2019 Asset Management Plan

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TOP ENERGY®
Te Puna Hihiko

Introduction

It gives me great pleasure to present Top Energy's FYE2020-29 Network Asset Management Plan (AMP).

This 2019 AMP follows on from the 2018 AMP in addressing the key issues of the connection of Ngawha Generation Ltd's expanded power station to the grid and providing a platform to meet the needs of our consumers in coming decades. Key to this is the completion of our second 110kV line to serve Kaitaia. While diesel generation will provide increased supply security to the majority of our northern area over the medium term, it will not be an acceptable supply alternative when the existing line needs taken out of service over an extended period for reconductoring, sometime around 2030. The new line will also complete a high capacity ring that will encircle our supply area, enhancing our ability to serve not only existing load centres but new load centres that are starting to emerge.

This AMP also discusses the increase in solar generation feeding into our network and how we plan to transition from an electricity distribution system that transfers energy to consumers in one direction from a centralised source, to a technology enabled distributed energy system with electricity injections at multiple locations and multi-directional energy transfers between small generators and consumers. It also discusses how emerging technologies are already changing the way that our consumers meet their energy needs and how these technologies could impact the way we develop the network to better meet the needs of all our users.

This AMP is the core planning and operations document that guides the management of our network and details our planned inspection, maintenance, and capital replacement strategies over the next ten years, as well as the target service levels that we are aiming to deliver to our consumers. In compiling this AMP, we have also complied with the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and focused on providing stakeholders with detailed information that accurately reflects the investment required to develop and maintain the network to better meet the needs of our consumers.

This is an exciting time for the Top Energy Group. We have commenced the construction of a fourth generating unit at our Ngawha geothermal power station and have consent to construct a fifth unit in FYE2026. If this fully consented expansion is completed, the generating capacity of the power station will increase from 25MW to more than 88MW. If this occurs, all the electricity requirements for the Far North will be generated within our supply area. This will enable us to deliver 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 that 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; and load information and management solutions.*

In developing this AMP for the period FYE2019-28 in accordance with this mission and vision, and being mindful of our corporate values and objectives, we have addressed a range of strategic challenges. These include:

- *Providing a secure supply to the north*. By the end of FYE2020, we will have installed sufficient diesel generation in the Kaitaia area to supply all small-use consumers during maintenance shutdowns of the 110kV Kaikohe-Kaitaia line, and we are planning to defer the next planned shutdown until after this project is complete. When construction of the second circuit is completed in FYE2030, supply to the north will become fully secure and we will able to supply the north with renewable energy sourced from Ngawha under all contingencies.

- *Connection of the expanded Ngawha power station*. By the end of FYE2020 we will have constructed a new 110kV line, at a cost of $12.3 million, between Ngawha and our Kaikohe grid exit point (GXP) to connect the power station directly to the transmission grid. Minor enhancements to this connection will be made in FYE2025 to accommodate the increased capacity.

- *Improvement in supply reliability.* Protection upgrades completed in FYE2017 have substantially reduced the impact of 33kV subtransmission network faults on supply reliability. Our reliability improvement initiatives are now focusing on our 11kV distribution network and completion of the Kaeo substation in March 2018 has significantly improved supply reliability in the Whangaroa area. We have set ourselves a target of improving our supply reliability to a level comparable to that reported by similar New Zealand distribution businesses by the end of this AMP planning period and have developed a comprehensive reliability improvement plan to achieve this.

- *Maintenance.* We are transitioning 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 and of asset criticality, which reflects the consequences of an in-service asset failure. This should over time lead to better targeting of our maintenance expenditure and a reduction in the SAIDI impact of faults due to asset failures.

- *Meeting the challenges of new technology.* We have purchased and are currently installing 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 are adding to our network. Over time, the system will be 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. The expenditure forecasts in this AMP also provide for the implementation of a small number of pilot projects designed to leverage the capabilities of emerging technologies in the development and operation of our network.

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

We are currently operating in a regulatory environment with some uncertainty. In particular:

- The Commerce Commission is currently developing a new price-quality path for the FYE2021-25 regulatory period. This could impact the revenue we can earn over the period and our ability to implement the network development plans set out in this AMP;

- The Electricity Authority is currently finalizing a review of transmission pricing. Its draft proposal has indicated a significant increase in transmission prices for consumers in the north of the country. The expanded Ngawha power station will significantly reduce the extent that electricity consumed in our supply area is generated south of Auckland and we hope that this will protect our consumers from much of this increase.

- The Electricity Authority is requiring electricity distribution businesses (EDBs) to develop more cost reflective pricing policies and, more broadly, the Government has launched an electricity price review, which will impact the wider industry. We are currently trialing new time-of-use tariffs and we are planning to review our pricing structures further in FYE 2021 and will need to take account of the outcomes of these trials and reviews.

- Industry response to the challenge of emerging technologies is a source of much debate, focused largely on the extent to which EDBs can recover the costs on implementing new technologies from regulated revenue.

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

Implementation of the plans described in this AMP will see us invest approximately $183 million on network capital expenditure and $60 million in network maintenance expenditure over the ten-year period of this AMP. This compares with forecasts of $173 million and $59 million respectively in our 2018 AMP. The Board and Management are confident that this expenditure will improve service outcomes to levels comparable to those experienced by consumers supplied by similar rural networks within New Zealand. Nevertheless, we continue to recognise the potential pricing impact of expenditure on this scale and will therefore focus on achieving a price-quality balance that is affordable and in the best interests of the communities that we serve.

In addition to the development of the 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 participant's 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 this AMP both informative and helpful. We welcome your feedback on the plan or any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website at http://topenergy.co.nz/contact/ or emailed to info@topenergy.co.nz.

Russell Shaw
Chief Executive, Top Energy Ltd

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1 Executive Summary

1.1 Overview

Top Energy Networks (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 160 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 25MW and with an additional 32MW planned for installation in FYE2020;
- *Top Energy Networks (TEN)*, which manages the electricity distribution network; and
- *Top Energy Contracting Services (TECS)*, which provides contracting services to the electric power industry.

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 2015.

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 2019 to 31 March 2029. 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 Requirements. 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 asset management policy has been developed in accordance with Top Energy's strategic objective of investing in business activities that:

- Contribute to infrastructure and economic development in the Far North District;
- Enhance the security of power supply in the area; and
- Provide economic employment opportunities.

Within this overarching strategic framework, TEN's mission 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 always act in accordance with industry standard safe working practices and, in consultation with our employees and contractors, we will develop and adopt systems and procedures 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 general 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 so that, over time, the reliability of supply that we provide to consumers improves to a level consistent with that generally provided in rural areas in other parts of New Zealand. 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

DESCRIPTION	QUANTITY
Area covered	6,822km^2
Consumer connection points	33,061(1)
Grid exit point	Kaikohe
Embedded geothermal generator injection point	Ngawha
Network Peak Demand (FYE2018)	70MW(2)
Electricity Delivered to Consumers (FYE2018)	325GWh
Number of Distribution Feeders	60
Distribution Transformer Capacity	285MVA(3, 4)
Transmission Lines (operating at 110 kV)	56km(3)
Subtransmission Cables (33kV)	21km(3)
Subtransmission Lines (33kV)	321km(3, 5)
HV Distribution Cables (22, 11 and 6.35kV)	208km(3)
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,574km(3)

Note 1: Includes inactive connections, as at 31 March 2018.
Note 2: Metered demand, as disclosed to the Commerce Commission.
Note 3: As at December 2018.
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 (FYE2018 unless otherwise shown)

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 above lists the key network parameters.

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 $251.5 million as at 31 March 2018; an increase of $13.7 million since 31 March 2017.

This increase in asset value was derived as shown in Table 1.2. The increase has largely been driven by the commissioning of new assets in accordance with our network development plan. The value shown in Table 1.2 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 at 31 March 2017	**237,830**
Add:	
New assets commissioned	19,745
Indexed inflation adjustment	2,616
Less:	
Depreciation	8,681
Asset disposals	22
Asset value at 31 March 2018	**251,488**

Table 1.2: Value of System Fixed Assets

1.5 Economics of Supply

Approximately 35% by length of our 11kV distribution network would be considered uneconomic if Ministry of Business, Industry and Employment (MBIE) cost of supply criteria is applied. These lines supply just 9% of our consumers. The issue is one of low customer density and low consumption, providing insufficient revenue to fund the capital and operating costs of the assets used to provide supply. While we are required by the Electricity Industry Act 2010 to continue to supply these consumers, this does not need to be through a network connection.

We investigated the uneconomic supply issue further in 2018 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.

We believe that we can continue to supply most consumers in remote areas without burdening other consumers through spot replacements of poles, crossarms, conductors and transformers as they become unserviceable. However, where segments of the remote network have deteriorated to the point where this approach is not sufficient, a full rebuild or an alternative solution using an emerging technology will be required to provide a continued supply. The issue is how to recover this cost.

When we identify a part of our network where continuing to provide a supply will require expenditure over and above an economic level, we will assess the capital expenditure required to maintain supply. This assessment will consider the level of service required by consumers, potential trade-offs between capital and operational expenditure and whether it would be possible to reduce consumer costs by utilising emerging technology (e.g. replacing a high voltage line with a low voltage micro-grid supported by batteries). The overall objective will be to develop a solution that meets the service level expectations of the community at a cost that they can reasonably afford.

1.6 Network Development

1.6.1 Introduction

The main objectives of our network development plan (initiated FYE2011 and named "TE2020"), 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; and
- 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 $157 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 and a new zone substation within Kerikeri town;
- Improve the fault resilience of our 33kV subtransmission network by upgrading the protection, 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;
- 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.

Our biggest challenge has been to secure a route for a new 110kV line between Wiroa and Kaitaia. When completed, this 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 the existing 110kV line is required, sometime after 2030. Route negotiations commenced in FYE2012 and, while most of the route has now been secured, we are awaiting hearings in the Environment Court before the route can be finalised. In the meantime, we are installing 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.

Top Energy is also increasing the capacity of its Ngawha power station to 57MW in FYE2020 and is planning to increase it further to 88MW in FYE2025. When completed, this will reduce the vulnerability of all consumers to interruptions of our connection to the national transmission grid as most electricity consumed in our supply area will be generated locally. We anticipate this will also 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. Our capital investment forecast includes an investment of $12.3 million for the construction of a new 110kV line to connect the new generating units to the transmission grid at our Kaikohe GXP.

1.6.2 Challenges

In planning and implementing strategies to improve the reliability of supply to consumers, we have had to address a number of challenges unique to our network.

- 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 one incoming radial line. For example, Northpower has two grid connections; a 220KV line to Marsden and a 110kV line over a separate route to Maungatapere.
- Our single 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 now 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 a small number of long 11kV feeders, with a large number of connected consumers on each. In the first three quarters of the current year (FYE2019), 54% of our unplanned distribution network SAIDI and 33% of 11kV faults originated from 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:

- Complete our Kaitaia generation project as an interim solution to improve supply security in our northern area;
- Connect the two new generators (G4 and G5) at our Ngawha power station directly to our Kaikohe GXP through a double circuit 110kV connection. This work will be funded by NGL's budget for increasing the power station's generation capacity;
- Construct the new 110kV circuit between Wiroa and Kaitaia. and
- 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. Our objective is to reduce the SAIDI impact of unplanned interruptions on the 11kV network over the AMP planning period, from a targeted 233 minutes in FYE2020 to 164 minutes in FYE2029, after normalization in accordance with the method used by the Commerce Commission in setting our SAIDI threshold under its price-quality regulatory regime.

1.7 Emerging Technologies

Five years ago, the only generation embedded in our network was the existing Ngawha geothermal plant; now we have 3.1MW of solar generation injecting power into our network from 700 injection points. As this trend accelerates, our network will 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 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. To this end, our capital expenditure forecast includes provision of for the implementation of projects that pilot the application of new technologies. The research will:

- Explore the economics and potential for using a battery supported, low voltage microgrid as an alternative to our traditional network architecture. Batteries distributed across a microgrid can be charged when demand is low and release energy at times of peak demand. This approach will reduce voltage drop, which will in turn increase the area that can be supplied at low voltage, thus reducing the need for transformers and medium voltage distribution lines.
- Compare the performance of a static voltage compensator (statcom) and battery, configured as a large uninterruptable power supply, as an alternative to a voltage regulator. When supported by a generator, both can be used to stabilise voltage, manage peak demand and improve the reliability of rural feeders. However, the statcom-battery arrangement will have a much faster response than a regulator and, in the event of a fault, can be configured to avoid any interruption to supply by using the energy stored in the battery to supply consumers until the generator starts up.

1.8 Advanced Distribution Management System

We are upgrading our network control operation through the installation of an Advanced Distribution Management System (ADMS). The initial deployment will include a new SCADA master station and an automated Outage Management System (OMS). The OMS will combine 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 SAIDI impact of supply interruptions. This will lead to improved management reporting. We are currently developing the interfaces to our SCADA communications systems and the master station graphical user screens, as well as migrating the connectivity data from our GIS to provide OMS functionality. We expect to have the SCADA and OMS modules operational by the end of the 2019 calendar year.

We will then integrate Distribution Management System (DMS) functionality into the system. This will overlay the above systems with a real-time model of the network, using inputs from SCADA, the GIS and our SAP Asset Management System (AMS). It will provide a decision support system for the operation of the network by making real-time information on network status and asset condition available to operators through a single, user-friendly graphical interface It will also automatically produce switching schedules, confirm that all required isolation procedures are undertaken before operators issue field staff a permit to work, and provide many other benefits. This will reduce operator error, support the enhanced safety procedures that we are introducing, and optimise the operation and management of the network. 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.

The ADMS will also facilitate operation of the new diesel generation. We plan to configure the ADMS to optimise the use of the new generators by automatically bringing them online following an interruption or when they are needed to alleviate localised network constraints.

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) have already been developed by our ADMS vendor. These will be added as required.

1.9 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 network under its price-quality control regime. However, our internal targets are more challenging than the thresholds set by the Commission, because 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 on. 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.
- Include only 50% of the actual SAIDI and SAIFI impact of planned interruptions in the normalized measure. This recognizes that our consumers receive advance notice of planned interruptions, which should therefore make them less disruptive.

Our normalised supply targets are shown in Table 1.3 and 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 very sensitive to the performance of this line, as an outage will affect all consumers in the northern region. While the installation of generation should limit the duration of any unplanned line interruption, supply will nevertheless be interrupted while the generators are started and brought on line. This will still have a material impact on both SAIDI and SAIFI because of the number of consumers affected.

In this AMP, we have introduced separate targets for planned and unplanned interruptions at our different voltage levels for the first time.

