- Transfer some load to Kaeo or NPL substations by reconfiguring the 11kV network.

5.11.2.8 Potential Feeder Capacity Constraints

While our 11kV feeders have sufficient capacity to accommodate incremental demand growth and increased small-scale solar penetration, they may not have the capacity to supply localised new block loads. Potential loads for which there is a capacity shortfall are shown in Table 5.10.

Development	Feeder	Demand	Mitigation	Constraint	Development Probability
Kaikohe irrigation	Ohaeawai	2-4 MW	Feeder upgrade	Capacity Voltage	Medium
Kaitaia irrigation	Awanui	2-4MW	New feeder	Capacity	Medium
Tokerau - Resort	Tokerau	5MW	22kV or new substation and 33kV line	Capacity Voltage	Low
Hokianga Wind	Herekino	5MW	Feeder upgrade	Capacity	Low
Energy Park	Ohaeawai	5MW	New 11kV feeder or 33/11kV substation	Capacity	Some low-load development confirmed. Low probability of new substation or feeder being required.

Table 5.10: Potential Feeder Capacity Constraints

Likelihood

- While the probability of any individual development is considered no higher than medium, the probability of at least one of the developments proceeding in due course is high.

Mitigation

- The developer will need to fund the cost of any feeder upgrade through a capital contribution.
- Alternatively, the developer will limit the size of any upgrade to within the spare capacity of the feeder.

5.11.2.9 Substation Transfer Capacity Constraints

As shown in Table 5.1, zone substations have now been upgraded so that supply can now be restored to all consumers within 1 hour in the event of a foreseeable N-1 contingency.[8] However, in the event of an unforeseeable high impact low probability (HILP) event that disables the entire substation, the amount of load that can supplied from alternative substations varies, as shown in Table 5.11. The network is not designed to withstand such an event and, if one did occur, the Emergency Preparedness Plan described in Section 7.3.3 would be activated.

Table 5.11 shows the proportion of each substation's current peak demand that can be supplied from neighbouring substations.

Substation	Peak Demand (MVA)	Summer Peak (MVA)	Shoulder Peak (MVA)	Transfer Capacity (MVA)	% Peak Demand
Kaikohe	9.7	6.2	8.1	1.0	10%
Kawakawa	6.8	5.5	5.4	2.5	37%
Moerewa	3.4	3.5	3.9	3.3	100%
Waipapa	9.7	5.1	6.9	7.6	78%

[8] The exception is Mt Pokaka, where supply cannot be restored to the mill within one hour if the mobile substation is located elsewhere. The customer has agreed to this level of security.

Substation	Peak Demand (MVA)	Summer Peak (MVA)	Shoulder Peak (MVA)	Transfer Capacity (MVA)	% Peak Demand
Omanaia	2.7	2.0	1.9	2.3[1]	85%
Haruru	5.7	4.5	4.8	0.5	9%
Mt Pokaka	2.5	2.1	2.2	1.5	60%
Kerikeri	7.7	5.0	6.0	6.0	78%
Kaeo	3.5	3.0	3.4	4.0	100%
Okahu Rd	8.4	5.9	6.7	3.7	44%
Taipa	6.3	4.9	4.6	3.0	48%
NPL	11.1	10.9	10.7	4.3	39%
Pukenui	1.9	1.9	1.9	1.8	95%

Note 1. Transfer capacity is onsite generation, supplemented by a small amount of 11kV load transfer from Kaikohe.

Table 5.11: Substation Transfer Capacity

Mitigation

- The transfer capacity between Haruru and Kawakawa will increase to 1.5 MVA on completion of the Russell Reinforcement project planned for FYE2022.
- Generation at Kaitaia Depot will also support the NPL substation.

5.11.2.10 Feeder Transfer Capacity Constraints

While distribution feeders are generally operated in a radial configuration, it should ideally be possible to back feed a feeder from an adjacent feeder in the event of a fault. In our supply area interconnectivity is limited.

- Some feeders, particularly in urban locations, can be fully supported by adjacent feeders (green in Figures 5.1 and 5.2).
- Some feeders, particularly those along main roads in rural areas, can be back fed from an adjacent feeder, but the capacity is limited and insufficient to provide full back feed at times of peak demand (amber in Figures 5.1 and 5.2).
- For geographic reasons much of the network cannot be back fed, (red in Figure 5.1 and 5.2). While faults on spurs located within this “red” network cannot be back fed, in some situations it may be possible to restore supply following a fault located elsewhere on the feeder, depending on the feeder backbone from which the network is supplied.

This is a common situation with rural networks but, arguably, is exacerbated in our network by the legacy factors discussed elsewhere in this AMP, where the limited points of injection to the 11kV network has resulted in many long radial feeders with a high number of connected consumers.

Implications

- Care must be exercised when operating the network as the ability to transfer load between feeders depends on location and time of day.
- Supply resilience varies across the network.
- Lack of back feed capability increases SAIDI.

Figure 5.1: Map of Feeder Interconnectivity in the Northern Region

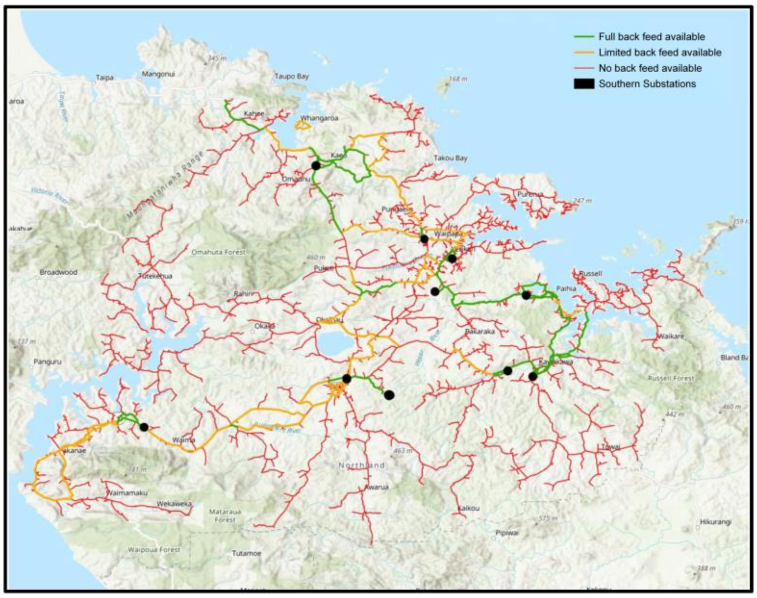

Figure 5.2: Map of Feeder Interconnectivity in the Southern Region

Table 5.12 shows feeders where interconnections currently exist but where the ability to transfer load is constrained and where, but where plans are in place to address the constraints during the first half of this AMP planning period.

Feeder Transferred	Recipient Feeder	Section point	Constraint	AMP Mitigation
Waima	Taheke	423	Voltage	Temporary disconnection of non-essential loads Remote Control of Tie Point FYE2021
Oruru	Totara North	R-363	Protection setting	Setting Change FYE2022
Oruru	Oxford St	R-017	Protection setting	Setting Change FYE2022
Purerua	Riverview	415	Voltage	Temporary disconnection of non-essential loads Remote Control of Tie Point FYE2021
Tokerau	Oxford St	1235 R-656	Voltage, Protection	Setting Change FYE2022
Matauri Bay	Orotere	1346, 1508	Conductor	Conductor replacement FYE2024
Opua/Russell	Joyces Rd	R-017	Protection setting	Setting Change FYE2022

Table 5.12: Feeder Transfer Capacity Constraints

Mitigation

- The forecast cost of implementing the mitigation measures shown in Table 5.12 are:
    - Remote control switches - $307,000
    - Setting changes - $59,000
    - Conductor replacement - $398,000
- The capital expenditure forecast in this AMP includes interconnecting the Matauri Bay and Whangaroa feeders by FYE2024 as well as both the South Rd and Rangiahua and the Bulls Gorge and Moerewa feeders by FYE2025.

5.11.2.11 Sub-Optimal Conductors Along Feeders

In order to optimise losses, manage voltage limits and provide appropriate network capacity, standards have been established for conductor sizes along a feeder. Generally, the front end of feeder backbones from the substation to about one third along its length uses the largest standard conductor, the next third and spur lines use a medium sized conductor and the end of lines, as well as SWER lines and short spurs the smallest size. Since the early days of the network the sizes of standard conductors have been increased, as the load increased, and the network extended. Consequently, older undersized conductor has been replaced with the new standard size of the day.

Unfortunately, not all spans of substandard conductor were changed to the new size when upgrade work was undertaken, and so there are now many short lengths of small conductor throughout the network. For example, there were 12 spans of 35mm^2 copper conductor through the middle of Moerewa. This conductor has recently been replaced with 157mm^2 aluminium conductor. Similarly, there are 6km of 25mm^2 and 35mm^2 copper conductor supplying Rawene, which will be replaced in FYE2022.

As an example, Figure 5.3 below shows locations within a portion of the network around Kaikohe, Moerewa and Kawakawa where there is undersized conductor, and the extent. In some instances, these sections are of considerable length and close to the substation source.

Short sections of undersize conductor will only have a small impact on feeder capacity or voltage limits and therefore will not create a significant network constraint. Nevertheless, progressive replacement of sub-optimal feeder conductor is still being undertaken. This is predominantly to rid the network of old galvanised steel and copper conductors because of rust and age embrittlement and consequent high risk of failure. There is also a risk of overheating and excessive sagging during high load times. This can cause heat cycling stresses, hot joints, and other potential failure modes.

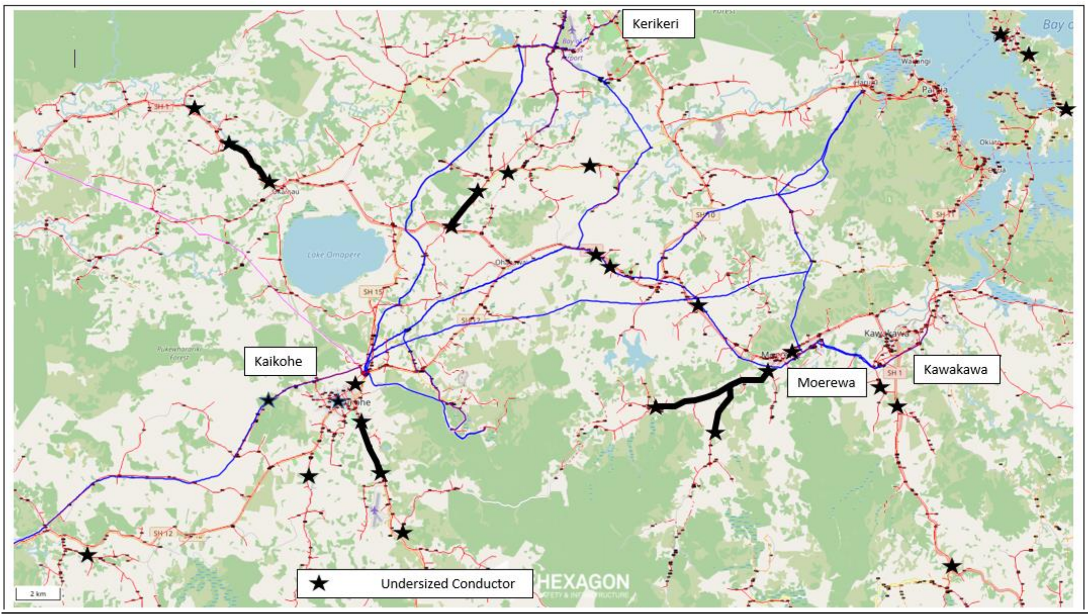

Figure 5.3: A Typical Area of the Network showing Locations of Sub-optimal Conductor

Mitigation

Table 5.13 summarises our plan to progressively replace network conductor either because of its condition or sub-optimal size. The initial focus will be on the copper and galvanised steel conductor remaining on our network, all of which is in poor condition. Once this has been replaced our focus will be on under-sized aluminium conductor.

Conductor	Length (km)	% of Network	Sub-Optimal	Condition	To be Replaced	AMP Budget
Copper and galvanised steel	88	3.26%	Yes	Poor	FYE2021-30	$2.9 million
Copper and galvanised steel	38	1.41%	No (SWER)	Poor	FYE2021-30	$1.2 million
Mink ACSR	85	3.15%	Yes	Fair	FYE2031-40	$2.8 million

Table 5.13: Sub-Optimal Conductor Replacement Plan

5.12 Network Development

Network development includes all capital expenditure on network assets. In this section, our planned network development over the AMP planning period is presented in the context of the four development priorities discussed in Section 5.4.

5.12.1 Priority 1 - Asset Life Cycle Renewals

Assets that are at the end of their lifecycle and are still required to meet our service delivery targets need to be replaced. If the rate at which assets are replaced is insufficient, there will be a decline in performance as the condition of the asset base deteriorates over time. This will result in a deterioration of the quality of supply due to an increase in the number of outages caused by equipment failures and increased fault response and equipment repair costs. We use the Asset Health Indicator (AHI) process described in Section 6 as a tool for measuring asset condition and prioritising assets for replacement.

Issues, such as criticality of a particular asset and the duration of end-of-life unreliability period for different asset classes, influence the type and quantity of assets that we should renew over the period of this plan. For example, concrete poles deteriorate slowly whereas wooden poles, because of their faster loss of strength, must be replaced more quickly after end-of-life condition indicators are first identified.

Asset renewal expenditure is given the highest priority to reassure consumers and the regulator that our asset base is being sustained in a fit-for-purpose state and that the number of unplanned interruptions caused by equipment failure does not increase over time.

We are forecasting average expenditure of over $7 million per year[9] for asset renewal on a regulated asset base currently valued at $280 million. This forecast, which is categorised by what is driving the expenditure, is discussed in the sections below.

5.12.1.1 Faults

Most faults are caused by the failure of an asset component such as a crossarm, in which case the cost of the repair is accounted for as operational expenditure. However, some faults require the replacement of a complete asset (e.g. a pole, transformer, or pillar), in which case the cost of the repair is capitalised. We have forecast expenditure of just over $1 million per year based on our historic capital expenditure on fault response, as shown in Table 5.14.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Subtransmission	53	53	53	53	53	265
Zone substations	-	-	-	-	-	-
Distribution and LV lines	630	630	630	630	630	3,150
Distribution and LV cables	52	52	52	52	52	260
Distribution substations and transformers	158	158	158	158	158	790
Distribution switchgear	157	157	157	157	157	785
Other network assets	-	-	-	-	-	-
Total	**1,050**	**1,050**	**1,050**	**1,050**	**1,050**	**5,250**

Table 5.14: Fault Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.12.1.2 Defects

As described in Section 6.1, we operate a structured asset inspection and defect management programme, where defects are identified, recorded, and programmed for remediation. While most defects identified by these inspections require the repair or replacement of asset components, our inspection also identifies assets that require complete replacement. In most cases, these replacements are programmed into the asset health driven replacement programme described in Sections 5.12.1.3 and 5.12.1.4, but sometimes a defect is identified where, for safety or other reasons, asset replacement outside of this programme is required. We maintain a special asset replacement budget to cover these situations. This is shown in Table 5.15.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Subtransmission	132	134	136	138	140	733
Zone substations	66	67	68	69	70	367
Distribution and LV lines	699	710	721	731	742	3885
Distribution and LV cables	66	67	68	69	70	367
Distribution substations and transformers	132	134	136	138	140	730

9 All expenditure forecasts presented in this AMP are expressed in FYE2022 constant prices, except where otherwise indicated.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Distribution switchgear	198	201	204	207	210	1099
Other network assets	26	27	27	28	28	151
Total	**1,320**	**1,340**	**1,360**	**1,380**	**1,400**	**7,330**

Note: Totals may not add due to rounding

Table 5.15: Defect Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.12.1.3 Projects

In addition to replacing individual assets that have failed in service or are approaching the end of their economic life, we also operate a programme of line refurbishments, where all assets and asset components with end-of-life condition drivers (discussed in Section 6.1) on a specific line are replaced at the same time. In this situation all project costs, even when they relate to the replacement of an asset component rather than a complete asset, are capitalised. Lines are selected for refurbishment because their performance is critical to the reliability of the network or because they pose an elevated safety risk. Subtransmission lines fall into the first category, while the second category includes 11kV lines in poor condition. The forecast also includes the replacement of identified substation assets known to be in poor condition.

Most recently, our line refurbishments have focused on our 33kV subtransmission lines. However, refurbishment work on 11kV and SWER lines in poor condition will be ongoing. Our forecast capital expenditure refurbishment projects is shown in Table 5.16.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Subtransmission						
Kaikohe-Omanaia line refurbishment	454					-
Kawakawa-Haruru crossarm replacements	243	662				-
Kaikohe-Kawakawa line refurbishment	481	176				-
Okahu Rd-NPL feeder rebuild				345		-
Total	**1,178**	**838**	**-**	**345**	**-**	**-**
Zone Substations						
Kaikohe capacitor bank protection replacement				121		
Replace 33kV switchgear at Kaitaia with indoor switchboard						1,207
Total				**121**	**-**	**1,207**
Distribution and LV Lines						
Pole replacements in Te Haumi Estuary	145					
Tokerau feeder refurbishment	382					
Rawene 11kV feeder reconductoring	283					
Opononi feeder rebuild	360					
Duncan Rd SWER conductor replacement		181				
Te Karai SWER refurbishment		326			300	

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Paua feeder refurbishment		473				
Rangiahua SWER rebuild			248			
Motukaraka rebuild			544			
Matawaia-Maramaku SWER rebuild				169		
Te Paki feeder refurbishment				474		
Kaikohe Mangakahia Rd conductor replacement				386		
Whangapae SWER rebuild						256
Tapuhi SWER rebuild						328
Motukiore to Duddy's Rd SWER rebuild						356
Total	**1,171**	**980**	**792**	**1,028**	**300**	**940**
Distribution Substations and Transformers						
Totara North feeder voltage regulator structure refurbishment	237					
Total	**237**	-	-	-	-	
TOTAL PROJECT DRIVEN	**2,585**	**1,818**	**792**	**1,494**	**300**	**2,147**

Note: Totals may not add due to rounding

Table 5.16: Project Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.12.1.4 Residual Asset Health Driven Replacements

Our expenditure forecast for proactive asset health driven replacements is shown in Table 5.17, disaggregated by asset type. This is residual asset replacement expenditure that is not fault or defect driven and has not been allocated to a specific asset replacement project. It represents the difference between a bottom-up assessment, based on our historic fault response and defect remediation expenditure levels and expenditure allocated to priority refurbishment projects targeted at parts of the network known to be in poor condition, and a top-down assessment of the health of our assets and the overall asset replacement levels needed to ensure that the overall network is maintained at the level that will ensure it remains fit for purpose over time. This expenditure is managed within budget envelopes.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Subtransmission						
110kV poles and hardware	536	582	583	583	580	2,918
110kV tower refurbishment	157	162	162	162	162	812
Subtotal	**692**	**744**	**744**	**745**	**743**	**3,730**
Distribution and LV Lines						
Conductor			134			1,938
Crossarms					474	1,912
Concrete poles			338	543	875	4,329
Wood poles	754	751	751	751	1,029	5,147
Unspecified line upgrades						736
Unspecified SWER refurbishment						734

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Subtotal	**754**	**751**	**1,222**	**1,294**	**2,378**	**14,797**
Distribution Substations and Transformers						
Transformer earths	105	104	104	104	104	521
Voltage regulators			233	176		
Subtotal	**105**	**105**	**338**	**280**	**104**	**521**
Distribution Switchgear						
Ring main units	252	332	334	334	334	1,669
Subtotal	**252**	**332**	**334**	**334**	**334**	**1,669**
Other network assets						
SCADA	95	73	73	73	73	293
11kV capacitors	**33**	**31**	**31**	**31**	**31**	**125**
Subtotal	**128**	**103**	**104**	**104**	**104**	**418**
TOTAL HEALTH DRIVEN	**1,932**	**2,036**	**2,743**	**2,758**	**3,664**	**21,135**

Note: Totals may not add due to rounding

Table 5.17: Residual Health Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.12.1.5 Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

Table 5.18 below consolidates the forecast asset renewal and replacement capital expenditure forecasts in Sections 5.12.1.1 – 5.12.1.4 into the asset categories used by the Commerce Commission for information disclosure.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Subtransmission	2,055	1,769	934	1,281	936	4,728
Zone substations	66	67	68	190	70	1,574
Distribution and LV lines	3,256	3,071	3,366	3,683	4,051	22,771
Distribution and LV cables	118	119	120	121	122	625
Distribution substations and transformers	632	397	632	576	402	2,041
Distribution switchgear	607	690	695	698	701	3,553
Other network assets	154	130	131	132	132	569
Subtotal	6,888	6,244	5,946	6,682	6,414	**35,862**

Table 5.18: Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

5.12.2 Priority 2 - Network Capacity Expansion

Our network capacity expansion plan documents our expectations regarding demand growth and network extensions. These in turn drive the need for upgrades and reconfiguration of the network to deliver on our quality of supply standards, such as security and voltage regulation. New large connections potentially challenge the capability of the network to deliver at short notice. Our planning therefore considers contingent capacity and "what-if" scenarios to communicate potential issues with developers.

Over the first half of the planning period our network development plan is driven by the need to address two capacity constraints in high growth areas of our network:

- Construction of a new 110kV substation at Wiroa. This will relieve the emerging capacity constraint in the Waipapa, Kerikeri area and Kaeo areas, which is now the most significant load centre in the southern part of our network. This constraint is discussed in Section 5.11.2.5.

- Increasing the supply capacity to the Russell peninsula. While there are two submarine cables supplying the peninsula, both terminate on the supply side of the single 11kV circuit between Okiato Point and the Rawhiti tee. Hence the two cables act as a backup to one another and are unable to share the load.

5.12.2.1 Consumer Connections

This relates to new assets, including transformers and small network extensions required to connect new consumers to the network. It is largely funded by capital contributions. Our total forecast expenditure on consumer connections and our forecast recovery in capital contributions is shown in Table 5.19.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Consumer driven-funded by capital contribution	3,500	1,646	1,279	1,279	1,279	6,406
Consumer driven-funded by Top Energy	613	611	610	610	610	2,345
Total	4,113	2,357	1,889	1,889	1,889	8,751

Note: Totals may not add due to rounding

Table 5.19: Consumer Connection Expenditure Forecast

5.12.2.2 Russell Reinforcement

We are planning to install a new 11kV cable between the termination of the Veronica Channel submarine cable at Okiato Point and the tee off point to the Rawhiti spur. This will enable the two submarine cables to share the load on the Russell peninsula and increase the supply capacity into an area experiencing high demand growth.

5.12.2.3 Wiroa 110/33kV Substation

To address the potential voltage constrain at Kaeo and Waipapa discussed in Section 5.11.2.5 we plan to construct a 110/33kV injection point at our existing 33kV switching station at Wiroa. The new substation, which we plan to construct over FYE2023-25 will have two transformers and will be supplied by incoming circuits connected to Kaikohe and Ngawha.[10] Three winding transformers are planned to provide for a future new point of injection into the 11kV network.

5.12.2.4 33kV Incoming Circuit - Kaeo

We are planning to construct a second 33kV incoming circuit into the Kaeo substation supplied from Wiroa. This circuit will utilise the Wiroa-Kaitaia 110kV line structures north of Wiroa and then divert onto a new single circuit line into the substation. This work is now planned for completion in FYE2031.

5.12.2.5 Kaitaia Substation Upgrades

Planned upgrades to the Kaitaia 110kV substation include the construction of a new line bay to accommodate the new incoming circuit from Wiroa and reconfiguration of the existing 110kV bus to accommodate a bus tie circuit breaker and make room for a new 110/33kV transformer. The new transformer, which will replace the existing T5 single-phase bank, is programmed for installation in FYE2029.

5.12.2.6 Network Capacity Expansion Expenditure Forecast

Our capital expenditure forecast for network capacity augmentation project is shown in Table 5.20. The table does not include expenditure on the new 110kV Wiroa-Kaitaia circuit, which we have categorised as reliability expenditure, as this is the primary driver for this circuit given the relatively modest growth in consumer demand in the northern part of our supply area.

[10] The incoming double circuit line is currently operated as a single circuit and is energised at 33kV to supply Wiroa from Kaikohe. The two circuits will be split and energised at 110kV with the construction of the new substation.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Russell reinforcement	1,106	339				
Distribution feeder conductor size upgrades		339	318		1036	
Wiroa 110kV substation		2,979	3,543	2,946		
Wiroa substation ripple injection plant			755			
Reconfigure Wiroa line into Kaikohe 110kV bus			310			
Install new 110kV circuit breaker at Kaitaia				572	145	
Additional voltage regulator installations					413	
Kaitaia 110kV transformer						3,813
Garton Rd 110kV substation						3,760
Wiroa substation 11kV injection point						1,855
Kaeo 33kV incoming circuit						2,635
Upgrade Parapara SWER line to 11kV						350
Other	157	157	157	157	157	784
Total	**1,263**	**3,813**	**5,083**	**3,676**	**1,750**	**13,195**

Note: Totals may not add due to rounding

Table 5.20: Network Capacity Augmentation Forecast

5.12.3 Priority 3 – Reliability Safety and Environment

Improvement of supply reliability, measured by network SAIDI and SAIFI, has been the primary driver of our network development programme for the last two regulatory periods. This has focused on rehabilitating our subtransmission network, adding new zone substations, the installation of upgraded protection systems to improve the security of the 33kV system and, most recently, the installation of diesel generation to secure those parts of the subtransmission system that are vulnerable through a lack of redundancy. As a result of these initiatives, the average annual time off supply per customer due to unplanned interruptions, after normalising for the impact of severe weather events, has reduced from about 350 minutes in FYE2009-10 to 260 minutes in FYE 2019-20, as shown in Figure 4.1. Similarly, the average number of interruptions per customer per year has reduced from around 4.5 to 3.5 over the same period.

The installation of generation in the Kaitaia area has mitigated, to a significant degree, the dependence for supply to Kaitaia on the single circuit 110kV line. However, it is unable to supply our largest customer JNL, and cannot prevent a short period of outage following a fault while generation is started and brought online. Over time, the cost of operating this generation will also increase as climate change increases the cost of carbon emissions under the government's emissions trading scheme. For these reasons we do not see operation of these generators for extended periods of time as economic, or environmentally desirable. This would be required, for example, if the existing 110kV line needs to be reconductored sometime after 2030. It is also uncertain whether the cost of battery storage will reduce to the point where an alternative solution, likely to be photovoltaic generation stabilised by batteries, will become technically or economically viable as an electricity supply alternative to the Far North.

We therefore plan to proceed with the construction of our planned Wiroa-Kaitaia circuit, but have deferred completion until FYE2030, by which time our current generation plant will be approaching the end of its economic life. In the meantime, our reliability improvement focus will be on making incremental improvements to the reliability of our distribution network, primarily though the construction of interconnections between adjacent feeders. This is discussed further in Section 5.12.3.1.

This reliability, safety and environment (RSE) category also includes capital expenditure driven by safety and environmental considerations. The Waipapa substation is one of our older zone substations and its design no longer meets accepted industry practice, as it includes uninsulated high voltage equipment with low ground clearance. While assets have been individually replaced over the years as they have reached the end of their economic lives, this has not mitigated the design risk. We plan to address the most serious hazard in FYE2022 by replacing the overhead 11kV reclosers protecting each feeder with ground mounted ring main circuit breakers fed by underground 11kV cables. This will be followed up from FYE2028 with the construction of a new switchgear building and the installation of new 33kV and 11kV indoor switchboards. At the same time, we will move the two transformers to ground level to mitigate the earthquake risk.

5.12.3.1 11kV Feeder Reliability Improvements

These improvements include the construction of interconnections between adjacent feeders to allow supply to be fed back from the end of a feeder following a fault, once the faulted section has been isolated. This allows supply to be restored to consumers downstream of a fault, usually by remote switching from the control room before the fault is repaired. Other interventions include the installation of switches, fuses and reclosers on low-reliability feeders and the retrofitting of remote control to existing switches.

5.12.3.2 Other Reliability Improvement Projects

Other capitalised reliability improvement projects include improvements to our protection systems, so they operate and discriminate more effectively, and interfacing our SCADA system to the ADMS. At the end of the planning period, we have allocated expenditure to interface the 11kV tertiary winding on the 40MVA 110kV transformer at Kaitaia to the 11kV network. The Waipapa zone substation upgrade has different drivers and is categorised as “Other Reliability, Safety and Environment” under the Commerce Commission’s expenditure classification. Another small project in this category is the relocation of the protection cabinets at the Mt Pokaka 33kV tee. These are currently pole mounted and are to be relocated to ground level to be protected from stock and to allow better access by technicians, who do not normally work at height.

5.12.3.3 Reliability Safety and Environment Expenditure Forecast

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Reliability of Supply						
Property rights for 110kV Wiroa-Kaitaia line	104	27	27			
Construction of 110kV Wiroa-Kaitaia line				696	5,410	35,968
Rangiahua-South Rd feeder interconnection		224		545		1,168
Matauri Bay-Whangaroa feeder interconnection		817	528			
Bulls Gorge-Moerewa feeder interconnection				650		
Other 11kV network reliability improvements	511	565	511	887	350	1,672
Communications system upgrade	216	92	163			
Minor zone substation upgrades	57	104	35	35	35	173
Protection improvements	214	313				
Subtotal	**1,097**	**2,142**	**1,263**	**2,812**	**5,795**	**38,980**

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Other Reliability, Safety and Environment						
Waipapa substation upgrade	545					3,797
Subtotal	**545**					**3,797**
Total	**1,642**	**2,142**	**1,263**	**2,812**	**5,795**	**42,778**

Note: Totals may not add due to rounding.

Table 5.21: Reliability Safety and Environment Capital Expenditure Forecast

5.12.4 Priority 4 - Technology Development

As discussed in Section 5.7, we actively monitor the emergence of new technologies and their potential benefits both to ourselves as network operators and to other network users, and we are open to embracing these technologies when the time is right. Currently their most promising application to our network appears to be remote area power supplies (RAPS) but, as discussed in Section 5.7.3, we have not been able to identify an application where a RAPS solution is potentially economic.

We have, however, allocated expenditure to initiatives aimed at maximising the benefits of our recently installed ADMS system. Our experience to date is that we do not fully capture the potential benefits of this system because of limitations in the available network data. We plan to address the remaining data gaps in respect of utilising this system for the management of our 11kV distribution network and over the next three years to undertake a significant low voltage network data capture initiative. We anticipate a step improvement in the management of our low voltage assets as we apply the functionality of the ADMS to this somewhat neglected area of our network management.

A breakdown of our forecast expenditure on these initiatives is shown in Table 5.22.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31
Complete ADMS data validation	159					
LV network data capture	314	836	520			
Total	**473**	**836**	**520**			

Note: Totals may not add due to rounding.

Table 5.22: Technology Development Expenditure Forecast

5.12.5 Consolidated Capital Expenditure Forecast

The allocation of our capital expenditure forecast to the different capital expenditure drivers is shown in Table 5.23 and graphically in Figure 5.4.[11] The category with the highest expenditure is asset renewal, consistent with our commitment to maintain our existing assets so they remain fit for purpose. The high expenditure on reliability improvement is driven by the cost of constructing the new 110kV line into Kaitaia, planned for completion in FYE2030.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31	Average Annual
Asset renewal	6,888	6,244	5,946	6,682	6,414	35,862	6,804
Customer connections	4,113	2,257	1,889	1,889	1,889	8,751	2,079
Capacity expansion	1,263	3,813	5,083	3,676	1,750	13,195	2,878
Reliability improvement	2,116	2,978	1,783	2,812	5,795	42,778	5,826

[11] The relatively small technology development expenditure has been integrated into the reliability, safety and environment expenditure category. This is consistent with the approach taken by the Commerce Commission.

$000	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027-31	Average Annual
Total	14,379	15,293	14,701	15,059	15,847	100,586	17,586

Table 5.23: Consolidated Capital Expenditure Forecast.