FYE	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SAIDI										
Planned 110kV	-	-	-	-	-	-	-	-	-	-
Planned 33kV	-	-	-	-	-	-	-	-	-	-
Planned 11kV	55	55	55	55	55	55	55	55	55	55
Unplanned 110kV	-	-	-	-	-	-	-	-	-	-
Unplanned 33kV	30	29	28	27	26	25	24	23	22	21
Unplanned 11kV	233	225	218	210	203	195	188	180	173	164
Total	**318**	**309**	**301**	**292**	**284**	**275**	**267**	**258**	**250**	**240**
SAIFI										
Planned 110kV	-	-	-	-	-	-	-	-	-	-
Planned 33kV	-	-	-	-	-	-	-	-	-	-
Planned 11kV	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Unplanned 110kV	-	-	-	-	-	-	-	-	-	-
Unplanned 33kV	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Unplanned 11kV	2.59	2.53	2.48	2.41	2.36	2.29	2.24	2.17	2.11	2.02
Total	**3.44**	**3.38**	**3.33**	**3.26**	**3.21**	**3.14**	**3.09**	**3.02**	**2.96**	**2.87**

Table 1.3: Reliability Targets

The change in these targets over the planning period is shown graphically in Figures 1.2 and 1.3 below, which also compare the targets with the historical reliability of our network. The graphs are indicative only, as the historical performance is not directly comparable to the performance targets going forward. Firstly, the measured reliability prior to FYE2013 did not include interruptions of our the 110kV transmission line, which was then owned by Transpower. Secondly, performance prior to FYE2008 was estimated rather than directly measured. Thirdly, the reported actual performance prior to FYE2010 has not been normalised in accordance with the Commerce Commission’s measurement methodology and, finally, the normalisation methodology from FYE2016 onwards was changed by the Commission.

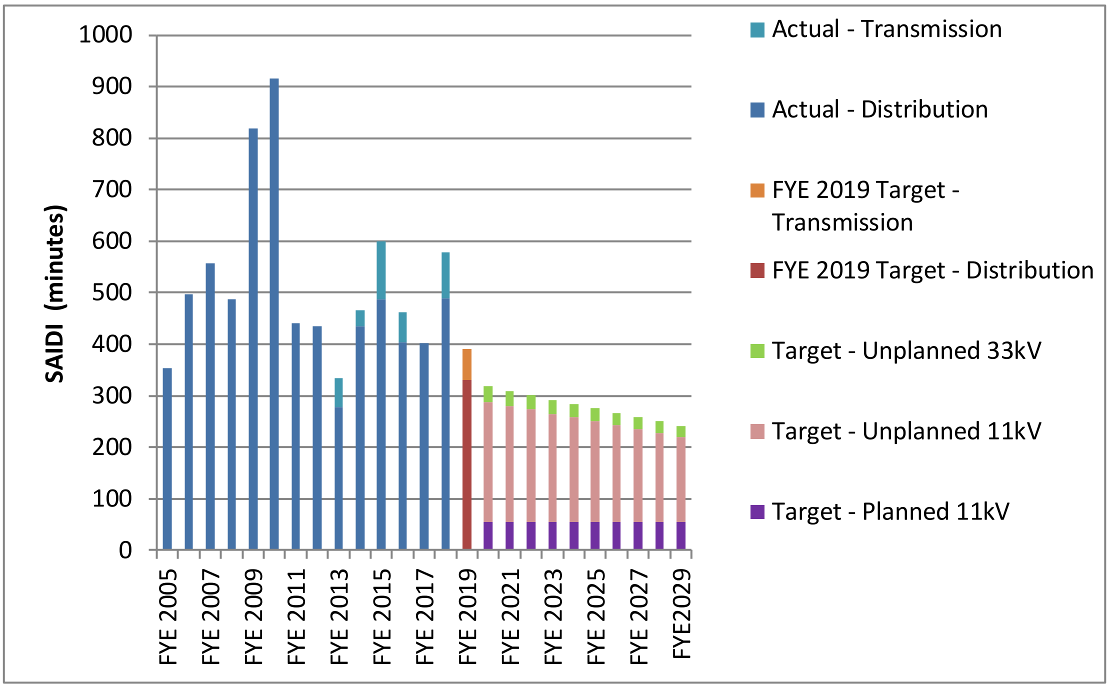

Figure 1.1: Historical and Target SAIDI

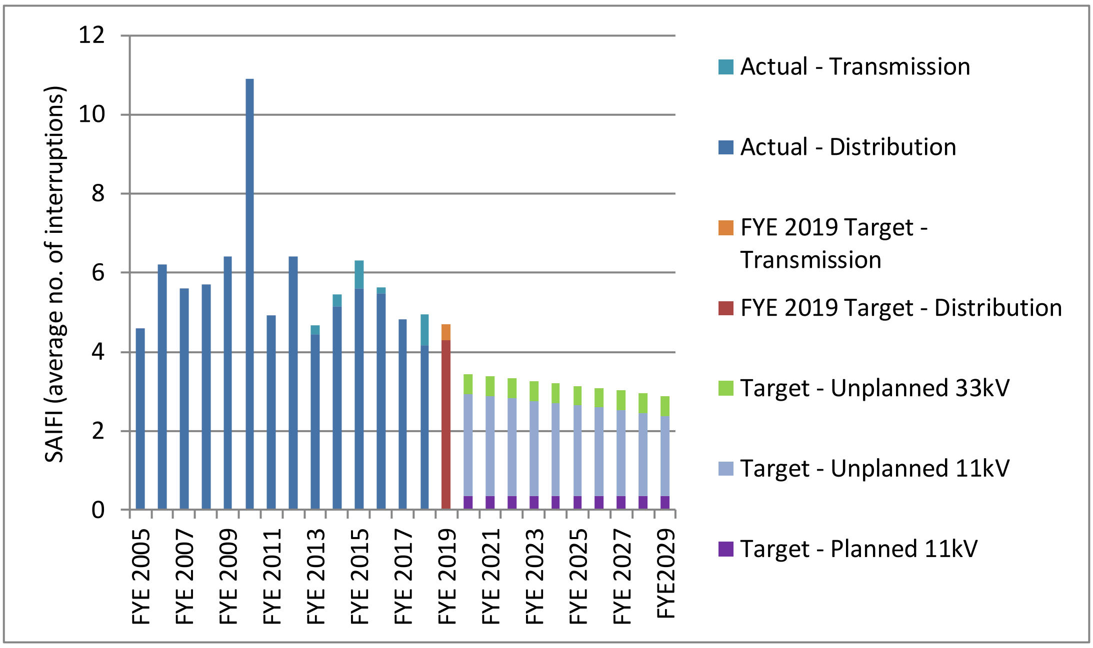

Figure 1.2: Historical and Target SAIFI

We have already achieved a significant improvement in the reliability of our 33kV network, primarily through the installation of upgraded protection to allow individual lines to be operated in parallel so that, in most cases, a fault no longer results in a supply interruption. The installation of will generation in our northern area will avoid the need for supply interruptions to allow maintenance on the 110kV line.

Going forward reliability improvement work will focus on reducing the impact of faults on our 11kV distribution network through:

- Larger capital projects designed to reduce the likelihood of faults affecting critical assets, or to make provision for supply to be restored downstream of a faulted section before the fault is repaired; and
- Other smaller capital projects, improved maintenance strategies and more effective operational processes to reduce the time taken to locate and repair a fault. This includes the installation of the ADMS.

We have modelled the impact of each of these interventions over the ten-year planning period as shown in Figure 1.3.

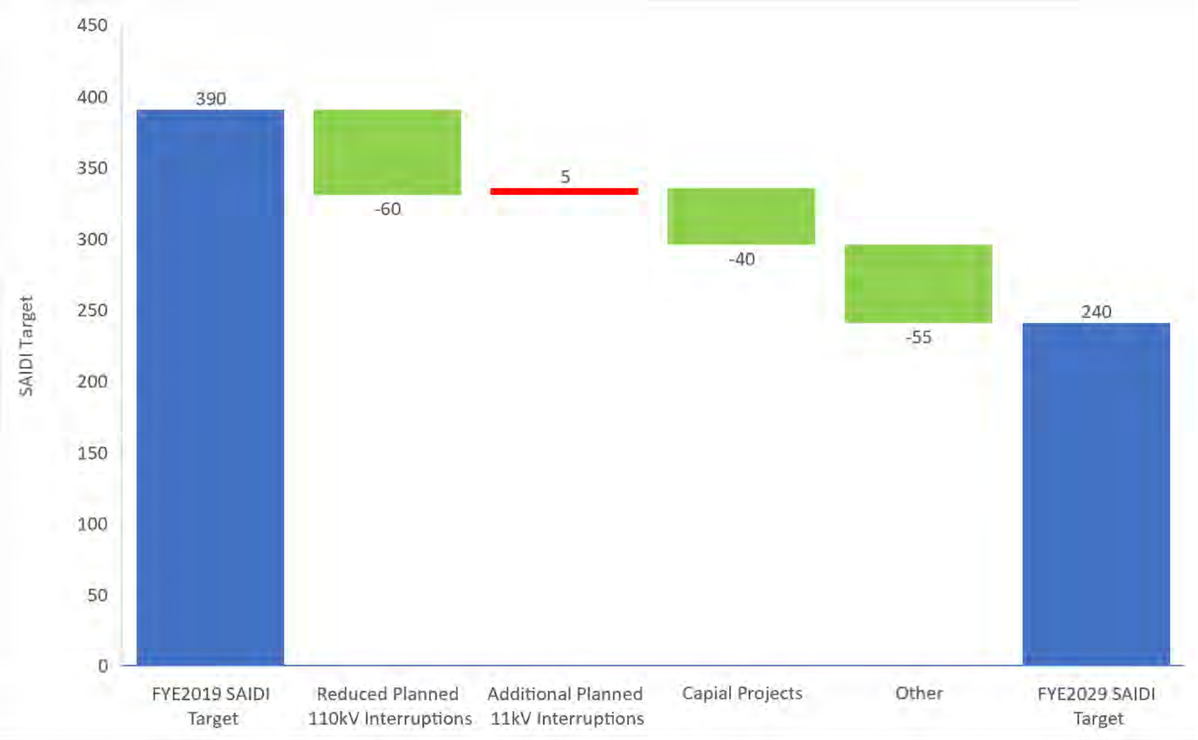

Figure 1.3: Impact of SAIDI Improvement Strategies

1.10 Capital Expenditure

The focus of our capital expenditure forecast is asset renewal and network development. To better reflect these drivers, we have recategorized much of the capital expenditure from the 2018 AMP and disaggregated our capital expenditure forecast into the following priority areas.

- *Priority 1 – Asset Life Cycle Renewals.* Our first priority is the maintenance of 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 planned 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 – Network Development.* Our second priority is the construction of new assets to meet any increase in demand for network services, increase network resilience, and ensure that we remain relevant to the needs of our consumers. Over this AMP planning period, our planned network development expenditure is focused on the installation of diesel generation to provide supply security to our northern area, the connection of the two new Ngawha generators to the Transpower grid, and the completion of the 110kV high capacity ring to interconnect our main load centres.

- *Priority 3 – Reliability Improvement.* Capital expenditure on reliability improvement initiatives is our third priority. While this expenditure is small compared with asset replacement and network development, this does not reflect any loss of focus on reliability improvement; our service level target of improving reliability to a level similar to that of our peers over the next ten years remains. Firstly, our asset renewal and network development expenditure will also drive improvement in supply reliability. Secondly, the ADMS, which when fully implemented, should deliver a quantum improvement in the management of our network. Finally, many of our planned reliability improvement initiatives over the planning period involve process improvements that do not require capital expenditure.

- *Priority 4 – Emerging Technology.* This expenditure relates to the development of network information systems and to the conduct of pilot projects designed to trial the application of technologies likely to impact our future network development, ensuring that we remain relevant, given the changing expectations and behaviour of our consumers. Over the medium term, this expenditure will enable the transition from an electricity distribution network to a distributed energy system.

Our forecast total capital expenditure over the ten-year AMP planning period is $183 million compared to $173 million in our 2018 AMP. Figure 1.4 shows how this forecast is allocated over the four priority areas and Table 1.4 quantifies this expenditure over the planning period. The high network development expenditure in FYE2020 is due to the installation of diesel generation in the Kaitaia area and the construction of a new 110kV line to connect the new Ngawha generator to the Transpower grid. Development expenditure at the end of the planning period is driven by the completion of the 110kV ring.

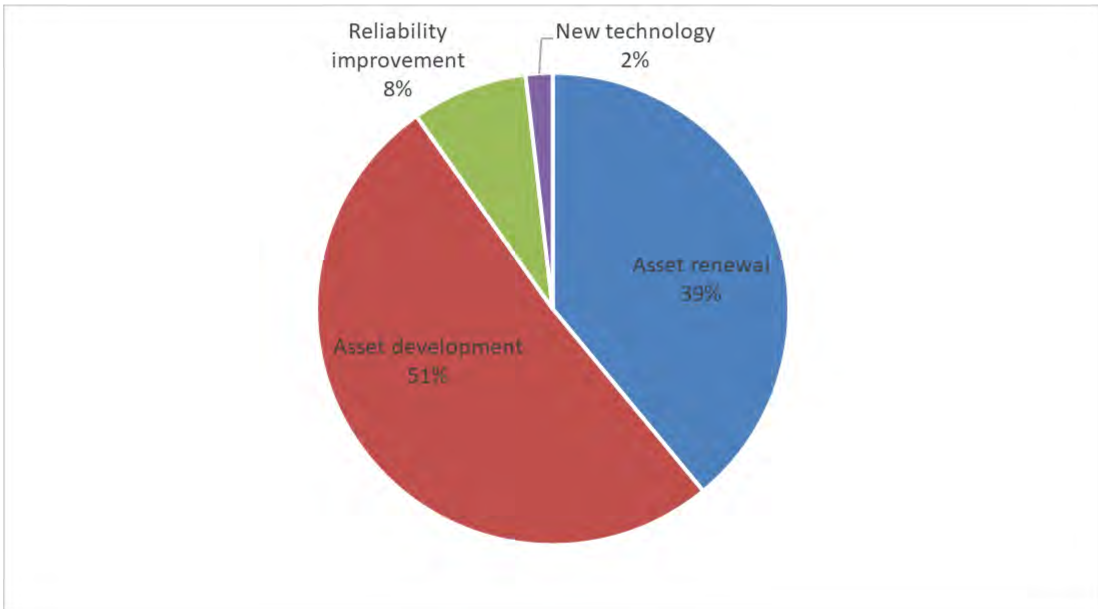

Figure 1.4: Allocation of Capital Expenditure by Priority

$000 (constant prices)	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29	Average Annual
Asset renewal	8,527	5,930	7,289	7,517	7,662	34,665	7,159
Asset development	21,810	3,526	3,263	6,302	6,740	52,281	9,392
Reliability improvement	735	4,537	2,834	1,910	830	3,727	1,457
New technology	865	554	1,298	34	34	581	337
Total	**31,937**	**14,548**	**14,683**	**15,763**	**15,266**	**91,254**	**18,345**

Table 1.4: Network Capital Expenditure Forecast

1.11 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. Assets likely to still be in serviceable condition are best left alone unless an unexpected failure will have a significant impact.

As noted above (Section 1.10), we have adopted the asset health indicators developed by the EEA as a basis for assessing the condition of our various asset fleets. Our initial assessments of asset heath are largely based on the age profiles of the different asset fleets, but over time assessments will be increasingly driven by our asset inspections, as our these become more standardised and we improve our knowledge of the rate of asset deterioration. Going forward, we are planning to correlate our asset health assessments with the causes of in-service asset failures, to improve the accuracy of our assessments and also to improve of targeting of asset renewals. 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. We have now established that 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 has programmed for the second half of 2019.

Our forecast total maintenance expenditure over the ten-year planning period is $60 million compared to $59 million in the 2018 AMP. Figure 1.5 shows how our maintenance expenditure forecast is allocated over the four maintenance categories and Table 1.5 quantifies this expenditure over the planning period.

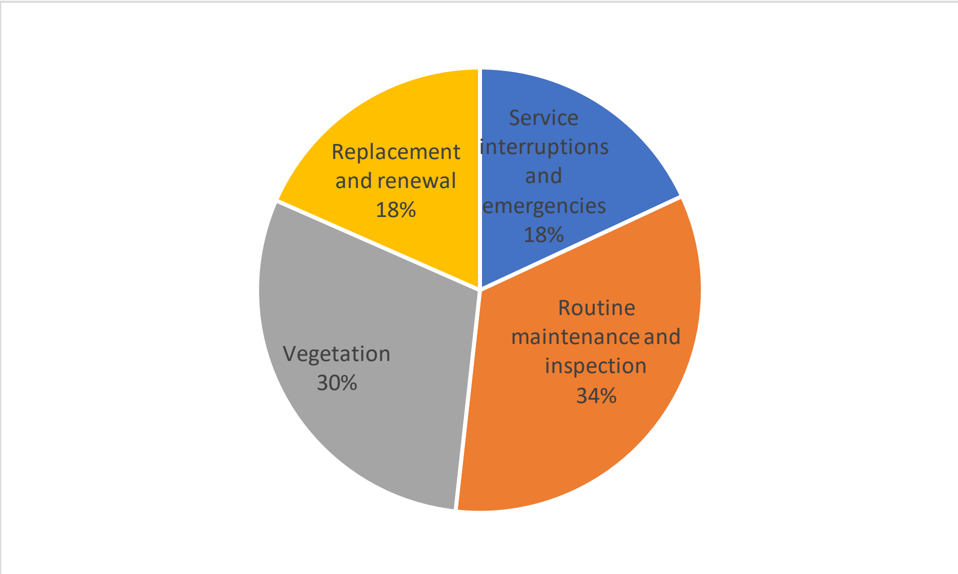

Figure 1.5: Allocation of Maintenance Expenditure by Category

$000 (in constant prices)	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29	Average Annual
Service interruptions and emergencies	1,199	1,174	1,149	1,124	1,099	5,118	1,086
Routine maintenance and inspection	2,071	1,994	2,020	2,034	1,974	10,151	2,024
Vegetation	1,787	1,787	1,787	1,787	1,787	9,009	1,794
Replacement and renewal	1,106	1,106	1,106	1,106	1,106	5,528	1,106
Total	**6,162**	**6,060**	**6,061**	**6,050**	**5,965**	**29,805**	**6,010**

Table 1.5: 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 25MW Ngawha geothermal power plant;
- **Top Energy Networks (TEN)**, which distributes electricity throughout the Far North; and
- **Top Energy Contracting Services (TECS)**, which provides construction and maintenance services to Top Energy Networks.

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. The network was originally 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 3.1MW of localised generation dispersed across approximately 700 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 $251 million as at 31 March 2018. 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	33,061(1)
Grid Exit Point	Kaikohe
Embedded geothermal generator injection point	Ngawha
Network Peak Demand (FYE2018)	70MW(2)
Electricity Delivered to Consumers (FYE2018)	325GWh
Number of Distribution Feeders	60
Distribution Transformer Capacity	285MVA(3,4)
Transmission Lines (operating at 110 kV)	56km(3)
Subtransmission Cables (33kV)	21km(3)
Subtransmission Lines (33kV)[5]	321km(3)
HV Distribution Cables (22, 11 and 6.35kV)	208km(3)
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,574km(3)

Note 1: Includes inactive connections, as at 31 March 2018.
Note 2: Metered load as disclosed to the Commerce Commission.
Note 3: As at December 2018.
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 (FYE2018 unless otherwise shown)

TYPE OF GENERATION	NO OF INJECTION POINTS	CAPACITY (MW)
Geothermal	1	25
Diesel	2	7
Photovoltaic	700	3.1

Table 2.2: Embedded Generation (as at 31 December 2018)

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.

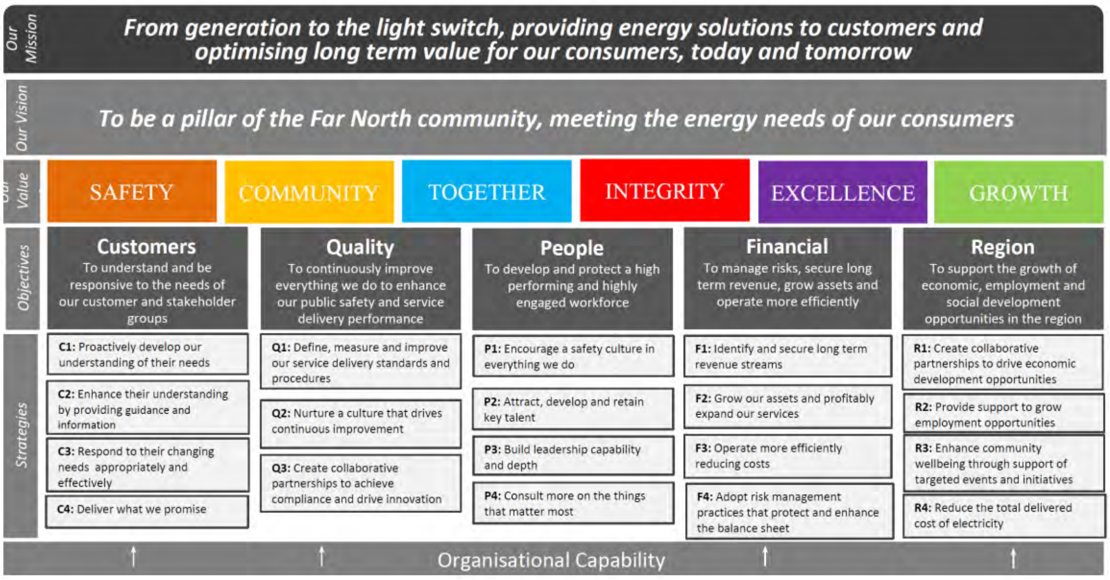

Figure 2.1 Group Strategy Map

2.2.2 Top Energy Networks

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

2.2.2.1 Mission

Our mission 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 mission is well aligned with that of the Group. While safety is not negotiable, our biggest challenges in delivering on our corporate mission 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 is to:

- *enable consumers to take greater control over their business and home energy supply needs by developing secure, two-way energy flow, and load information and management solutions.*

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 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 ongoing 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 FYE2020-29 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 is 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 are dependent on a single 110kV transmission circuit that requires an annual maintenance outage lasting up to nine hours. Unplanned supply interruptions are also a risk – while these are relatively infrequent, they can last an indeterminate period. During these outages, EFTPOS machines cannot work, fuel cannot be purchased, and businesses and consumers suffer inconvenience and cost.

  The existing line is now in good condition and the immediate concern is to provide an alternative supply. However, sometime after 2030, the conductor will have deteriorated to the point where replacement will be necessary, which will require the line to be taken out of service for extended periods. Furthermore, new regulatory constraints on the use of live line work practices mean that reliance on the single circuit to meet the supply requirements of the northern region is no longer a practical medium-term option, as the line now needs to be deenergised for all maintenance work. This means an increased number of planned interruptions, unless a second line or an alternative generation source in the Kaitaia area is available. The 2014 slip in the Maungataniwha Ranges, which caused a tower in this line to move 10 metres and some tower members to break, has reinforced the vulnerability of the existing supply to our northern area in extreme weather conditions. We were fortunate that this incident did not cause an interruption to supply and acknowledge that an extended supply interruption could easily have occurred. We must recognise that an extended unplanned outage of this line remains a possibility and plan for such a contingency.

  Until recently we have focused on the installation of a second 110kV line routed closer to the eastern seaboard to secure the supply to Kaitaia. This would meet all future requirements using proven technology. However, it is a long-life, high-cost solution with a long lead time. We have made good progress in acquiring property rights for this new line; however, we await the ruling of the Environment Court in relation to three properties, where landowners are challenging the planned route.

  The alternative of installing diesel generation, which is discussed further in Section 5.13.2.1, may not be a sustainable long-term solution, not least because it uses a sunset technology with high operating costs and high greenhouse gas emissions. However, as it has a relatively low capital cost and can be installed quickly, it is now seen as the only option that will provide a secure supply to the northern area within a timeframe acceptable to our consumers. We are viewing it as an interim solution that will remain in place until the new 110kV line has been constructed.

- While there has been significant improvement in our reliability of supply in recent years, it remains below our consumers' expectations. 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, heavily-loaded feeders.

  Our reliability improvement plan has focused on the development of our transmission and subtransmission assets. Protection upgrades have now 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 focused on transitioning to an 11kV network architecture that reduces the number of consumers interrupted following a fault and allows supply to be restored more quickly to consumers not directly affected. This will involve the installation of new protective devices with improved discrimination in the core network, the installation of additional interconnections between neighbouring feeders, the installation of fault indicators to help locate a fault after it has occurred and the installation of backup generation on long rural feeders.

- Recent changes in the Health and Safety in Employment legislation have constrained the rate at which we are able to improve our reliability of supply. 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.

  This increase in the number of planned interruptions increases our risk of breaching the reliability thresholds under the Commerce Commission's price-quality regulatory regime. However, the Commission can exercise discretion, and we would hope that we would not be unduly penalised in the event of a threshold breach if it was a consequence of changes to the policies of the government entity responsible for enforcing workplace health and safety legislation. The reliability thresholds will be reset in FYE2020 and we expect these to take due account of the impact of these new operating constraints.

- 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 325GWh in FYE2018. This decline 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 also need to develop our network to accommodate the expansion of the Ngawha Power Station. The 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; and
- Comply with clause 2.6.1 of the Commerce Commission’s Electricity Distribution Information Disclosure Determination 2012.

2.4 Asset Management Policy

This asset management plan is guided by our asset management policy, which has been approved by Top Energy’s Board. 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 that minimize the risk of harm to people and property;
- 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;
- Provides, over time, a reliability of supply consistent with that generally provided in rural areas of other parts of New Zealand. To do this we use a range of strategies including targeted network development, more effective maintenance, the application of new and innovative technologies, and improved response to supply interruptions that do occur;
- 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; and
- Monitors the technological changes affecting our industry and is ready to modify our asset management strategies where necessary in order 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 by the end of FYE2021.

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 will 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; and
- Increasing stakeholder understanding by providing guidance and information. Our AMP is reviewed by a professional, non-technical editor to ensure that its content is presented succinctly to a broad readership. 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.*

We will 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. Over time, we are planning to develop and implement 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; and
- Creating collaborative partnerships to achieve compliance and drive innovation. We are actively involved with industry groups such and the Electricity Networks Association (ENA), the 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 will do this by:

- Improving our processes for the recruitment and retention of key talent;
- Building leadership capability and depth by incorporating leadership competencies into all management personnel development plans, and providing annual leadership development opportunities;
- 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:

> *secure long-term revenue, grow assets and profitable services, and operate more efficiently.*

We will do this by:

- securing our long-term revenue stream by implementing a pricing strategy designed to increase the certainty of our revenue levels; and
- growing our assets and profitably expanding our services 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; and
- operating more efficiently to reduce costs through the development and implementation of a standardized project management delivery framework, reviewing behaviours to identify 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 will 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; and
- Encouraging and supporting employees to volunteer for community emergency services.

2.6 Strategic Issues

2.6.1 Connection of Embedded Generation

The Stage 1 expansion of the Ngawha Geothermal Power Station from 25MW to 57MW by FYE2021 will shift the centre of electricity supply to our consumers from remote generation located south of Auckland, to generation located close to our network. Ngawha currently generates approximately 70% of the electricity requirements of consumers connected to our network and, at current levels of demand, we estimate that this will increase to over 98% once the first stage expansion has been completed.

The new generating unit will inject electricity into the Transpower grid at Kaikohe, where it will supply the local demand within our supply area and export surplus energy south to Maungatapere. Once the Stage 1 expansion is complete, we expect that up to 45% of the electricity generated at Ngawha will be exported and that the grid connection to Maungatapere will be used for export 85% of the time, compared to around 10% of the time at present.

On completion of the Stage 1 expansion, our consumers will be less reliant on the grid as a source of energy and the primary function of the connection to Maungatapere will be to export electricity generated at Ngawha south for use by consumers outside our area.

There are sufficient local renewable generation resources available for our supply area to be fully self-sufficient and the 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 need to be transmitted through the congested Auckland isthmus. The network provides an essential service to investors wanting to utilise this generation resource - it connects generators with their market, both local and national. To deliver these services, we will need to transition from a distributor of electricity sourced from a remote bulk supply, to a manager of electricity flows within a system of distributed energy resources.

2.6.2 Economic Development from an Improved Energy Supply

An energy park at Ngawha, with a number of sizeable energy loads, is well into its planning phase and some resource consents have already been granted. This is located close to the network injection point at Kaikohe and within the Kaikohe-Ngawha-Wiroa network backbone. A medium-size industrial development near our Wiroa switching station has also received resource consent. The strategic locations of these developments will improve asset utilisation and the efficiency of our network investments.

2.6.3 Tourism

The tourism sector is booming in our supply area and the population of our popular tourist areas swells over the summer period. This creates high levels of demand that persist for only a short time over the peak holiday season. Furthermore, the catering, accommodation, and other ventures associated with the tourism sector are sensitive to losses of supply, even for relatively short durations. Hence, they have a high value of lost load (VOLL), which is a measure of the cost to consumers when an electricity supply is not available.

2.6.4 Increased Demand for Resilience

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, and this limits the benefits that we can derive from our grid connection. Our connection to the grid has been unexpectedly interrupted four times in the last five calendar years. Given the increased national focus on resilience to climate change and natural disasters, and the higher reliance by many consumers on security of supply, the transmission grid arguably no longer meets our needs. While Transpower has recently invested heavily in improving the security of supply into Auckland, consumers in our supply area have derived little benefit from this investment.

2.6.5 Unsustainability of Transmission

Transmission costs are increasing, and the Electricity Authority’s proposed new transmission pricing methodology will increase the costs to our consumers even further, resulting in an unsustainable value proposition. Importing bulk electricity from the grid is no longer the most economically efficient means of satisfying our consumers’ energy requirements. Grid electricity will be used less and less to meet new demand, and this will create a spiral of change towards local and self-generation with our transmission and subtransmission networks increasingly interconnecting generation and load.

2.6.6 Connection Growth

The number of connections to our network is increasing by more than 1% per year. Retirees escaping the rising cost of living in Auckland, whilst living on fixed incomes, are moving into our supply area and building new houses where the capital cost of using emerging technologies is marginal. They exploit energy efficiency technology and new technologies that provide them with an opportunity to minimise the impact of the upwards price path of grid supplied electricity. This trend partly explains our static level of residential electricity consumption, notwithstanding the increased number of domestic consumers.

2.6.7 Grid Parity

The cost of new technologies is approaching a point where they present consumers with a similar cost option to purchasing electricity from the grid. Our fringe grid location means high transmission charges and a high consumer tariff compared to other parts of the country, which may account for the fact that we have the second highest penetration of roof-top photovoltaic generation arrays in New Zealand. More than 2% of consumers now have their own photovoltaic generation and the total connected capacity is currently 3.1MW. Photovoltaics will continue to displace grid generation. Furthermore, storage technology is reaching the price point where a unit of energy can be stored and used at a similar cost to a unit from the grid, and the cost of storage is expected to reduce by 50% over the next five years.