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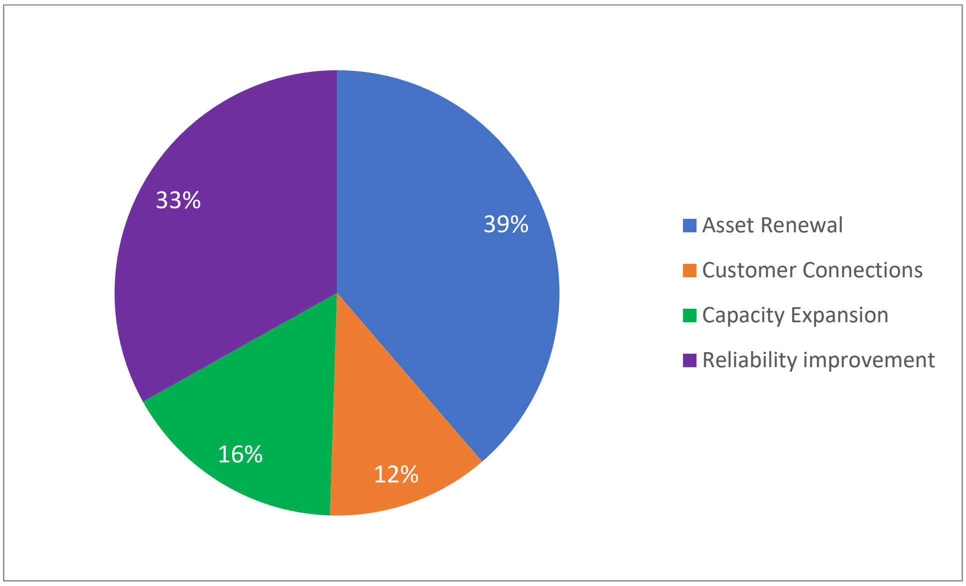

Figure 5.4: Allocation of Capital Expenditure to Expenditure Drivers

Section 6 Life Cycle Asset Management

6 Lifecycle Asset Management

This section of the AMP outlines the policies, strategies, and practices that we use to ensure that assets deliver acceptable performance and can be operated safely over their full economic service life.

6.1 Maintenance and Renewal Planning Criteria and Assumptions

Our lifecycle asset management practices are planned to deliver the required level of service for the lowest possible lifecycle asset cost. We use a risk-based approach where we control our risk exposure by:

- ensuring our assets do not pose a safety risk to the public or to our employees and contractors; and
- focusing our maintenance effort on critical assets, where criticality is a function of both the probability and consequence of an asset failure.

Our forecast maintenance costs are categorised as follows:

6.1.1 Service Interruptions and Emergencies

Our service interruptions and emergency expenditure forecast provides for the reactive maintenance, and if necessary, replacement, of assets where immediate and unplanned intervention is required to address critical safety issues or to maintain supply to consumers. This work is driven by unexpected asset failures, which can result from third-party interference such as a car hitting a pole, foreign interference from birds or animals, damage from lighting or storms, or asset component failures. The forecast, which is based on costs incurred in previous years, has two elements; an opex element that covers the repair or replacement of components and a capex element that covers the replacement of complete assets.

Our Kerikeri control room is staffed at all times, and field staff are on standby outside normal working hours to attend to service interruptions and emergencies. The cost of operating our control room is included in the system operations and network support forecast and is not considered a lifecycle asset management cost.

6.1.2 Routine and Corrective Maintenance and Inspection

Our routine and corrective maintenance and inspection programme is designed to ensure that assets continue in service for their expected economic life. It includes targeted asset inspections and non-invasive condition assessments, together with invasive maintenance interventions to reduce the likelihood of premature failure of key assets. In line with our risk-based maintenance philosophy, the programme is driven by asset health and criticality; it focuses on assets where end-of-life drivers are most likely to be present, and also on assets where an unexpected failure would result in widespread supply interruptions or a high safety risk.

6.1.2.1 Asset Health Indicators

We use the EEA's Asset Health Indicator (AHI) Guide to describe the condition of an asset. This uses the five-point categorisation shown in Table 6.1.

EEA Asset Health Indicator Guide	
H5	As new condition - no drivers for replacement
H4	Asset serviceable – no drivers for replacement, normal in-service deterioration
H3	End-of-life drivers for replacement present, increasing asset related risk
H2	End-of-life drivers for replacement present – high asset related risk
H1	Replacement recommended

Table 6.1: Asset Health Indicator Categorisation

Under the EEA classification, the transition between H4 and H3 marks the “onset of unreliability”, which is the point at which an asset starts to deteriorate, and closer monitoring of its condition is justified.

6.1.2.2 Risk Based Inspection and Maintenance

All assets are visually inspected in accordance with a time-based inspection program, where the frequency of inspection depends on the type of asset and the expected rate of deterioration. During the inspection, the inspector notes any asset defects and determines whether the asset is likely to remain in service until the next programmed inspection. Where it is determined that an asset may not survive until its next programmed inspection, it is diverted into the defect management system described in Section 6.1.2.3. Assets rated H1-H3 under the EEA’s asset health indicator categorisation system fall into this category.

6.1.2.3 Defect Management

The objective of our defect management system is to ensure that:

- Assets exhibiting end-of-life drivers are re-inspected at appropriate intervals.
- Maintenance is undertaken as necessary to extend the life of the asset.
- Assets are replaced at the appropriate time. This will depend on the criticality of the asset, which is primarily determined by the consequences of an in-service failure; critical assets are replaced earlier to minimize the risk of the asset failing, whereas non-critical assets may be allowed to run to failure.

When an asset enters the defect management system, it is assigned a defect priority as follows:

- X defects are considered to present a high risk. Assets with an X defect are monitored monthly until the defect is remediated.
- A-Defects are considered to present an elevated risk. Assets are monitored six-monthly until remediation is completed.
- B-Defects are equipment considered to present an increasing risk. Assets are monitored two-yearly until remediation is completed.

These defect priorities are broadly equivalent to the risk categories R1-R3 in the EEA’s recently published Asset Criticality Guide. Risk categories in the criticality guide are two dimensional in that they take into account not only the condition of an asset but also the consequences should the asset fail in service.

This frequent monitoring of known defects enables risk to be regularly assessed. If a change in risk is identified, then the defect priority is updated, and the frequency of re-inspections is changed. This approach ensures defects are actively monitored and managed. Data on any backlog in the repair or re-inspection of defects is included in the General Manager Network’s monthly Board report.

Additional measures are also taken to ensure that defect management is both effective and efficient. These include:

- Faults due to equipment failure are cross-referenced to the defect register to determine whether the fault was the consequence of a known defect. The SAIDI and SAIFI impacts of equipment failures are also reviewed annually. These processes are used to assess the effectiveness of our defect management.
- We coordinate the management of defects with our asset renewal capex programme, so we don’t repair defects shortly before an asset is to be renewed. Situations may also arise where several small defects on a single asset drive earlier asset renewal.
- Asset components may be separated out and managed separately if we find, through fault analysis, that their failure rate is increasing. We have already identified an increasing trend in crossarm failures and have made a separate provision in our asset renewal capex forecast for a proactive crossarm replacement programme.

The defect management process is shown in Figure 6.1.

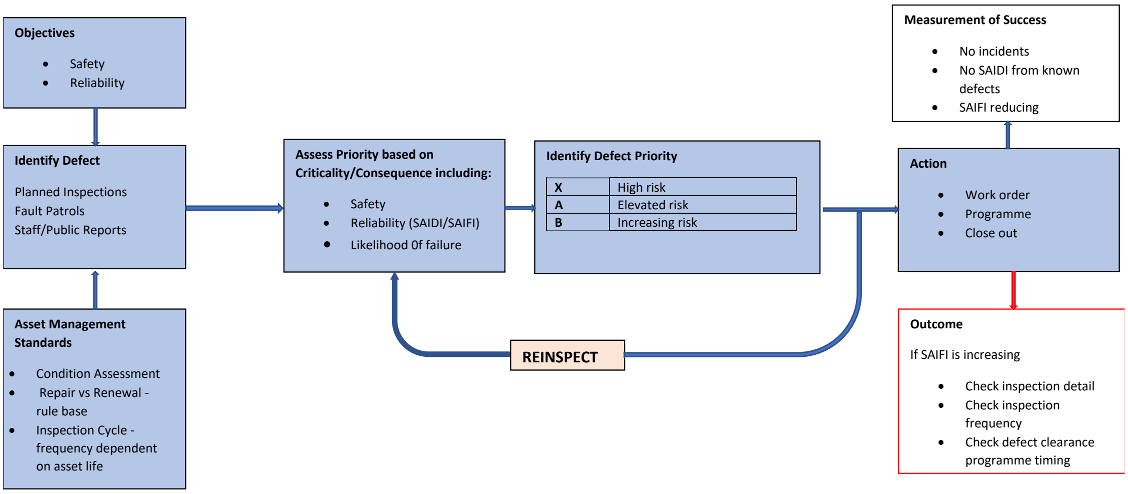

Figure 6.1: Defect Management Process

When the asset enters the defect management system, it is assigned a defect priority as follows:

- X defects are considered to present a high risk. Assets with an X defect are monitored on a monthly cycle until the defect is remediated.
- A-Defects are considered to present an elevated risk. Assets are monitored on a six-monthly cycle until remediation is completed.
- B-Defects are equipment considered to present an increasing risk. Assets are monitored on a two-yearly cycle until remediation is completed.

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6.1.3 Replacement and Renewal Maintenance

Replacement and renewal maintenance are proactive condition-based maintenance triggered by the findings of the inspection, condition assessment and defect management programmes described in Section 6.1.2. The objective of the renewal maintenance programme is the prevention of unexpected, in-service failures with unacceptable safety or network performance consequence.

Whether defect-driven asset replacement and renewal activities are treated as opex or capex is often an issue of scale. Should an inspection identify a problem requiring the replacement of part of an asset, such as an insulator or cross arm, defect remediation would be classed as a repair and treated as opex. Should a complete asset, such as a pole, need to be replaced the cost of the work would be capitalised (capex). We also capitalise maintenance projects targeted at the proactive replacement of crossarms and pole top hardware as these generally do not last as long as their associated concrete pole and are a primary cause of supply interruptions due to defective equipment. Capital replacements are discussed further in Section 6.1.4.

6.1.4 Capital Replacement

Once an asset has deteriorated to the point where it cannot economically be kept in service applying renewal maintenance strategies it is replaced. Our asset replacement strategies for each asset category are described in Sections 6.3-6.11.

Our capital forecast for the replacement of existing assets (as distinct from the creation of new assets) is described in Section 5.12.1. As described in that Section, there are four components:

- Capex in response to service interruptions and emergencies (Section 6.1.1). This expenditure is reactive, and the forecast is based on historic costs.
- Reactive capex driven by our defect management system. Again, this forecast is based on historic costs.
- Proactive expenditure on refurbishment projects. Most of this expenditure is on subtransmission and distribution line refurbishments and is driven by the lower unit cost of replacing assets as part of a structured refurbishment project than that of replacing individual assets on a piecemeal basis. Some of this expenditure is allocated to the proactive replacement of critical substation assets known to be in poor condition.
- Expenditure on the proactive replacement of assets on a piecemeal basis. The need for this expenditure is determined by our top-down assessment of the health of our different asset fleets and the need to keep the overall health of each asset fleet at an acceptable level. Our top-down analysis of the various asset fleet categories is presented in Sections 6.3-6.11.

6.2 Vegetation Management

6.2.1 Introduction

Vegetation is hazardous if it contacts live conductors. We manage the consequent public safety risk through our protection systems, which see vegetation contact as a fault and interrupt supply.

Vegetation contacting or falling on our electricity assets presents several public safety risks:

- Electrocution
- Fire
- Power surges
- Network equipment failure (e.g. powerlines and poles breaking/falling)

Our preferred strategy is to permanently eliminate a vegetation hazard by:

- Establishing vegetation clear zones where no planting is permitted. However, we do not own the planting under our line and have limited property rights over the land where our assets are located. This limits our ability to unilaterally require tree clearing; an agreement is generally required. Nevertheless, new plantings need to minimize foreseeable hazards that they may potentially create.
- Eliminating hazards by relocating lines to a safer location. This is again by agreement with the landowner and/or tree owner. For new plantings, such as commercial woodlots and shelterbelts, there are safety obligations under the Health and Safety at Work Act 2015 on Persons Controlling a Business or Undertaking (PCBU).
- Requiring active management on an ongoing basis, where a tree owner prefers trimming. We will seek an agreement with the tree owner on how they intend to meet their obligation to maintain vegetation at a safe clearance from our assets as defined in the Electricity (Hazards from Trees) Regulations 2003. This will include trees that, although they are outside regulatory clearances, still present a risk of falling onto our assets.

Secondary to safety is the issue of service interruption caused by vegetation. Contact with vegetation has a significant impact on our supply reliability. Outage statistics demonstrate that our supply area has a high vegetation growth rate, which creates a high tree trimming workload. This requires an intense and focussed vegetation control program to achieve an acceptable outcome within the limitations of the resourcing available within the region.

Faults that result from trees growing into lines (as distinct from those falling) are a failure of the tree owner and/or landowner to maintain compliance with the required regulatory clearance. Once such a fault occurs, the situation has progressed to a level of hazard that, for safety reasons, requires specialist competencies to remedy. We necessarily must be involved.

Our vegetation management strategy is discussed in greater detail in the following sections:

6.2.2 Risk Management

Tree owners' lack of awareness of safety issue and their responsibilities.	• Advertising and public safety campaigns. • Notices to tree owners in accordance with the Electricity (Hazards from Trees) Regulations 2003.
Vegetation burning in power lines (includes overhanging vegetation).	• This is a serious hazard requiring urgent intervention. We notify tree owners and, where necessary, use our powers under the Electricity (Hazards from Trees) Regulations 2003 to remove the immediate threat and achieve a forced cut within three months.
Other vegetation risks include: • Ascendable trees growing close to power lines allowing potential access to live conductors. • Vegetation growing close to power lines presenting a future risk to power lines and public safety. • Trees at risk of falling that are within the fall distance of power lines. • Trees shedding bark or branches that fall or get blown onto power lines. • Vegetation covering ground mounted equipment or growing around poles and restricting access. • Vegetation entering ground mounted equipment near or on live components. • Persons attempting to remove vegetation encroaching live equipment without being aware of the risks or not taking the necessary precautions. • Vegetation growing into private lines or service lines that we do not own.	Our risk management strategies include: • Liaising with vegetation owners to remove vegetation or trim it to achieve the required regulatory clearances. • Not re-energising private lines after vegetation has caused a fault until vegetation has been removed or trimmed by the line owner. • Use of covered conductor in exceptional circumstances. • Provision of close approach and isolation services to tree owners managing their own vegetation. • Negotiation of formal agreements with tree owners on future management of the site and safety coordination. This applies particularly to commercial plantings.

6.2.2.1 Vegetation in Road Reserves

The New Zealand Transport Agency (NZTA) has advised us that it has "no interest" in vegetation growing within its road reserves and the FNDC has similarly advised that it has "no interest" in vegetation growing within its road reserves in rural areas. We manage this vegetation ourselves without a requirement for owner consent. Our management strategies include:

- Mechanical clearing at ground level.
- Hedge trimming where accessible from the roadside and neighbouring property.
- Spraying canopy or injecting the trunk.

We take a less aggressive approach to protected trees or, at our discretion, where we consider a tree has a high amenity value. Sections 6.2.3-6.2.4 provide additional information on our work practices.

Trees growing within urban road reserves are "owned" by the FNDC and are managed in accordance with our protocols for the management of privately-owned trees.

6.2.3 Preventive Maintenance

Inspections.	• Reactive post fault inspections as required. • Annual vegetation proximity and risk inspections of 110kV and 33kV lines. • Two-yearly vegetation proximity and risk inspections of other lines.
Administration.	• Public safety campaigns and information mail drops. • Notices to tree owners. • Negotiation of agreements with tree owners.

6.2.4 Summary of Tree Management Practices

General.	• All lines are surveyed regularly for vegetation interference in accordance with inspection frequencies in Section 6.2.3. • During these inspections, vegetation is assessed for compliance with Electricity (Hazards from Trees) Regulations 2003. • Where applicable, vegetation owners are then engaged and assisted in managing their vegetation in accordance with our vegetation management strategies.
Hedges.	• Hedges are recorded in a register. Owners are encouraged to trim their hedges with a regular trimming cycle. • Hedge owners are encouraged to remove high hedges or reduce height allow hedges to be trimmed without violating the regulatory minimum approach distances to live lines. • Reminder notices are issued regularly to encourage hedge owners to trim hedges before they become a hazard to lines that would then require our intervention. • Bamboo hedges present a higher risk due to their growth rate and their potential for being pulled into lines at ground level. Owners are advised to remove the hedge as the only practical solution.
Privately owned trees and FNDC trees in urban zones.	• Tree owners are encouraged to remove trees that have the potential to threaten lines or that require ongoing trimming and expense beyond the value of the tree. • We will offer (once only) to remove or cut trees at our cost to a state manageable by the tree owner. In return, the tree owner will be required to sign an agreement that no tree will be planted on their property (knowingly or not) that could interfere with our network equipment. Any vegetation found interfering with network equipment thereafter will be removed at the owner's cost. • A tree owner who does not take up the option outlined above will be subject to the Electricity (Hazards from Trees) Regulations 2003. Trees will receive a first cut and trim and any vegetation management costs we incur thereafter will be charged to the tree owner.
Farm plantings and commercial wood lots.	• A formal agreement recording PCBU-to-PCBU safety coordination is required. This defines the responsibilities for the management of identified hazards and safe access on a at all times.
FNDC trees in non-urban zones.	• Trees in non-urban areas are of "no interest" to FNDC and are trimmed or removed at our discretion and cost.

NZTA trees.	• Trees within state highway road reserves are of "no interest" to NZTA and are trimmed or removed at our discretion and cost.
Trees on Department of Conservation (DOC) land.	• These are removed or trimmed at our cost and as agreed with DOC.

6.3 Poles

6.3.1 Failure Modes

Interference.	• Excavations. • Third party attachments (drilling into poles). • Accidental contact (vehicles).
Typical degradation.	• Spalling, rotting, rusting of poles. • Foundation movement.
Accelerated degradation.	• Material degradation in coastal and geothermal environments. • Vehicular impact. • Tree falling. • Ground subsidence.
Known equipment issues.	• Wood poles are organic and are susceptible to rot and cellular breakdown. The breakdown rate is variable and dependent on the tree type, growing environment, pole processing, wood treatments and environmental conditions in which the pole is installed. These variables make the rate of deterioration of wood poles unpredictable. Larch poles pose a heightened risk as they can look good on the outside but be hollow and weak inside. • L-and T-shape concrete poles have a known construction flaw. Short pieces of reinforcing were welded together to make full length pieces when the correct length was unavailable. Affected units have failed and the whereabouts of these units is unknown.

6.3.2 Risk Management

Climbing a pole identified as "unsafe to climb".	• Any pole assessed as unsafe to climb is tagged with a "DO NOT CLIMB" tag and must not be climbed without being mechanically supported.
Wood pole loses strength due to rot.	• All wood poles are treated as unsafe and given a below ground inspection to determine they are safe before they are climbed. • We have ultrasonically checked all wood poles on the network for residual strength and all high-risk poles identified by this process have now been replaced. The results of this assessment are now being used to prioritise poles for scheduled replacement.
L/T shape pole failure.	• L and T-shape poles are not climbed without being supported. These are not tagged, as field staff are made aware of this requirement during competency training.
Poles can be climbed unassisted.	• New structures are designed to be difficult to climb unassisted. Securing signage and other attachments to our poles is prohibited. The Far North District Council is aware of the risk and this restriction. • When a climbable pole is discovered, we undertake a risk assessment and prioritise remediation as appropriate to manage the risk. This may

include removing the climbing aid, installing a climbing barrier, or replacing the pole.

6.3.3 Preventive Maintenance

Visual.	• Reactive patrols post-fault as required. • Pole condition assessment in accordance with our risk-based inspection strategy.
Test.	• Wood pole ultrasonic serviceability assessment programme.

6.3.4 Corrective and Reactive Maintenance

Minor unplanned and reactive remediation.	• Foundation repair and stay installations. • Hardware replacements.

6.3.5 Age and Condition – Concrete and Steel Poles

6.3.5.1 Subtransmission – 110kV

Steel Towers

The 12 steel tower steel towers were installed about 1966 as they were used to support the dismantled 50kV line that originally supplied Kaitaia. These have been well maintained and are still in serviceable condition.

Steel Poles

There were 43 steel poles installed in FYE2020 on the new 110kV line that was built to transmit the power generated by the new OEC4 unit at Ngawha power station to the grid at Kaikohe. There are also 33 steel poles are on the Kaikohe-Kaitaia line, all of which have been installed since we acquired this line from Transpower in April 2012. All 110kV steel poles on our network are in as new condition.

Concrete Poles

The numbers in the 110kV concrete pole age profile below represent structures rather than individual poles. There is some uncertainty about the accuracy of the age data we have on our 110kV assets. We think the line was commissioned in 1980 prior to the commissioning of the Okahu Rd substation. It may be that some poles were relocated assets when they were installed.

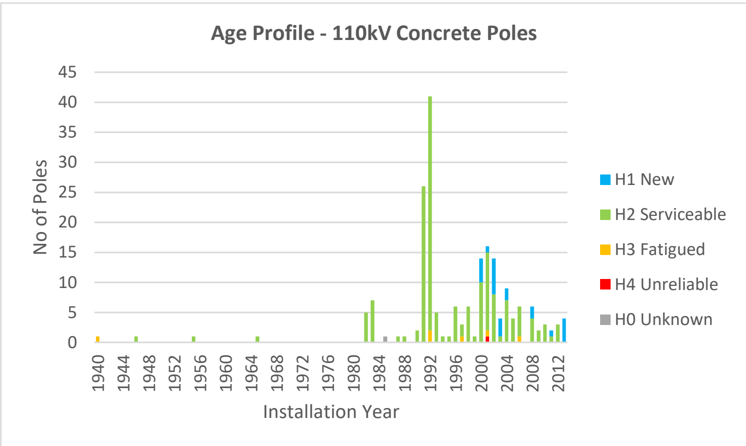


Figure 6.2: Age Profile – 110kV Concrete Poles

6.3.5.2 Subtransmission-33kV

Steel Poles

There are 83 steel poles or tower structures on our 33kV subtransmission network. These include the poles installed on the new Kaikohe-Wiroa line, which is constructed at 110kV, as it will eventually form part of the planned second 110kV circuit to supply our northern area but is currently operating at 33kV. Of these, ten structures on the Moerewa-Haruru line are in fatigued condition and a project to replace these poles is in progress.

Concrete Poles

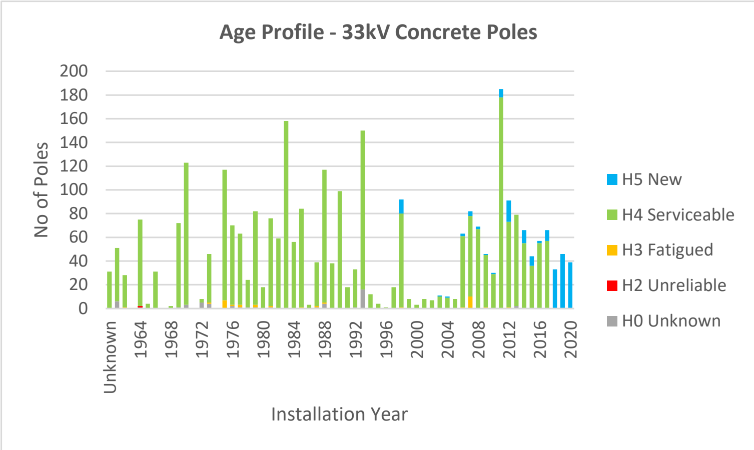


Figure 6.3: Age Profile – 33kV Concrete Poles

6.3.5.3 Distribution - Concrete

Two and Three Wire Lines

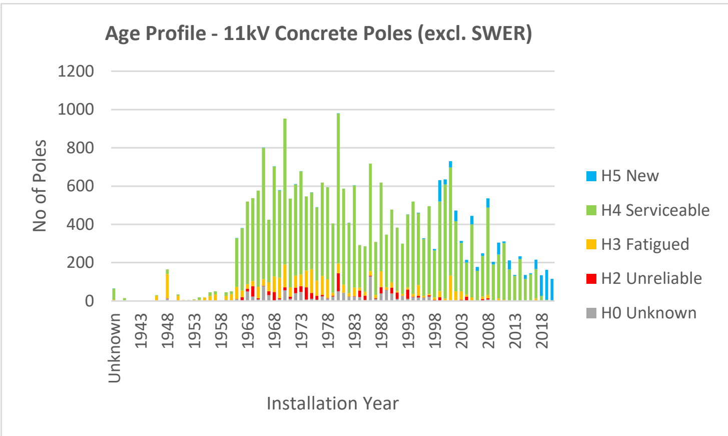


Figure 6.4: Age Profile - Distribution Concrete Poles (excl. SWER)

SWER

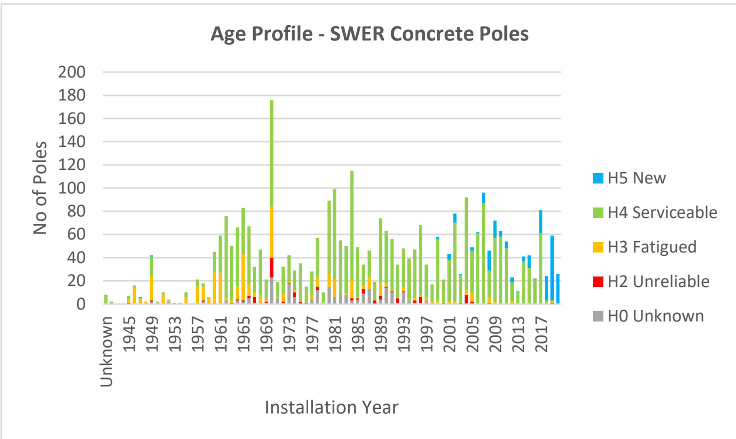


Figure 6.5: Age Profile - SWER Concrete Poles

6.3.5.4 Low Voltage

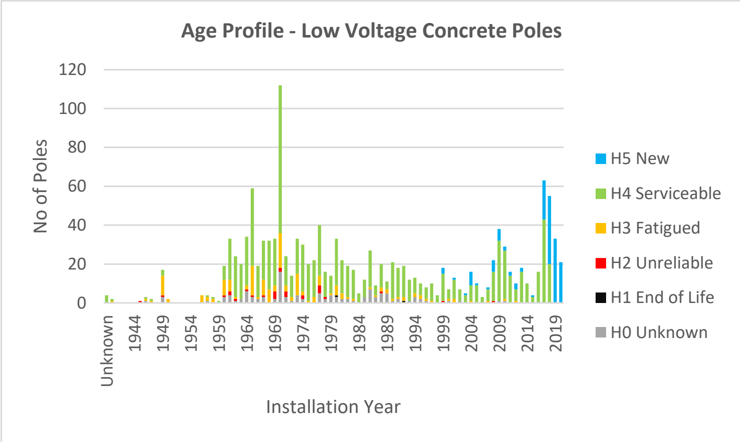


Figure 6.6: Age Profile – Low Voltage Concrete Poles

6.3.6 Wood

6.3.6.1 Subtransmission-110kV

All of our 110kV wood poles are on the Kaikohe-Kaitaia line. The numbers in the age profile below represent structures rather than individual poles. There is some uncertainty about the accuracy of the age data as the line was commissioned in 1980 prior to the commissioning of the Okahu Rd substation however it may be that some poles were relocated assets when they were installed.

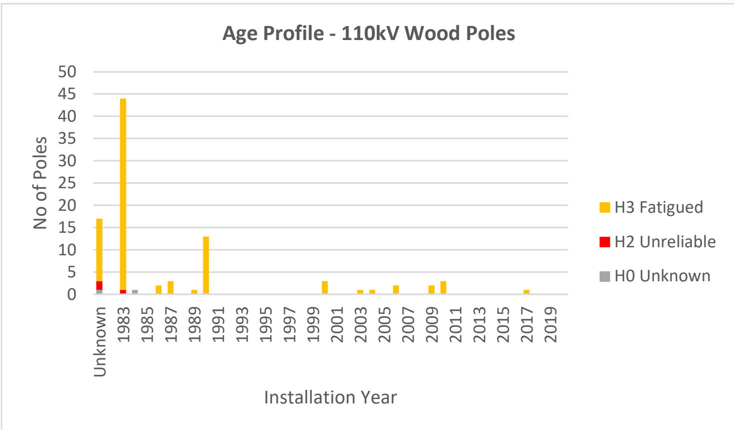


Figure 6.7: Age Profile – 110kV Wood Poles

6.3.6.2 Subtransmission-33kV

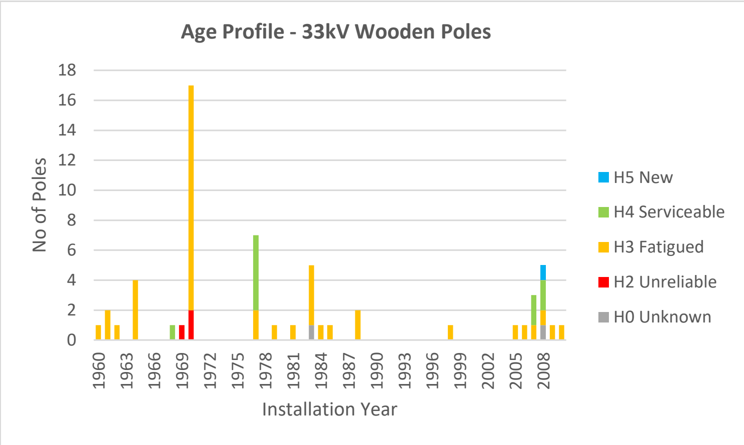


Figure 6.8: Age Profile – 33kV Wood Poles

6.3.6.3 Distribution

Two and Three Wire Lines

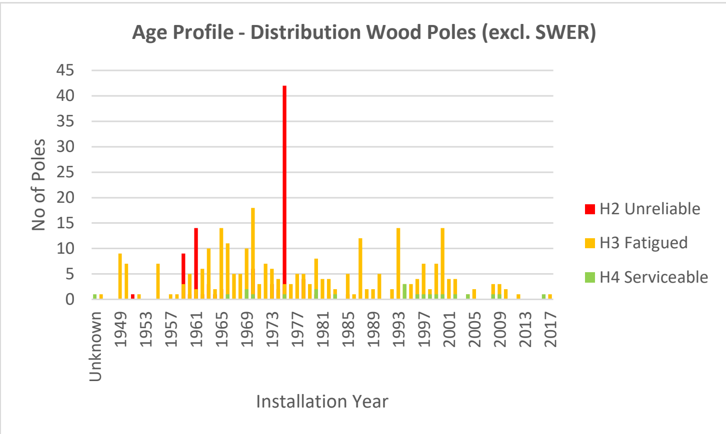


Figure 6.9: Distribution Wood Poles (excl. SWER)

SWER

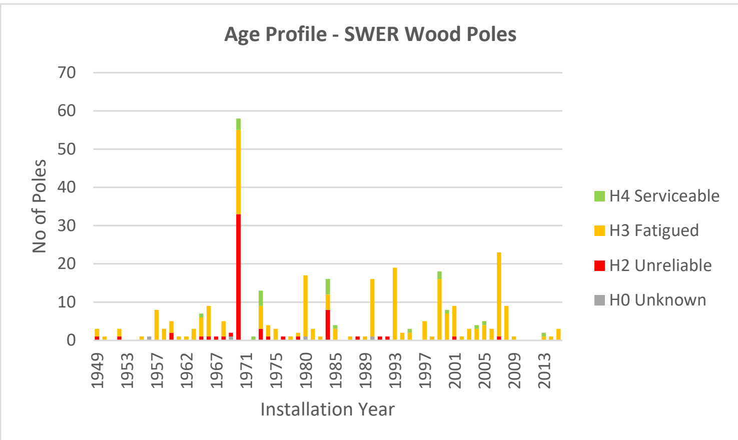


Figure 6.10: Age Profile – SWER Wood Poles

6.3.6.4 Low Voltage

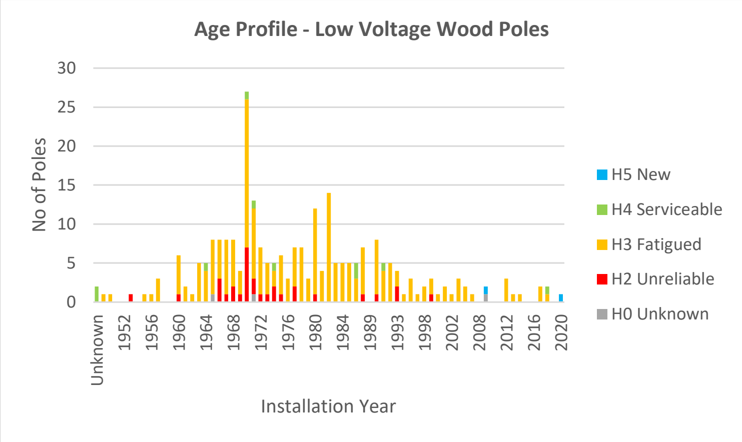


Figure 6.11: Age Profile – Low Voltage Wood Poles

6.3.7 Pole Health Summary

6.3.7.1 Concrete Poles

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV	1	-	1	6	167	23	**198**
33kV	50	-	1	32	2,673	197	**2,953**
11kV 2 and 3 wire	1,054	-	794	2,448	21,655	1,018	**26,969**
11kV SWER	207	-	84	409	2,352	218	**3,270**
LV	113	2	28	153	944	145	**1,385**
Total	**1,425**	**2**	**908**	**3,048**	**27,791**	**1,601**	**34,775**

Table 6.2: Health Summary – Concrete Poles

6.3.7.2 Wood Poles

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV	2	-	3	84	-	-	**89**
33kV	2	-	3	42	10	1	**58**
11kV 2 and 3 wire	-	-	93	278	22	-	**393**
11kV SWER	4	-	61	233	21	-	**319**
LV	3	-	31	213	10	2	**259**
Total	**11**	**-**	**191**	**850**	**63**	**3**	**1,118**

Table 6.3: Health Summary – Wood Poles

6.3.8 Replacement Programme

110kV structures.	• These are critical assets and replacement of structures in poor condition is prioritized. We have allowed for the repainting and replacement of rusted members on one steel tower per year. When the conductor needs to be replaced,

	which will be sometime after 2030, we will assess tower condition to determine whether replacement with steel poles is justified. • Our forecast also allows for the replacement of two pole structures per year, prioritized by structure condition.
Wood poles.	• We have an accelerated replacement programme in place for wood poles as a risk management measure, as pole deterioration is often internal and can be hard to detect. We are planning for the proactive replacement of approximately 120 poles per year, which will see all wood poles on the network replaced over the next 10 years. We are prioritizing replacements using the results of our recently completed ultrasonic wood pole testing programme.
Concrete poles.	• Concrete poles deteriorate slowly and usually remain serviceable for many years after end-of-life deterioration becomes apparent. We have allowed for the replacement of approximately 90 concrete poles per year. These are most likely to be L and T shaped poles, particularly where these are located in positions where access for a bucket truck or mobile crane is difficult. We expect our rate of concrete pole replacement to ramp up once most wood poles on our network have been replaced. • A small number of pole replacements each year are reactive and result from events such as vehicle damage or ground subsidence.