2.6.8 Economics of Remote Supply

Our cost-to-serve model has identified that the replacement or renewal of the existing assets on much of our rural network is uneconomic. Energy efficient technology that reduces electricity consumption will only worsen this situation. However, new technology also presents an opportunity to address issues such as resilience. An example is the development of new tourism ventures in remote locations, where the cost of connecting and achieving satisfactory security of supply through traditional network augmentation is prohibitive. A distributed energy solution incorporating a local energy source could address this problem. We are positioning ourselves to be responsive in developing solutions that meet our consumers' electricity requirements at a reasonable cost, so that we encourage investments that enhance the economic wellbeing of the wider community.

2.6.9 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. Our supply area has a relatively high percentage of retirees and global trends indicate that electric vehicles have a high uptake in retired populations. We expect New Zealand to follow this trend and the penetration of electric vehicles in our supply area to increase faster than the national average. We will benefit from the development of load management features that allow vehicle batteries to be used for energy storage when integrated into energy supply systems, and we expect a trend to emerge well within the ten-year planning horizon of this AMP, where consumers connected to our network will start using vehicle batteries in this way. With proper load management, electric vehicles will increase the storage capacity on our network and allow the operation of our distributed energy system to be enhanced and further optimised. A key challenge will be matching the addition of new distributed energy supplies to the growth in new loads such as electric vehicles.

2.6.10 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, and less reliant on the use of physical assets.

2.7 Rationale for Asset Ownership

Our rationale for asset ownership is derived from our mission statement, which as noted in Section 2.2.2.1, 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 was to use a network of conductors and transformers to deliver electricity, sourced from a centralised transmission grid interconnecting a relatively small number of large generators, to individual consumer premises. 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 in excess of forty years. 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.

Moving forward, we are open to the use of non-network solutions to meet the needs of our consumers. This will involve the installation of diesel generation to provide supply security to our northern area in the absence of a second incoming circuit. We have already installed diesel generation for this purpose at Taipa and at our Kaitaia construction and maintenance depot, and we are committed to constructing a new diesel generation farm in Bonnetts Rd, close to Kaitaia, to provide further back-up supply capacity.

We are obliged by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers already supplied from our existing lines. With many lines currently serving consumers in remote areas in poor condition, providing supply through a local generation or microgrid solution could be more cost-effective than rebuilding these lines.

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 that directly connect with the 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 generally 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 given 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:

- 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; and the
- 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 2015. 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 its network assets over a ten-year planning period. It is operational, as the detailed plans and budgets within the AMP for the first year of the ten-year planning period form the basis for the current Annual Plans, which control asset management expenditure for FYE2020. 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; and
- 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 capital, operations and maintenance expenditure 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 2019 and relates to the period from 1 April 2019 to 31 March 2029. It was approved by the Board on 26 March 2019 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; and
- Local media.

Table 2.2 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;
- A balance is sought between the cost of non-supply and the investment needed to provide the desired level of reliability; and
- 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, in order to 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. • We are developing a distribution network planning standard to reduce the impact of distribution network faults on the reliability of supply and will progressively upgrade the distribution network to comply with this standard. This work will be prioritised to focus on areas with a high level of non-compliance.
	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 are implementing 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	• Phone Plus has been contracted to ensure consumers are directed to the appropriate point of contact for quick and efficient service.

STAKEHOLDER	EXPECTATIONS	ACTIONS
		• 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. • We provide incentives for the connection of new generation in situations where a connection will benefit our consumers by reducing transmission costs or avoiding costly network augmentation.
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.

STAKEHOLDER	EXPECTATIONS	ACTIONS
	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.
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.

STAKEHOLDER	EXPECTATIONS	ACTIONS
	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 general 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 2.2.

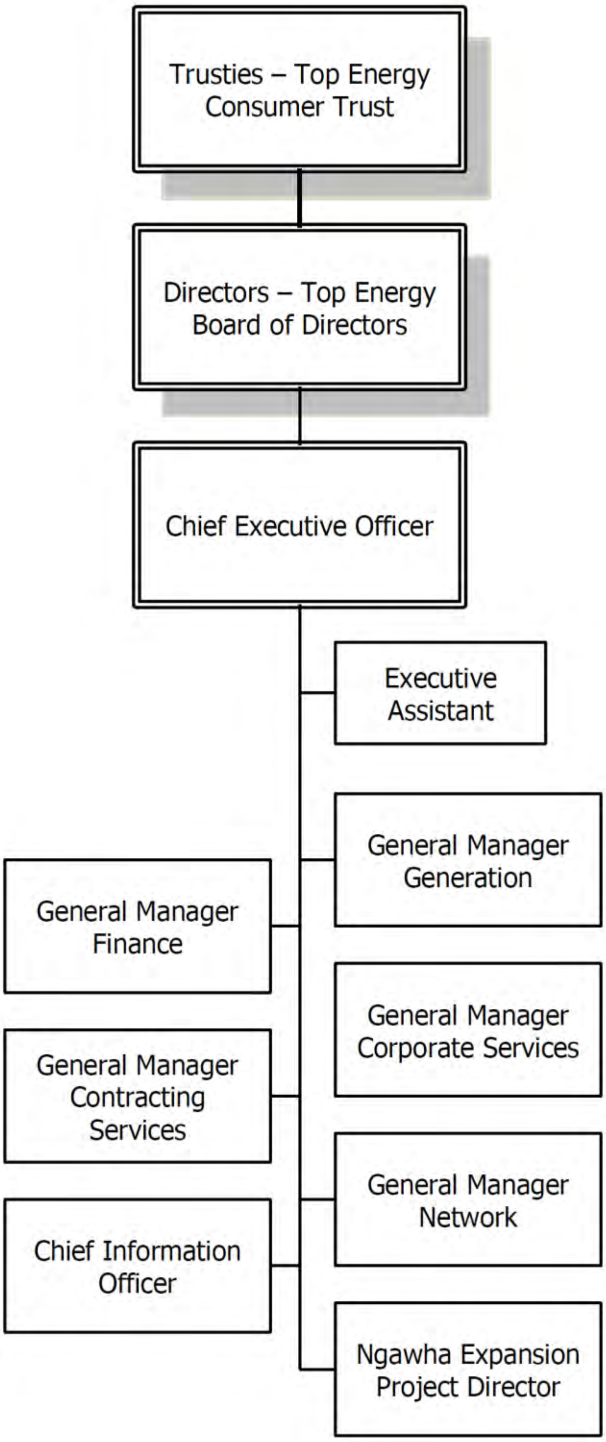

Figure 2.2: Top Energy Structure

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; and
- 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 without supervision 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.

TEN currently has a staffing establishment of 46 full-time equivalents and is structured as outlined in Figure 2.3 below.

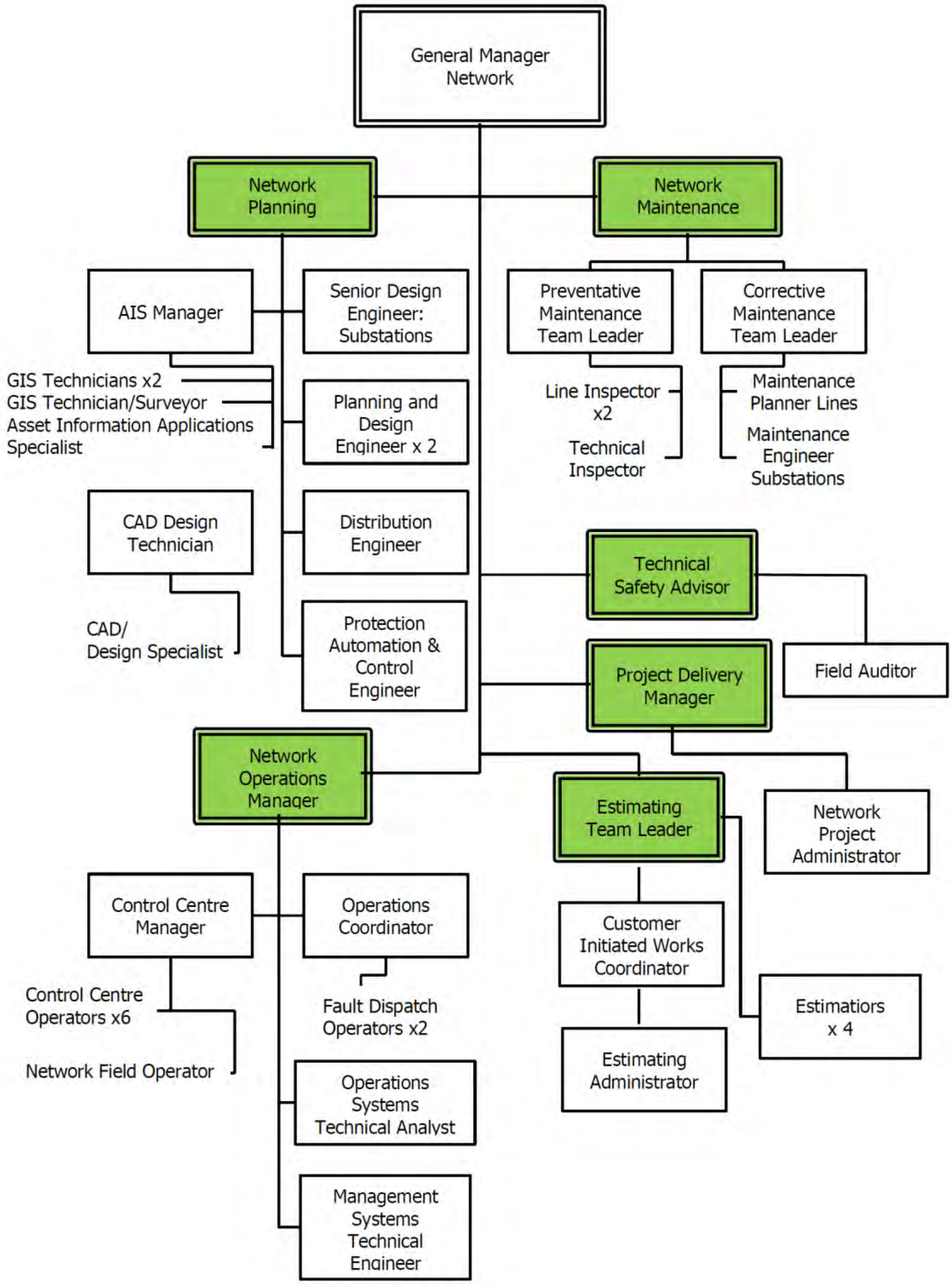

Figure 2.3: Top Energy Networks – Structure

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.
Programme Delivery Manager	To manage the delivery of the capital investment programme budgets individually assigned for each project.
Manager Asset Information Systems	To manage the GIS department budget to ensure the asset data integrity is maintained.
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	$30,000

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 use the iPower SCADA system for operational, real-time load data-gathering requirements, load control, and logging and reporting state changes from controllable devices. The system provides for circuit breakers at the two transmission substations and all zone substations to be remotely operated from our central control room at Kerikeri. In addition, it is possible to remotely operate switches and reclosers situated at strategic locations throughout the subtransmission and distribution networks.

The SCADA system also records system and feeder half-hour demand information, which is available via the company's intranet for further analysis and processing in separate systems.

We are currently upgrading our SCADA master station to an advanced distribution management system (ADMS), which will provide a significantly higher level of functionality. This upgrade is discussed further in Section 5.14.

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; and
- 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. We currently use this to manually generate our SAIDI and SAIFI reliability reports, although this information will be generated automatically once our new ADMS is commissioned.

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 Phone Plus to handle consumer calls. Phone Plus uses its Customer Management System (CMS) 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; and
- control, circuit and wiring diagrams.

2.9.7 Asset 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 inspection is undertaken internally by TEN; 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 most asset categories is now complete. We expect to complete the initial inspections of concrete poles in FYE2020 and service pillars in FYE2021. We will then transition to a revised inspection regime that focuses on assets approaching the end of their expected economic life and newer assets that are still likely to be fit for service will not have regular maintenance inspections. This is discussed in Section 6.1.2.2.

2.10 Asset Data Accuracy

We maintain a dedicated GIS team that is 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; and
- 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 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 5.13.4).

We are nearing the end of our first round of asset inspections since we started recording data on asset condition in SAP and the quality and usefulness of this data recorded has gradually improved with the introduction of standardised reporting templates. The accuracy of the dataset should further improve as we continue our inspection programme. This will provide better information on asset health and lead to more effective selection of assets for renewal.

2.11 Asset Management Systems

2.11.1 Asset Inspections and Maintenance Management

As described in Section 2.9.7, our asset inspection programme is uploaded into, and managed through, SAP. 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. 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 different maintenance policies for specific asset types is provided in Chapter 6 of this AMP. Asset condition information is loaded directly into SAP by our asset inspectors using remote, hand-held input devices.

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 6.1.6.

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 an ambitious 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 Chapter 5 of this AMP.

2.11.3 Network Performance Measurement

We currently use a real-time fault management system that we have developed internally. Once a call is received by the control room staff, a fault job is raised. This details information such as time raised, location, dispatcher notified, team details, on-site arrival, site departure and work carried out. This provides a detailed fault analysis tool for tracking, managing and post-fault analysis of all network fault events. The fault management system also provides a list of faults with active or incomplete status, so we can follow-up to ensure service attendance was achieved.

For each fault that has an impact on SAIDI and SAIFI, there is an individual switching record created. The record is then entered into a database that contains the necessary data to generate an outage report and provide statistical data for use in producing accurate performance reports. This information is also used for statistical analysis of supply interruptions, which can inform maintenance and future fault prevention planning.

Operational fault and switching times are logged for each fault event by Control Room staff. This information is used to run a GIS query for each fault to determine the numbers of consumers affected at each switching stage of the fault and, subsequently, calculate the SAIDI and SAIFI impact for each high voltage supply interruption.

Monthly and annual audits are carried out on all fault calculations. In the event of an error, a wider sample (or the entire population) is audited. Annual audits 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, SAIFI and CAIDI performance, are prepared for inclusion in the General Manager Network's monthly Board report.

As discussed in Section 5.19, our new ADMS will replace our current fault management system and will also automate measurement of network reliability. Further, in addition to the broad SAIDI and SAIFI measures used by the Commerce Commission, we are developing reliability measures that better reflect the level of reliability individual consumers can expect by categorising feeders into urban, rural, and remote, and separately reporting the average reliability across each category. Urban consumers can expect a more reliable supply than rural consumers, because urban feeders are generally shorter and therefore less exposed to risk. Similarly, consumers of rural feeders would receive a more reliable supply than those on feeders categorised as remote. Reliability measures would reflect this.

2.12 Assumptions and Uncertainties

The network development plan and other asset management strategies described in this AMP are ambitious 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. Increases in transmission and subtransmission capacity tend to be lumpy rather than incremental; therefore, the development plan will increase network capacity in excess of the immediate requirement. Even if electricity delivery volumes grow, over time the level of network investment will reduce, which this should assist in stabilising future pricing.	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 recent decline in electricity volumes delivered is now stabilising and we anticipate volumes will increase when the Ngapuhi Waitangi Tribunal claim is settled or when the penetration of electric vehicles increases.
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's 2015-20 price path determination was supportive of our network development plan and we expect this support to continue during the 2020-25 regulatory period.
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.	Our network development plan has prioritised improvements to the transmission and subtransmission network. However, if our ability to effectively control peak load is reduced, we may need to increase the capacity of the distribution network faster than currently planned. This would utilise funds currently budgeted for other activities. This is a significant long-term risk 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.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
RELIABILITY AND QUALITY	Consumers want an improvement in the reliability and quality of electricity supply.	The Trust and Board both consider that improving the reliability of supply is consistent with our SCI objective of investing in activities that contribute to economic development within its supply area. Our load centres have moved due to changing demographics over the last 25 years. There is now a disparity between our network design and the location of our major loads as well as an expectation of greater security and reliability of supply. A balance is to be found between investment in improve our network or better meet consumer requirements and consumers' ability to pay line charges. We have consulted widely with consumers and received strong support for our network development plan.	There is a risk that the support for reliability driven network development initiatives will decline as consumers feel the impact of increased line charges.
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 planned 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.