6.4 Crossarm Assemblies

6.4.1 Failure Modes

Typical degradation.	• Rusting insulator stems. • Rusting crossarm straps. • Rotting wood.
Accelerated degradation.	• Glass/porcelain insulator breakage (e.g., wind, impact, poor load design or installation).
Known equipment Issues.	• Two-piece ceramic insulator (prone to the top shearing off).

6.4.2 Risk and Mitigation

2-piece insulator failure during in-service handling.	• Pre-work assessment of two-piece insulator condition for work method augmentation and risk mitigation.

6.4.3 Preventive maintenance

Visual Inspection.	• Pole-top condition inspection from ground using binoculars at same time as a pole is inspected. • Reactive post-fault patrols as required.

6.4.4 Corrective and Reactive Maintenance

Pole head hardware.	• Replace affected components (e.g., arms, insulators, binders, straps, bolts).

6.4.5 Replacement Programme

Typically, up to 50% of the SAIDI impact of interruptions due to in-service equipment failure can be attributed to the failure of crossarms and insulators.

As crossarms and insulators are not treated as separate "assets" in our financial system, isolated component replacements are not capitalised. Operational expenditure constraints, and the fact that many crossarm and insulator defects are not seen during ground-based visual asset inspections, has resulted in an inadequate level of historical replacement.

We are introducing a new programme of crossarm and insulator replacements where these components will be proactively replaced over critical distribution network line sections. The line sections to be included in this programme will be selected based on analysis of the location of past high impact interruptions due to insulator and crossarm failure and are likely to be on feeder backbones close to zone substations. Proactive replacements over a specific line section will be treated as projects and capitalised.

6.5 Overhead Conductor

6.5.1 Failure Modes

Interference.	• Foreign object strikes line (e.g., windblown debris, drones). • Vegetation growing into lines (e.g., trees, vines). • Animal climbing or flying into lines (e.g., birds, possums). • Accidental contact (e.g., high load vehicles, fishing lines, people cutting trees).
Typical degradation.	• Connector (e.g., loosening or corroding). • Retention device (e.g., loosening or corroding binder, dead-end, or armour rod). • Degradation from natural environmental exposure.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Lightning strike. • Overloading (e.g., high demand, underrated conductors). • Vibration.
Known Equipment Issues.	• Steel conductor (e.g., rusting and weakening). • Copper conductor (e.g., aging and weakening). • Bi-metal 'pencil' connector (e.g., grease leaching). • Hot tap connector (e.g., temporary connector used as a permanent connector). • Two-piece ceramic insulator (i.e., prone to the top shearing off).

6.5.2 Risk and Mitigation

Conductor failure during in-service handling.	• No live line work on copper or steel conductor. (All live line work is currently suspended while a full risk assessment undertaken).
Close approach service.	• A close approach service is provided to enable contractors to better manage risk where conductors are present.

6.5.3 Preventive Maintenance

Visual Inspection.	• Post fault reactive patrols. • Two-yearly vegetation survey for conductors <33kV. • Annual vegetation survey for conductors ≥33kV.

6.5.4 Corrective and Reactive Maintenance

Conductor.	• Join broken conductors (i.e., no conductor replacement). • Cut out and replace damaged sections (i.e., partial span replacement).

- Whole span replacement (i.e. one or more span replacement).

6.5.5 Subtransmission-110kV Conductor

There is a total circuit length of 56km coyote ACSR conductor on the Kaikohe-Kaitaia line. This shows no significant visual indicators of deterioration. The conductor condition was assessed in 2009 and minor galvanisation deterioration was detected in the core. We are also installing vibration dampers when any structures on the line are replaced. Nevertheless, the age of the conductor is such that it could need replacement sometime after 2030.

In FYE2021 we commissioned a new 4.7km double circuit line to connect the Ngawha OEC4 generator to our network. This line uses nitrogen AAAC conductor.

6.5.6 Subtransmission-33kV Conductor

Most of our 349km of 33kV subtransmission conductor is AAC, although ACSR has been used over about 33km where extra strength is required. Approximately 36km of recently installed conductor is AAAC. An age profile of our 33kV subtransmission conductor is shown below. This conductor includes the Kaikohe-Wiroa line, which is energised at 33kV.

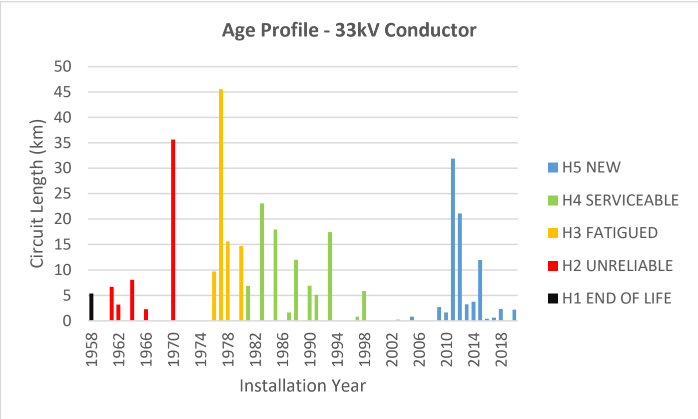


Figure 6.12: Age Profile – 33kV Conductor

6.5.7 Distribution Conductor – Two and Three Wire Lines

6.5.7.1 Aluminium and ACSR

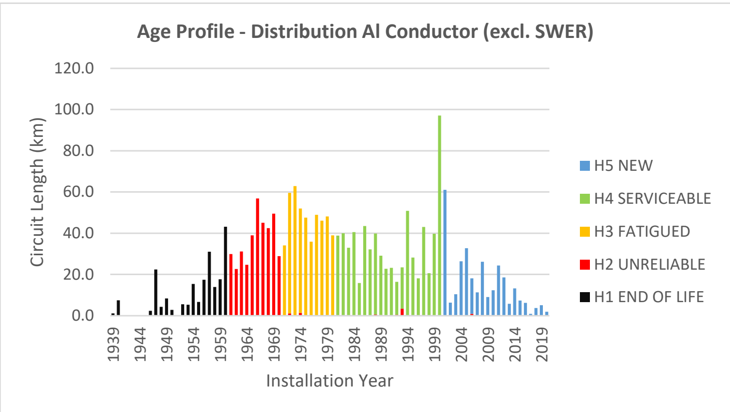


Figure 6.13: Age Profile – Distribution Aluminium and ACSR Conductor (excl. SWER)

6.5.7.2 Copper

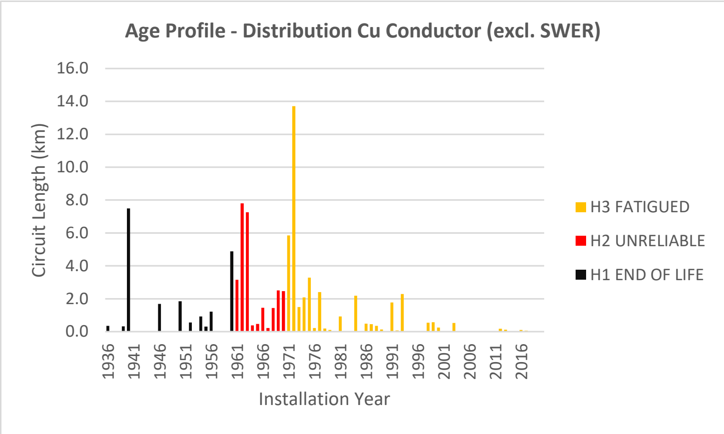


Figure 6.14: Age Profile - Distribution Copper Conductor (excl. SWER)

6.5.7.3 Steel

There is less than 0.5km of galvanised steel conductor remaining on our two-wire distribution network, all of which has reached end-of-life and is scheduled for replacement.

6.5.8 Distribution Conductor - Single Wire Earth Return Lines

6.5.8.1 Aluminium and ACSR

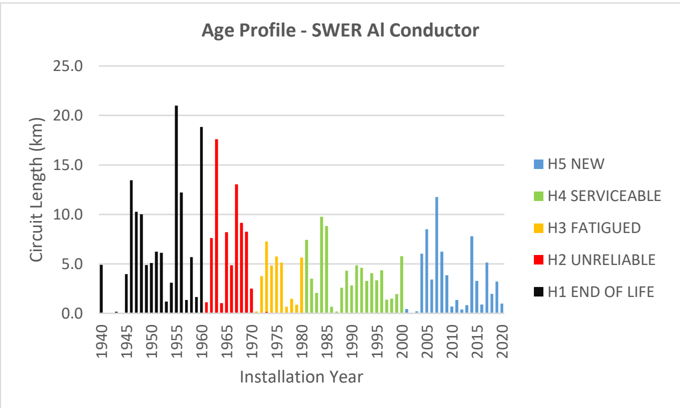


Figure 6.15: Age Profile – SWER Aluminium and ACSR Conductor

6.5.8.2 Copper

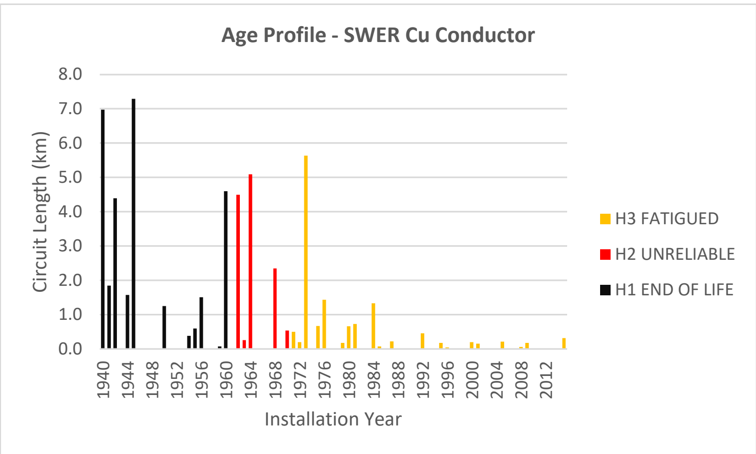


Figure 6.16: Age Profile – SWER Copper Conductor

6.5.8.3 Steel

There is a total of 22km of steel conductor remaining on our SWER network, all of which has reached end-of-life and is scheduled for replacement.

6.5.9 Low Voltage

6.5.9.1 Aluminium and ACSR

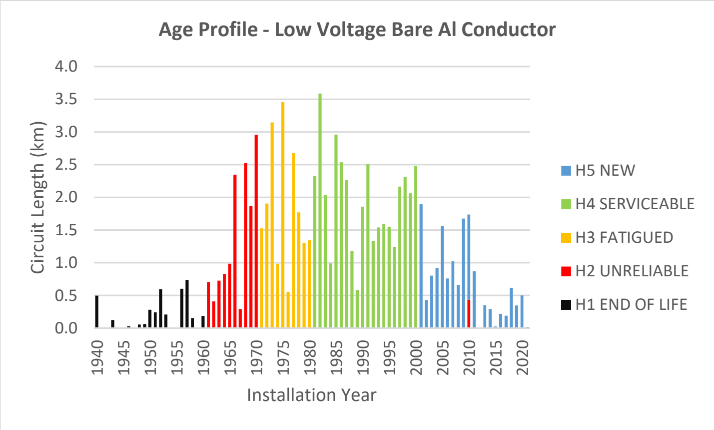


Figure 6.17: Age Profile – Low Voltage Aluminium and ACSR Conductor

6.5.9.2 Copper

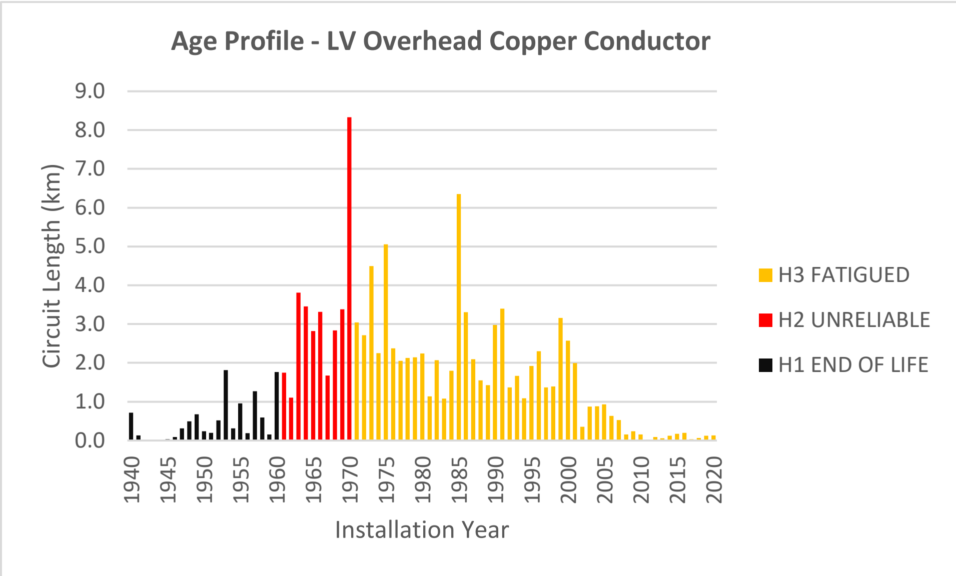


Figure 6.18: Low Voltage Copper Conductor

6.5.10 Overhead Conductor Health Summary

6.5.10.1 Bare Aluminium and ACSR Conductor

Circuit-km	Unknown	H1 End of Life	**H2 Unreliable**	**H3 Fatigued**	**H4 Serviceable**	**H5 New**	**Total**
33kV	-	5	56	86	98	83	**328**
11kV 2 and 3 wire	-	205	379	471	691	300	**2,046**
11kV SWER	-	130	74	36	77	67	**384**

LV	-	4	14	19	39	15	91
Total	**-**	**344**	523	612	**905**	**465**	2,849

Table 6.4: Health Summary – Aluminium and ACSR Conductor

6.5.10.2 Bare Copper Conductor

Circuit km	Unknown	H1 End of Life	**H2 Unreliable**	**H3 Fatigued**	**H4 Serviceable**	**H5 New**	**Total**
11kV 2/3 wire	-	20	27	41	-	-	**88**
11kV SWER	-	31	13	13	-	-	**57**
LV	-	10	33	80	-	-	**123**
Total	**-**	**61**	**73**	**135**	-	-	**268**

Table 6.5: Health Summary – Copper Conductor

6.5.10.3 Unknown Material – All Voltages

Circuit-km	Unknown	H1 End of Life	**H2 Unreliable**	**H3 Fatigued**	**H4 Serviceable**	**H5 New**	**Total**
Total		1	3	2	5	16	27

Table 6.6: Health Summary – Conductor (Unknown Material)

6.5.11 Replacement Programme

We are planning to replace up to 10 cct-km of conductor per year. This is prioritised as follows:

- Steel conductor: Steel is not a good conductor of electricity, but was used in remote areas, particularly on SWER lines, as it was strong, cheap, and enabled long spans. All our steel conductor has now deteriorated to the point where it has reached end-of life.
- Copper conductor: The 273km of copper conductor that remains in service is prone to failure due to its small size and deteriorating condition.
- Mink conductor: We have 85km of mink ACSR conductor on our network, much of which is now well over 60 years old. It is a small conductor that is prone to breakage and can be difficult to repair.

Once the steel conductor on our network has been replaced, we will start progressively replacing our copper and mink conductor, prioritising the conductor sections to be replaced by their condition.

6.6 Cables

6.6.1 Failure Modes

Interference.	• Third party excavation or drilling. • Anchor strike to submarine cables. • Storms moving moorings across submarine cables.
Accelerated degradation.	• Unsealed terminations in LV distribution allows water ingress. • Poor bedding or installation techniques can reduce sheath life.
Known Equipment Issues.	• Insulation used in early XLPE insulated cables is susceptible to water ingress and is known to have a reduced life. Cables installed pre-2000 may be affected.

6.6.2 Risk and Mitigation

Cable strike by third party excavation or drilling.	• A cable location service is provided to enable contractors to better manage risk when working where cables are present.
Damage to marine cable crossing from boat anchor or mooring.	• Signage is installed on shorelines and cable routes are marked on marine charts to minimise the risk of damage to submarine cables and harm to the public.

6.6.3 Preventive Maintenance

Visual.	• Associated equipment inspection. When equipment with a cable termination is checked, then the cable termination is also checked where practicable. • Annual submarine cable crossing signage assessment.

6.6.4 Corrective and Reactive Maintenance

Cable faults.	• Repair sheath damage. • Cut away damaged cable to good cable and join in a new piece. • Overlay larger, damaged sections.
Termination fault.	• Strip back old or damaged termination and repair. • Cut away damaged termination to good cable, join in a new piece, and terminate.

6.6.5 Subtransmission-33kV (XLPE)

We have a total of 21km of 33kV underground cable, all of which is in serviceable or as new condition.

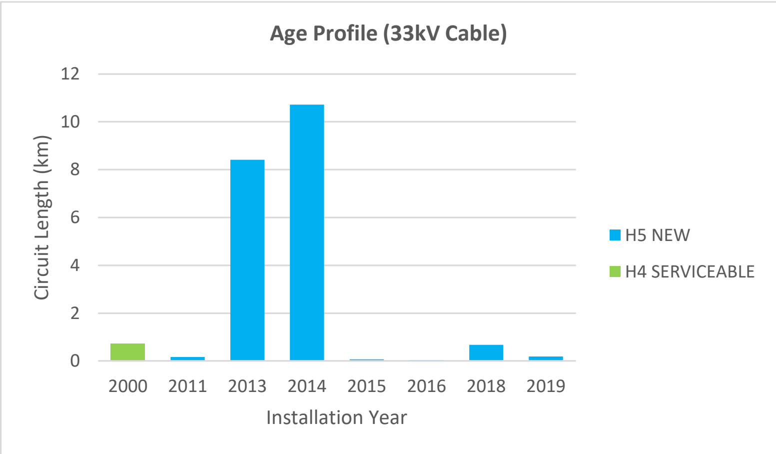


Figure 6.19: Age Profile – 33kV Underground Cable

6.6.6 Distribution (XLPE/PVC)

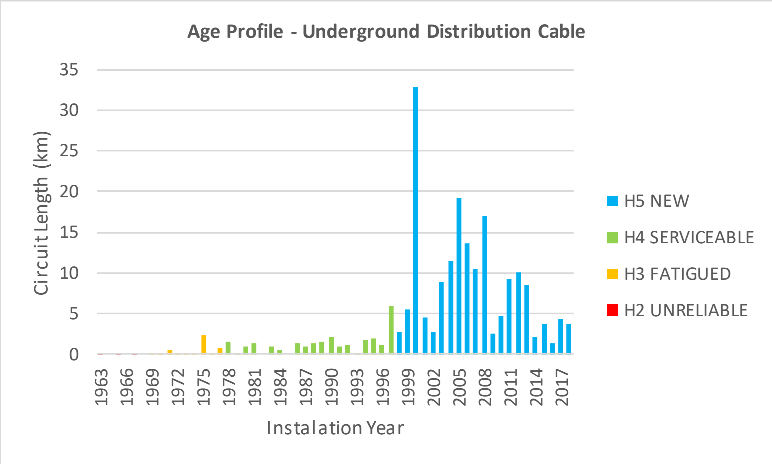
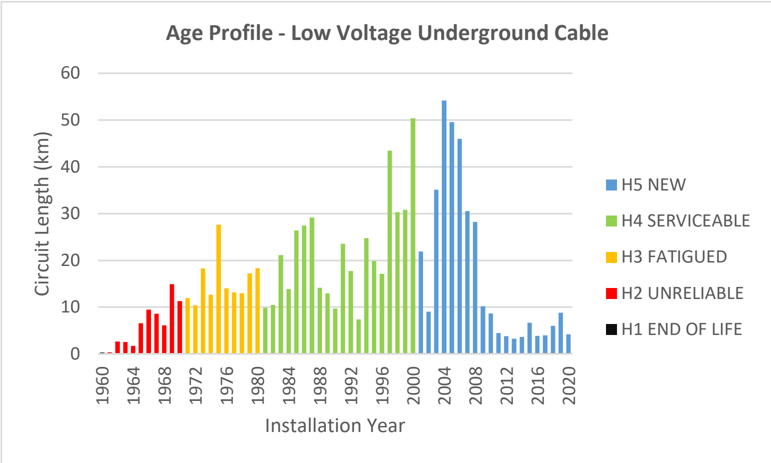


Figure 6.20: Age Profile – Underground Distribution Cable



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Note: Excludes streetlight cable

Figure 6.21: Age Profile – Underground Low Voltage Cable

6.6.7 Cable Health Summary

Circuit-km	Unknown	H1 End of Life	**H2 Unreliable**	**H3 Fatigued**	**H4 Serviceable**	**H5 New**	**Total**
33kV	-	-	-	-	1	20	**21**
Distribution	-	0.3	1	6	65	159	**231**
LV	-	0.1	42	103	291	248	**684**
Total	**-**	**0.4**	**43**	**109**	**357**	**427**	**936**

Table 6.7: Health Summary – Underground Cable

6.6.8 Replacement Strategy

The quantity of cable classified as unreliable or end of life is all low voltage and not considered a critical asset. As unassisted cable failure does not generally create a safety issue, our strategy is to run to failure.

6.7 Streetlight Circuits

6.7.1 Age Profile

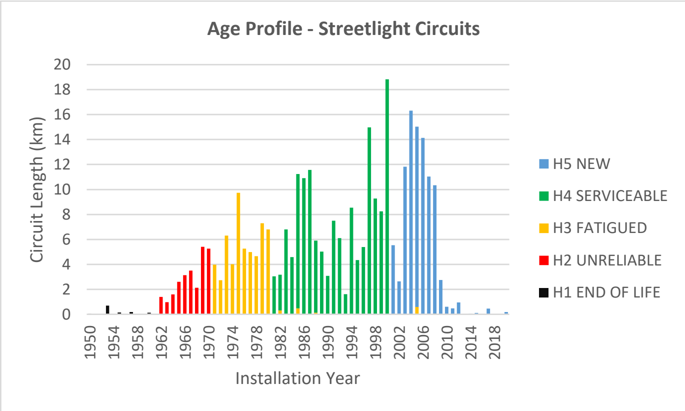

Figure 6.22: Age Profile – Streetlight Circuits

6.7.2 Streetlight Circuit Health Summary

cct-km	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	1	26	58	149	92	326

Table 6.8: Health Summary – Streetlight Circuits

6.7.3 Replacement Strategy

No planned replacements have been provided for.

6.8 Distribution Transformers

6.8.1 Failure Modes

Typical degradation.	• Normal environmental exposure causing corrosion. • Seal degradation leading to oil leaks and water ingress. • Minor surface damage from incidental contact with ground mounted units.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Overloading causes excessive heat, which breaks down components. • Vehicle impact.

6.8.2 Risk and Mitigation

Exposure to live internal parts.	• Ground mounted transformer enclosures are fitted with locks and bolts to prevent access. Warning notices are attached to equipment advising of the extreme risk within the enclosure. The emergency response number is also attached to enable people to call for help if any problem is identified.
Oil leaking into environment.	• Proximity to drains, waterways and other sensitive locations is considered when installing small distribution transformers. Any leaks identified are contained and repaired, and contaminated soil is disposed of appropriately.

Other issues which present a high risk.	• All distribution transformers are inspected in accordance with our time-based inspection strategy, and any identified safety issues are recorded and programmed for remediation. An emergency response number is also available to the public to report problems.

6.8.3 Age Profiles

6.8.3.1 Pole Mounted Distribution Transformers

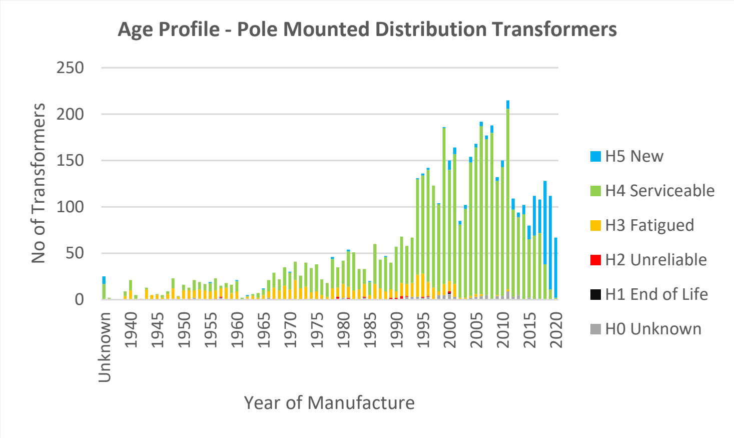

Figure 6.23: Age Profile – Pole Mounted Distribution Transformers

6.8.3.2 Ground Mounted Distribution Transformers

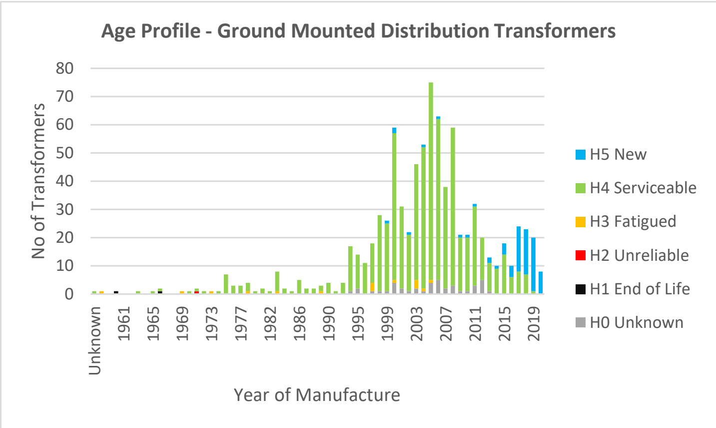

Figure 6.24: Age Profile – Ground Mounted Distribution Transformers

6.8.3.3 Ground Mounted Substation Housings

We have only five distribution substations situated in their own specially constructed buildings; the earliest of which was built in 1960 and the most recent in 2004. All buildings are in serviceable condition.

6.8.4 Distribution Transformer Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Pole mounted	100	1	22	610	3,871	475	**5,079**
Ground mounted	41	2	1	15	709	79	**847**
Total	**141**	**3**	**23**	**625**	**4,580**	**554**	**5,926**

Table 6.9: Health Summary – Distribution Transformers

6.8.5 Replacement Strategy

Our distribution transformer fleet is generally good condition with only 0.4% considered unreliable or end of life. Units are replaced if actual or potential overloading is detected, or if oil leaks or excessive levels of rust are found during asset inspections. Many older transformers are not fitted with surge arresters and a small number of transformers fail each year after being struck by lightning. The condition of distribution transformers removed from service is assessed by an external repair workshop and, if economic, the transformer is refurbished prior to being returned to service.

6.8.6 Voltage Regulators

6.8.6.1 Introduction

Voltage regulators contain parts that are frequently moving, making them susceptible to wear. Oil testing is used to determine the amount of wear and contamination present. When oil testing indicates increased operational risk, then the unit is removed and sent for testing, and reconditioning if economical.

All new and replacement regulators are 32-step, 150-amp units.

6.8.6.2 Failure Modes

Interference.	• Foreign object strikes line (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into power lines). • Accidental contact (e.g., vehicle).
Typical degradation.	• Normal environmental exposure causing corrosion or seal degradation leading to oil leaks, water ingress, exposure of live parts or structural weakening.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Overloading causes excessive heat which breaks down components. • Termination failure from poor installation. • Lightning strike.

6.8.6.3 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock or bolts or both. • Mounted on a pole and out of easy reach. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Oil leaking into environment.	The risk of the proximity to drains, waterways and other sensitive locations is considered when installing equipment containing contaminants. Any leaks identified are contained and repaired. Contaminated material is disposed of appropriately. Larger equipment is bunded and complies with all resource consent requirements. Spill kits and spill response plans are stored at zone substations to manage larger spill events.
Electric shock.	Equipment is fully bonded to an earth system, creating an equipotential zone to minimise the risk of electric shock. Earthing and protection is designed minimise the risk of exposure to faults.
Public awareness of risks and reporting problems.	Warning notices are attached to enclosures advising of the risks contained within the enclosure. Contact numbers are attached to enclosures, which enable people to call for help if any problem is identified.

6.8.6.4 Preventive Maintenance

Inspection.	• Post fault reactive inspections. • Condition and earth inspections in accordance with our risk-based inspection programme.
Test.	• Oil tests – undertaken as part of inspection programme. • Operational tests undertaken six-yearly. • Ten-yearly earth tests.
Service.	• If oil test results are low, the regulator is removed from service and its condition is assessed. If economical, it is reconditioned.

6.8.6.5 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing or damaged locks. • Repair, recondition or scrap equipment with damage that allows access to live or operable parts as appropriate.
Earth system malfunction.	• Repair damaged earth conductors. • Extend or replace earth bank to improve earth bank resistance and functionality.
Mounting and foundation malfunction.	• Replace damaged platform or components. • Re-secure equipment to platform. • Repair subsided foundations and ensure affected equipment is level. • Repair, recondition or scrap equipment with damaged mountings as appropriate.
Equipment leaks.	• Repair, recondition or scrap equipment with oil leak as appropriate.
Environmental contamination.	• Contain any leaks, clean up contamination and dispose of contaminated material responsibly.
Damage affecting equipment safety or operability.	• Repair, recondition or scrap equipment where damage affects the safety and operability of the equipment as appropriate.

6.8.6.6 Age Profile

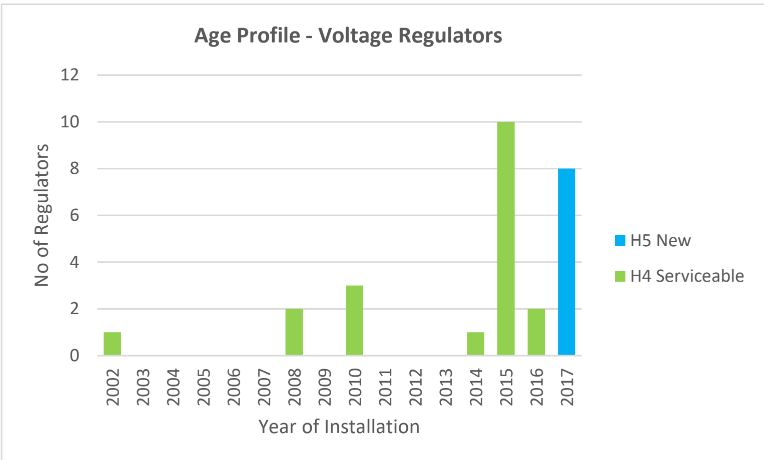

Figure 6.25: Age Profile – Voltage Regulators

6.8.6.7 Voltage Regulator Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	-	2	17	8	27

Table 6.10: Health Summary – Voltage Regulators

6.8.6.8 Replacement Strategy

Regular maintenance is required due to the frequency of regulator operation while in service, and we maintain a spares inventory so that units can be rotated in and out of service to allow this. We do not envisage a need to replace any of our existing fleet over the planning period. However, some of the structures on which our regulators are mounted have deteriorated to the point where refurbishment is required, and our capital replacement forecast provides for this.

6.9 Zone Substations

6.9.1 Buildings and Grounds

6.9.1.1 Introduction

Substation buildings are constructed with a variety of materials and styles. Construction is to Building Code requirements and the buildings are expected to remain serviceable for many decades. Our oldest building was constructed in 1939 and remains in a serviceable condition.

Waipapa substation will be upgraded during the planning period. Temporary remediation of priority safety issues in the 11kV switchyard is a confirmed project for FYE2022. Our capital forecast also provides for a new switchgear building and installation of new 33kV and 11kV indoor switchboards by FYE2030 and, at the same time, we will construct new transformer pads and lower the existing transformers to ground level. This expenditure is categorised reliability, safety, and environment, rather than replacement, as the main driver is safety.

Asbestos is present at some substations. This asbestos is non-friable and low risk. It will be removed when any building is refurbished.

A shipping container has been utilised as a primary building to house control gear at Mt Pokaka substation and containers are also used as housings for generator sets.

6.9.1.2 Failure Modes

Interference.	• Vandalism (e.g., damage to buildings, enclosures, break-ins, theft of equipment). • Pests (e.g., animals, insects, nesting).
Typical degradation.	• Spalling, rotting, rusting of structural elements. • Cladding degradation due to normal environmental exposure. • Foundation movement.
Accelerated degradation.	• Material degradation in coastal and geothermal environments. • Leaks or flooding accelerating degradation to structural elements. • Vehicle impact.

6.9.1.3 Risk Management

Access to energised or operable equipment by	Switchyards are enclosed with security fencing. Buildings and enclosures are locked with high security locks. Security keys are carefully managed to minimise the risk of coming into the possession of unauthorised persons. Security cameras, electronic key access and remote monitoring is installed at zone

unauthorised persons.	substations. Substations are routinely checked to confirm security measures remain intact and functioning as intended.
Water or pest ingress affecting equipment operation.	Substations are routinely inspected. If leaks or pests are detected, then ingress points are sealed, and any leaks or pests are cleaned up or removed. Any affected equipment is checked for damage and remediated as necessary.
Asbestos exposure.	Signage is present at all substations warning of the potential risk. Cutting or moving of building materials is prohibited. If cutting or moving of building material is necessary, then the problem is escalated, and a specialist will be engaged to provide support.
Hazardous material spills.	Signage is present at all substations warning of the presence of hazardous substances. Spill kits and emergency plans are also available at each substation.
General hazard management.	Signage is present at all substations stating minimum personnel protective equipment (PPE) requirements. Workers entering a site are required to assess and manage hazards. A hazard board is also installed to enable workers to notify others entering the site of hazards. A defect reporting process enables issues to be registered, prioritised, and scheduled for remediation.

6.9.1.4 Preventive Maintenance

Inspection.	• Monthly inspection of security (e.g., doors, windows, locks, security fence), services (e.g., lights, power points, water, wastewater), pests, leaks (e.g., building, water pipes, wastewater system) and air-conditioning. • Quarterly Inspection of transformers, switchgear, bus, panels, AC/DC systems, earth connections, communications equipment.
Test	• Quarterly assessment of all primary electrical equipment with a thermal camera and partial discharge detector.
Service	• Sweep/vacuum in non-hazardous areas, replace consumables (e.g., soap, toilet paper) during monthly inspections. • Wash building exterior as required. • Mow lawns, maintain gardens, check boundary fence monthly.

6.9.1.5 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing or damaged locks. • Repair or replace doors, windows, and gates, as necessary. • Engage service provider to repair malfunctioning monitored electronic security system.
Equipment in distress.	• Take safety precautions, escalate the issue, and initiate remedial action as appropriate to the level of risk.
Building leaks.	• Minimise the risk of damage to sensitive equipment. • Engage service provider to remediate the leak and replace any damaged structural elements or cladding. • Inspect, test, and repair any equipment damaged by the leak as appropriate.
Ground subsidence	• Engage service provider to assess the extent of the subsidence. • Undertake action to mitigate any risks associated with the subsidence. • Reinstate the subsidence to original state if practicable. • Undertake any repairs to building or equipment affected by the subsidence if possible. Significant subsidence, like that incurred through an earthquake, sinkhole, landslide, or tsunami, may result in irreparable damage to the site.

6.9.1.6 Substation Buildings

We have three 110kV substation buildings, one constructed in 1939 and a second in 1945. Both remain in a serviceable condition. The third building is the control room for the recently commissioned Ngawha 110kV switchyard. Other substation buildings include zone substation control and switchgear rooms and a small number of small buildings housing distribution substations. The fatigued buildings in the age profile below are the Pukenui control building, two distribution substation housings and the old control rooms at Moerewa and Kaikohe zone substations, which are now used for storage. All remain fit for purpose, based on their current use.

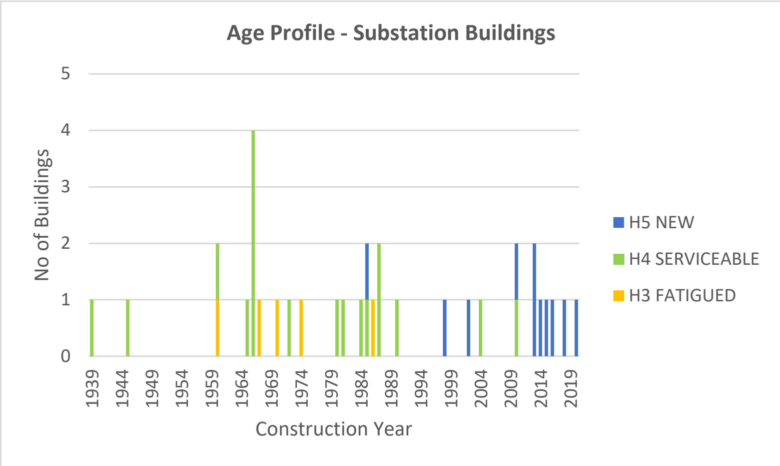

Figure 6.26: Age Profile – Substation Buildings

6.9.1.7 Substation Building Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	-	5	18	11	34

Table 6.11: Health Summary – Substation Buildings

6.9.1.8 Replacement Strategy

Building maintenance on all substation buildings will be undertaken as required to ensure all remain fit for purpose.

6.9.2 Power Transformers

6.9.2.1 Age Profile

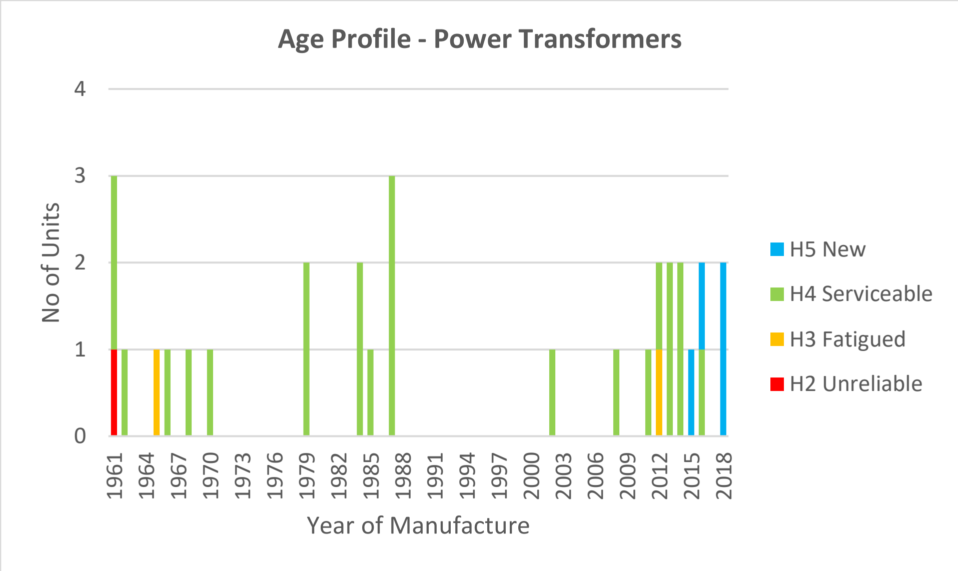

Figure 6.27: Age Profile – Power Transformers

6.9.2.2 Power Transformer Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Total	-	-	1	2	23	4	30

Table 6.12: Health Summary – Power Transformers

6.9.2.3 Power Transformer Replacement Strategy

The unreliable transformer bank is a 110kV single-phase bank at Kaitaia that is not in service. It was replaced by a new three-phase transformer in FYE2016, but never removed. Consequently, there are a total of seven identical single-phase units located at the substation, only three of which need to be in service for the second bank. We are therefore confident of being able to keep a second bank in service over the medium-term, by swapping out single-phase units if required.

The transformer in fatigued condition is at Pukenui. Testing has shown a low degree of polymerisation, indicating some deterioration of the paper insulation, but this has not progressed to the point where the transformer needs to be taken out of service. Should the transformer fail unexpectedly, there is a generator at the substation that can supply the load until the mobile substation can be relocated and energised.

6.9.3 Circuit Breakers

6.9.3.1 Outdoor 110kV Circuit Breakers

We have 11 outdoor 110kV circuit breakers, five at Kaikohe, three at Kaitaia and two at Ngawha. The two unreliable units are at Kaitaia. One of these second is programmed for replacement in FYE2025 and the second is not in service but is an identical circuit breaker that is kept as a spare.

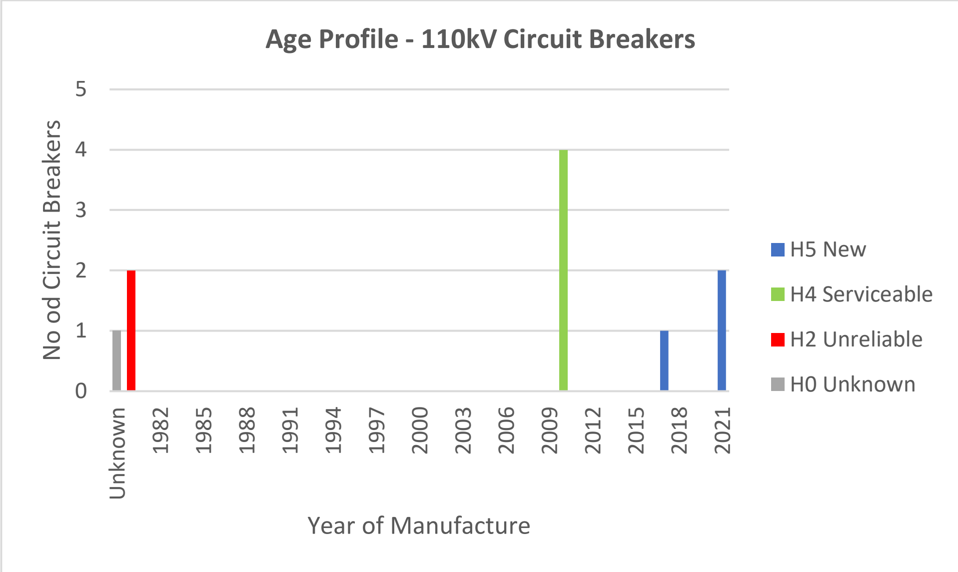

Figure 6.28: Age Profile – 110kV Circuit Breakers

6.9.3.2 Indoor 33kV Circuit Breakers

We have a total of 47 indoor 33kV circuit breakers on the network at Kaikohe, Wiroa, Moerewa and Kaeo substations. They were installed between FYE2014 and FYE2018 and all are in as new condition.

6.9.3.3 Outdoor 33kV Circuit Breakers

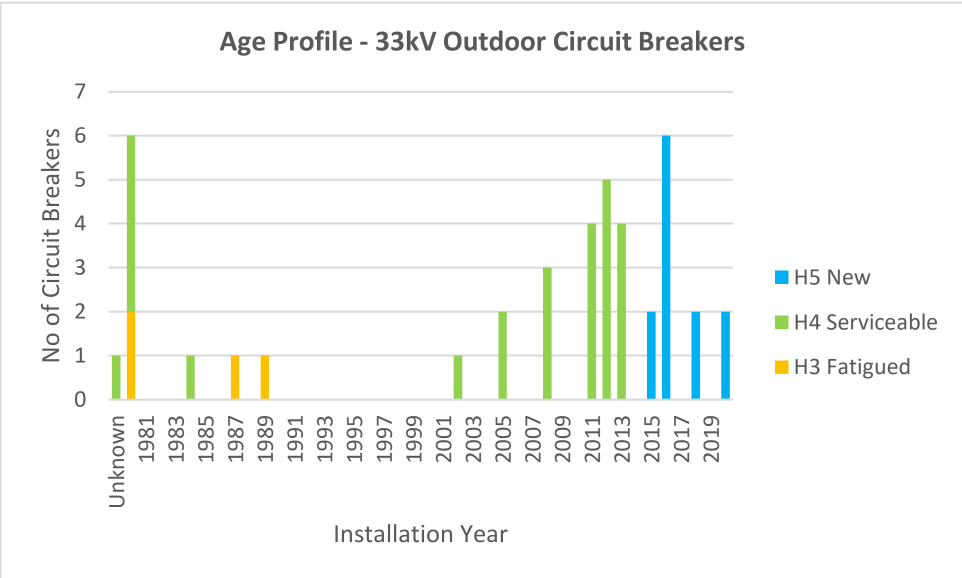

Figure 6.29: Age Profile – 33kV Outdoor Circuit Breakers

6.9.3.4 Indoor 11kV Circuit Breakers

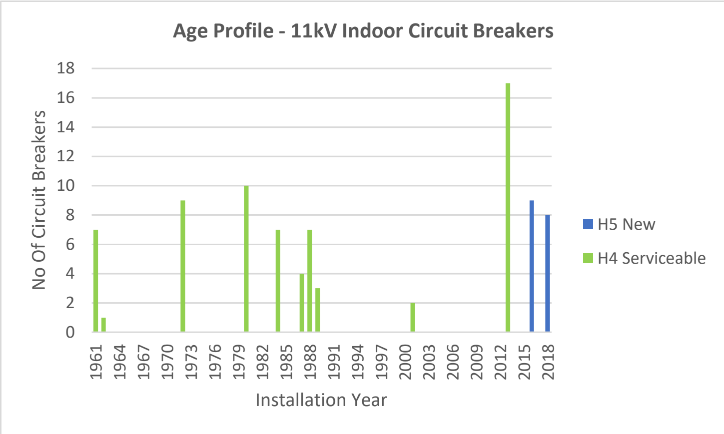

Figure 6.30: Age Profile – 11kV Indoor Circuit Breakers

6.9.3.5 Outdoor 11kV Circuit Breaker

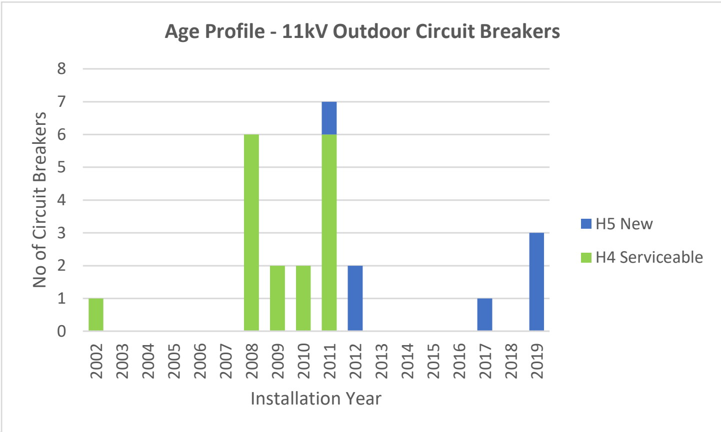

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Figure 6.31: Age Profile – 11kV Outdoor Circuit Breakers

6.9.3.6 Circuit Breaker Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV Outdoor	1	-	2	-	1	7	**10**
33kV Indoor	-	-	-	-	-	38	**38**
33kV Outdoor	-	-	-	4	25	10	**39**
11kV Indoor	-	-	-	-	67	17	**84**
11kV Outdoor	-	-	-	-	17	7	**24**
Totals	**1**	**-**	**2**	**4**	**113**	**75**	**195**

Table 6.13: Health Summary – Circuit Breakers

6.9.3.7 Circuit Breaker Replacement Strategy

As noted in Section 6.9.3.1, we plan to replace the in-service, unreliable 110kV circuit breaker located at Kaitaia by FYE2025.

6.10 Switchgear

6.10.1 Introduction

6.10.1.1 General

A variety of switchgear has historically been utilised. Switchgear manufacturers have used several medium for insulation and arc quenching, some of which (e.g. oil) has now been superseded, while other equipment no longer meets safety or operational requirements (e.g. arc flash management, remote control operation).

Design requirements for new switchgear include, as appropriate:
- Remote control and SCADA visibility.
- Elevated switch handles.
- Non-withdrawable gear.
- Arc flash containment.
- Plug in cable connections.
- Stainless steel for coastal installations.

6.10.1.2 Air-Break Switchgear

We no longer buy new air-break switches. Existing air-break switchgear is replaced at end-of-life with switchgear fitted with vacuum or SF_6 interrupters, and with air, resin or SF_6 insulation as appropriate for the application. Pole mounted switches are replaced with stick operated units or are retrofitted with a rocker arm for stick operation. This minimises the risks associated with having a handle within reach of the ground and the need for an associated earth system. Remote operation may also be provided when a unit is replaced.

6.10.1.3 Oil Filled Switchgear

Oil filled switchgear is being phased out due to its:
- High maintenance requirement.
- Flammability in certain failure conditions.
- Environmental impact as a contaminant.

We no longer purchase oil filled switchgear and new plant is fitted with vacuum or SF_6 interrupters and air, resin or SF_6 insulation as appropriate for the application. Remote operation may also be provided for when a unit is replaced.

6.10.2 Failure Modes

Interference.	• Foreign object (e.g., vegetation, pests). • Vandalism. • Accidental contact (e.g., vehicle).
Typical degradation.	• Normal environmental exposure causing corrosion or seal degradation, leading to oil leaks, water ingress, exposure of live part or structural weakening.
Accelerated degradation.	• Corrosion in coastal and geothermal environs. • Termination failure from poor installation. • Lightning strike.

6.10.3 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock or bolts or both. • Mounted on a pole and out of easy reach.

	Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Oil leaking into environment.	The risk of the proximity to drains, waterways and other sensitive locations is considered when installing equipment containing contaminants. Any leaks identified are contained and repaired. Contaminated material is disposed of appropriately. Larger equipment is bunded and complies with all resource consent requirements. Spill kits and spill response plans are stored at substations to manage larger spill events.
Electric shock.	Equipment is fully bonded to an earth system creating an equipotential zone to minimise the risk of electric shock. Earthing and protection is designed to minimise the risk of exposure to faults.
Molten metal from ABS operation igniting scrub.	• Operational conditions are checked prior to operation to minimise the associated risks. • Replacement switches are selected to minimise this risk.
Switch fails and vents in public place.	To date, this has never happened on our network. New switchgear is selected the minimise the risk of arc flash and explosive failures. This risk is progressively being reduced as equipment condition or operational requirements drive replacement.
Public awareness of risks and reporting problems.	Warning notices are attached to enclosures advising of the risks contained within. Contact numbers are attached to enclosures, which enable people to call for help if any problem is identified.

6.10.4 Preventive Maintenance

Inspection.	• Switchgear is reactively inspected following a fault that may have resulted in equipment damage. • Field-mounted switchgear is routinely inspected in accordance with our risk-based asset inspection programme. • Substation switchgear is included in our quarterly zone substation inspections.
Service.	• Oil filled substation circuit breakers are serviced every four years. This includes an operational check and may include an oil change and contract replacement, depending on the condition and the number of operations. • Batteries on remote controlled switchgear are replaced every six years.
Test *(field).*	• Six-yearly remote management system test. • Four-yearly oil test for oil-filled switchgear. • Ten-yearly earth test.
Test *(substation).*	• Two-yearly earth bond test. • Two-yearly remote management system test.

6.10.5 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing or damaged locks. • Repair, recondition or scrap equipment with damage that allows access to live or operable parts as appropriate.
Earth system malfunction.	• Repair damaged earth conductors. • Extend or replace earth bank to improve earth bank resistance and functionality.
Protection system malfunction.	• Check and test that protection system meets design standard. • Correct, repair, or replace protection to meet design standard.

Mounting and foundation malfunction.	• Repair or replace hanger arm, platform, pad, or components. • Re-secure equipment to hanger arm, platform, or pad. • Repair subsided foundations and ensure affected equipment is level. • Repair, recondition or scrap equipment with damaged mountings as appropriate.
Equipment leaks.	• Repair, recondition or scrap equipment with oil leak, as appropriate.
Environmental contamination.	• Contain any leaks, clean-up contamination and dispose of contaminated material responsibly.
Damage affecting equipment safety or operability.	• Repair, recondition or scrap equipment where damage affects the safety and operability of the equipment, as appropriate.

6.10.6 Outdoor 33kV Switches

6.10.6.1 Age Profile

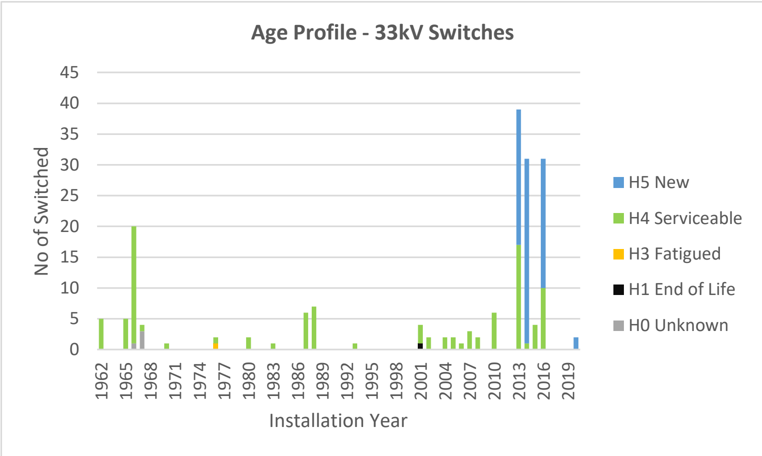

Figure 6.32: Age Profile – 33kV Switches

6.10.6.2 Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	4	1	-	1	102	75	183

Table 6.14: Heath Summary – 33kV Switches

6.10.7 Overhead Distribution Switches

6.10.7.1 Age Profile

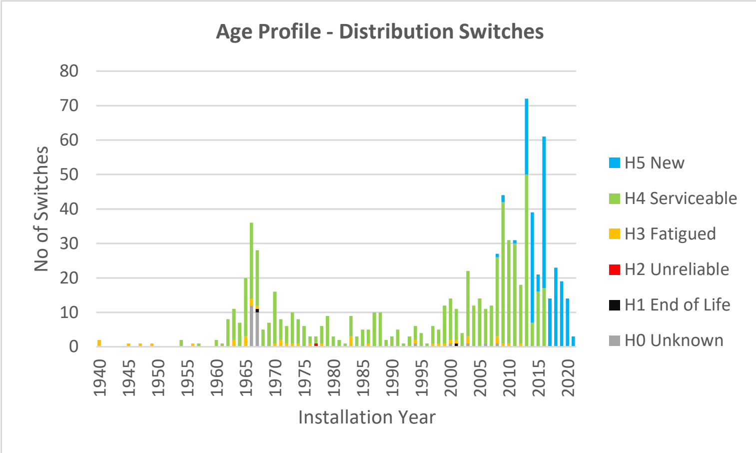

Figure 6.33: Age Profile – Overhead Distribution Switches

6.10.7.2 Overhead Distribution Switch Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	27	2	1	39	573	180	822

Table 6.15: Health Summary – Distribution Switches

6.10.8 Sectionalisers

6.10.8.1 Age Profile

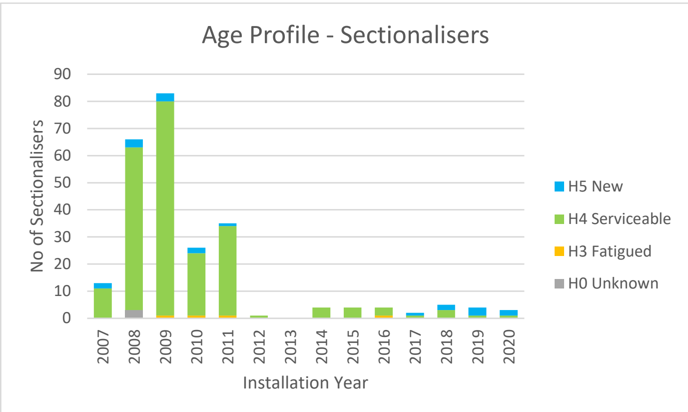

Figure 6.34: Age Profile - Sectionalisers

6.10.8.2 Sectionaliser Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	3	-	-	4	224	19	250

Table 6.16: Health Summary – Sectionalisers

6.10.9 Reclosers

6.10.9.1 Age Profile

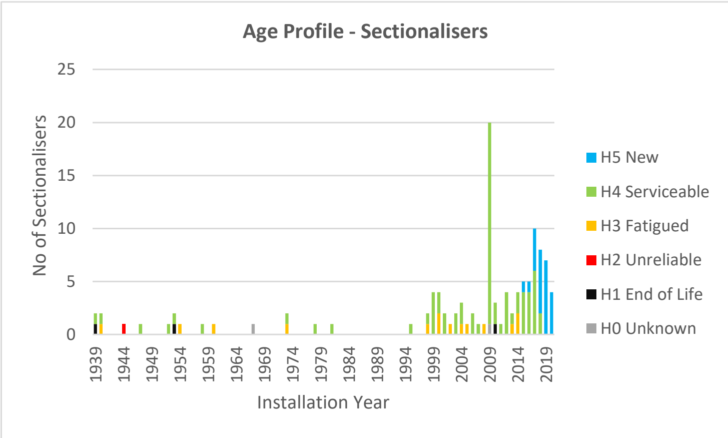

Figure 6.35: Age Profile - Reclosers

6.10.9.2 Recloser Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	2	3	1	14	71	23	114

Table 6.17: Health Summary - Reclosers

6.10.10 Ring Main Units

6.10.11 Age Profile

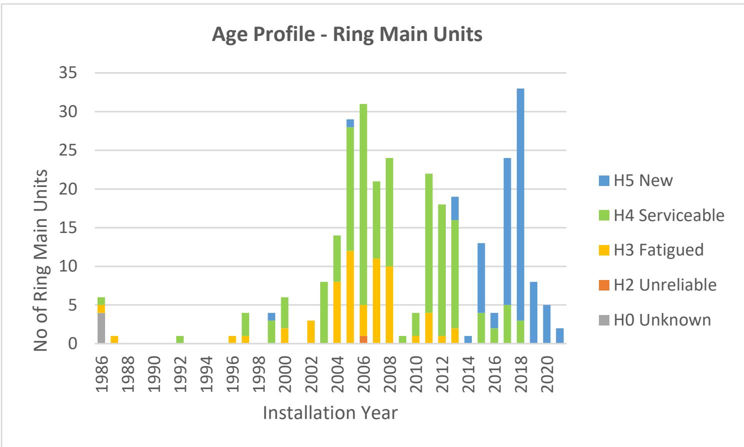

Figure 6.36: Age Profile – Ring Main Units

6.10.11.1 Ring Main Unit Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	4	-	1	62	159	81	307

Table 6.18: Health Summary – Ring Main Units

6.10.12 Distribution Fuses

6.10.12.1 Age Profile

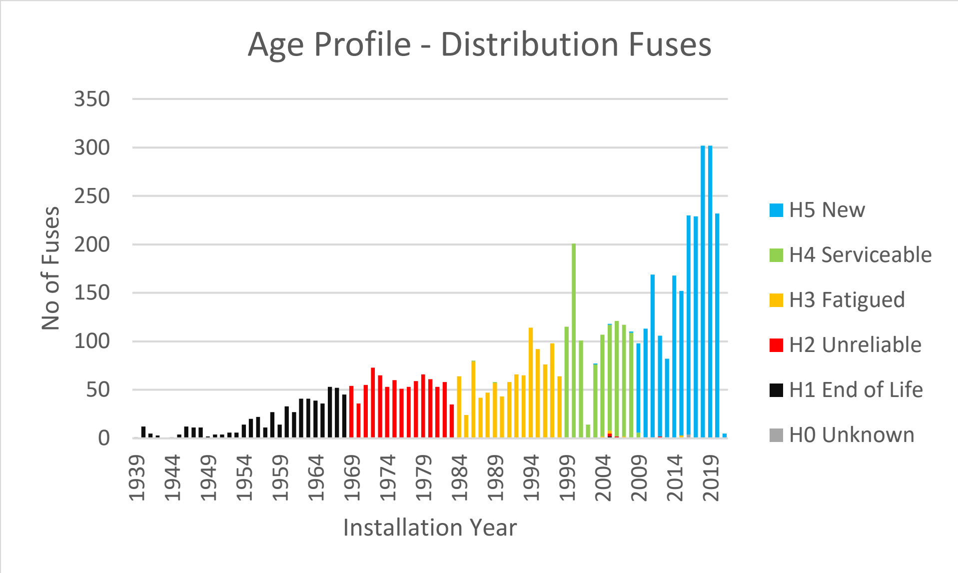

Figure 6.37: Age Profile – Distribution Fuses

6.10.12.2 Distribution Fuse Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	9	566	838	995	1.068	2,173	5,649

Table 6.19: Health Summary – Distribution Fuses

6.10.13 Switchgear Replacement Strategy

Our capital expenditure forecast provides for the proactive replacement of seven ring main units, five 11kV and two 33kV air-break switches annually.

Our health assessment of 11kV fuses indicates a substantial number that have reached end-of-life. Fuses are generally run to failure, as a failure in service generally does not have a significant SAIDI or safety impact.

6.10.14 Underground Service Fuse Pillars

6.10.14.1 Failure Modes

Interference.	• Vandalism. • Accidental contact (e.g., vehicle, mower).
Accelerated degradation.	• Flooding. • Foundation subsidence. • Poor design or installation.

6.10.14.2 Risk Management

Exposure to live or operable parts.	• Equipment is designed to prevent access to live or operable parts by unauthorised persons, and to minimise the risk of harm by being self-enclosed and secured by bolts.

	• Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable. • Earlier boxes were constructed with bare lugged connections. These are replaced with sealed systems upon replacement of the box, which makes them less likely to expose live parts if the security is compromised.
Poor connections overheat and damage box.	• Connections that come loose over time or through poor installation practice will overheat. This often burns-out the fuse base and mountings. Occasionally, the location of the fuse and the intensity of the heat is enough to melt the enclosure. New fuse bases utilise shear-off bolted connections ensuring the connection is properly tightened.
Box is regularly damaged.	• Any pillar that suffers repeated breakdown due to exposure to an event (i.e., location makes it prone to vehicular impact, vandalism, flooding, erosion, vegetation) will be considered for relocation or redesign to manage any associated risk.

6.10.14.3 Preventive Maintenance

Inspect.	• Post fault reactive inspection • Routine inspections in accordance with our risk-based asset inspection strategy

6.10.14.4 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing screws or if this is not possible, then use self-tapping screws to secure enclosure; or • Replace box if enclosure cannot be secured.
Box is not secured to ground.	• Reinstate any ground subsidence; or • Correct improper installation work.
Box cannot be accessed.	• Remove any obstructions; or • Redesign and relocate to a more accessible location.