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 as at 31 March 2019. 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 plan.	

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 improve the reliability of supply provided to our consumers, as measured by SAIDI and SAIFI, to levels comparable to that typically received by consumers in other rural provincial parts of New Zealand and to develop a network that meets the needs of consumers 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. While the completion of this line is too far away to meet consumer expectations of improved supply reliability (due to landowners challenging the planned route in court), completion of a second circuit is still the only identified option using currently available technology that will fully meet consumer aspirations over the longer term;
- installing diesel generation close to Kaitaia to provide security of supply to our northern area in the short-term at a relatively low-cost;
- development and implementation over time of a standard network architecture to reduce the SAIDI and SAIFI impact of a fault on the 11kV and low voltage networks;
- replacement of assets that require renewal as they near the end of their economic life;
- targeting vegetation management at trees that are a safety hazard and at those parts of the network where supply reliability can be improved;
- improving the efficiency of the maintenance effort by focusing on assets that are nearing the end of their economic lives and are therefore most likely to fail in service; and
- designing and implementing pilot projects that will enable us to better understand the impact of new technologies on the way we develop the network and manage its operation.

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 2.2.1 and underpins the longer-term development of the economically-depressed Far North region. While the bulk of the asset management expenditure has been on network development, the strategy does not ignore other periods of the asset life cycle, since improvement in the performance of the existing asset base is essential if the targeted improvements in SAIDI and SAIFI are to be realised. 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 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. This was activated for the July 2014 storm, which lasted three days and caused significant damage to our assets and resulted in extended supply interruptions for many of our consumers. We have subsequently reviewed our response to this event and revised our Emergency Preparedness Plan to incorporate the lessons learnt. We proactively anticipate and plan for foreseeable emergencies and this planning has resulted, for example, in the construction of a mobile substation, the installation of diesel generators at Taipa and the planned installation of additional generation in the Kaitaia area in FYE2019 and FYE2020.

2.13.3 Asset Management Implementation

The General Manager Network is responsible for asset management implementation and controlling expenditure on network development and maintenance. Asset management procedures are documented in our ISO 9002 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 Interface Agreement and Sourcing Strategy, 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 inspection is undertaken by asset inspectors working directly for TEN.

2.13.4 Corrective and Preventive Action

Our ISO 9001 quality management system process defines the business process place for determining preventive and corrective actions when an asset problem is identified. This requires the process owner to undertake a root cause analysis, determine appropriate corrective actions and track these through to close-out. The process works well when a major incident arises. However, our response tends to be reactive and we continue to develop a culture that encourages our staff to proactively identify issues and implement incremental process improvements. Such issues, once identified, should be tracked through the process and formally closed out, but this does not always happen.

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. Hand held electronic input devices are used by asset inspectors to upload asset condition data into SAP directly from the field. Nevertheless, it will take one full inspection cycle before this asset condition data entry process is complete. 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 asset management policy, which is discussed in Section 2.4, underpins all our asset management effort.

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 55001 for an organisation to have documented asset management plans. The AMP is also consistent with the structure of the standard, in that Chapter 2 covers strategic issues in some detail and Chapters 5 and 6 provide the detailed action plans derived from these strategies.

We have qualitative objectives derived from the corporate mission statement and 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 Chapter 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 the level of defect 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 significantly 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 Interface Agreement and Sourcing Strategy

The Interface Agreement and Sourcing Strategy documents define the formal relationship between TEN and TECS, and are critical to the implementation of the action plans within this AMP. The Interface Agreement defines the pseudo-contractual relationship between the two business units, based on an asset manager–service delivery model.

Functions such as asset inspection and maintenance planning are now undertaken directly by TEN. Good progress has been made in improving previous issues experienced with the management of the interface between the two divisions, and the accountabilities and responsibilities of individual staff members are now clearly defined. The relationship between TEN and TECS continues to evolve and improve.

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.

Our long-term goal of creating and implementing formalised, fully documented, ISO 55001-certified asset management system remains. However, a project has not been established to achieve this objective.

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. The decision to suspend live-line work is an example of this.

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 to the extent the Board now includes an asset management subcommittee, which guides the strategic direction of this AMP 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. The enables us to prepare a comprehensive document without unduly distracting key TEN management staff from other work.

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. The language and structure of the AMP has also been externally reviewed to ensure that it is meaningful to a wider stakeholder audience.

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. Through this process, we have gained an understanding of stakeholder expectations regarding the reliability of their electricity supply, 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 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 that improved service delivery is to be expected over time and is 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 stakeholder, by the CEO and TEN's senior managers, continues to support our operational and organisational objectives. 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 ambitious. 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. While the challenges of this investment programme are unique, Top Energy and its shareholder have already demonstrated an ability to successfully undertake challenging projects for the benefit of our stakeholders. The successful construction, commissioning and operation the existing 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 new 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.

- We have replaced a number of 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 and Kawakawa, and installed a new 33kV indoor switchboard at Kaikohe.
- We have installed and commissioned 4MVA of diesel generation at Taipa, and 3.75MVA at our Kaitaia construction and maintenance depot as part of our ongoing project to increase supply security in our northern area using local generation.
- 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 a 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 underground 11kV cable been installed between Paihia and Opua to provide an alternative 11kV feeder that can supply the Russell peninsula, should a fault occur between Kawakawa and Okiato Point on the Russell Express feeder.

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

- financing;
- the ability to secure line routes;
- engineering; and
- 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 $251 million on 31 March 2018.

With the help of external consultants, Top Energy has put together a carefully designed financing plan for this investment programme. This includes:

- revenues from line charges; and
- increased bank borrowings. We have secured the bank funding needed to fund the investment.

Nevertheless, finance is the limiting constraint on the rate at which we can deliver our network development plan. This is due to lower than expected revenues resulting from a gradual decline in energy delivered since FYE2012 and a need to maintain sustainable borrowing levels impacted by the expansion of the Ngawha Geothermal Power Station, which also requires bank funding.

2.17.2 Engineering

The design of the network development works within this AMP requires specialist engineering skills and resources, which will be 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 will be undertaken internally, while the construction of new substations will be 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 far 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 could rise to hazardous levels creating a risk of shock and possibly death to persons and stock coming 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 have also decided that 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 and pose a significant safety risk. However, these lines are not regularly inspected and there are no systems in place for ensuring they are maintained in a safe condition. We have suggested to the Commerce Commission that we include these lines in our inspection programme and advise the owners if repairs are required. However, 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.

There is a risk that, following a public safety incident involving a private line somewhere in the country, legislation will be enacted that requires the local distribution company to assume ownership of these lines, as is the case in other jurisdictions. We would then become responsible for their safety and maintenance. Even if ownership is assumed at no cost, this will impose a substantial financial liability that we have not provided for.

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 1,000-6,000 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 25MW Ngawha geothermal power station, situated about 7km Southeast of Kaikohe, is also delivered to Kaikohe though two 33kV subtransmission lines. 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 415V three-phase, 480/240V two-phase and 240V single phase.

We have installed approximately 4MW diesel generation at our Taipa zone substation and 3MW within our construction and maintenance depot north of Kaitaia, and we intend to install additional diesel generation at a new site in Bonnets Rd, west of Kaitaia. When this is commissioned, we will be able to 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.

During FYE2018, we supplied an average 31,641 active connections. The maximum demand on our network was 70MW and the total energy delivered to consumers was 325GWh. The average energy supplied to each individual consumer was the second lowest in the country.

3.1.3 Grid Exit Point

Our one GXP is the termination of the Transpower 110kV Maungatapere-Kaikohe circuits. 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 and, with the increase in the capacity of the Ngawha power station, the existing lines will meet all foreseeable requirements.

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 network constraint between Kaikohe and Kaitaia is one of security rather than capacity.

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 Networks

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.

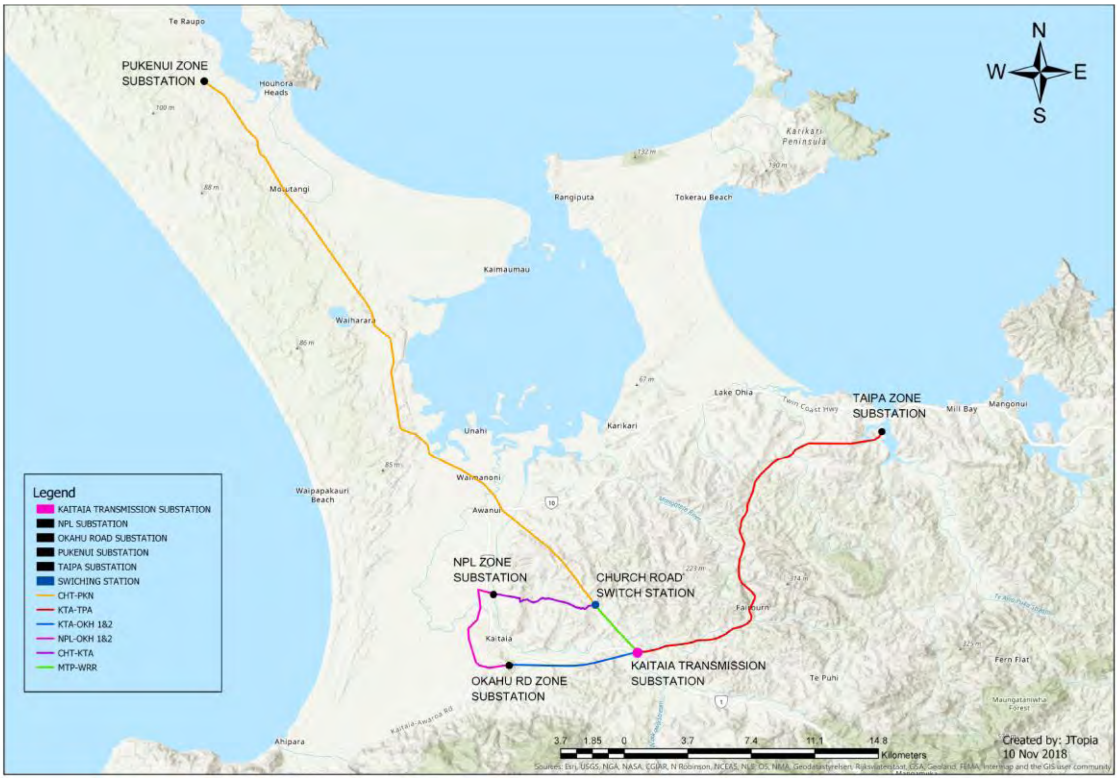

Figure 3.1: Subtransmission Network – Northern Area

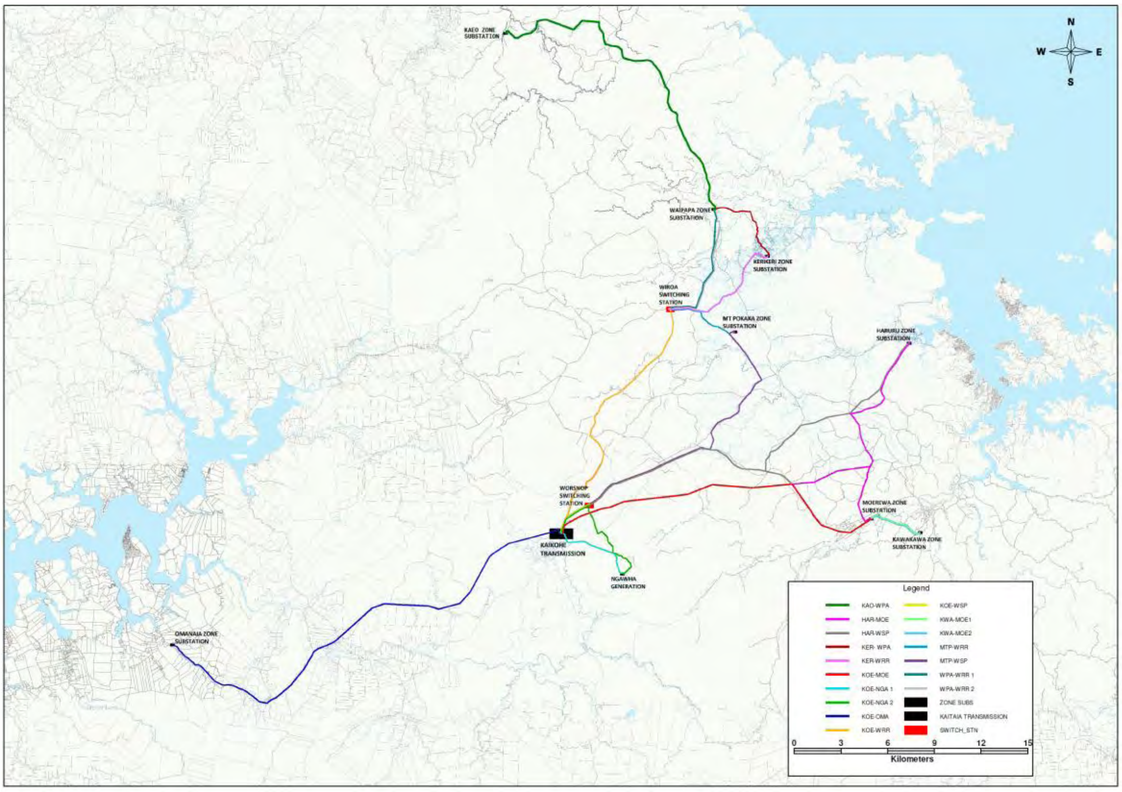

Figure 3.2: Subtransmission Network – Southern Area

Table 3.1 below shows the transformer capacity and level of security provided at each zone substation. The limiting factor that determines transformer capacity is the temperature of the transformer oil. Most transformers are fitted with air coolers; the capacity of a transformer is increased if the transformer is fitted with fans to force air though the coolers (air forced or AF) or with pumps to pump oil through the coolers (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.

Substations with a security level of 1, as shown in Table 3.1, have two transformers and two incoming circuits. Supply will be maintained without interruption following the loss of either a transformer or an incoming circuit. Substations with a security level 2 of do not have this level of redundancy, but provide a higher level of supply security than level 3 substations, which have both a single transformer and a single incoming circuit.

In the event of an extended fault affecting a level 2 or 3 substation, there may be distribution transfer capacity available, where the distribution network can be reconfigured to provide supply from other zone substations. The amount of distribution transfer capacity that can be provided will depend on the network load and there will be less capacity available at times of high demand. We also have a 7.5MVA mobile substation that can be relocated to an affected substation, however the time required to relocate and connect this substation is up to 10 hours.