6.10.14.5 Age Profile

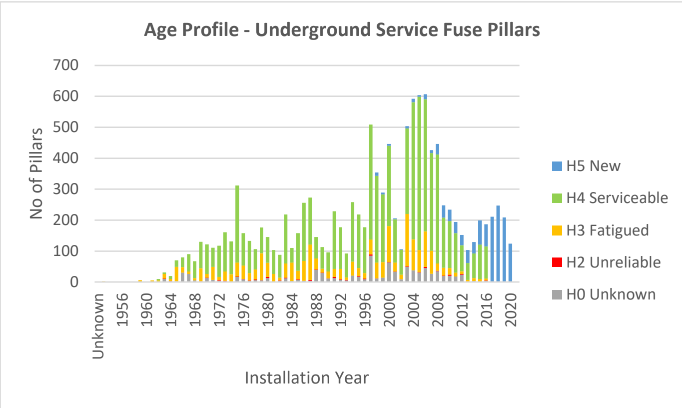

Figure 6.38: Age Profile – Underground Service Pillars

6.10.14.6 Underground Service Fuse Pillar Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	871	-	67	2,093	7,915	1,278	12,224

Table 6.20: Health Summary – Underground Service Pillars

6.10.14.7 Replacement Strategy

Fibreglass boxes can become brittle while metal boxes require earth systems for safety, so we now use plastic boxes to avoid these issues. There are very few fibreglass or metal boxes remaining on the network and they are targeted for replacement when identified. Assets identified as being a safety hazard, either on inspection or following reports from the public, are also replaced. We anticipate replacing around 15 boxes per year.

6.11 Other

6.11.1 Protection Equipment

6.11.1.1 Failure Modes

Interference.	• Foreign object tangled in protection device (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into protection device, component theft).
Typical degradation.	• Normal environmental exposure causing corrosion or seizing of components. • Battery or power supply failure. • Repeated fault exposure.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Condensation. • Pests (e.g., animals, insects, nesting). • Poor design or installation. • Lightning strike.

6.11.1.2 Risk Management

Exposure to live or operable parts	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimises the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock, or bolts, or both. • Mounted on a pole and out of easy reach. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Protection system power supply or communications failure	Systems requiring power supplies or communication systems are routinely checked and tested. Equipment with these systems is often self-monitoring and provide warnings prior to failure if conditions indicate a problem.

6.11.1.3 Preventive Maintenance

Inspect *[Distribution].*	• Post-fault reactive inspections. • Ten-yearly earth and condition inspection. • Hardware, including protection devices, that are attached to poles are visually checked during programmed pole inspections.
Test *[Distribution].*	• Six-yearly protection relay test. • Ten-yearly earth test.
Inspect *[Substation].*	• Protection devices are visually checked during substation inspections.
Test *[Substation].*	• Annual earth grid and bond test. • Four-yearly protection relay test.

6.11.1.4 Corrective and Reactive Maintenance

Equipment malfunction.	• Diagnose malfunction and repair or replace faulty component.
Fuse, arrestor or protection operation.	• Investigate cause of protection operation. • Remediate fault cause. • Reset or replace protection device as appropriate.
Earth system damage.	• Repair earth system.

6.11.1.5 Protection Relay Age Profiles

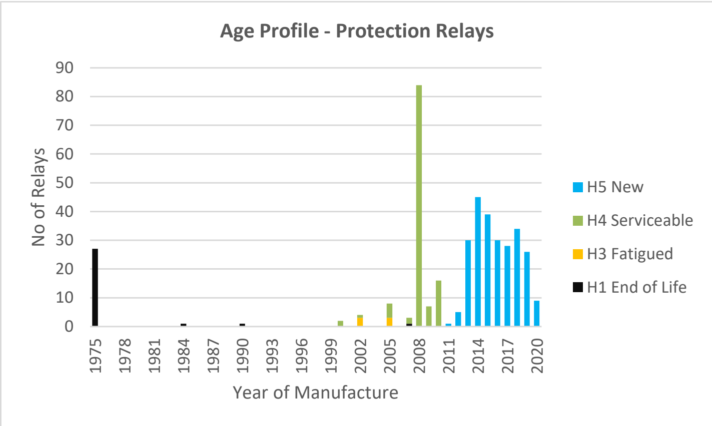

Figure 6.39: Age Profile – Substation Protection Relays

6.11.1.6 Protection Relay Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	30		6	117	247	400

Table 6.21: Health Summary – Substation Protection Relays

6.11.1.7 Replacement Strategy

Obsolete mechanical relays remain at both Kaikohe 110kV substation and on the 11kV switchboard at the Kaikohe zone substation. These relays are still serviceable and will be replaced if testing shows them to be unreliable.

6.11.2 SCADA and Communications

While we have replacing our SCADA master station with an ADMS, the hardware outside our control room is being retained and incorporated into the new system.

6.11.2.1 Failure Modes

Interference.	• Foreign object blocks signal (e.g., vegetation, structure, aerial damage). • Vandalism (e.g., damage, theft of components).
Typical degradation.	• Normal environmental exposure causing corrosion. • Power supply failure (e.g., battery, charger). • Water or pest ingress (e.g., condensation, ants).
Accelerated degradation.	• Corrosion in coastal and geothermal environs. • Lightning strike.

6.11.2.2 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock, or bolts, or both. • Mounted on a pole and out of easy reach. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Loss of equipment operational control or telemetry Server failure	• Communication systems are routinely checked and tested. These systems are often self-monitoring and provide warnings if conditions indicate a problem. • A disaster recovery site exists at Ngawha, which can be used in the event of a server failure.
Tele-communications failure	Multiple communication pathways exist in case of a telecommunications failure. Service level agreements are in place with service providers to minimise any downtime. If there are multiple pathway failures, then remote control equipment can be manually operated and locally monitored.

6.11.2.3 Preventive Maintenance

Inspection *[Distribution].*	Post-fault reactive inspection.
Inspection *[Substation].*	Quarterly battery and charger inspection.
Test.	Six-yearly remote-controlled communications and SCADA functional test.
Service.	Six-yearly remote-controlled communications and SCADA battery replacement.

6.11.2.4 Corrective and Reactive Maintenance

Equipment malfunction.	Diagnose malfunction and repair or replace faulty component.

6.11.2.5 RTU Replacement

Remote terminal units (RTU) are installed in our zone substations and in the field. While we have not prepared an RTU age profile or a fleet condition assessment, about ten substation RTUs and 30 field units are obsolete, in that they are no longer supported by the manufacturer. We respond to failures of these units using spare parts from our inventory and from units that have been removed from service for various reasons while still operational. We anticipate being able to keep these obsolete units serviceable using this approach for a further ten years in the case of substations and five years for units located in the field. After this, any obsolete RTUs that fail in service will need to be replaced with new units.

6.11.3 Capacitors

6.11.3.1 Introduction

Capacitors are used to improve the power factor[12] across the network to maintain compliant voltage and reduce losses. Our capacitors are pole mounted in the 11kV distribution network and protected with a small vacuum circuit breaker.

6.11.3.2 Failure Modes

Interference.	• Foreign object strikes (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into power lines). • Accidental contact (e.g., vehicle).
Typical degradation.	• Normal environmental exposure causing corrosion or seal degradation leading to oil leaks, water ingress, exposure of live part or structural weakening. • Dielectric breakdown.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Termination failure from poor installation. • Lightning strike.

6.11.3.3 Preventive Maintenance

Inspection.	• Post fault reactive inspection. • Earth and condition inspection in accordance with our risk-based asset inspection programme.
Test.	• Ten-yearly earth test.

6.11.3.4 Corrective and Reactive Maintenance

Earth system malfunction.	• Repair damaged earth conductors. • Extend or replace earth bank to improve earth bank resistance and functionality.
Protection system malfunction.	• Check and test that protection system meets design standard. • Correct, repair, or replace protection to meet design standard.
Mounting and foundation malfunction.	• Repair or replace hanger arm, platform, pad, or components. • Re-secure equipment to hanger arm, platform, or pad. • Repair, recondition or scrap equipment with damaged mountings as appropriate.
Equipment leaks.	• Repair, recondition or scrap equipment with oil leak as appropriate.
Damage affecting equipment safety or operability.	• Repair, recondition or scrap equipment where damage affects the safety and operability of the equipment as appropriate

12 Power factor is a technical parameter that is essentially a measure of the efficiency with which energy is delivered. An improved power factor will increase the amount of useful energy delivered at a given current level, which will result in reduced losses and improved voltage regulation.

6.11.3.5 Age Profile

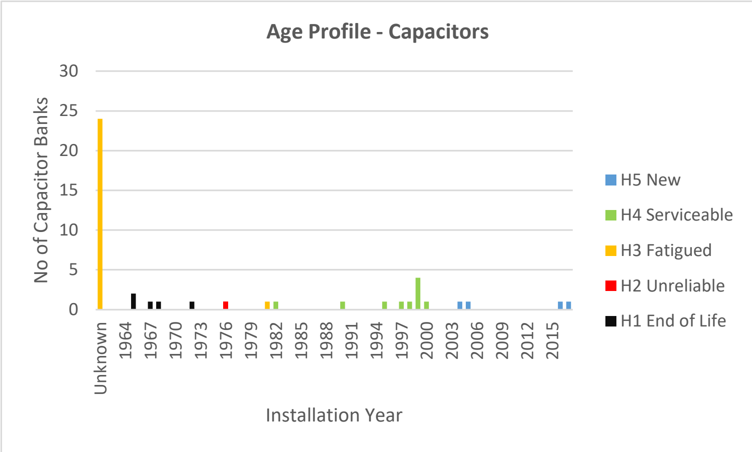

Figure 6.40: Age Profile - Capacitors

6.11.3.6 Health Summary

	H0 Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	5	1	25	10	4	45

Table 6.22: Health Summary - Capacitors

6.11.3.7 Replacement Strategy

Capacitors were installed to manage power factor and are not considered operationally critical or requiring proactive renewal or replacement. As a result, some units have now reached end-of-life. We are planning to replace one unit per year.

6.11.4 Load Control Equipment

6.11.4.1 Failure Modes

Typical degradation.	• Normal environmental exposure causing corrosion. • Control unit component failure.
Accelerated degradation.	• Water or pest ingress (e.g., condensation, ants, dust, cobwebs).

6.11.4.2 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being contained within a secure control building. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Loss of equipment operational control or telemetry.	Remote control and associated communication systems are routinely checked and tested. These systems are often self-monitoring and provide warnings if conditions indicate a problem.
Ripple plant failure.	A service agreement is in place with the manufacturer for the provision of spare parts, service technician, 24hr support and an emergency backup plant.
Server failure.	A disaster recovery site exists at Ngawha that can be used in the event of a server failure. A software support agreement is in place with software provider.

6.11.4.3 Preventive Maintenance

Inspection.	• Post-fault reactive inspection. • Quarterly visual plant inspection.
Test.	Annual transmitter test, covered by service agreement with manufacturer.
Service.	Annual ripple plant room, tuning circuit, and injection transformer clean and service.

6.11.4.4 Corrective and Reactive Maintenance

Equipment malfunction	• Activate service agreement with service provider. • Diagnose malfunction and repair or replace faulty component.
Damaged or faulted equipment	• Activate service agreement with service provider. • Clean up any debris and contamination in plant room. • Replace damaged equipment

6.12 Breakdown of Network Maintenance Forecasts

The tables below disaggregate the network maintenance forecasts further than shown in the regulatory schedule s11b (see Appendix A). The disaggregation of the service interruption and emergencies forecast is based on a breakdown of our current reactive repair costs and the disaggregation of our asset replacement and renewal forecasts is based on an analysis of our defects schedule. We use these breakdowns to signal our likely resource and skill requirements to our contractors.

The forecasts below show opex only. Therefore, they do not capture our full maintenance costs, as the replacement of complete assets, as well as targeted line refurbishments packaged as separate projects, are all capitalised. A breakdown of the defect and fault-driven maintenance capex forecast, excluding the cost of accelerated asset replacements discussed in Section 6.1.4, is shown in Table 6.23.

6.12.1 Service Interruptions and Emergencies

($000)	FYE									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Lines and poles	671	671	671	671	671	671	671	671	671	671
Cables and pillars	189	189	189	189	189	189	189	189	189	189
Transformers	135	135	135	135	135	135	135	135	135	135
Buildings and grounds	2	2	2	2	2	2	2	2	2	2
Switchgear and protection	118	118	118	118	118	118	118	118	118	118
Secondary systems	198	198	198	198	198	198	198	198	198	198
Total	**1,313**	**1,313**	**1,313**	**1,313**	**1,313**	**1,313**	**1,313**	**1,313**	**1,313**	**1,313**

Note 1: Totals may not add due to rounding
Note 2: In constant FYE2022 prices.

Table 6.23: Service Interruptions and Emergency Maintenance Opex by Asset Category

6.12.2 Routine and Corrective Maintenance

($000)	FYE									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Routine maintenance & inspection	**2,120**	**1,976**	**1,942**	**1989**	**2,001**	**2,041**	**2,005**	**2,020**	**2,063**	**2,005**
Vegetation	**1,850**	**1,850**	**1,850**	**1,850**	**1,850**	**1,850**	**1,850**	**1,850**	**1,850**	**1,850**
Asset replacement & renewal										
Lines and poles	456	456	456	456	456	456	456	456	456	456
Cables and pillars	58	58	58	58	58	58	58	58	58	58
Transformers	219	219	219	219	219	219	219	219	219	219
Buildings and grounds	86	86	86	86	86	86	86	86	86	86
Switchgear and protection	105	105	105	105	105	105	105	105	105	105
Secondary systems	96	96	96	96	96	96	96	96	96	96
Subtotal – replacement & renewal	**1,019**	**1,019**	**1,019**	**1,019**	**1,019**	**1,019**	**1,019**	**1,019**	**1,019**	**1,019**
TOTAL	**4,989**	**4,846**	**4,812**	**4,858**	**4,871**	**4,911**	**4,874**	**4,889**	**4,933**	**4,874**

Note 1: Totals may not add due to rounding.
Note 2: In constant FYE2022 prices.

Table 6.24: Breakdown of Routine and Corrective Maintenance

6.12.3 Summary of Maintenance Opex Forecast

($000, constant prices)	FYE									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Service interruptions and emergencies	1,313	1,313	1,313	1,313	1,313	1,313	1,313	1,313	1,313	1,313
Routine maintenance and inspection	2,120	1,976	1,942	1,989	2,001	2,041	2,005	2,020	2,063	2,005
Vegetation	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Replacement and renewal	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019
Total	**6,303**	**6,159**	**6,125**	**6,171**	**6,184**	**6,224**	**6,188**	**6,203**	**6,246**	**6,187**

Note: Totals may not add due to rounding

Table 6.25: Breakdown of Maintenance Opex Forecast

6.12.4 Breakdown of Asset Replacement Capex Forecast

($000, real)	FYE									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Transmission and subtransmission lines	2,055	1,769	934	1,281	936	943	942	946	947	949
Transmission and zone substations	66	67	68	190	70	72	73	73	74	1,282
Distribution lines	3,256	3,071	3,366	3,683	4,051	5,046	4,858	4,125	4,518	4,224
Distribution cables	118	119	120	121	122	123	124	125	126	127
Distribution substations and transformers	632	397	632	576	402	404	407	408	410	411
Distribution switchgear	607	690	695	698	701	704	707	713	715	715
Other network assets	154	130	131	132	132	133	134	134	135	31
Total	**6,888**	**6,244**	**5,946**	**6,682**	**6,414**	**7,425**	**7,246**	**6,524**	**6,926**	**7,740**

Note: Excludes accelerated asset replacements with safety and supply reliability drivers
Numbers might not add due to rounding.

Table 6.26: Breakdown of Maintenance Capex Forecast

6.13 Non-network Capital Expenditure

The non-network assets covered by this AMP are limited to computer hardware and software, motor vehicles assigned to TEN staff, office equipment and miscellaneous equipment, such as survey equipment and the new ADMS. This situation is not expected to change over the planning period and expenditure is generally limited to the purchase of additional assets to accommodate increases in TEN staff levels and replacement of assets as required. The capex forecast in Appendix A, Schedule 11a, includes the purchase of non-network assets.

6.14 Non-network Operations Expenditure

This AMP discusses in some detail:

- The existing and planned service levels provided by our network assets.
- The development and maintenance strategies we will use to achieve these service levels and accommodate the forecast increase in demand for electricity.
- The direct costs of implementing these strategies.

It does not consider in detail the indirect cost of achieving these asset management objectives. These costs include:

- The cost of operating the network in real time, including the cost of managing and staffing the network control centre in Kerikeri.
- The cost of planning and implementing the asset management strategies described in this AMP. This includes the cost of staffing the TEN asset management team, as shown in Figure 2.5.
- The cost of the business support functions required for our TEN team to function effectively. These include governance, commercial, human resource, regulatory, finance and other support services, which are provided by Top Energy's corporate services staff and are shared with Top Energy's other operating divisions. The costs of providing these services are allocated to TEN in a way that is consistent with the Commission's regulatory requirements.

Table 6.27 shows the forecast costs of providing these services in constant prices. These forecasts are based on the current costs of providing these support services and are also shown in the corresponding expenditure categories in Schedule 11b of Appendix A.

($000, real)	FYE									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
System operations and network support	6,374	6,302	6,128	6,069	6,166	6,169	6,217	6,280	6,346	6,436
Business support	6,412	6,412	6,414	6,419	6,426	6,436	6,447	6,461	6,476	6,494
Total	**12,786**	**12,714**	**12,542**	**12,488**	**12,592**	**12,605**	**12,664**	**12,741**	**12,822**	**12,930**

Table 6.27: Non-network Opex Forecast

Section 7 Risk Management

7 Risk Management

7.1 Risk Management Policy

The Top Energy Group's risk management policy recognises risk as a core business responsibility and commits the Group to provide all necessary resources to assist those accountable and responsible for managing risk. The policy requires the following activities to ensure that its policy is implemented:

- Integrating risk management into all business processes.
- Establishing and operating systematic risk management processes consistent with the requirements of AS/NZS ISO 31000: 2009.
- Requiring risk assessments carried out in accordance with the standard to be a part of all business cases.
- Making all staff members responsible for responding to risks they become aware of, by initiating and utilising the risk management processes in line with their delegated risk authority.
- Maintaining a balance of risks, benefits, and costs to ensure that risks with the potential to impact negatively on the business are kept as low as practicable.
- Prioritising risk treatment and ensuring the risk management process is reviewed and monitored, so that mitigation remains effective as the nature of some risks change.
- Maintaining a "risk aware" culture, where risk is recognised as an everyday part of business.
- Creating awareness through training and regular communication of our risk values.
- Reviewing and auditing regularly to test that mitigation processes are effective.

7.2 Risk Management Process

Governance of the Top Energy Group is the responsibility of the Board of Directors. The CEO and his executive management team are responsible and accountable to the Board of Directors for the representation, direction, and business success of the Group. This delegation of responsibility requires a formal management process, which includes the flow of information to and from the CEO and the Board. All aspects of the Group's activities are included in this process, including exposure to risk, a critical aspect in the effective discharge of the executive management team's management responsibilities.

To ensure that risk management is recognised and treated as a core management function, the Group has established a corporate risk management committee, and implemented a cost-effective and coordinated framework for the management of risk. This framework ensures that a formal and consistent process of risk identification, assessment, acceptance and treatment is carried out company wide. Emphasis is placed on exposure to business and safety risks that may exist in the short to medium-term.

In managing the areas of significant risk, the Group's risk management framework provides for:

- The identification of major risk areas incorporating all relevant programmes, processes, projects, activities, and assets.
- A standard framework and risk register for the identification, assessment, acceptance and/or mitigation of risks across all major risk areas.
- Regular reporting of the risk register, including reporting of the status of risk profiles, to alert management to any critical changes to the Group's overall risk profile.

- Annual reappraisal of the risk register and associated processes by the executive management team, with findings reported to the Audit & Risk Committee (ARC) of the Board.
- Bi-annual reporting to the ARC on the identified risks and the associated management of those risks.

Our network risk management process focuses on the assessment of credible network risks, which include asset failure due to the normal asset ageing processes, overloading, material deterioration, human error, poor workmanship, lightning, fire, earthquake, and flood. All EDBs experience these risks.

7.2.1 Corporate Risk Management Committee

The corporate risk management committee manages an ongoing, cyclical process of identifying risks and ensuring appropriate mitigation strategies are in place for each identified risk. The committee comprises the CEO and the General Managers from each division of the business, the Health, Safety and Risk Manager, and various specialists who may be co-opted onto the committee from time-to-time.

7.2.2 Network Risk Management Committee

TEN has its own specialised network risk committee consisting of:

- General Manager Network.
- Network Maintenance Manager.
- Network Operations Manager.
- Network Planning Manager.
- Network Project Delivery Manager.
- Technical Safety Advisor.

Our Technical Safety Advisor manages the committee, organises four-monthly meetings, seconds other internal expertise as required and is responsible for updating the risk register.

The network risk committee reviews and maintains the network risk register. The review includes checks to ensure that:

- All existing risks remain valid.
- New risks are identified.
- All risks are appropriately treated/mitigated.
- Existing risk mitigation plans are actioned.
- The company's risk management policy is being followed.

Our network risk register is presented to the corporate risk committee on an annual basis. The following table outlines the cyclical review and reporting activities associated with our network risk management process.

ACTIVITY	RESPONSIBILITY	FREQUENCY
Update risk register.	All staff.	As required.
Review risks contained within network risk register.	Network risk committee.	Four-monthly.
Risk register/mitigation plan to corporate risk committee.	General Manager Network.	Annually.
Approve risk register and mitigation plans.	Corporate risk committee.	Annually.

Table 7.1: Network Risk Management Review and Reporting Cycle.

7.2.3 Risk Management Framework

We employ a quantitative approach to risk management that evaluates both risk likelihood and risk consequence. Where event outcomes can be quantified with a probability, this is used in the risk analysis.

This approach accommodates risk events of high consequence that are characterised by uncertainty or surprise rather than historical occurrence. History is not necessarily a useful guide to future events; consequently, a systematic and rigorous process has been adopted to identify high risk possibilities.

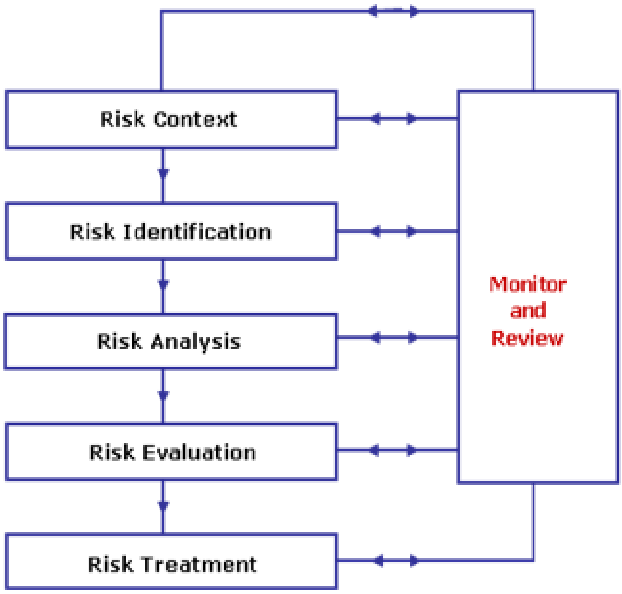

Figure 7.1: Network risk management process

Our network risk process is consistent with AS/NZS ISO 31000: 2009 and incorporates the steps shown in Figure 7.1. The process includes the following main elements:

- *Risk context:* Defining the strategic, organisational, and physical environment under which the risk management is carried out. Establishing the context involves identifying, planning and mapping-out the framework of the whole risk management process. Network risks are classified in the following areas (domains) and typical sub-areas:

RISK DOMAINS	CONSEQUENCE ARISING FROM POOR MANAGEMENT PRACTICES
Public/Employees.	Harm to public. Harm to staff.
Environmental.	Damage to the environment. Sustainability.
Regulatory Compliance.	Regulatory compliance – general. Health & safety. Industry specific. Environmental.
Asset Management.	Loss, damage, destruction. Denial of access. Inability to meet consumer requirements. Inability to meet growth requirements.
Business Model/Change Management.	Market competitive forces. Changed stakeholder expectations. Poorly managed change processes.

RISK DOMAINS	CONSEQUENCE ARISING FROM POOR MANAGEMENT PRACTICES
Financial.	Revenue loss or constraints. Increased expense flows.
Products/Services.	Liability arising from product or service delivery.
Technology.	High reliance on specific technologies. Impact relating to the failure of technology. Impact of significant technological changes.

Table 7.2: Risk process main elements

- *Risk identification:* Identifying all elements relevant to the risk context. After establishing this, the next step is to identify potential risks. A culture of risk awareness at all levels is encouraged within Top Energy to recognise, assess, and manage a risk before possible adverse impact on public, personnel, or company. There are also formal processes based around focus groups that actively identify new and review known risks.

  Identified risks are considered by the network risk committee and the person responsible for the risk domain. Once approved, it forms part of the risk register and is then remedied or mitigated. Risks considered are not limited to current risks, but also include those that may arise over the predicted life of the asset. This long-term view strongly influences capital and maintenance planning for the network.

- *Risk analysis and evaluation:* Estimating the likelihood of the identified risks occurring, the extent and cost implications of loss and comparing the levels of risks against pre-established criteria. This process facilitates effective decision-making.

  Risks are analysed and evaluated in terms of consequence and probability, which in turn deliver an associated risk ranking level of high, medium, or low. It is Group policy to regularly monitor high and medium-level risks. Where possible, additional analysis is undertaken to establish sensible consequence and probability levels. For example, in the case of network outages, consumer's costs of non-supply calculations often involve the analysis of historical asset failure rates.

  The Group's risk analysis and evaluation framework (Appendix C) is used to assess risks that are recorded within the network risk register.

- *Risk treatment:* Defining the actions to remove, mitigate or prepare for the risk. This involves developing contingency plans where appropriate.

7.3 Network Risk Management

7.3.1 Health and Safety

The safety of our employees, contractors and the public is of utmost importance in the operation, maintenance, and expansion of the network. The Group employs a Health and Safety Manager who is responsible for promoting Health and Safety across all divisions of the organisation and actively investigating all health and safety incidents. In addition, there is a Technical Safety Advisor within TEN reporting directly to the General Manager Networks.

We operate under the EEA Safety Rules that meet the requirements of the Acts, Regulations, Codes of Practice and Guidelines that govern the electricity industry.

We are committed to a reduction in both the frequency and severity of injuries to staff, contractors, and the public. The long-run results of initiatives implemented under this system demonstrate the commitment by staff to effectively manage health and safety. A philosophy of continuous improvement prevails within our health and safety system, with focus maintained on the following core activities:

- Employer commitment.

- Planning, review, and evaluation.
- Hazard identification, assessment, and management.
- Information, training, and supervision.
- Incident and injury reporting, recording and investigation.
- Employee participation.
- Emergency planning and readiness.
- Management of contractors and subcontractors.

Further, a high standard is maintained in the timeframes and process for the reporting and investigation of incidents. Similarly, employee commitment is being maintained through the continuing development of "safe teams", which involve employees at all levels in the management of health and safety by including employees in regular meetings to discuss and improve health and safety in their individual work areas.

We have gained accreditation as an Electrical Workers' Registration Board (EWRB) safety refresher provider and continue to make a significant investment in the training and development of our employees, as they undergo both regulatory and NZQA Unit Standard based training towards appropriate National Certificates for their various roles.

We offer training to upskill existing employees in the following work practices:

- Close-proximity vegetation work.
- Utility arborist.
- Vegetation management (including regulatory and legal compliance).
- Control room operator.

We maintain, and are continually improving, our authorisation holder's certificate (AHC) system, which requires formal assessments of current competency before staff are permitted to work on and around the network. This assessment process ensures the safety of employees as they only work within their proven competency.

The current AHC system has been updated to integrate the EWRB's competency-based refresher classes and we are working toward incorporating the National Common Competency Framework along with the majority of the EDB's. We maintain a proactive role in staff competency, monitoring industry safety issues, and implementing training and guidance where required.

Our recently commissioned ADMS is used to reduce the likelihood of a health and safety incident arising through operator error. The ADMS, which includes a network model and is used to produce switching schedules for all network outages, will generate an alarm if a planned switching schedule will result in a network condition where it is unsafe for a clearance to be issued.

7.3.1.1 Transmission Risks

Our transmission system comprises a single 110kV circuit between Kaikohe and Kaitaia and the recently completed 110KV transmission line that transports electricity generated by the Ngawha OEC4 generating unit to Kaikohe. It also includes the 110kV transformers and switchgear at the Kaikohe and Kaitaia substations and the Ngawha 110kV switchyard. These are critical assets, not least because of failure of the Kaikohe-Kaitaia circuit means that the 10,000 consumers in our northern area are no longer connected to the grid. While we acquired most of our transmission assets from Transpower in April 2012, the experience of TECS staff in the maintenance of 110kV transmission assets is limited. To minimise and mitigate our transmission risk:

- We have undertaken a comprehensive condition assessment of our transmission assets and developed a replacement plan that will ensure that the assets are replaced before they reach the end of their expected economic life. Provision for these asset replacements is included in the capital expenditure forecasts in this AMP.
- We have contracted the maintenance of all our 110kV line and substation assets to an experienced external service provider. The contract requires that these assets be inspected and

maintained to a level at least equivalent to that of similar Transpower assets. We also prioritise the repair of defects identified in transmission asset inspections.

- We facilitate regular site inspections and, in the process, engage with owners of property over which our 110kV assets are situated.

We have recently completed the installation of diesel generation in the Kaitaia area to avoid the need for maintenance shutdowns and to provide resilience in the event of an unplanned line outage. This is discussed further in Section 7.3.2.

7.3.1.2 Network Spares

We maintain an inventory of critical spares where there could be long delivery times in the event of network equipment failure. In most cases, the equipment we use is standardised and of modular design and can relatively easily be replaced using our inventory of equipment held to maintain and expand the network. Nevertheless, we regularly review our inventory of specialised spares and have joined a cooperative group of other EDBs to provide mutual support and risk mitigation when needed.

For the 110kV transmission assets, critical spares have been procured for standard hardware, cross arms, insulators and poles. An arrangement has also been made with Transpower to obtain a 110/33kV transformer bank at short notice if required. Our mobile substation is also a network critical spare.

7.3.1.3 Defect Management

Defects identified during our asset inspection programme are included in our defect management programme where they are risk assessed and categorised. This programme requires assets identified as defective to be inspected more frequently with the objective of allowing them to remain in service until they reach the end of their economic life, but at the same time ensuring that critical assets are replaced before they fail in service.

We monitor the implementation of our defect management programme using indicators related to outstanding defects and the SAIDI impact of defective equipment faults. We also report data on any backlog in the repair or remediation of defects monthly to the Board.

Our defect management program is described in detail in Section 6.1.2.3.

7.3.1.4 Vegetation Management

Our ongoing vegetation management programme is described in Section 6.2. While the primary focus of this programme is the management of supply reliability, trees growing into our lines are a public safety and property hazard and addressing this problem is prioritised when the fire risk is high.

We are also working with commercial plantation owners to develop vegetation management agreements and are actively campaigning to remove bamboo growing in the vicinity of our lines.

7.3.1.5 Asset Management

We have developed lifecycle asset management plans, including a risk management plan, for all our main asset groups. These are summarised in Sections 6.3 – 6.11.

7.3.2 Network Resilience

Network resilience relates to the ability of the network to withstand high impact, low probability events. The network development plan that we have implemented over the last ten years has focused on building a transmission and subtransmission network that is resilient to high impact events and we have now got to the point where we can restore supply with a target restoration time of 1 hour following a single element failure anywhere on our transmission or subtransmission network. This is explained in Table 5.1.

Our mobile substation is also available to support the subtransmission network as required. Now that we have increased the resilience of the transmission and subtransmission networks through our investment in diesel generation, the mobile substation is most likely to be used to save on the cost of running diesel generation for an extended period following the loss of a transformer or switchgear asset at one of our smaller zone substations.

Notwithstanding this significant improvement in network resilience, the 110kV Kaikohe-Kaitaia line remains vulnerable to a severe storm causing a landslide that results in the failure of one of the transmission tower foundations in the Maungataniwha Range. This happened in FYE2015 when a tropical storm remained stationary over our supply area for three days. Fortunately, on that occasion there was no supply interruption as the tower was supported by its conductors and did not fall over.

We have largely mitigated the consequences of such an event by installing diesel generation at Kaitaia. However, any repair could take some weeks as a replacement structure would need to be specifically designed for its location and access to these tower sites is difficult, particularly in wet weather. Running this generation for an extended period would be disruptive and place a heavy financial burden on Top Energy.

The construction of a second 110kV line through into Kaitaia over a more accessible eastern route will fully mitigate this risk. While planning for this second line commenced in FYE2013, we have been thwarted by landowner opposition and we are still awaiting a Supreme Court judgement in respect of three properties along the route.

Vulnerabilities remain on the distribution network primarily due to the number of long rural radial feeders serving the sparsely populated rural parts of the network remote from the major population centres. The length of these feeders means they have a high fault exposure. Their remoteness extends the time required to repair a fault and this, together with their relatively large number of connected consumers means that the SAIDI impact of faults can be high, particularly during adverse weather events when there can be several faults spread across different parts of the network. This is one reason why the reliability of the supply we provide consumers is volatile and sensitive to weather conditions. We are taking an incremental approach to addressing these vulnerabilities that focuses on improving the protection coordination across the network, the installation of circuit breakers along a feeder so that a fault at the end of a feeder does not affect the whole feeder, and the installation of fault location indicators. Our forecast capital expenditure provides for these improvements.

Network vulnerabilities and constraints are also discussed in Section 5.11.

7.3.3 Emergency Preparedness and Response Plan

Events can arise that are outside our network design envelope or exceed the response capacity of our field resources. The most likely scenario is a major storm event but other events, such as the loss of both transformers at a large substation, are possible.

We have an Emergency Preparedness and Response Plan to deal with such situations. This is designed to ensure that our network capabilities are sustained as far as practicable during emergency circumstances and events through the adoption of effective network management and associated practices. They ensure that we have the capability and resources to meet our community obligations, including fulfilment of civil defence emergency management requirements, while at the same time enhancing stakeholder and public confidence.

The plan addresses how we respond to major emergencies electricity supply by focusing on the four ‘R’s:

- *Reduction* (mitigation) of potential and actual threats or impacts arising from a diversity of natural and man-made hazards or risks that surround Top Energy and its assets. This does not extend to the management of network asset-related risks separately addressed during network planning, which are included in the risk register.
- *Readiness* (preparedness) to anticipate and prepare for potential and actual risks or threats beyond those alleviated by other means.
- *Response* to a potential and actual emergency, to stabilise the situation and prevent further danger and unnecessary outage.
- *Recovery* following response, to restore full normal services and functions.

The objectives of the plan are:

- To provide general guidelines that can be combined with sound judgment, initiative, and common sense to address any emergency, irrespective of whether that set of circumstances has been previously considered and planned for. These guidelines define the roles, duties and obligations of Top Energy and other personnel in preparing for and managing an emergency, prioritised on:

  - Protection of life (staff and public).
  - Safety and health of staff, service providers, consumers, and the public.
  - Protection of property and network assets.
  - Protection of the environment.
  - Ongoing integrity of the electricity network.
  - Establishment and maintenance of relationships and communication channels within Top Energy and with third parties.

- To provide a business continuity programme for the electricity network that will:
  - Raise and sustain appropriate individuals' preparedness, competence, and confidence to appropriate levels.
  - Provide Top Energy with the necessary facilities, information and other resources for response and recovery management.
  - Develop adequate relationships and approaches to ensure sustained plan implementation and evolution.
- To provide guidance to Top Energy staff for responding to, and recovering from, electricity network emergencies.
- To assist Top Energy to comply with statutory requirements and accepted industry standards with respect to management and operation of the electricity network during an emergency.

The plan covers emergency event classification, emergency response team roles and responsibilities, communications and reporting processes, emergency response prioritisation, detailed emergency response actions and business continuity programme maintenance procedures.

Our Emergency Preparedness Plan was activated during the July 2014 storm discussed in Section 7.3.2. It was also activated when insulators on both circuits of Transpower's Maungatapere-Kaikohe 110kV grid connection were damaged by bullets in 2016 causing an extended outage to our whole supply area; and during a subtropical storm in January 2018, which had a raw SAIDI impact of almost 100 minutes over a two-day period. It is reviewed after each activation to capture the lessons learnt from our management of that event.

We are currently updating our formal emergency response plan and splitting it into two separate documents, one covering preparedness and one covering response. The revised plan will formalise the regular testing of our preparedness and response capability and specify the frequency with which infrequently used systems, such as communications systems, that are in place to facilitate our response to high impact low probability (HILP) events, are reviewed and tested.

7.3.4 Lifelines Group

The Civil Defence Emergency Management Act 2002 requires organisations managing lifelines to work together with the civil defence emergency management group in their region. Lifelines are the essential infrastructure and services that support our community (e.g. utility services such as water, wastewater and storm water, electricity, gas, telecommunications and transportation networks including road, rail, airports and ports). Top Energy is an active member of the Northland Lifelines Group co-ordinated by the Northland Regional Council, which coordinates efforts to reduce the vulnerability of Northland's lifelines to hazard events, ensuring they can recover as quickly as possible after a disaster.

The role of the group is to:

- Encourage and support the work of all authorities and organisations (including local authorities and network operators) in identifying hazards and mitigating the effects of hazards on lifelines.
- Facilitate communication between the authorities and organisations involved in mitigating the effects of hazards on lifelines, to increase awareness and understanding of interdependencies between organisations.

- Create and maintain awareness of the importance of lifelines and of reducing the vulnerability of lifelines to the various communities within the region.
- Promote ongoing research and technology transfer aimed at protecting and preserving the lifelines of the region.

As part of the lifelines group coordination activities, we have committed to work with the Northland Civil Defence Emergency Management Group to provide use of our ripple control network for the activation of audible alarm sirens or tones. A procedure has been adopted to ensure that we meet this commitment to operate our injection equipment and deliver support to the Northland Lifelines Group Community Tsunami warning system. This procedure sets out the requirements for:

- The acknowledgement of activation requests.
- The activation of alarms.
- The process for notifications, and the logging of events and activations.
- The protocols for testing and reporting of system failures.

We also participate in formal civil defence exercises organised by the Northland Lifelines Group.

7.3.5 Load Shedding

We maintain a load shedding system to meet our regulatory requirement to ensure that an automatic under-frequency load shedding system is installed for each grid exit point to which a local network is connected (in our case, Kaikohe). The system enables the automatic disconnection of two blocks of demand as explained in Section 5.9.

We also maintain an up-to-date process for the manual disconnection of demand for points of connection, in accordance with our regulatory requirements.

A feeder shedding schedule is maintained, which specifies the shedding priority (manual and automatic) by under-frequency zone and substation for the 11kV network and the Transpower point of supply. This information is provided on an annual basis to Transpower and the Electricity Authority in accordance with their automatic under-frequency load shedding requirements.

7.3.6 Contingency Plans

We have standardized switching instructions that are managed and updated on a regular basis by our central control room staff. These switching instructions outline the methods for rearranging the electrical network to supply consumers during network contingencies (equipment outages).

We have also commissioned a separate and completely independent emergency control centre at the Ngawha Power Station, and our training programmes provide for regular operator familiarisation and testing activities.

7.3.7 Mobile Substation

Many of our risk scenarios involve consumer non-supply through equipment failure in zone substations, particularly in substations where there is only one transformer. In FYE2003, we mitigated this risk by purchasing a mobile substation and modifying single-transformer substations to allow the unit to be installed quickly following formalised procedures.

7.4 Safety Management

As noted in Section 2.4, we are required by our Asset Management Policy to develop an AMP that gives safety our highest priority. Safety management covers a broad range of issues including how we design, build and operate our network, ensure that we meet all legal compliance requirements, and interface with our contractors and other external organisations, the general public and our network users.

Section 63A of the Electricity Act 1992 requires us to have a Public Safety Management System (PSMS). Our PSMS is certified as compliant with NZS 7901 and is regularly audited externally to maintain this certification. These audits cover both the alignment of our documented PSMS with NZS 7901 and the extent that our staff comply with the requirements of the system. We have integrated our PSMS into our asset management safety practices and use it to manage the safety risks in operating our network. Ensuring that our compliance with our PSMS is externally audited provides a level of governance that ensures that our safety practices take due account of the requirements of the Health and Safety at Work Act 2015 and other relevant legal requirements.

The coverage of our PSMS extends beyond our own network assets into consumer-owned assets. This is because, while we do not own consumer assets and therefore are not responsible for their compliance, we do operate them, and we must ensure the safety of our staff. We also have responsibilities with respect to the equipment we allow to connect to our network and be energised.

7.5 Network Risks

7.5.1 Corporate Risk Register

Table 7.3 schedules the risks in Top Energy's Corporate Risk Register that have been assigned to TEN and the controls we have in place to mitigate these risks.

No.	Risk	Probability	Consequence	Mitigation
Risks from the Top Energy Group Risk Register that are Assigned to TEN				
15.	Third party loss or damage.	High, mitigated to moderate.	Exposure to compensation or fines.	• Compliance with Electricity (Safety) Regulations and associated Codes of Practice. • Public Safety Management System certified to NZS 7901 in place.
5.	Failure of network equipment or systems, owing to inadequate design specification, installation, operation or maintenance.	Extreme, mitigated to moderate.	Regulatory investigation.	• Adoption of ISO 55000/PAS 55 as a best practice asset management standard. • Assessment of asset management capability and maturity, and continuous improvement as per the standard. • The use of external consultancy when inhouse capability insufficient.
16.	Cost overruns and delays in implementing network projects.	Extreme, mitigated to moderate.	Impact on pricing control – loss of incentives and/or penalty	• Dedicated in-house project delivery manager to support competent planning team.
20.	Unplanned network outage affecting more than 10,000 customers for longer than 12 hours.	Extreme, mitigated to moderate.	Breach of regulatory quality targets.	• Provision of network resilience with diesel generation; • Contingency plans, including disaster recovery and emergency preparedness.

No.	Risk	Probability	Consequence	Mitigation
19.	Loss of incoming grid supply for more than 24 hours.	Moderate, mitigated to low.	Loss of grid supply to all consumers.	The network currently has 17.2MW of diesel generation it can deploy to critical load locations in the event of sustained loss of grid supply. Supply would need to be rationed in the event of an extended interruption. Our Emergency Response Plan includes the contact details of hire generator suppliers who would be used to augment the generation capacity in the southern area.
21.	Environmental damage.	Moderate, mitigated to low.	Exposure to compensation or fines	• Compliance with resource consents. • Response plans (e.g. oil containment and spill kits). Current focus areas include identification of environmental vulnerabilities and then updating mitigation provisions.

Table 7.3: Corporate Risk Register

7.5.2 Network Safety Management System Hazard Register

In implementing its Public Safety Management System, TEN maintains a formal Hazard Register. This is actively managed by the Technical Safety Advisor and reviewed four-monthly by the Network Risk Management Committee as discussed in Section 7.2.2. For each risk the register identifies risk mitigation strategies including relevant external safety regulations and guidelines as well as internal processes that are in place to manage the risk. Each risk is assigned a residual risk score that is based on:

- Consequence – the likely worst outcome from exposure to the risk.
- Frequency – how often exposure to the hazard is likely to occur.
- Likelihood – how likely the consequences would be incurred on each exposure.

Residual risk scores greater than 800 are considered extreme – there are no such risks on the current register. Risk scores between 200 and 800 are considered high and those between 40 and 200 are rated mediums. Scores below 40 are considered acceptable. Table 7.4 shows the risks on the register that are currently rated high or medium.

Risk	Residual Risk Score
Vegetation at risk of being in contact with live network assets	800
Person interacting with vegetation planted for non-commercial purposes under, or too close to, power lines	600
Cross polarity or other issue occurs during the installation of smart meters	480
A member of the public decides to cut trees around live power lines and receives an electric shock	400
Contact between overhead power lines of dissimilar voltages resulting in over-voltages to installations	400
Privately owned lines not being maintained to industry and regulatory standards posing a risk to persons and property	240
Vehicle striking live overhead line with over-dimensional load	200

Risk	Residual Risk Score
Non-compliant ground clearances of lines	200
Contamination from leaking oil filled equipment	200
Low fault current leading to slow protection operation	200
Public movement through inactive or unended worksites resulting n harm to persons or property	160
Aircraft striking aerial conductors in its flight path	80
Unauthorised third party assets mounted on or near pole or other equipment	80
Low structure enable unassisted climbing and access to live exposed parts	80
Security of ground mounted transformers is breached allowing access to live internals	80
Lightning striking equipment, resulting in potential rise in connected installations or earth potential rise around the affected equipment	48
Current leakage to earth causing unacceptable step and touch potential	48

Table 7.4: High and Medium Risks on Safety Hazard Register

7.6 Climate Change

We anticipate that climate change will primarily impact the management of our network in two ways:

- Changes in weather patterns will affect the reliability of supply to consumers which, all else being equal, is strongly correlated with the weather; and
- Decarbonisation of the economy will impact both the demand for electricity and the expectations of network users in relation to the services we provide.

7.6.1 Changing Weather Patterns

The Ministry for the Environment predicts the following changes to the weather patterns in our supply area:

- Compared to 1995, average temperatures are likely to increase by 0.7°C to 1.1°C by 2040, and to increase further beyond that, at a rate that will depend on how successful the world is in reducing carbon emissions. This could lead to more frequent droughts, which in turn could lead to water shortages, increased demand for irrigation and increased risk of wildfires. Our area currently experiences very few frosts and in future frosts are likely to become extremely rare. This suggests that growth in our winter peak demand will ameliorate but electricity consumption over the summer will increase with an increased demand for air conditioning and water pumping. Eventually we could have a summer peaking load, as is currently the case throughout mainland Australia.
- While there will be some variability in seasonal rainfall, changes in annual rainfall are expected to be small and our area is not expected to experience a significant change in the frequency of extremely rainy days as a result of climate change. In fact, it is likely to experience a decrease in daily extreme rainfall by 2090 under the highest emissions scenario. While there is expected to be little change in the frequency of storms and cyclones, the intensity of ex-tropical cyclones is likely to increase and these could cause more damage as a result of heavy rain and strong winds.
- While there may be n increase in westerly wind flow during winter and north-easterly wind over summer, the frequency of extremely windy days is not expected to increase.
- New Zealand tide records show an average rise in mean sea level of 1.7mm per year over the 20th century. Globally the rate of rise has increased, and further rise is expected in the future.

This will lead to an increase in flooding in low-lying coastal areas. The Taipa substation is located in such an area and will eventually need to be relocated or redeveloped to mitigate this. This is discussed further in Section 7.6.3.

The Far North District Council and the Northland Regional Council are both monitoring sea level rise and have published map, such as Figure 7.2, showing areas of coastal inundation for varying degrees of change. Similar maps have also been produced to show the impact of earthquake induced tsunami on the coastline.

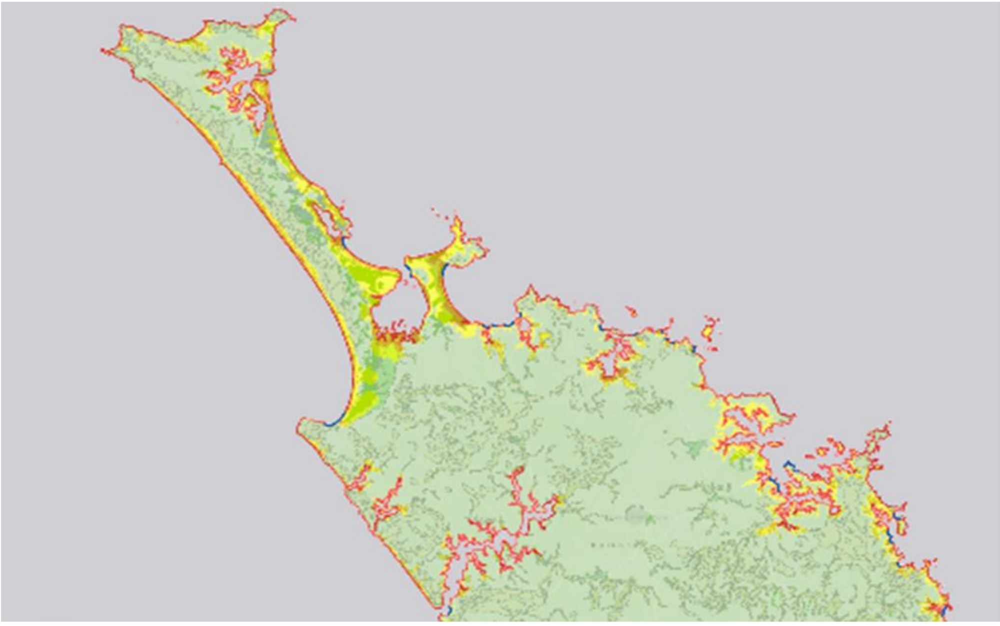

Figure 7.2: Northland Regional Council Tsunami and Flood Hazard Zones

These predictions are consistent with our own observations over the last ten years. While reliability of the supply we provide has improved over this time, as shown in Figures 4.1 and 4.2, the year-on-year volatility of the normalised reliability has been high, as these figures also show. It is unclear how best to allow for weather variability when setting our annual reliability targets. While, historically, the provision we have made for weather in in setting the targets in our AMPs and Statements of Corporate Intent would seem to be insufficient – we have only hit our SAIDI targets in FYE2013 and FYE2019, both years of benign weather, we are very reluctant to significantly change our approach to target setting because we see a risk that a more realistic provision could introduce complacency across the organisation.

The forecasts reflect an increased intensity of major storms and an increase in average wind speeds across our supply area. Over time the impact of the weather on the reliability of our network is therefore likely to increase as a result of climate change. We must therefore develop a network that is increasingly resilient to climate impacts. This will entail not only improved vegetation management but, over time, introducing a network architecture that reduces the number of consumers affected by a single fault.

We already mitigate the impacts of changing weather patterns through our vegetation management plans, asset replacement programmes, and the implementation of safety by design for new assets. The measure of success will depend on how well capital investment keeps pace with natural degradation of the network plus the incremental cost of matching the advancing impact of intensifying weather patterns. The situation will need to be monitored on an ongoing basis and adjusted or managed accordingly.

7.6.2 Decarbonisation of the Economy

While changing weather paters are likely to have an adverse impact on network reliability, decarbonisation of the economy to decelerate the rate of climate change is likely to have an even greater impact on the development and management of our network. In particular:

- As noted in Section 2.6.4, the penetration of small-scale photovoltaic generation within our network is now 5.65MW. Almost 3.5% of our consumers have now connected photovoltaic generation behind the meter and penetration is increasing at a faster rate than anywhere else in the country. We do not see this trend abating and think it could accelerate. This could create congestion on the low voltage network if a number of behind-the-meter installations are connected to the same circuit. In this situation there will be a sudden drop in output of all adjacent generators when the sun goes behind a cloud. This volatility will trigger an automatic response from the inverters connecting the photovoltaic cells to the network, but these can interfere with one another creating a stability issue. Other potential problems are sudden overvoltage or undervoltage swings when the generation output changes. While such problems have yet to emerge on our network, they are a significant issue in Australia where there are much higher levels of connected photovoltaic generation. As noted in Section 5.11.1.1, on 1 April 2021 we will introduce a new tariff of 0.5 cents per kWh of generation exported into our low voltage network so that we can better understand this issue and mitigate any problems that arise.

  It is also possible that the continuing reduction in the cost of battery energy systems will mitigate this issue due to the fast response of battery electronic controls.

- We have already received three applications from investors proposing to install a total of up to 67MW of utility scale photovoltaic generation in our northern area to capture an increasing demand for renewable electricity generation as the economy decarbonises. As discussed in Section 5.11.2.1 and 5.11.2.2 the amount of such generation that we are able to connect will be limited both by the capacity of the generation circuits available to export the electricity south and also by the ability of the network to control the voltage swings caused by the volatile generation outputs.

- The government is strongly encouraging the uptake of electric vehicles and the number of such vehicles registered in our supply area is increasing, as noted in Section 2.6.6. As the number of electric vehicles increases there is a potential for localized distribution network overloads if a significant number of vehicles are charged during times of peak demand. A stronger time-of-use tariff may be needed to incentivise this.

- Decarbonisation of the economy is expected to be accompanied by a significant long-term increase in the demand for electricity, due to the electrification of transport and process heat. While there are no industries in our supply area that require large amounts of process heat, we are likely to experience a growth in incremental demand from the electrification of light vehicles. Fortunately, our transmission and subtransmission networks, with the exception of the voltage constraint at Waipapa and Kaeo that will be addressed in FYE2024, has ample capacity to accommodate additional demand. In the longer term, there may be a demand for the installation of high-capacity charging stations as heavy transport is electrified but we anticipate that any localized network augmentations needed to supply these new block loads would be paid for by the developer.

- It may be that the use of diesel generation is discouraged as the push to decarbonize the economy increases and this could impact the operation of our diesel generation fleet in the longer term. This could potentially be mitigated by the use of biodiesel, notwithstanding Z Energy's recent hibernation of its biofuel plant.

- In time Top Energy may be required to measure the carbon footprint of its operations and to take steps to minimize its emissions.

7.6.3 Vulnerability of Substation Assets

Taipa Substation is the most critical asset likely to be impacted by Tsunami or sea level rise. It is situated 250 metres from the Oruru River estuary and approximately 1.8m above mean high water level. The arrow in Figure 7.3 shows where past high tides have encroached upon the site. Studies have been undertaken to assess the risk and, as a consequence, an alternative site has been procured and consented for a new substation to be built at Garton Rd, Oruru. This substation is planned to be constructed in the ten-year period following completion of our new 110kV line in FYE2010.

Figure 7.3: Taipa Substation Tidal Flood Encroachment

Other substation assets which are low-lying are Kaeo and Omanaia substations. The risk to these sites is not as great as for Taipa, and is dependent on significant sea level rise, high tide and flooding all occurring simultaneously. To mitigate these risks flood remediation has been undertaken at Omanaia, and Kaeo substation has been elevated above any anticipated flood condition.

Section 8 Evaluation of Performance

8 Evaluation of Performance

This Section evaluates our asset management performance in respect of:

- The change in the reliability of supply that we have provided our consumers over the last ten years. From the beginning of this decade, we have increased the level of expenditure on the network with the objective of improving the reliability of supply we provide our consumers.
- The extent to which we have met the service level performance targets for FYE2020, the most recent year for which complete data is available. The targets were set in our 2019 AMP.
- Our expenditure on network development and maintenance in FYE2019 and FYE2020.
- The quality of our asset management systems and procedures.

8.1 Reliability

Consistent with the requirements of the both the regulatory default price-quality path and information disclosure regimes, network reliability is measured by SAIDI and SAIFI. However, in resetting the default price-quality path for both the FYE2016-2020 and the FYE2021-2025 regulatory periods, the Commerce Commission changed the methodology to be used in normalising the raw SAIDI and SAIFI measures before assessing regulatory compliance. No corresponding change were made to the information disclosure regime, so the normalisation approaches in the measurement of reliability that are applied under the two regulatory frameworks are now different.

We have been able to "reverse-engineer" the normalisation of the raw reliability of supply that we have provided our consumers since FYE2009, using the normalisation methodology the Commerce Commission has introduced for measuring reliability in assessing our performance against our default price-quality path for the FYE2021-25 regulatory period. As discussed in Section 4.2, normalisation removes much of the volatility due to weather variability and is therefore a better indication of our success in influencing reliability by managing those drivers we can control. This is the first time we have been able to normalise our past performance over an extended period using a consistent normalisation methodology and thus provide a valid comparison of our normalised year-on-year performance.

Figures 8.1 and 8.2, which reproduce the graphs shown in Figures 4.1 and 4.2, provide this comparison for unplanned interruptions.

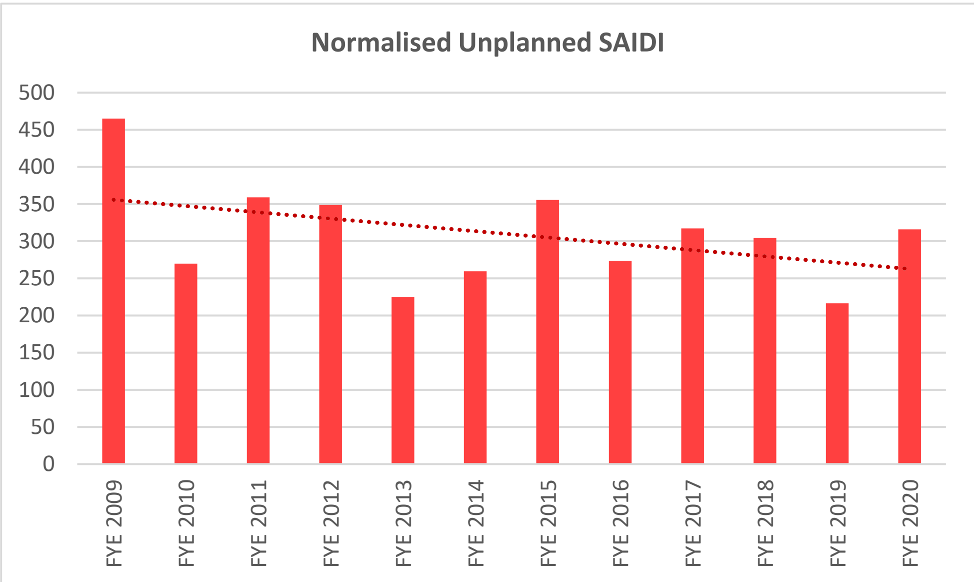

Figure 8.1: Normalised Unplanned SAIDI FYE 2009-20

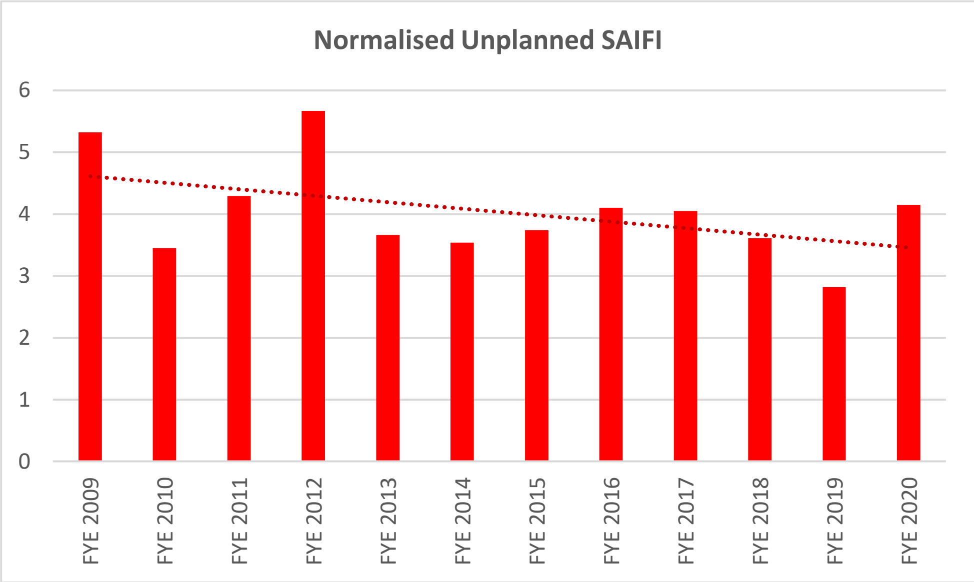

Figure 8.2: Normalised Unplanned SAIFI FYE 2009-20

The two figures above show that:

- Over the 11-year period since FYE2009, we have improved our expected normalised SAIDI due to unplanned interruptions from about 350 to 260 minutes, an improvement of 26%.
- Over the same period, we have improved our expected normalised SAIFI due to unplanned interruptions from 4.6 to 3.5, an improvement of 24%.
- The normalisation process reduces, but does not eliminate, the volatility due to weather variability. Over this period, the two years with the lowest volatility were FYE 2013 and FYE 2019, both years with unusually benign weather conditions.

Over the first half of the period the reliability improvement was largely driven by increased expenditure in vegetation management and the introduction of remote-controlled switches on the 11kV network to allow, in many cases, supply to be restored more quickly to consumers not directly affected by a fault, without waiting for a fault to be repaired. Over the latter part of the period, the subtransmission system has been reconfigured into a number of rings. This initiative, along with the associated protection system upgrades has achieved significant reliability improvements so that most faults on the 33kV network no longer result in a supply interruption. The construction of new zone substations at Kerikeri and Kaeo have also contributed to our reliability improvement as the 11kV feeders supplied from these substations are shorter and fewer consumers lose supply when a fault occurs.

Figure 8.3 shows how we have reduced the raw SAIDI impact of unplanned interruptions over the five-year period FYE2016-20. The SAIDI numbers shown are raw SAIDI, prior to normalisation. It shows that while we have been able to improve the reliability of both our subtransmission and distribution networks, the improvement in subtransmission reliability has been most significant. We have now reached the point where the expected impact of unplanned interruptions due to faults on our 33kV network is less than 40 SAIDI minutes.

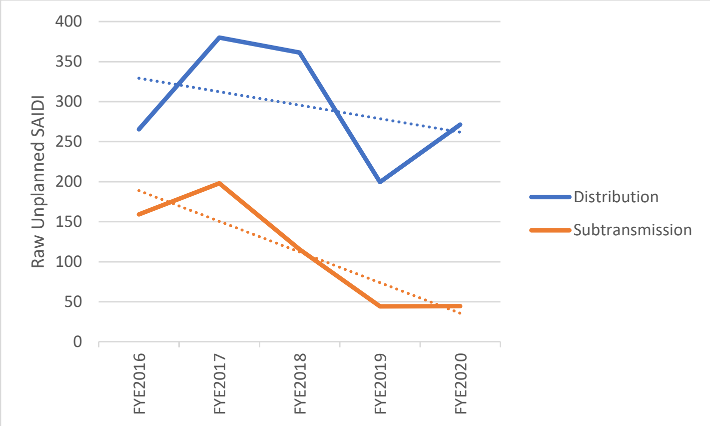

Figure 8.3: Raw SAIDI Impact of Unplanned Interruptions, FYE2016-20

Going forward we see some further SAIDI improvement in the short term due to the backup diesel generation we commissioned in FYE2021. After that, reliability improvement is likely to be incremental. We think we have already captured most of the “easy” reliability gains available on the 11kV network. Away from the eastern seaboard this network is still characterised by long feeders with a limited number of interconnections. This part of the network has a high fault exposure and step improvements in reliability would require significant upgrade to the network architecture involving the installation of more zone substations or the construction of new feeder interconnections. These investments would be expensive and much of this part of the network is already uneconomic.

8.1.1 Causes of Unreliability

Table 8.1 breaks down our raw SAIDI, prior to normalisation, over the five-year period FYE2016-20 by cause.

	FYE2016	FYE2017	FYE2018	FYE2019	FYE2020	Average	Percent
Adverse Environment	2	2	0	0	0	1	0%
Adverse Weather	37	110	103	0	3	51	12%
Defective Equipment	139	121	95	67	122	109	27%
Human Error	2	7	6	0	4	4	1%
Lightning	3	8	3	22	8	9	2%
Third Party Interference	76	50	65	49	63	61	15%
Vegetation	58	95	83	61	81	76	19%
Wildlife	8	144	6	13	13	37	9%
Unknown	99	43	116	32	22	62	15%
Total	**424**	**578**	**477**	**244**	**316**	**408**	
Normalised	274	317	305	216	316	286	

Table 8.1: Raw SAIDI Impact of Unplanned Interruptions by Cause

8.1.1.1 Defective Equipment

Table 8.1 shows that defective equipment continues to the primary cause of network unreliability and Figure 8.4 shows the variation in unplanned SAIDI resulting from faults due to equipment failure over the period FYE2016-20. While the graph shows an improving trend, there was a sharp deterioration in FYE2020.

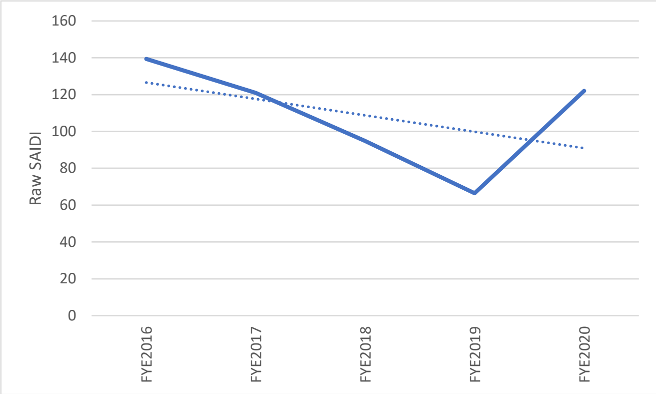

Figure 8.4: Raw SAIDI Impact of Defective Equipment Faults FYE2016-20

While the SAIDI impact of defective equipment faults almost doubled between FYE2019 and FYE2020, the number of defective equipment faults increased by only 25%. Much of the higher SAIDI impact was due to two 33kV faults, which together had a SAIDI impact of 32 minutes. The most severe fault, which had a SAIDI impact of over 25 minutes, was caused by a conductor joint failure on one of the two lines supplying the Bay of Islands. The incident occurred when the second line was out of service for maintenance, so the normal backup supply was not available. In the second incident, a suspension insulator on the single incoming circuit to our Omanaia substation failed at a time when there was lightning in the general area. We have subsequently commissioned diesel generation at our Omanaia substation, which would have been used to reduce the SAIDI impact of the fault had it been available at the time. While we will continue to monitor the situation, we think it is too soon to conclude that the 2020 outcome was the start of a longer-term trend rather than an aberration.