SUBSTATION	UNIT	NOMINAL RATING (MVA)	MAXIMUM CAPACITY (MVA)	SECURITY LEVEL	COMMENT
Southern GXP					
Kaikohe	T1	11.5/23	17[1]	1	
	T2	11.5/23	17[1]		
Kawakawa	T1	5/6.25	6.25	1	
	T2	5/6.25	6.25		
Moerewa	T1	3/5	5	1	
	T2	3/5	5		
Waipapa	T1	11.5/23	23	1	
	T2	11.5/23	23		
Omanaia	T1	3/5	5	3	There is provision for the installation of a relocatable generator to provide supply during refurbishment of the incoming 33kV line.
Haruru	T1	11.5/23	23	1	
	T2	11.5/23	23		
Mt Pokaka	T1	3/5	5	2	Single transformer. Should this transformer fail, there is sufficient distribution transfer capacity available to restore supply to all small use consumers, but not to the Mt Pokaka mill.
Kerikeri	T1	11.5/23	23	1	
	T2	11.5/23	23		
Kaeo	T1	5/10	10	2	Single incoming circuit.
	T2	5/10	10		
Northern GXP					
Okahu Rd	T1	11.5	11.5		
	T2	11.5	11.5		

SUBSTATION	UNIT	NOMINAL RATING (MVA)	MAXIMUM CAPACITY (MVA)	SECURITY LEVEL	COMMENT
Taipa	T1	5/6.25	6.25	2	Single incoming circuit. Local generation is available to restore supply to most consumers following a fault.
Pukenui	T1	5	5	3	
NPL	T1	11.5/23	23	1	
	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

3.1.6 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 3.2 to 3.13 show the extent of the distribution system supplied from each of our zone substations.

The distribution network supplies approximately 5,940 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, 86% 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 3.2 – 3.13 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.