Most faults attributed to defective equipment are due to a failure of pole top hardware or conductor. rather than the failure of a discrete plant item such a transformer, circuit breaker or ring main switch. Replacement programmes for pole top hardware are firmly embedded in the capex forecasts in this AMP; subtransmission lines are well though their upgrading programmes, and crossarm and insulator replacements on distribution lines have commenced and will be ongoing for the foreseeable future. With the random nature of pole top failures, the replacement programme will not have a significant impact on SAIDI reduction or the reduction in the numbers of outages from this cause in the short to medium term.

Conductor replacement programmes are underway. Most conductor failure faults are due to other causes such as vegetation. Our programme to address conductor failure as a fault cause is specifically targeted at particular conductor types that are known to show age embrittlement and corrosion and are inclined to fail, such as copper and steel conductors. This is discussed in Section 6.5.11.

8.1.1.2 Adverse Weather and Vegetation

As can be seen from Table 8.1, we stopped attributing faults to adverse weather after FYE2018 and attributed these faults to other causes. For this analysis we have therefore amalgamated adverse weather and vegetation, since faults during adverse weather generally result from vegetation issues. Table 8.2 shows the combined SAIDI impact of adverse weather and vegetation faults over the period in the capex

	FYE2016	FYE2017	FYE2018	FYE2019	FYE2020	Average
Adverse Weather	37	110	103	0	3	51
Vegetation	58	95	83	61	81	76
Total	**98**	**195**	**186**	**61**	**84**	**125**
Annual Unplanned SAIDI	424	578	477	244	316	408
Percent annual SAIDI	**22%**	**35%**	**39%**	**25%**	**26%**	**31%**

Table 8.2: Unplanned Weather-Related SAIDI FYE2016-2

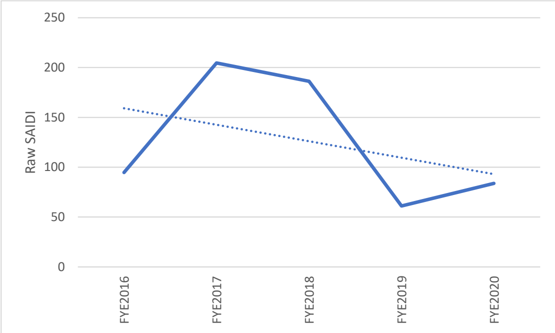

Figure 8.5: Raw SAIDI Impact of Weather-Related Faults FYE2016-20

We will continue to monitor weather driven SAIDI, including vegetation, as a percentage of the total raw SAIDI due to unplanned interruptions and take action should this start to increase significantly above its current level of 25%. Table 8.2 suggests that this ratio is higher in years when the weather is particularly bad but, going forward, we expect this ratio to be more consistent due to the reduced SAIDI impact of faults on the 33kV network.

8.1.1.3 Third Party Interference

The unplanned SAIDI impact of third-party interference incidents has not deviated much from its five-year average of around 60 SAIDI minutes, and on average accounts for around 15% of the SAIDI impact of unplanned interruptions. Third party interference faults are predominantly caused by cars hitting 11kV poles – we had 20 such incidents in FYE2019 and 22 in FYE2020. The SAIDI impact of such incidents is high due to the time required to transport a new pole to the site of the incident, remove the old pole and erect the new one. Many of these incidents occur in remote areas where our 11kV network is constructed within narrow, winding road corridors.

8.1.1.4 Incidents with Unknown Cause

Over the five-year period incidents with an unknown cause accounted for 15% of our total SAIDI. This metric is dominated by two separate incidents:

- In 2016 there was a tripping of the 110kV Kaikohe-Kaitaia circuit. When the line failed to reclose, we patrolled the line in accordance with our standard safety procedures, which are aligned with those used by Transpower. No fault was found and a follow-up patrol with corona camera and partial discharge detection equipment failed to determine a cause. This incident had a SAIDI impact of 64.8 minutes, a situation that has now been mitigated by the installation of diesel generation in the Kaitaia area.
- In 2018 there was a tripping of the 110kV network that Transpower's protection suggested was a substation 110kV busbar fault at Kaikohe substation. Due to the potential implications of such a fault, we undertook an extensive investigation to find a possible cause before the system was re-energised, with no fault being found. This incident had a SAIDI impact of 86.8 minutes. To prevent a reoccurrence this situation, we have now split the Kaikohe 110kV bus, installed a bus coupler circuit breaker and also bus zone protection.

These total SAIDI impact of these two faults was 151.6 minutes, which is more than 50% of the total SAIDI impact of unknown faults over the five-year period.

8.2 Achievement of Service Level Targets

Our performance against the service level targets for FYE 2020 that were in our 2019 AMP are shown in Table 8.3.

The normalised SAIDI and SAIFI measures in Table 8.3 are defined differently from the corresponding measures in Section 4 of this AMP as they are based on the normalisation approach used by the

Commerce Commission in assessing our compliance with the reliability thresholds for the FYE2016-20 regulatory period.[13] The main differences are:

- The targets were the sum of the impacts of both planned and unplanned interruptions. We now set separate targets for planned and unplanned interruptions.
- Planned interruptions were de-weighted by 50%. Our current targets for unplanned interruptions are unweighted.
- Unplanned interruptions were normalised on a calendar day, rather than a rolling 24-hour period. In addition the boundary values are those that applied to the FYE2016-20 regulatory period, whereas the targets in Section 4 use the FYE2021-25 boundary values.

Service Level Indicator	Internal Target	Outcome
Normalised SAIDI	318	365.6
Normalised SAIFI	3.44	4.46
Loss Ratio	9.3%	8.5%
Ratio of Total Opex to Total Regulatory Income	33%	34%

Table 8.3: Achievement of FYE2020 service Level Targets

While we did not meet our internal targets, our normalised SAIDI and SAIFI were nevertheless the second lowest that we achieved over the five years of the FYE2016-20 regulatory period. Over the period, this outcome was bettered only in FYE2019, when the weather was unusually benign. There were no major event days in FYE2020.

The definitions that were applied to the measurement of loss ratio and the ratio of total opex to total regulatory income have not changed from those in Section 4 of this AMP.

8.3 Financial and Physical Performance

A comparison of our actual expenditure in FYE2020 for both network capex and network maintenance opex with the budgeted expenditures, as presented in the 2019 AMP, is provided in Table 8.4. While there are significant variances in individual line items, variances in total network capex and total network capex were both below the Commission's 10% materiality threshold.

EXPENDITURE CATEGORY	BUDGET FYE2020	ACTUAL FYE2020	VARIANCE	
Network capital expenditure ($000)				
Consumer connection	1,636	2,548	912	56%
System growth	20,174	16,34	(3,827)	(19%)
Asset replacement and renewal	8,527	5,698	(2,829)	(33%)
Reliability, safety and environment	1,600	10,190	8,590	537%
Asset relocations	-	-		-
Subtotal – network capital expenditure	**31,937**	**34,783**	**2,846**	**9%**
Maintenance expenditure ($000)				

13 These measures were superseded by the Commission's default price-quality path determination for the FYE2021-25 regulatory period. The reliability targets in Section 4 are based on the revised measures.

EXPENDITURE CATEGORY	BUDGET FYE2020	ACTUAL FYE2020	VARIANCE	
Service Interruptions and emergencies	1,199	1,706	507	42%
Vegetation management	2,071	1,900	(171)	(8%)
Routine and corrective maintenance and inspection	1,787	1,754	(33)	(2%)
Asset replacement and renewal	1,106	965	(141)	(13%)
Subtotal – maintenance expenditure	**6,163**	**6,324**	**161**	**3%**
TOTAL DIRECT NETWORK EXPENDITURE	**38,100**	**41,107**	**3,007**	**8%**

Table 8.4: Comparison of actual and budget network capex and network maintenance opex in FYE2020

8.3.1.1 Network Capital Expenditure

As shown in Table 8.4 actual capital expenditure in FYE2020 was 9% higher than forecast with material variations from budgeted levels in all expenditure categories.

Consumer Connections

- We have little control over this expenditure and there was more consumer-driven activity than expected. The additional expenditure was largely offset by increased consumer contributions.

System Growth

- The majority of the system growth expenditure in FYE2020 was on the 110kV line and substation that are now being used to transmit power generated by OEC4 at Ngawha to the grid. By the end of the year pole erection was complete but line stringing was delayed because the contractor we planned to use was unavailable. This work was carried over until FYE 2021.
- We also completed the installation of a larger transformer and backup generators at the Omanaia substation. This work had been carried over from FYE2019.

Asset Replacement and Renewal

- Capital expenditure on asset replacement and renewal was $2.8 million less than forecast due to the concentration of resources on major capital projects including the new 110kV Ngawha line and the installation of diesel generation at Kaitaia.

Reliability, Safety and Environment

- This expenditure was primarily on the installation of the backup diesel generation in the Kaitaia area. This project was categorised as capacity expansion in our 2019 AMP but was managed as a reliability improvement project, as reliability improvement more accurately describes the driver for this project.

8.3.1.2 Network Maintenance Expenditure

As shown in Table 8.4, operational expenditure on network maintenance in FYE2020 was 5% above budget due to the 42% overrun in the cost of responding to service interruptions and emergencies shown in Table 8.4. Our control over expenditure in this category is limited. This overrun was largely offset by reductions in expenditure in the other maintenance categories.

8.4 Asset Management Improvement Programme

Our organisational philosophy is one of continuous improvement across all of Top Energy's business units and our certification to ISO 9001 is testimony to this. This was the culmination of a major business improvement initiative that had been running for several years and affected all business units within the Group.

EVALUATION OF PERFORMANCE

Our asset management systems are underpinned by our public safety management system and our quality system that are both externally certified as compliant with recognised standards and subject to regular external audits. These are process-orientated total quality management systems. The maturity of our asset management is assessed in Schedule 13 of Appendix A. We have scored ourselves at Level 3 (on a rating system of 1-4 with 4 indicating that the requirements of a recognised standard have been exceeded) on most indicators due to the maturity of our quality and safety management systems.

We will focus our asset management improvement programme on improving those areas that we have identified as weak and are therefore impediments to achieving our overarching goal of meeting stakeholder expectations as efficiently as possible. Our short-term focus will be on the following areas:

- The updated service level agreement between TEN and TECS is being bedded in. There are opportunities for improvement at the interface between TEN and TECS, and our efforts to improve communication will continue.
- The information available to the ADMS on the phasing of 11kV network is incomplete. In FYE2022 we plan to capture the missing data and label the phasing in the field.
- Over the period FYE2022-24, we have initiated a data capture project to capture missing information on our low voltage network assets. This will then be used to enable active management of these assets from the control room using the ADMS. Isolation and earthing to work on the low voltage network is currently self-managed in the field but will be managed from the control room once our data capture project is complete. The increased penetration of small-scale photovoltaic generation has increased the risks associated with work on the low voltage network because of the potential for inadvertent livening of the network from secondary sources.

Section 9 Appendices

9 Appendices

9.1 Appendix A – Asset Management Plan Schedules:

Schedule 11a	CAPEX Forecast
Schedule 11b	OPEX Forecast
Schedule 12a	Asset Condition
Schedule 12b	Capacity Forecast
Schedule 12c	Demand Forecast
Schedule 12d	Reliability Forecast
Schedule 13	Asset Management Maturity Assessment
Schedule 14a	Mandatory Explanatory Notes on Forecast Information

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	2,176	4,113	2,302	1,965	2,005	2,045	1,930	1,980	2,008	2,048	2,089
11		System growth	7,172	1,263	3,890	5,288	3,901	1,894	173	177	4,961	5,391	4,735
12		Asset replacement and renewal	4,276	6,888	6,369	6,186	7,091	6,943	8,198	8,160	7,494	8,115	9,250
13		Asset relocations											
14		Reliability, safety and environment:											
15		Quality of supply	425	1,098	2,185	1,315	2,985	6,273	7,413	5,532	15,281	15,361	1,124
16		Legislative and regulatory											
17		Other reliability, safety and environment		1,018	853	541	-	-	-	2,219	-	833	1,334
18		**Total reliability, safety and environment**	425	2,116	3,038	1,856	2,985	6,273	7,413	7,751	15,281	16,195	2,457
19		**Expenditure on network assets**	14,049	14,380	15,598	15,296	15,981	17,154	17,714	18,068	29,745	31,748	18,531
20		Expenditure on non-network assets	400	1,559	510	520	531	541	552	563	574	586	598
21		**Expenditure on assets**	14,449	15,939	16,108	15,816	16,512	17,695	18,266	18,631	30,319	32,334	19,128
22													
23	*plus*	Cost of financing	830	55	56	57	58	60	75	80	150	180	200
24	*less*	Value of capital contributions	2,000	3,500	1,679	1,331	1,357	1,384	1,412	1,452	1,469	1,499	1,529
25	*plus*	Value of vested assets	5	5	5	5	5	6	6	6	6	6	6
26													
27		**Capital expenditure forecast**	13,284	12,499	14,491	14,548	15,218	16,376	16,934	17,265	29,006	31,022	17,806
28													
29		Assets commissioned	31,716	15,939	12,619	18,275	15,285	11,318	7,221	3,149	38,011	40,025	19,094

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
32			**$000 (in constant prices)**										
33		Consumer connection	2,176	4,113	2,257	1,889	1,889	1,889	1,748	1,758	1,748	1,748	1,748
34		System growth	7,172	1,263	3,813	5,083	3,676	1,750	157	157	4,319	4,601	3,962
35		Asset replacement and renewal	4,276	6,888	6,244	5,946	6,682	6,414	7,425	7,246	6,524	6,926	7,740
36		Asset relocations	-	-	-	-	-	-					
37		Reliability, safety and environment:											
38		Quality of supply	425	1,098	2,142	1,264	2,813	5,795	6,714	4,912	13,303	13,111	940
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other reliability, safety and environment	-	1,018	836	520	-	-		1,970		711	1,116
41		**Total reliability, safety and environment**	425	2,116	2,978	1,784	2,813	5,795	6,714	6,883	13,303	13,822	2,056
42		**Expenditure on network assets**	14,049	14,380	15,293	14,702	15,059	15,847	16,044	16,044	25,894	27,097	15,506
43		Expenditure on non-network assets	400	1,559	500	500	500	500	500	500	500	500	500
44		**Expenditure on assets**	14,449	15,939	15,793	15,202	15,559	16,347	16,544	16,544	26,394	27,597	16,006
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											

Company Name	**Top Energy**
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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*
50													
52		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
53	**Difference between nominal and constant price forecasts**		**$000**										
54	Consumer connection		-	-	45	76	116	156	182	222	260	300	341
55	System growth		-	-	76	205	225	144	16	20	642	790	773
56	Asset replacement and renewal		-	-	125	240	409	529	773	914	970	1,189	1,510
57	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:												
59	Quality of supply		-	-	43	51	172	478	699	620	1,978	2,251	183
60	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment		-	-	17	21	-	-	-	249	-	122	218
62	**Total reliability, safety and environment**		-	-	60	72	172	478	699	868	1,978	2,373	401
63	**Expenditure on network assets**		-	-	306	594	922	1,306	1,670	2,024	3,850	4,651	3,025
64	Expenditure on non-network assets		-	-	10	20	31	41	52	63	74	86	98
65	**Expenditure on assets**		-	-	316	614	952	1,348	1,722	2,087	3,924	4,737	3,123
66													

67			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
68	**11a(ii): Consumer Connection**							
69	*Consumer types defined by EDB**		**$000 (in constant prices)**					
70	All types		2,176	4,113	2,257	1,889	1,889	1,889
71	[EDB consumer type]							
72	[EDB consumer type]							
73	[EDB consumer type]							
74	[EDB consumer type]							
75	**include additional rows if needed*							
76	**Consumer connection expenditure**		2,176	4,113	2,257	1,889	1,889	1,889
77	*less* Capital contributions funding consumer connection		2,000	3,500	1,646	1,279	1,279	1,279
78	**Consumer connection less capital contributions**		176	613	611	610	610	610

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
79	**11a(iii): System Growth**						
80	Subtransmission	7,000			310		
81	Zone substations			2,979	4,298	3,519	145
82	Distribution and LV lines	120	1,263	835	475	157	1,192
83	Distribution and LV cables						
84	Distribution substations and transformers						413
85	Distribution switchgear						
86	Other network assets	52					
87	**System growth expenditure**	7,172	1,263	3,813	5,083	3,676	1,750
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	7,172	1,263	3,813	5,083	3,676	1,750
90							

Company Name	**Top Energy**
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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)
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sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission	920	2,055	1,769	934	1,281	936
95	Zone substations	74	66	67	68	190	70
96	Distribution and LV lines	2,095	3,256	3,071	3,366	3,683	4,051
97	Distribution and LV cables	122	118	119	120	121	122
98	Distribution substations and transformers	420	632	397	632	576	402
99	Distribution switchgear	451	607	690	695	698	701
100	Other network assets	194	154	130	131	132	132
101	**Asset replacement and renewal expenditure**	4,276	6,888	6,244	5,946	6,682	6,414
102	*less* Capital contributions funding asset replacement and renewal						
103	**Asset replacement and renewal less capital contributions**	4,276	6,888	6,244	5,946	6,682	6,414
104							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
107	**11a(v): Asset Relocations**						
108	*Project or programme**	**$000 (in constant prices)**					
109	[Description of material project or programme]						
110	[Description of material project or programme]						
111	[Description of material project or programme]						
112	[Description of material project or programme]						
113	[Description of material project or programme]						
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations						
116	**Asset relocations expenditure**	-	-	-	-	-	-
117	*less* Capital contributions funding asset relocations						
118	**Asset relocations less capital contributions**	-	-	-	-	-	-
119							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
122	**11a(vi): Quality of Supply**						
123	*Project or programme**	**$000 (in constant prices)**					
124	Property rights - 110kV Wiroa-Kaitaia line	85	100	27	27		
125	Construction - 110kV Wiroa-Kaitaia line					696	5,410
126	Feeder interconnections			1,041	528	1,195	
127	11kV network reliability improvement	102	511	565	511	887	350
128							
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply	238	487	509	198	35	35
131	**Quality of supply expenditure**	425	1,098	2,142	1,264	2,813	5,795
132	*less* Capital contributions funding quality of supply						
133	**Quality of supply less capital contributions**	425	1,098	2,142	1,264	2,813	5,795
134							

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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)

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sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
136	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Waipapa substation safety improvements		545				
154	ADMS data validation		159				
155	LV network data capture		314	836	520		
156							
	**include additional rows if needed*						
157	All other projects or programmes - other reliability, safety and environment						
158	**Other reliability, safety and environment expenditure**	-	1,018	836	520	-	-
159	*less* Capital contributions funding other reliability, safety and environment						
160	**Other reliability, safety and environment less capital contributions**	-	1,018	836	520	-	-
161							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
162		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
163	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
164	**11a(ix): Non-Network Assets**						
165	**Routine expenditure**						
166	*Project or programme**	**$000 (in constant prices)**					
167	General	150	364	500	500	500	500
168	[Description of material project or programme]						
169	[Description of material project or programme]						
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	**include additional rows if needed*						
173	All other projects or programmes - routine expenditure						
174	**Routine expenditure**	150	364	500	500	500	500
175	**Atypical expenditure**						
176	*Project or programme**						
177	ADMS Stage 2 Implementation	250	550				
178	GIS Software		645				
179	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	**include additional rows if needed*						
183	All other projects or programmes - atypical expenditure						
184	**Atypical expenditure**	250	1,195	-	-	-	-
185							
186	**Expenditure on non-network assets**	400	1,559	500	500	500	500
187							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,612	1,313	1,339	1,366	1,393	1,421	1,450	1,479	1,508	1,538	1,569
11	Vegetation management	1,815	1,850	1,887	1,925	1,963	2,002	2,043	2,083	2,125	2,168	2,211
12	Routine and corrective maintenance and inspection	2,022	2,120	2,016	2,020	2,111	2,166	2,253	2,258	2,320	2,417	2,396
13	Asset replacement and renewal	896	1,019	1,039	1,060	1,081	1,103	1,125	1,148	1,171	1,194	1,218
14	**Network Opex**	6,345	6,302	6,281	6,371	6,549	6,693	6,871	6,968	7,124	7,317	7,394
15	System operations and network support	6,139	6,374	6,428	6,376	6,440	6,674	6,811	7,001	7,214	7,435	7,692
16	Business support	6,350	6,412	6,540	6,673	6,812	6,956	7,106	7,260	7,422	7,588	7,761
17	**Non-network opex**	12,489	12,786	12,968	13,049	13,252	13,630	13,917	14,262	14,635	15,023	15,453
18	**Operational expenditure**	18,834	19,088	19,249	19,420	19,801	20,323	20,788	21,229	21,760	22,340	22,847
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 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,612	1,313	1,313	1,313	1,313	1,313	1,313	1,313	1,313	1,313	1,313
23	Vegetation management	1,815	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
24	Routine and corrective maintenance and inspection	2,022	2,120	1,976	1,942	1,989	2,001	2,041	2,005	2,020	2,063	2,005
25	Asset replacement and renewal	896	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019
26	**Network Opex**	6,345	6,302	6,158	6,124	6,171	6,183	6,223	6,187	6,202	6,245	6,187
27	System operations and network support	6,139	6,374	6,302	6,128	6,069	6,166	6,169	6,217	6,280	6,346	6,436
28	Business support	6,350	6,412	6,412	6,414	6,419	6,426	6,436	6,447	6,461	6,476	6,494
29	**Non-network opex**	12,489	12,786	12,714	12,542	12,488	12,592	12,605	12,664	12,741	12,822	12,930
30	**Operational expenditure**	18,834	19,088	18,872	18,666	18,659	18,775	18,828	18,851	18,943	19,067	19,117
31	**Subcomponents of operational expenditure (where known)**											
32 *33*	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	309	340	340	340	340	340	340	340	340	340	340
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 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	26	53	80	108	137	166	195	225	256
43	Vegetation management	-	-	37	75	113	152	193	233	275	318	361
44	Routine and corrective maintenance and inspection	-	-	40	78	122	165	212	253	300	354	391
45	Asset replacement and renewal	-	-	20	41	62	84	106	129	152	175	199
46	**Network Opex**	-	-	123	247	378	510	648	781	922	1,072	1,207
47	System operations and network support	-	-	126	248	371	508	642	784	934	1,089	1,256
48	Business support	-	-	128	259	393	530	670	813	961	1,112	1,267
49	**Non-network opex**	-	-	254	507	764	1,038	1,312	1,598	1,894	2,201	2,523
50	**Operational expenditure**	-	-	377	754	1,142	1,548	1,960	2,378	2,817	3,273	3,730

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.01%	2.61%	8.76%	79.92%	4.60%	5.75%	4	2.62%
11	All	Overhead Line	Wood poles	No.	-	17.08%	76.03%	5.64%	0.27%	0.98%	4	17.08%
12	All	Overhead Line	Other pole types	No.	-	-		75.00%	25.00%	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.52%	17.07%	26.22%	29.88%	25.30%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-		83.58%	16.42%	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	70.00%	30.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	10.26%	64.10%	25.64%	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	0.55%		0.55%	55.74%	40.98%	2.19%	4	0.55%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	28.57%	-	-	71.43%	-	4	28.57%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	79.76%	20.24%	-	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	70.83%	29.17%	-	4	-
35												

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	3.33%	6.67%	76.67%	13.33%	-	4	3.33%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	10.46%	18.93%	23.79%	32.21%	14.62%	-	2	2.82%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	39.52%	18.79%	10.58%	16.63%	14.47%	-	2	4.43%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.23%	0.45%	22.50%	76.82%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	0.36%	12.09%	66.26%	21.29%	-	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	100.00%	-	-	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.82%	0.27%	4.95%	81.04%	11.54%	1.37%	4	1.10%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	8.78%	12.97%	15.98%	25.36%	36.36%	0.56%	2	8.78%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	0.33%	20.20%	51.79%	26.38%	1.30%	4	0.33%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.02%	0.43%	12.01%	76.22%	9.35%	1.97%	4	0.45%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.24%	0.12%	1.77%	83.71%	9.33%	4.84%	4	0.35%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	62.96%	7.41%	29.63%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	40.00%	60.00%	-	-	4	-
55	LV	LV Line	LV OH Conductor	km	6.54%	21.96%	46.26%	18.22%	7.01%	-	2	-
56	LV	LV Cable	LV UG Cable	km	-	6.14%	15.06%	42.54%	36.26%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	7.98%	0.31%	17.79%	45.71%	28.22%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	0.55%	17.12%	64.75%	10.45%	7.13%	4	0.55%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	7.50%	-	1.50%	29.25%	61.75%	-	4	7.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
61	All	Capacitor Banks	Capacitors including controls	No.	11.11%	2.22%	55.56%	22.22%	8.89%	-	4	13.33%
62	All	Load Control	Centralised plant	Lot	-	-	-	100.00%	-	-	4	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Kaikohe	10	17	N-1	1	57%	17	57%	No constraint within +5 years	
10	Kawakawa	7	6	N-1	3	109%	6	74%	No constraint within +5 years	1.5MW to be transferred to Haruru in FYE2022, after completion of Russell reinforcement project.
11	Moerewa	3	5	N-1	3	68%	5	68%	No constraint within +5 years	
12	Waipapa	10	23	N-1	8	42%	23	45%	No constraint within +5 years	
13	Omanaia	3	-	N-0	2	-	-	-	Transformer	Transfer capacity includes 2MW of onsite generation. Mobile transformer is available if needed.
14	Haruru	6	23	N-1	1	25%	23	34%	No constraint within +5 years	1.5MW to be transferred from Haruru in FYE2022
15	Mt Pokaka	3	-	N-0	2	-	-	-	Transformer	Mobile transformer available. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	8	23	N-1	6	33%	23	37%	No constraint within +5 years	
17	Kaeo	4	-	N-0	4	-	-	-	Subtransmission circuit	There will be only one incoming subtransmission circuit until the southern section of the 110kV line is completed, expected to be in FYE2030.
18	Okahu Rd	8	12	N-1	4	73%	12	77%	No constraint within +5 years	
19	Taipa	6	-	N-0	3	-	-	-	Transformer	Transfer capacity is primarily onsite diesel generation. We may move the mobile transformer to Taipa if load grows faster than currently forecast.
20	NPL	11	23	N-1	4	48%	23	48%	No constraint within +5 years	
21	Pukenui	2	-	N-0	2	-	-	-	Transformer	Transfer capacity includes onsite diesel generation. Mobile transformer available.
22	Kaikohe 110kV	48	55	N-1	-	87%	55	44%	No constraint within +5 years	The Ngawha power station also supports the 110kV load but this is not available if both incoming 110kV circuits from Maungatapere are out of service. Approximately 24 MVA of the Kaikohe 110kV peak load will be transferred to Wiroa when the 110/33kV Wiroa substation is commissioned in FYE2024.
23	Kaitaia 110kV	24	-	N-0	19	-	-	-	Subtransmission circuit	Transfer capacity is diesel generation in northern area
24	[Zone Substation_16]					-			[Select one]	
25	[Zone Substation_17]					-			[Select one]	
26	[Zone Substation_18]					-			[Select one]	
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

29 *[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*		**Number of connections**					
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
11	*Consumer types defined by EDB**							
12	Residential		270	275	280	285	290	295
13	Other		125	135	140	145	150	155
14	[EDB consumer type]							
15	[EDB consumer type]							
16	[EDB consumer type]							
17	**Connections total**		395	410	420	430	440	450
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		210	220	230	240	250	260
21	Capacity of distributed generation installed in year (MVA)		33	1	1	10	21	1
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
25	GXP demand		46	14	14	14	15	15
26	*plus* Distributed generation output at HV and above		25	57	57	57	57	57
27	**Maximum coincident system demand**		71	71	71	71	72	72
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		71	71	71	71	72	72
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		128	14	14	15	15	15
32	*less* Electricity exports to GXPs							
33	*plus* Electricity supplied from distributed generation		220	349	352	354	356	358
34	*less* Net electricity supplied to (from) other EDBs							
35	**Electricity entering system for supply to ICPs**		348	364	366	368	370	373
36	*less* Total energy delivered to ICPs		317	331	333	335	337	339
37	**Losses**		31	33	33	33	33	34
38								
39	**Load factor**		56%	58%	59%	59%	59%	59%
40	**Loss ratio**		9.0%	9.0%	9.0%	9.0%	9.0%	9.0%

Company Name	**Top Energy**
AMP Planning Period	**1 April 2021 – 31 March 2031**
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*
9	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	136.2	125.0	125.0	125.0	125.0	125.0
12	Class C (unplanned interruptions on the network)	315.9	274.0	266.0	257.0	249.0	241.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.86	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	4.31	3.03	2.98	2.91	2.86	2.81

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2021– 31 March 2031
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Top Energy has a high level asset management policy that is part of its ISO 9001 certified quality management system and that applies to both its generation and network assets. Beneath that, there is a network asset management policy that relates specifically to our network assets. However, while the policy objectives are well understood by the TEN team, there is still a sense within the organisation that asset management relates only to TEN. There is a need to develop a culture where other departments within the organisation recognise their role in implementing the network asset management effort.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	Our network asset management strategy and its alignment with the mission, vision and values of the wider Top Energy Group are described in Section 2.2 of the AMP. The strategy was agreed with the Board at a strategic planning workshop. Improvement in safety and network reliability over time is the main objective of the strategy and this is well understood within the organisation and has been communicated extensively with external stakeholders.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	We have implemented a network development programme that has focused on improving reliability over time. This has guided our investment in the creation of new assets and has been sussessful in prigressively improving the reliaiblty to the supply we provide to our consumers. We also have an inspection programme in place that is controlled through our SAP asset management database. Measuring points and assessment criteria for all asset types are well defined. This has enabled us to complete a condition assessment of all asset groups and identify assets that have a high risk of failure. Our expenditure forecasts provide for the replacement of these assets, with priority being given to those in more critical network locations or where failure would create a safety risk.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Once the AMP is prepared, project delivery and maintenance plans are prepared which describe in more detail how the capital and maintenance budgets for the first year of the plan will be spent and how the work will be delivered. This must be consistent with the higher level work plan described in the AMP for the first year of the planning period. We continue to develop systems that ensure that the maintenance spend is more efficient that is currently the case.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	Our quality system is certified as ISO 9001 compliant and contains procedures that set out the various roles and responsibilities for service delivery and the linkages between the personnel involved. Compliance with these procedures is externally audited on a regular basis to ensure we remain compliant. The responsibities of Networks staff responsible for maintenace are clearly set out in their job descriptions and our annual plans identifiy the personnel responsible for the implementation of individual projects. Planning of maintenance work is done within the Networks Division and the required work is communicated to Top Energy Contracting Services using documented work orders.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Our quality system is certified as ISO 9001 compliant and contains procedures that set out the various roles and responsibilities for service delivery and the linkages between the personnel involved. Compliance with these procedures is externally audited on a regular basis and we remain compliant.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	Our quality system is certified as ISO 9001 compliant and contains procedures that set out the various roles and responsibilities for service delivery and the linkages between the personnel involved. Compliance with these procedures is externally audited on a regular basis and we remain compliant. We are also continually refining our standard designs, as well as our outsourcing and procurement processes, to maintain consistency, avoid unnecessary duplication and ensure that all resources needed to deliver the work programme are available as and when required.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	As described in Sections 7.3.3 and 7.3.4 of the AMP, we have a documented Emergency Preparedness Plan in place that defines roles, responsibilities and procedures to be followed when a situation arises that exceeds our capacity to manage in the normal course of business. The Plan has been activated in response to major storms and the Covid 19 pandemic and is reviewed and revised as necessary to incorporate the lessons learnt frollowing each activation. We are also actively involved in the Northland Lifelines Project and maintain strong links with other organisations responsible for the management of civil emergencies.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Responsibility for delivering the requirements of the asset management strategy, objectives and plans rests with the General Manager Networks. Top Energy Networks has a documented organisational structure that fully covers the development and delivery of the asset management plan. The responsibilities and accountabilities of each position in the structure are well defined in the relevant position description. The level of deleegated authgority for each position is appropriate.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Prior to each budget year, we prepare a detailed programme of works, as well as a resource forecast and resourcing strategy to deliver the programme. The rate at which we can achieve our asset management objectives is primarily constrained by the available funding. This has reduced in recent years to accommodate our investment in Ngawha and this has limited the rate at which we can achieve our medium and long term asset management objectives. In this AMP we have reset our asset management targets accordingly.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Performance against the works programme and the quality targets set out in our AMP is reported to the Board monthly. Following each Board meeting the CEO debriefs his direct reports, who in turn are required to formally debrief their staff.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	A Service Level Agreement I(SLA) is in place between Networks and Top Energy Contracting Services. This is based on the asset owner / service provider model and set out the responsibilities of each party and, where appropriate, key performance indicators. This was only finalised in February 2020 and will not be fully bedded in until the end of FYE 2021. Processes for the management of external contractors are well defined but we have still to develop procedures for the approval of contractors before they can tender for work on the network.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	Documented work programmes, position descriptions and assessments of human resource requirements are in place. We do not have formal succession plans but our General Manager Networks provides the Board once a year a documented contingency plan describing the arrangements he would put in place to cover the unavailability of any of his direct reports.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	A formal competency framework is in place for control room operators and is in development for the remainder of our business. Position descriptions are up to date for all positions and formal recruitment and selection processes, including psychometric testing, are in place. Staff training requirements are discussed agreed and signed off annually. Our training budget is up to 5% of salary costs is in place and training hours are routinely monitored.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	We have a formal staff assessment system in place where a personal development plan (PDP) is prepared in consultation with each staff member in January. This contains both performance targets linked to our mission and values, and a personal training plan. Performance against the PDP is reviewed with the staff member at the middle and end of each year. Work is outsourced where competent in-house resources are not avaialable.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Appropriate processes and procedures are documented in our ISO 9001 certified quality management system. Compliance with these procedures is externally audited on a regular basis and we remain compliant. Relevent information is uploaded onto the in-house intranet and available to all staff that need to access it.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	The information is documented in our ISO 9001 certified quality management system. Compliance with these procedures is externally audited on a regular basis and we remain compliant.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Our GIS identifies the location and connectivity of all system assets for operational purposes. GIS information is complete and reliable except for gaps on the LV network. Information on the condition of individual assets is held in SAP and we have documented inspection standards that specify what information is to be recorded and how asset condition is to be assessed for the different asset types.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Information is electronically entered into SAP from the field by asset inspectors using electronic PDIs. Currently GIS information is updated manually by a dedicated data management team and we are developing an electronic link between GIS and SAP. While this interface is now working it has not been implemented in a way that meets our needs. Getting "as built" information back from the field can be a problem. We have written an "as built" standard but compliance can still be weak. This is a KPI in oiur new Service Level Agreement with TECS		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	As indicated in response to Q63 above systems for recording asset information are in place. While GIS has been used for some years, SAP is is more recent but a full asset inspection round has now been completed since it wwas installed. We have recently installed an Advanced Distribution Management System to provide more effective real time management of the assets. There are still gaps in the information we hold on our low voltage distribution networks and a planned data capture project to address this has been deferred.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	We have a Public Safety Management system that is certified to NZS 7901 and externally audited. We also operate a risk register that is updated on an ad hoc basis. We are developing systems to identify and record design and operational risks. While these systems tend to be managed independently, we are currently developing a risk management system that is fully integrated with our asset management and corporate business processes. These processes could be improved by introducing a regular audit of our management of asset risks.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Where a serious risk is identified it is communicated throughout the organisation. However there is no formal process in place to train staff in the management of the risk. There may also be benefit in proactively identifying potential asset risks and pre-emptively developing response plans for the management of these risks.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	Our General Manager Finance is responsible for identifying our legal obligations. However he is unlikely to capture all changes to our technical obligations. Our active involvement with industry organisations such as the Electricity Networks Association and Electricity Engineers Association means that it is unlikely changes to our technical obligations would be missed. Nevertheless processes to ensure that such changes are identified and complied with have still to be formalised.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Artefacts relevant to the implementation of our asset management plans are all developed and in use. The use of these artefacts is documented in our ISO 9001 certified quality management system which is externally audited on a regular basis.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	Processes that define how artefacts relevant to the implementation of our asset management plans are used and linked together are defined in our ISO 9001 certified quality management system, which is externally audited on a regular basis.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	As previously described, we have a formal asset inspection programme in place and defined standards for recording and measuring asset condition. This information is now being used to prepare formalised condition assessments for most asset classes, to develop expenditure forecasts for lifecycle maintenance and asset replacement activities and to develop annual work plans. We are also developing leading indicators related to defects identified during asset inspections and the rates at which these defects are remediated.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	We have an Accident and Incident Investigation Policy and Process, based on the ICAM methodology, which is applied to all events that are considered significant. All SAIDI events over two SAIDI minutes are investigated. This is required by our ISO 9001 certified quality system, which is externally audited on a regular basis.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Our ISO 9001 quality system and our NZS 7901 Public Safety Management System are audited in accordance with their certification requirements. Internal audits are also undertaken in accordance with ISO 9001 requiremants. Our measurement of supply reliability is also externally audited in accordance with the Commission's requirements. There is also a formal process in place to audit the field activities undertaken on the network.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	We have a formal corrective action process for addressing issues identified in our external and internal quality system audits. We also have a Business Improvement Committee that prioritises business improvements including improvement suggestions made by staff. As noted in Q99, we have a formal incident investigation process based on the ICAM methodology. Our ISO 9001 certified quality system sets out the criteria for triggering the investigation porocess, including all loss of supply events over 2 SAIDI minutes. The process includes the instigation of corrective actions where this is appropriate. Compliance is audited through our regular ISO 9001 compliance audits.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	Our Board has a significant focus on business improvement and the Top Energy Group defines Executive level responsibility for identifying, prioritising and implementing business improvements. The successful certification of our NZS 7901 Public Safety Management System and our ISO 9001 Quality System are evidence of this. Within TEN, we are becoming increasingly engaged with the wider asset management community, particularly as it relates to the electricity distribution sector.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	We are increasing our engagement with the wider asset management community, particularly as it relates to electricity distribution. Our staff have regular contact with vendors offering new and improved technologies and our staff training plans include, where appropriate, exposure to new technologies becoming available to the industry.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name Top Energy Limited

For Period Ended 31 March 2031

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause **Error! Reference source not found.**.

1. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause **Error! Reference source not found.**. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section **Error! Reference source not found.**.

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

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Constant prices are for FYE2022. Going forward, we have assumed an inflation rate of 2% per annum as this is the mid-point of the Reserve Bank's 1-3% inflation target. We do not consider an inflation rate assumption based on an analysis of industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Constant prices are for FYE2022. Going forward, we have assumed an inflation rate of 2% per annum as this is the mid-point of the Reserve Bank's 1-3% inflation target. We do not consider an inflation rate assumption based on an analysis of industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

9.2 Appendix B – Nomenclature

GENERAL	
kV kilo-volt	1,000 volts of voltage; typically used in the description of the nominal rating of transmission (110kV), subtransmission (33kV) and distribution (11kV, 22kV and 6.35kV) circuits.
kA kilo-ampere	1,000 amperes of current. Fault current is typically measured in kA or its MVA equivalent, according to MVA=sqrt3 x kV x kA.
kW kilo-Watt	1,000 watts of real power (e.g. a 2kW oil-filled heater is real power the consumer actually uses, represented on the x axis) as opposed to reactive power, which is the quadrature component.
MVA	One million volt-amperes (1,000 kilo volt-amperes) of apparent power. Apparent power is the vector equivalent of reactive or quadrature component power and real power. Apparent power is typically larger than either real or quadrature power and is the quantity that the system actually needs to provide, in order to get real power to the consumer. Generators and lines are all rated in terms of MVA, but the consumer typically only uses real power; a lesser quantity. The quadrature difference is used in the equipment and circuits along the way and is necessary for them to work.
MW	One million watts (1,000 kilo watts) of real power.
MVAr	The quadrature vector component, that when added to real power, gives apparent power.
kA rms	One of the ratings of equipment is 'square-root of the mean of the squares'.
3-phase	3-phase or three phase means 3-phase power. In this case there are three conductors; in this country red, yellow, and blue. All three phases are out of phase with each other by 120 degrees.
INFORMATION TECHNOLOGY RELATED	
GIS	Geographic Information System. A computerised system that spatially represents the assets.
GPS	Global Positioning System. Handheld GPS devices receive and average locational signals from multiple satellites to give a location. The device includes software called a data dictionary, whereby attributes of the asset being captured are also entered. The data captured with GPS devices is entered onto the GIS system.
CMMS	Computerised Maintenance Management System involving a register of asset type, its condition, interlinked to the GIS and to the financial system. A CMMS is used to implement maintenance strategies in a consistent manner for large volumes of assets. This involves interaction with mobile hand-held information technology devices, scheduling, prioritizing and interaction with the financial system both at estimating/works order stage, for invoicing, general ledger, and work in progress reporting.
SCADA	Supervisory Control and Data Acquisition. A system involving communication equipment to monitor and control remote equipment from a central point. It includes remote terminal units (RTUs) to marshal signals at the remote location and communication either via radio, microwave, or the telephone system. The central control point receives and sends signals to the remote equipment. Data is logged here, and control functions may occur either according to the control room operator's command or automatically.
CIRCUIT RELATED	
OH	Overhead.
UG	Underground.
GXP	Grid Exit point. The point at which an EDB network is connected to the Transpower grid. For the Top Energy network, the GXP is the incoming circuit breakers at the Kaikohe substation. Transpower has retained ownership of these circuit breakers.
Subtransmission	Circuits carrying electricity at 33kV (in our case) from the transmission substations at Kaikohe and Kaitaia to our zone substations.

Zone substation	A facility that steps the electricity down from 33kV to 11kV (or 22kV) for distribution out to the locations near to consumers.
Distribution	Both OH and UG circuits at 11kV, 22kV, or 6.35kV that distribute power from zone substations to distribution substations or distribution transformers.
Distribution substation/ Distribution Transformer	A facility involving either a pole mounted transformer or a ground-mounted transformer, whereby electricity is stepped down from distribution voltage (11kV, 22kV or 6.35kV) to low voltage.
LV	Low voltage circuits either OH or UG at either 415V 3 phase or 480V/240V single phase that reticulate electricity from distribution substations to consumers' premises.
SWER	A low-cost distribution system called single wire earth return (SWER) used to reticulate electricity to remote areas involving low load densities. The start of the SWER system is a pole mounted isolating transformer where electricity is converted from conventional two or three -wire 11kV distribution to either 11kV SWER or 6.35kV SWER, which are the two SWER voltages we use. The SWER system involves a single overhead conductor to supply conventional distribution substations or distribution transformers near to the consumers. The return conducting path to the isolating transformer is through the earth. This avoids cost of more than one overhead distribution conductors. Once the electricity reaches the distribution substation, LV reticulation to homes occurs in the conventional manner.
Transfer capacity (≥ 3h)	The substation load that can be switched away to adjacent substations within three hours. It is considered that one feeder could be switched within this time. Accordingly, it is the largest of the feeder loads that can be picked up by adjacent substations in an emergency condition.
Firm capacity (N-1)	For a two-transformer substation, is the capacity of the smaller of the two transformers plus the transfer capacity (3hr). The transfer capacity is considered a contribution to firmness, because this load can still be supplied within three hours from elsewhere. Firm capacity cannot occur at a substation with only one transformer (e.g. Taipa, Pukenui, Mt Pokaka and Omanaia).
Switched capacity	The sum of capacities that can be supplied to the zone substation location, including transfer capacity (≥ 3hr), from elsewhere if that zone substation is out of service.
Note	We size our transformers for local load forecast and future envisaged transfer capacity for feeders between a zone substation and its neighbour that a zone substation would have to supply if the neighbouring zone sub failed. Our approach is to cover one major equipment outage event, not two. So, if a zone substation fails, the feeders between it and an adjacent zone substation are picked up by the adjacent zone substation, with all of the transformers at the adjacent zone substation operating concurrently. If we were to cover the event of both a zone substation failing and one of the transformers at an adjacent zone substation also failing concurrently, then that would require much larger transformers and an approach that we consider inappropriate for a substantially rural lines business.
CONDUCTOR RELATED	
ACSR	Aluminium Conductor Steel Reinforced conductor used for OH lines
HD AAC	Hard Drawn All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABC	Aerial Bundled Conductor involving an overhead, insulated multi-core cable.
PVC	Polyvinyl Chloride. An insulation used for low voltage conductors.
XLPE	Cross linked Polyethylene. An insulation type prevalently used for conductors at distribution and subtransmission voltages.
PILC	Paper Insulated Lead Sheathed Conductor.
PILCSWA	Copper conductor with insulation of PILC and Steel Wire Armour. An outer light PVC serving is typically used outside of the armour.
OTHER EQUIPMENT RELATED	

ABS	Air Break Switch. These are manually operated or motorised remote-control switches. These switches are used to create an open point between two feeders, to achieve more operational flexibility on the lines.
Pillar Box or Pillar	A ground mounted LV fuse enclosure, where electricity from LV circuits is connected to the final LV service mains to consumers' premises.
RMU	Ring Main Unit. A ground-mounted unit with set of three switches, one with fuse arrangement. The fused switch is configured to supply and protect a distribution transformer.
Recloser	Normally a pole-mounted protection device acting as a small circuit breaker on either a subtransmission or distribution circuit. An automatic circuit recloser is a self-contained device with the necessary circuit intelligence to sense over current, to time and interrupt the over currents and to reclose automatically to re-energize the line. If the fault should be permanent, the recloser will 'lock open' after a pre-set number of operations and isolate the faulted section from the main part of the system.
Sectionaliser	A Sectionaliser is a pole mount protective device that automatically isolates faulted sections of line from a distribution system. Normally applied in conjunction with a backup recloser or breaker, a sectionaliser opens and allows the backup device to reclose onto the remaining unfaulted sections of the line.
Circuit Breaker (CB)	A circuit breaker is usually employed at the substation level in distribution system over current protection applications. It is a mechanical switching device capable of making, carrying, and breaking currents under normal operation and also capable of making, carrying, and breaking currents under specified abnormal condition for a specified time.
TRANSFORMER RELATED – COOLING NOMENCLATURE	
ONAN	Oil Natural, Air Natural (no fans or pumps)
ONAF	Oil Natural, Air Forced (fans but no pumps)
OFAF	Oil Forced, Air Forced (fans and pumps)
ODAF	Oil Directed Flow, Air Forced (fans and typically pumps plus internal vanes that direct oil flow through the core-coil winding assembly)
TRANSFORMER CONDITION NOMENCLATURE	
DP	Degree of Polymerization. This is a measure of the condition of cellulose-based paper insulation in oil. A new transformer will have a DP value of around 1,000. Through a combination of pyrolysis and hydrolysis, the paper-in-oil insulation gradually degrades to an end life of around DP 150 to DP 200. The most accurate way of ascertaining DP is through an actual paper sample cut opportunistically from the core-coil assembly during a major refurbishment; or from a small sample piece of paper insulation, if the manufacturer has provided one in an easy to get at location (typically at the top, inside the transformer tank). Not all manufacturers provide this unless asked. Outside of major refurbishment occasions, a less invasive method is to indirectly determine DP through analysing Furan derivatives from an oil sample. Furans are a by-product of the cellulose degradation process. An indication of whether a Furan analysis or further investigation would be required is obtained from Dissolved Gas Analysis (DGA) whereby dissolved gas by-products from pyrolysis and hydrolysis action in an oil sample are analysed using gas spectrometer and other means. Other electrical tests may also be used as required to give an indication to the engineer of what is happening inside the transformer; one of the most revealing being partial discharge analysis.
PD	A partial discharge is essentially a minor conduction across an insulation medium; not exactly a full discharge, which would be a spark that would involve full insulation failure. A partial discharge by contrast gives an early indication of insulation degradation. Full failure is typically some time away; this could be anywhere from imminent, to months or even years away. The PD techniques enable this to be analysed, failure times predicted and more importantly, the location of degrading insulation to be pin-pointed. In the case of a transformer, before the expensive process of de-tanking.
Buccholz Relay	A protection device on a transformer situated below the header tank or 'conservator'. Gases generated inside the transformer will gravitate up to this point. If the magnitude of them is sufficient, the relay will operate and trip the transformer; hopefully before a failure involving serious damage can occur.

BUSINESS RELATED	
ODV	Optimised Deprival Valuation. An industry-wide standard method of valuing monopoly lines businesses set and administered by the New Zealand Commerce Commission to enable line business performance to be compared consistently and as the basis for regulatory control of maximum return on assets.
OUTAGE RATES – FIGURES OF MERIT	
SAIDI:	System Average Interruption Duration Index calculated by: $SAIDI = \frac{\sum \text{Number of customers affected} \times \text{Duration of interruption}}{\text{Total number of customers}}$ I.e. the average number of minutes a consumer will be without power in a year
SAIFI:	System Average Interruption Frequency Index calculated by: $SAIFI = \frac{\sum \text{Number of customers affected by interruptions}}{\text{Total number of customers}}$ I.e. the average number of outages per year for any consumer
CAIDI:	Consumer Average Interruption Duration Index calculated by: $CAIDI = \frac{SAIDI}{SAIFI} = \frac{\sum \text{Number of customers affected} \times \text{Duration of interruption}}{\sum \text{Number of customers affected by interruptions}}$ I.e. the average duration of an outage

9.3 Appendix C – Risk Management Framework

9.3.1 Risk Management Process

The adopted risk management framework is consistent with AS/NZS 4360 (now superseded by AS/NZS ISO 31000:2009), which defines risk assessment and management.

9.3.2 Risk Management Context

The key risk criteria adopted for assessing the consequences of identified risks are:

- health and safety;
- financial impact;
- environmental impact;
- public image/reputation;
- business interruption; and
- regulatory compliance.

9.3.3 Risk Analysis

The basis for assessing risk is risk probability and risk consequence, which are used to determine risk severity ratings are defined in Tables C.1 and C.2 respectively. Table C.3 provides the basis for the assessment of risk severity and Table C.4 shows the level of management normally accountable for risks of differing levels of severity.

RARE	UNLIKELY	POSSIBLE	LIKELY	ALMOST CERTAIN
Event may occur, but only in exceptional circumstances Occur less than once in 20 years	The event could occur at some time Occur once every 10 years	The event is not uncommon. Occur once every 5 years	Likely to occur despite best efforts. Occur once a year	Likely to occur several times. Occur more than once per year

Table C.1: Assessment of risk probability

CONSEQUENCE	HEALTH & SAFETY	FINANCIAL IMPACT	ENVIRONMENTAL IMPACT	PUBLIC IMAGE REPUTATION	BUSINESS INTERRUPTION	REGULATORY
Catastrophic	Multiple fatalities Serious long-term health impact on public	Financial costs or exposure exceeds $75M (DCF basis) Shareholder flight	An incident that causes significant, extensive or long-term (5 years or more) ecological harm .	Continuing long-term damage to company reputation. International or government Investigation. Long-term impact on public memory.	Total service cessation for a week or more	Jail term of any length or fine exceeding $100,000.
Major	Single fatality and or multiple serious injuries	Financial cost or exposure exceeds $10M (DCF basis). Share value stagnation, shareholder dissatisfaction.	An incident which causes significant, but confined, ecological harm over 1-5 years.	Local TV news headlines and/or regulator investigation. Medium-term impact on public memory.	Cessation of service to Northern or Southern areas for a number of days	Prosecution of Director or employee
Moderate	Individual serious injury or multiple/recurring minor injuries	Loss or increased costs from $1M to $10M (DCF basis).	Significant release of pollutants with mid-term recovery	Local press attention and or low profile regulator investigation	Cessation of service for over 10% of consumer base for more than a week	Prosecution of business or prohibition notice.
Minor	First aid injuries only	Loss or increased costs from $50k to $1M (DCF basis)	Transient environmental harm	Limited local press attention	Cessation of service for more than a week	Improvement notice.
Insignificant	No requirement for treatment	Loss or increased costs less than $50,000 (DCF basis).	An incident which causes minor ecological impacts that can be repaired quickly through natural processes.	No impact on public memory	Cessation of service for more than a 24hrs	Regulator expresses verbal or written concern.

Table C2: Assessment of risk consequence

	INSIGNIFICANT 1	MINOR 2	MODERATE 3	MAJOR 4	CATASTROPHIC 5
Almost certain 1	High	High	Extreme	Extreme	Extreme
Likely 2	Moderate	High	High	Extreme	Extreme
Possible 3	Low	Moderate	High	Extreme	Extreme
Unlikely 4	Low	Low	Moderate	High	Extreme
Rare 5	Low	Low	Moderate	High	High

Table C.3: Assessment of risk severity

Extreme	Extreme Risk - Should be brought to the attention of Directors and continuously monitored
High	High Risk – Requires the attention of the CEO and General Managers
Moderate	Moderate Risk – appropriately monitored by middle management
Low	Low Risk – Monitored at a supervisory level

Table C.4: Risk management accountability

9.4 Appendix D – Cross References to Information Disclosure Requirements

The table below cross references the requirements of Attachment A of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 with the contents of this AMP.

Handbook Reference	Requirement	AMP Ref	Comment
Summary			
3.1	The AMP must include a summary that provides a brief overview of the AMP contents and highlights information that the EDB considers significant.	1.	
Background and Objectives			
3.2	The AMP must include details of the background and objectives of the EDB's asset management and planning processes	2.1, 2.5	
Purpose Statement			
3.3	The AMP must include a purpose statement that		
3.3.1	Makes the status of the AMP clear.	2.3	
3.3.2	States the corporate mission or vision as it relates to asset management	2.2	
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process	2.8.1	
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management	2.8.1	
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes and plans;	2.5	
Planning 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.	2.8.2	
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	2.8.2	
Stakeholder Interests			
3.6	The AMP must identify the EDB's important stakeholders and indicate	2.8.4	
3.6.1	- how the interests of stakeholders are identified;	2.8.3	

Handbook Reference	Requirement	AMP Ref	Comment
iii	- what these interests are;	2.8.4	
iv	- how these interests are accommodated in the EDB's asset management practices: and	2.8.4	
v	- how conflicting interests are managed.	2.8.3	
Accountabilities and Responsibilities for Asset Management			
3.7.1	The AMP must describe the extent of Board approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to the Board.	2.8.5	
3.7.2	At the executive level, the AMP must provide an indication of how the in-house asset management and planning organisation is structured.	2.8.5	
3.7.3	At the field operations level, the AMP must comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.	2.8.5	
Significant Assumptions and Uncertainties			
3.8	The AMP must identify significant assumptions, which must: :	2.12	
3.8.1	Be quantified where possible.	2.12	
3.8.2	Be clearly identified in a manner that makes their significance understandable to interested persons including:	2.12	
3.8.3	Include a description of the changes proposed where the information is not based on the EDB's existing business.	N/A	
3.8.4	Identify the sources of uncertainty and the potential effect of the uncertainty on the prospective information.	2.12	
3.8.5	Include the price inflator assumptions used to prepare the information in Schedules 11a and 11b.	2.12 (final row)	
3.9	Include a description of the uncertainties that may lead to changes in future disclosures.	2.12	
Asset Management Strategy and Delivery			
3.10	To support the AMMAT disclosure, the AMP must include an overview of asset management strategy and delivery.	2.13.1 2.17	

Handbook Reference	Requirement	AMP Ref	Comment
Asset Management Data			
3.11	To support the AMMAT disclosure, the AMP must include an overview of the processes for managing asset management data; and	2.10, 2.14	
3.12	A statement covering any limitations on the availability and completeness of asset management data and disclosure of initiatives intended to improve the quality of this data.	2.10, 2.14	
Asset Management Processes			
3.13	The AMP must include a description of the processes used for:		
3.13.1	- Managing routine asset inspections and network maintenance;	2.11.1	
3.13.2	- Planning and implementing network development projects; and	2.11.2	
3.13.3	- Measuring network performance.	2.11.3	
Asset Management Documentation, Controls and Review Processes			
3.14	To support the AMMAT disclosure, the AMP must include an overview of asset management documentation, controls and review processes.	2.15	
Communication and Participation Processes			
3.15	To support the AMMAT disclosure, the AMP must include an overview of communication and participation processes.	2.16	
Assets Covered			
4.1	High Level Description of the Distribution Area		
4.1.1	The high-level description of the distribution Area must include: - the regions covered;	3.1.1	
4.1.2	- identification of large consumers that have a significant impact on network operations or asset management priorities;	3.1.12	
4.1.3	- description of the load characteristics for different parts of the network; and	3.1.12	
4.1.4	- the peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any.	2.1 Table 2.1	

Handbook Reference	Requirement	AMP Ref	Comment
4.2	Description of the Network Configuration		
4.2.1	The AMP must include a description of the network configuration which includes: - identification of the bulk electricity supply points and any embedded generation with a capacity greater than 1 MW;	3.1.2, 3.1.3	
4.2.1	- the existing firm supply capacity and current peak load at each bulk supply point;	3.1.4 Table 2.1	
4.2.2	- a description of the [transmission and] subtransmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the subtransmission network;	3.1.4, 3.1.5, Table 3.1	
4.2.2	- the extent to which individual zone substations have N-x subtransmission security;	Table 5.1	
4.2.3	- a description of the distribution system including the extent to which it is underground;	3.1.7	
4.2.4	- a brief description of the network's distribution substation arrangements;	3.1.7	
4.2.5	- a description of the low voltage network, including the extent to which it is underground; and	3.1.8	
4.2.6	- an overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems.	3.1.9 3.1.10 3.1.11	
4.4	Description of the Network Assets		
	The AMP must include a description of the assets that make up the distribution system that includes, for each asset category: voltage levels, description and quantity of assets, age profiles, and a discussion of the condition of the assets, further broken down as appropriate and including, if necessary, a discussion of systemic issues leading to premature asset replacement.	3.2 6	Section 3.2 provides a general description of each asset fleet while age profiles and asset health profiles and other maintenance issues are discussed in Section 6.
4.5	The asset categories discussed must at least include:		
	[Transmission]	6.3.1 6.3.2	
4.5.1	Subtransmission	6.3.1 6.3.2	
4.5.2	Zone substations	6.9	

Handbook Reference	Requirement	AMP Ref	Comment
4.5.3	Distribution and LV lines	6.3.1 6.3.2	
4.5.4	Distribution and LV cables	6.6	
4.5.5	Distribution substations and transformers	6.8	
4.5.6	Distribution switchgear	6.10	
4.5.7	Other system fixed assets	6.11	
4.5.8	Other assets	6.13	
4.5.9	Assets installed at bulk supply points owned by others	3.1.3	The incoming 110kV circuit breakers at Kaikohe fall into this category.
4.5.10	Mobile substations and generators whose function is to increase supply reliability or reduce peak demand	3.1.5 3.1.6	
4.5.11	Other generation plant.	N/A	
Service Levels			
6.	Performance indicators for which targets are defined must include SAIDI and SAIFI values for the next 5 disclosure years.	4.2	SAIDI and SAIFI targets are provided for each year of the planning period to reflect the duration of the network development plan.
7.	Performance indicators for which targets are defined should also include		
7.1	- Consumer orientated service targets that preferably differentiate between different consumer types	4.2	Currently SAIDI and SAIFI are the only performance indicators used. These measures are not differentiated by consumer type although we measure these indicators by feeder to assist us mange network reliability.
7.2	- Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	4.3.1 4.3.2	Loss ratio Operational expenditure ratio
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 stakeholder's requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.4	
Network Development Planning			

Handbook Reference	Requirement	AMP Ref	Comment
11.1	The AMP must include a description of the planning criteria and assumptions for network developments.	5.1	
11.3	The AMP must include a description of any strategies and processes that promote cost efficiency including through the use of standardised assets or designs.	5.1.4	
11.5	The AMP must include a description of the strategies or processes (if any) that promote the energy efficient operation of the network.	5.2	
11.6	The AMP must include a description of the criteria used to determine the capacity of equipment for different types of assets on different parts of the network.	5.1.4 5.1.5	
11.7	The AMP must describe the process and criteria for prioritising network developments and how these processes and criteria align with the overall corporate goal and vision.	5.4	
11.8	Demand Forecasts		
11.8.1	The AMP must describe the demand forecasting methodology, including all the factors used in preparing the estimates.	5.5	
11.8.2	The AMP must provide separate demand forecasts to at least the zone substation level and cover at least a minimum five year forecast period.	5.6.1	
11.8.2	The AMP must discuss how uncertain but substantial individual projects or developments. The extent to which these uncertain load developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts.	5.6.2	
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	5.11	
11.8.4	The AMP must discuss the impact on the load of any anticipated levels of distributed generation in the network and the projected impact of any demand management initiatives.	5.9 5.11	
	Network Development Plan		

Handbook Reference	Requirement	AMP Ref	Comment
11.9	The AMP should include an analysis of the network level development options available 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;	5.12	These are addressed as appropriate for all the projects discussed in this section.
11.9.2	- the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;		
11.9.3	- considerations of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment	5.12.3	
11.10.1	The AMP must include: - a detailed description of the material projects and a summary description on the non-material projects currently underway or planned to start in the next twelve months;	5.12	
11.10.2	- a summary description of the programmes and projects planned for the next four years (where known); and		
11.10.3	- an overview of the material projects being considered for the remainder of the AMP planning period.		
11.11	The AMP must include 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.	5.8	
11.12	The AMP must include a description of the EDB's policies on non-network solutions including:	5.7 5.9	
11.12.1	- economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation;		
11.12.2	- the potential for non-network solutions to address network problems or constraints.		
Lifecycle Asset Management Planning (Maintenance and Renewal)			
12	The AMP must provide a detailed description of the lifecycle asset management processes, including:		

Handbook Reference	Requirement	AMP Ref	Comment
12.1	The key drivers for maintenance planning and assumptions.	6.1	
12.2	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include:		
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 and the intervals at which this is done;	6.1 6.3-6.11	An overview of the way in which maintenance is managed is given in Section 6.1 and the remaining sections deal with individual asset categories.
12.2.2	- any systemic problems identified with ant systemic asset types and the proposed actions to address these problems;		
12.2.3	- budgets for maintenance activities broken down be asset category for the AMP planning period	6.12	
12.3	Identification of the 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 and 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.	6.1	
12.3.2	- a description of the innovations made that have deferred asset replacement;		
12.3.3	- a description of the projects currently underway and planned for the next twelve months;	5.12.1	All capital expenditure forecasts including both proactive and reactive asset replacements are discussed in Section 5.12.1. A year-by-year breakdown of our asset replacement capex forecast, disaggregated by asset category is provided in Table 6.26.
12.3.4	- a summary of the projects planned for the next four years; and		
12.3.5	- an overview of the other work being considered for the remainder of the planning period.		
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;		

Handbook Reference	Requirement	AMP Ref	Comment
13.2	development, maintenance and renewal policies that cover them;	6.13 6.14	We do not consider our expenditure on non-network assets to be material.
13.3	a description of material capital expenditure projects (where known planned for the next five years); and		
13.4	a description of material maintenance and renewal projects (where known) planned for the next five years.		
Risk Management			
14.	The AMP must provide details of risk policies and assessment and mitigation including:		
14.1	- methods, details and conclusions of risk analysis;	7.1 7.2	
14.2	- strategies used to identify areas of the network that are vulnerable to high impact, low probability events and a description of the resilience of the network and asset management systems to such events;		
14.3	- a description of the policies to mitigate or manage the risks of events identified in subclause 14.2 above; and		
14.4	- details of emergency response and contingency plans.	7.3.3-7.3.7	
Evaluation of Performance			
15.	AMPs must provide details of performance measurement, evaluation and improvement including:		
15.1	- a review of progress against plan, both financial and physical;	8.3	
15.2	- an evaluation and comparison of actual service level performance against targeted performance;	8.1 8.2	
15.3	- an evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 (see Appendix A) against relevant objectives of the EDB's asset management and planning processes; and	8.4	Additional information is provided in the following sections: 2.11 2.12 2.13 2.14 2.15
15.4	- an analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors) the AMP must describe any planned initiatives to address the situation.		
Capability to Deliver			
16	The AMP must describe the processes used by the EDB to ensure that:		

Handbook Reference	Requirement	AMP Ref	Comment
16.1	- the AMP is realistic, and the objectives set out in the plan can be achieved;	2.17	
16.2	- the organisation structure and the processes for organisation and business capabilities will support the implementation of the AMP plans.	2.17	

9.5 Appendix E – Certification for Year Beginning Disclosures

TOP ENERGY®
Te Puna Hihiko

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Euan Richard Krogh and David Alexander Sullivan, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top Energy Limited prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) 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 Top Energy Ltd's corporate vision and strategy and are documented in retained records.

E R Krogh

D A Sullivan

30 March 2021

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