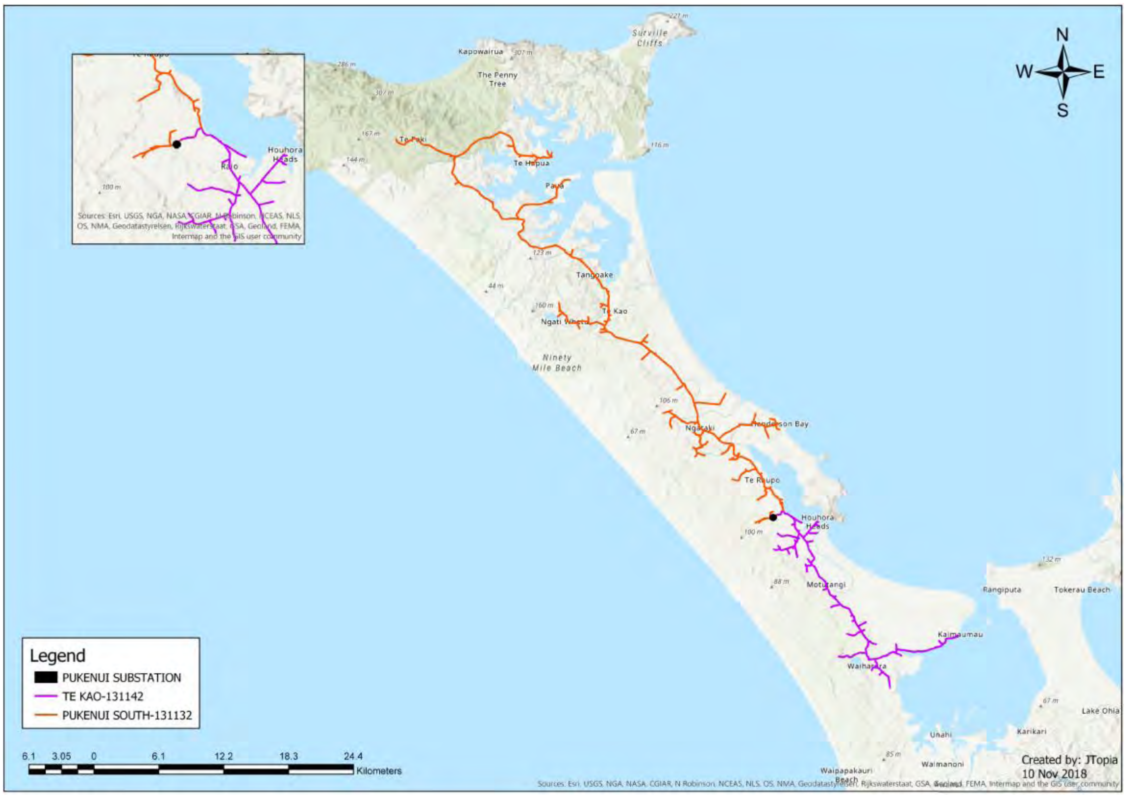

Figure 3.3: **Geographic diagram of the Pukenui zone substation**

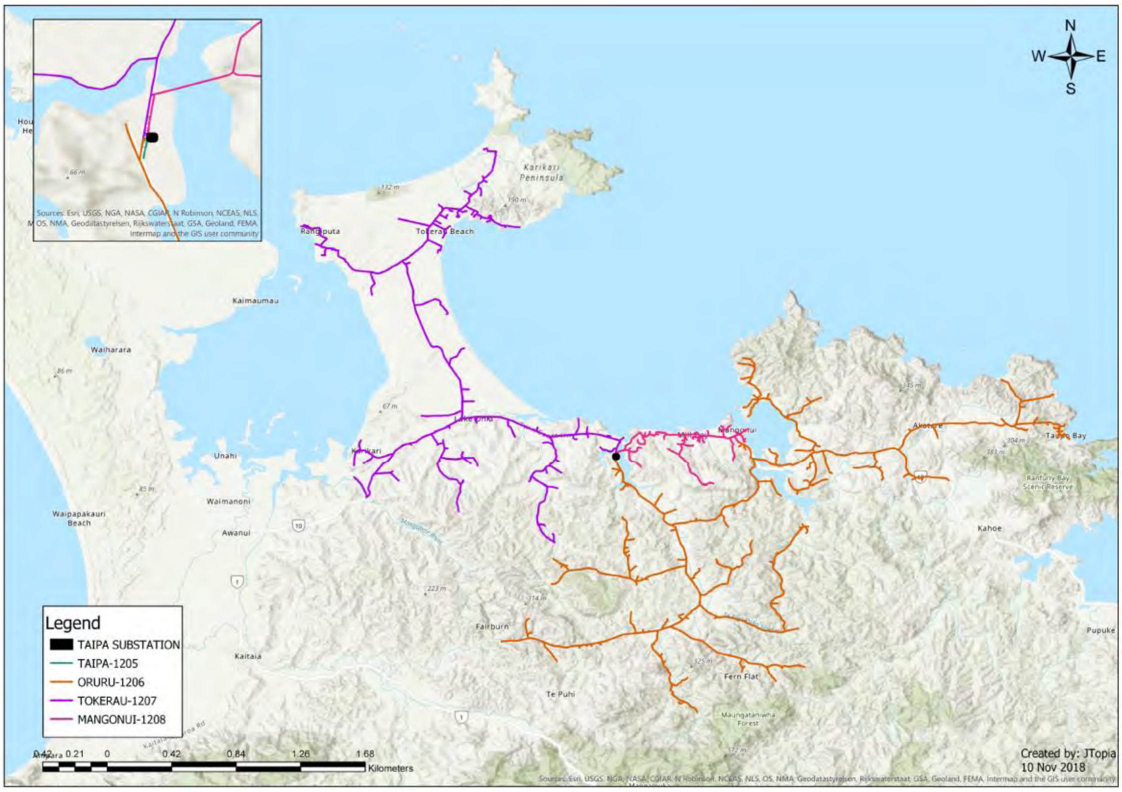

Figure 3.4: **Geographic diagram of the Taipa zone substation**

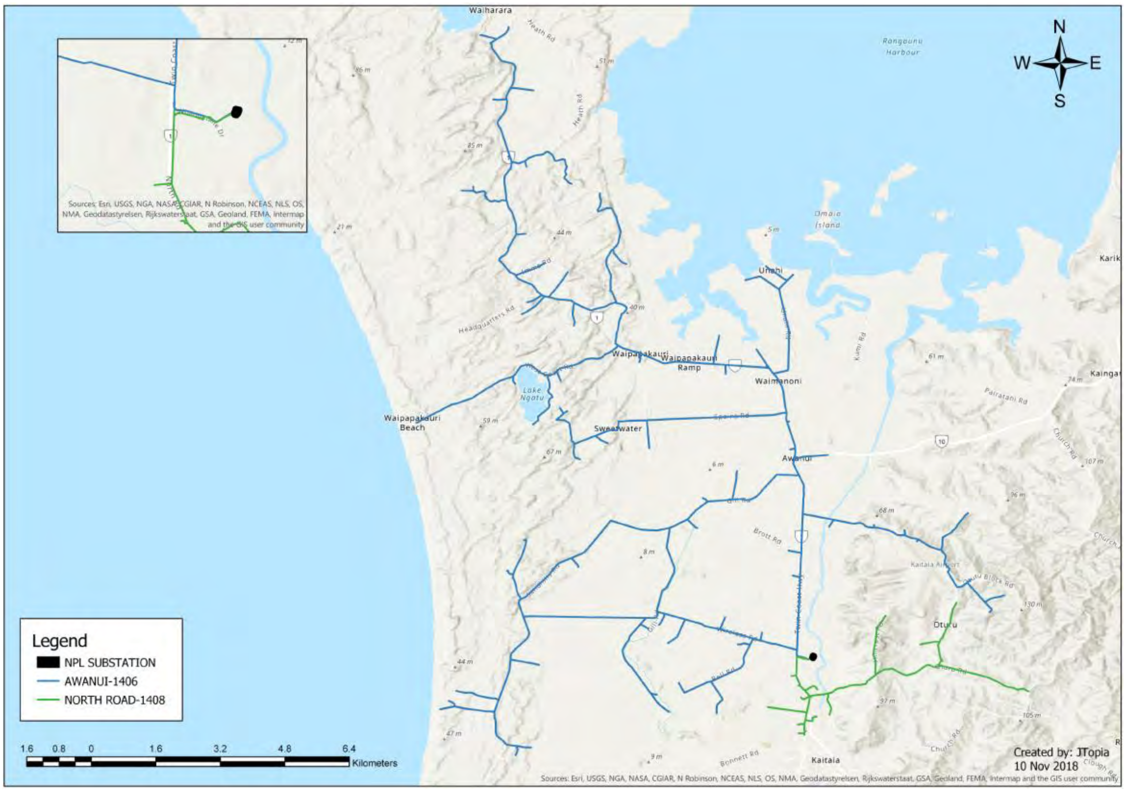

Figure 3.5: Geographic diagram of the NPL zone substation

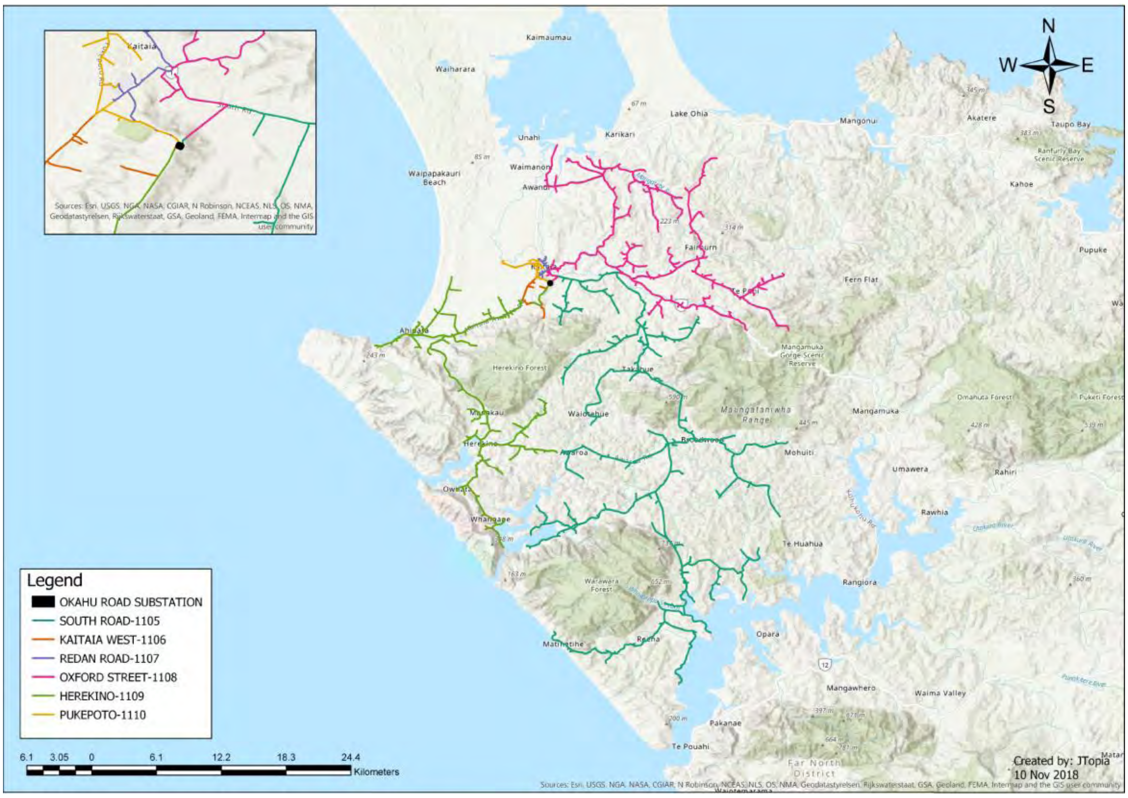

Figure 3.6: Geographic diagram of the Okahu Road zone substation

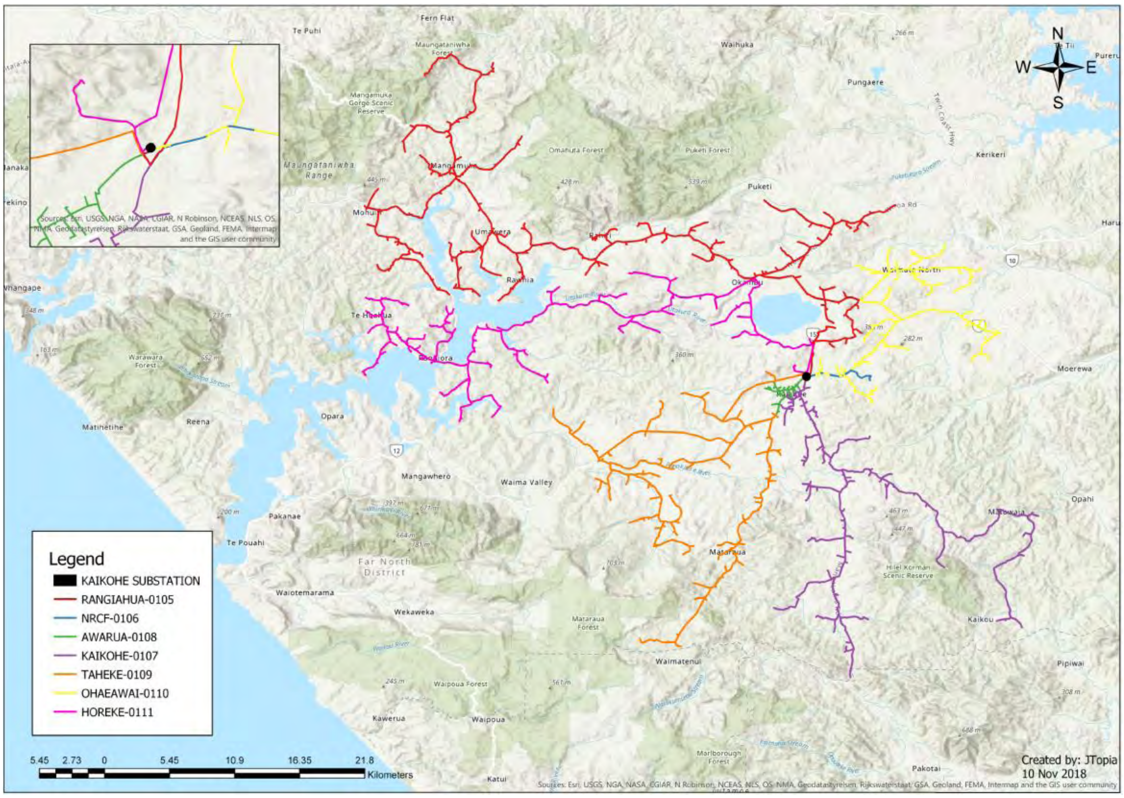

Figure 3.7: **Geographic diagram of the Kaikohe zone substation**

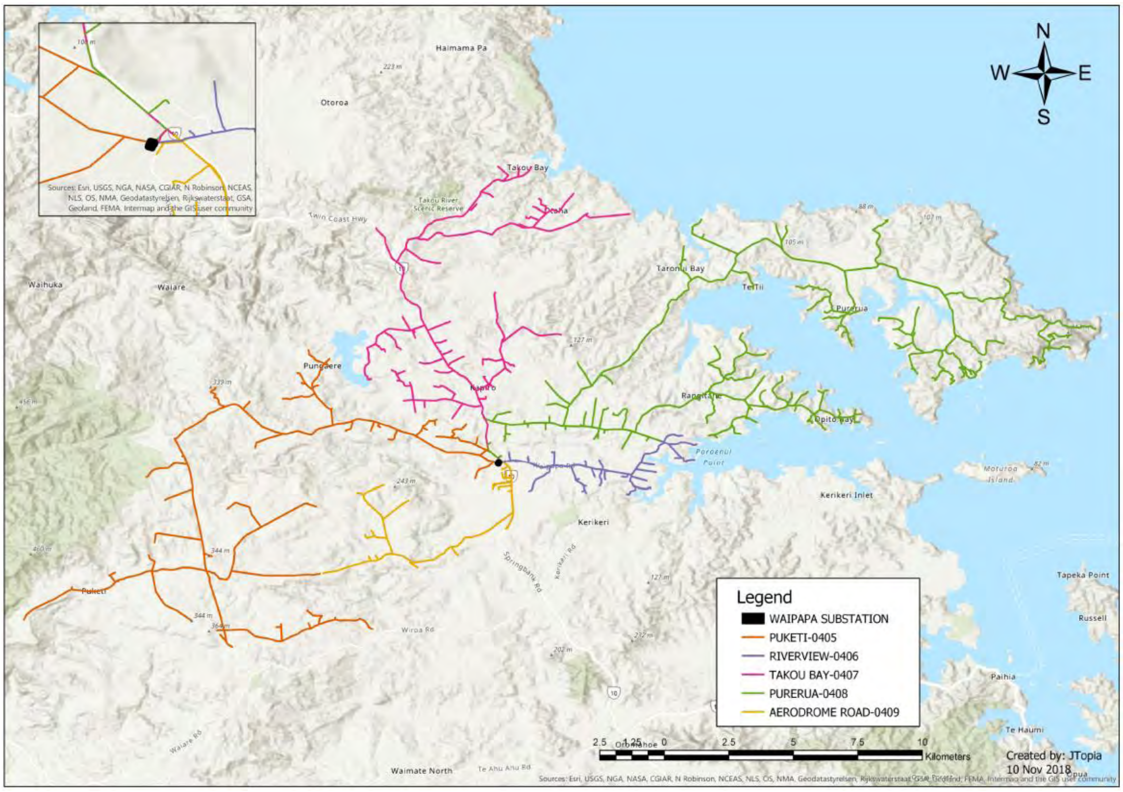

Figure 3.8: **Geographic diagram of the Waipapa zone substation**

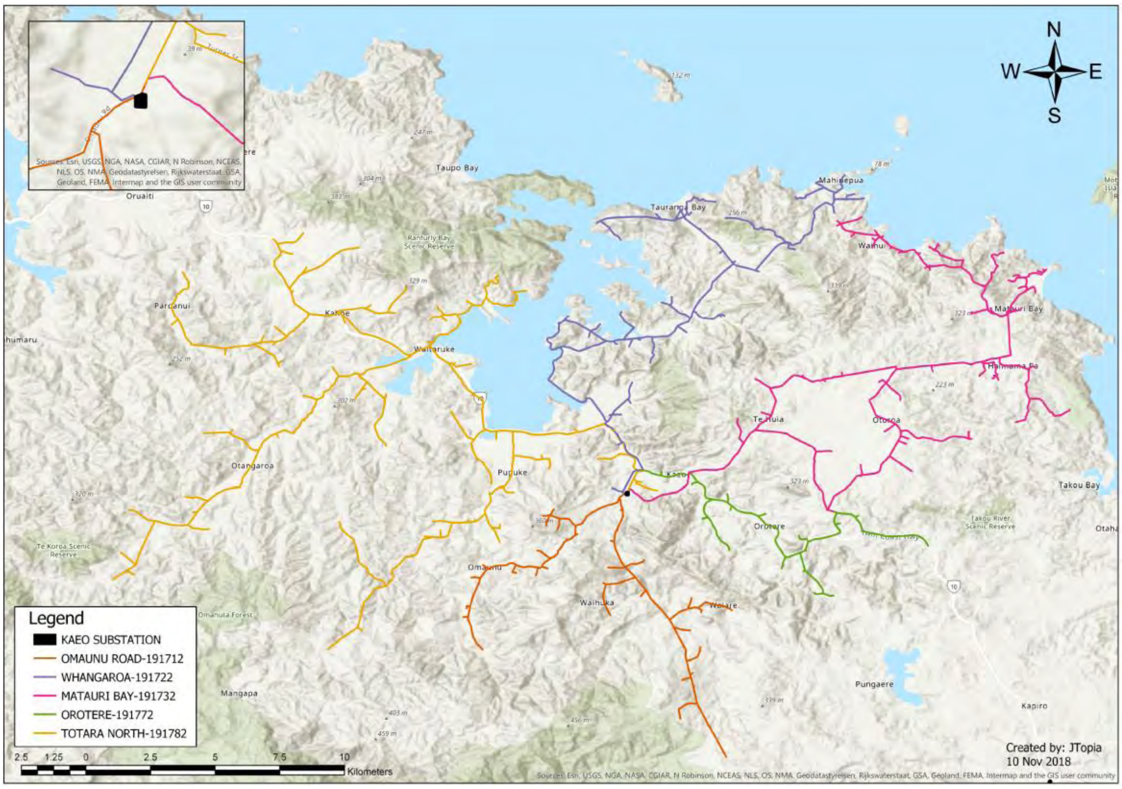

Figure 3.9: Geographic Diagram of the Kaeo Substation

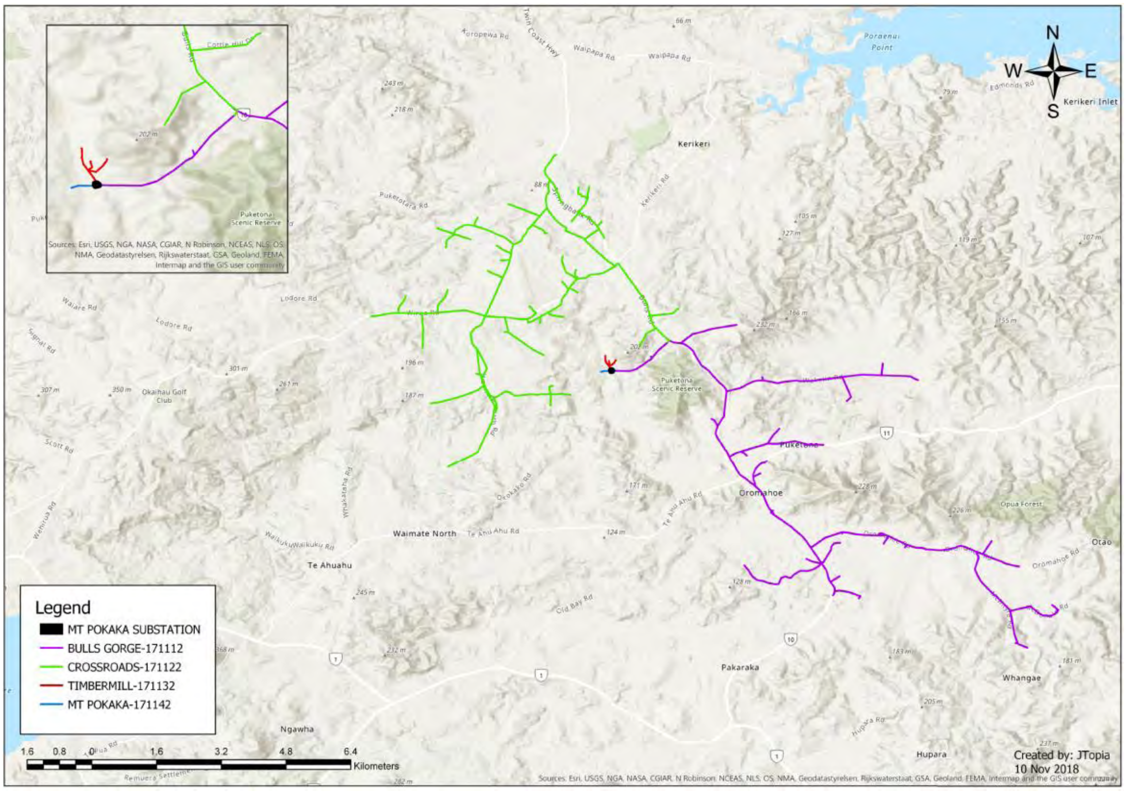

Figure 3.10: Geographic diagram of the Mt Pokaka zone substation

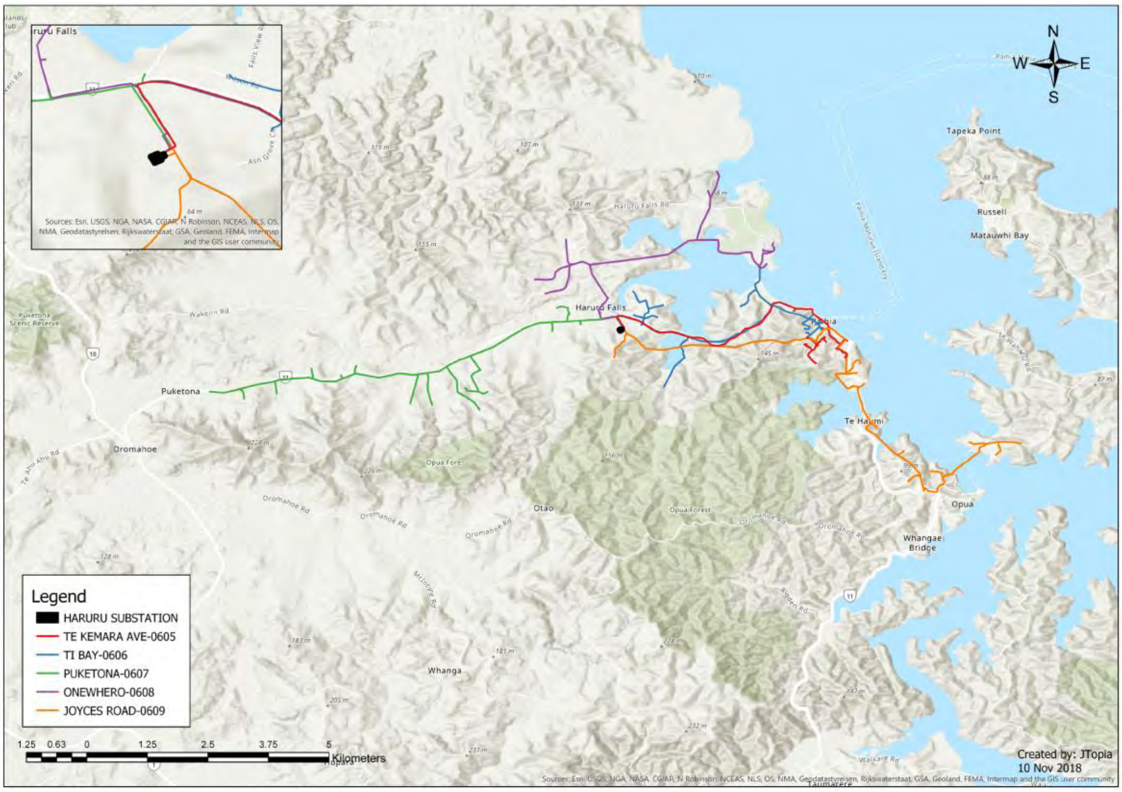

Figure 3.11: **Geographic diagram of the Haruru zone substation**

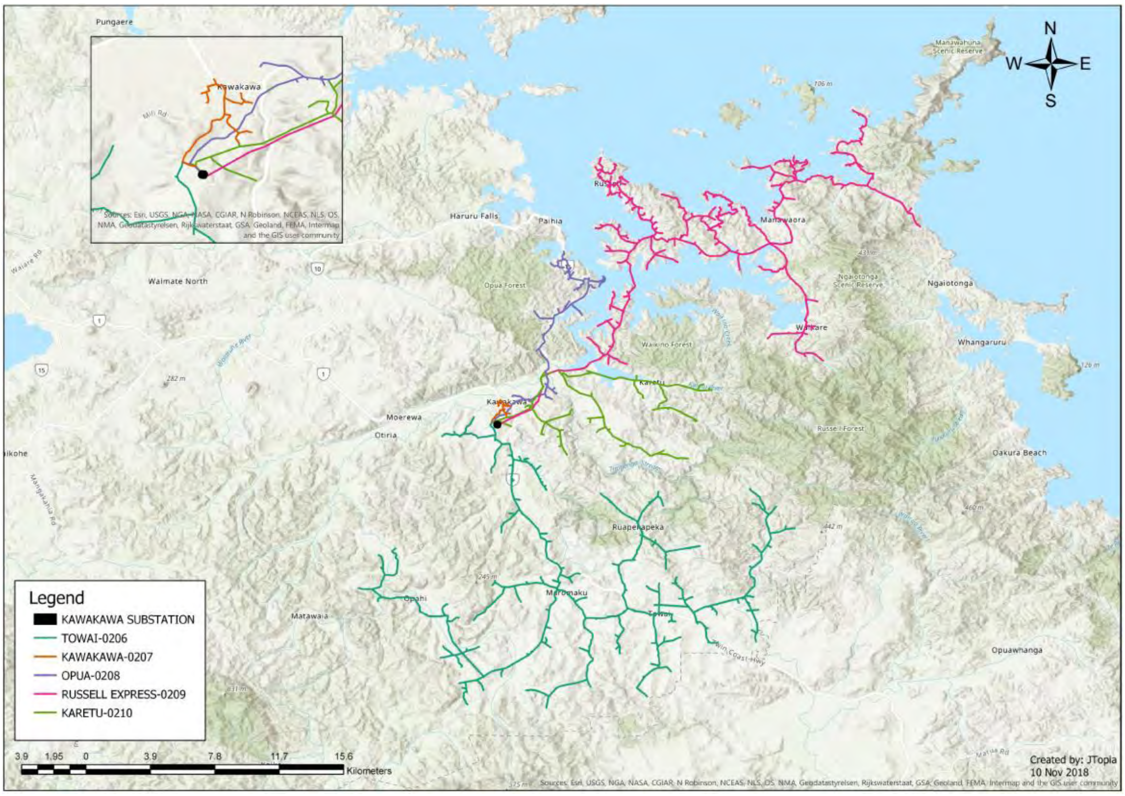

Figure 3.12: **Geographic diagram of the Kawakawa zone substation**

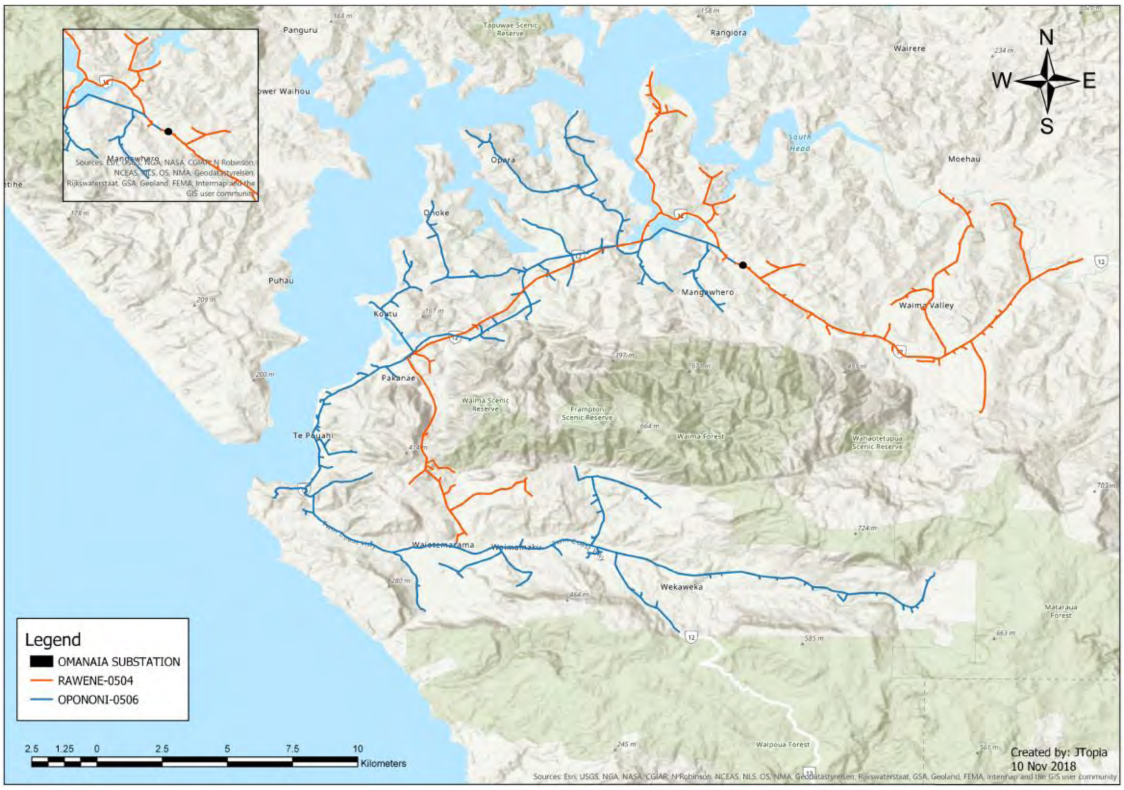

Figure 3.13: Geographic diagram of the Omanaia zone substation

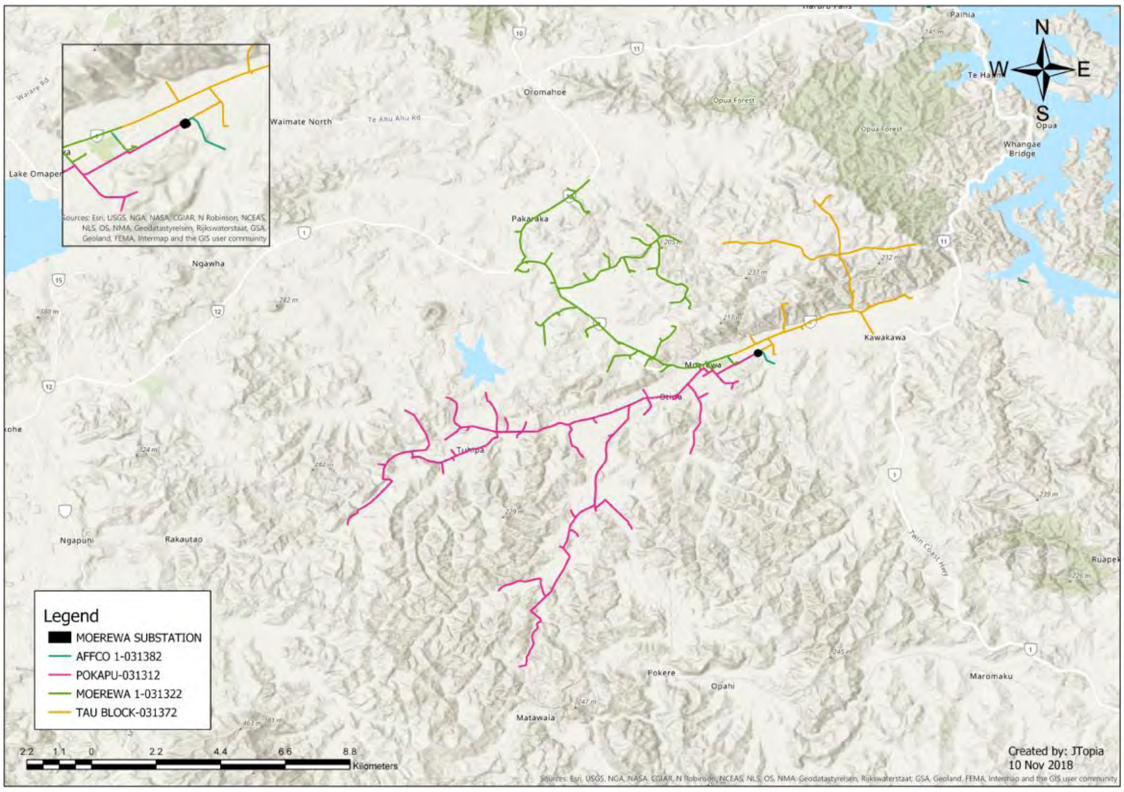

Figure 3.14: Geographic diagram of the Moerewa zone substation

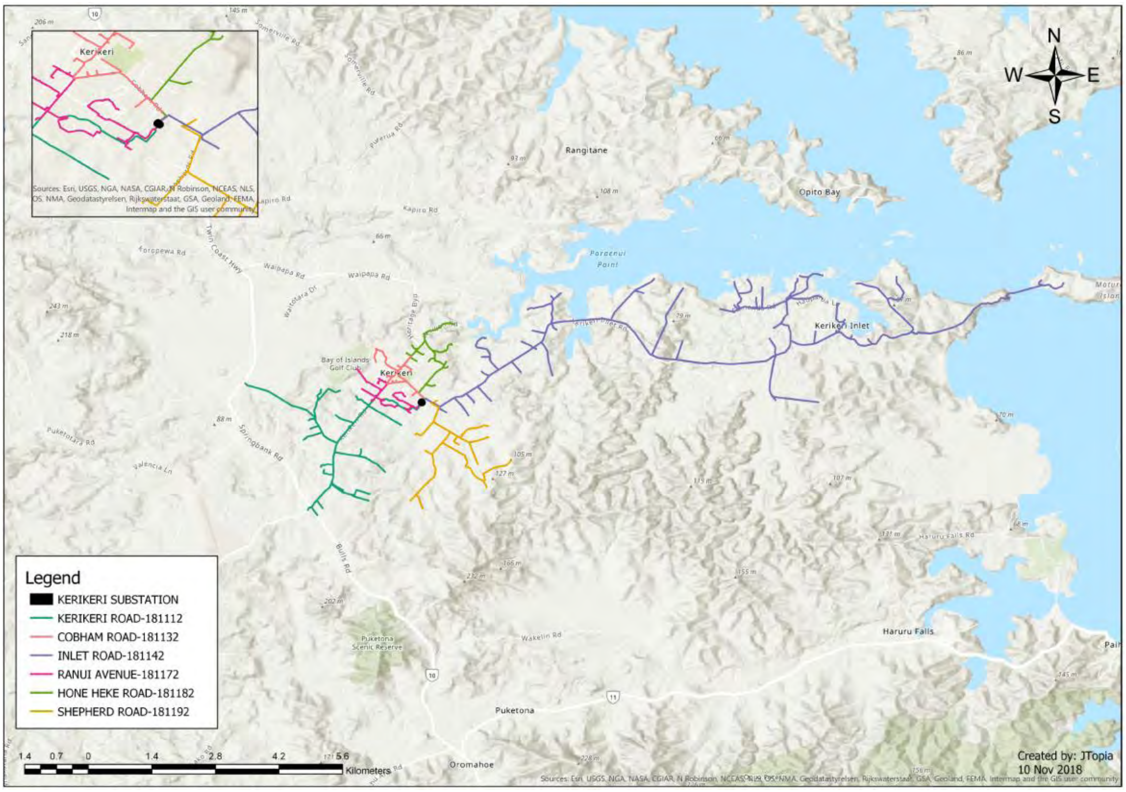

Figure 3.15: Geographic Diagram of the Kerikeri Zone Substation

3.1.6.1 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 43 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.

3.1.7 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.

3.1.8 Protection Assets

We use a mixture of protective devices including:

- electromechanical relays;
- numerical relays;
- integrated protective devices such as fuses, pole top reclosers and sectionalisers; and
- 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 our 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.

3.1.9 SCADA and Communications

Our System Control and Data Acquisition (SCADA) system monitors the state of our network in real time and allows 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. It uses an iPower SCADA system to operate and monitor the network.

Our iPower SCADA system was installed in 2004. 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; and
- 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, primarily using fibre-optic cable.

3.1.10 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 potential benefit of demand management.

We are currently using 45 of the 100 channels available for load control.

3.1.11 Mobile Substations and Emergency Generation

We own a 33/11kV, 7.5MVA mobile substation that was commissioned in FYE2003. Its main function is to mitigate the risk of a transformer failure at one of our single-transformer zone substations at Taipa, Pukenui, Omanaia or Mt Pokaka.

We have installed two 2MW diesel generator sets at Taipa substation and three 1MW sets at our Kaitaia depot. These are used to reduce consumer supply interruptions during maintenance shutdowns of the Kaikohe-Kaitaia 110kV transmission line.

The Taipa generators are also used to maintain supply during interruptions if the single incoming circuit supplying the substation and would also be used in the event of a transformer failure. The load and the number of consumers supplied from Taipa is significantly larger than from the other single-transformer zone substations, therefore the impact of a loss of supply from the substation on the measured reliability of the total network would be greater. In the event of a transformer failure, the generators would only be used until the mobile substation could be relocated, due to the high cost and environmental impact of diesel generation.

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 seven public electric vehicle charging stations dispersed across our network as shown in Figure 3.16 below. A further two sites are under construction.

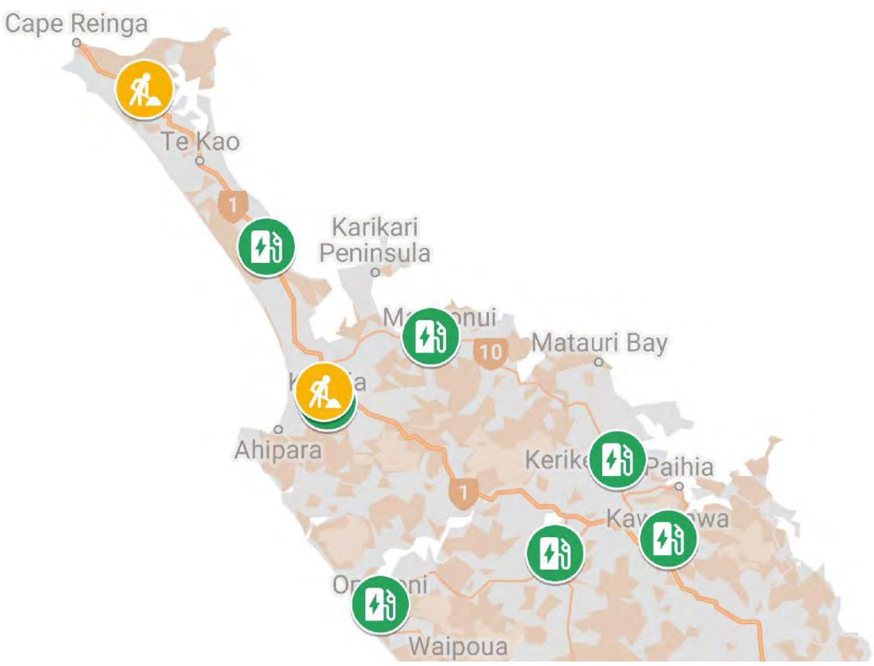

Figure 3.16: Public Electric Vehicle Charging Station Locations

As of December 2018, there were just over 100 plug-in electric and plug-in hybrid vehicles registered within our supply area, as shown in Table 3.2 below.

	Plug-in Electric	Plug-in Hybrid	Total
Awanui	2	2	**4**
Bay of Islands	-	1	**1**
Cable Bay	1	-	**1**
Coopers Beach	1	-	**1**
Kaeo	1	1	**2**
Kaikohe	3	-	**3**
Kaitaia	5	3	**8**
Kawakawa	1	1	**2**
Kerikeri	40	9	**49**
Manganui	1	-	**1**
Moerewa	1	-	**1**
Omapere	1	-	**1**
Opua	1	-	**1**
Paihia	6	2	**8**
Rawene	-	1	**1**
Russell	9	6	**15**
Taipa	1	-	**1**
Waipapa	-	1	**1**
Total	**74**	**27**	**101**

Table 3.2: Plug-in Electric and Hybrid Vehicles Registered in Top Energy 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 to 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.

We believe that we can continue to supply most consumers in remote areas without burdening other consumers through spot replacements of poles, crossarms, conductors and transformers as they become unserviceable. However, there are some segments of the remote network that have deteriorated to the point where this approach is not sufficient and a full rebuild or an alternative solution using an emerging technology will be required to provide a continued supply. The issue is how to recover this cost. This is discussed further in Section 5.8.

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	53	60-80
110kV poles	40	3	
33kV	83	14	
Subtotal	**136**	**15**	-
Concrete			
110kV	347	22	60-80
33kV	2,999	29	
Distribution -excluding SWER	24,282	35	
SWER	2,736	34	
Low voltage	1,034	40	
Subtotal	**31,398**	**34**	-

Asset	Quantity (No.)	Average Age (yr)	Expected Life (yr)
Wood			
110kV	182	38	35-45
33kV	128	43	
Distribution – excluding SWER	476	43	
Distribution - SWER	366	39	
Low voltage	199	43	
Subtotal	**1,351**	41	-
TOTAL	**32,885**	**35**	

Table 3.3: 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	43	50-60
110kV Kaikohe-Wiroa line[1]	36	7	
33kV	284	35	
Distribution (excluding SWER)	2,032	37	
SWER	372	45	
LV	987	27	
Subtotal	**3,767**	**35**	**-**
Copper			
Distribution (excluding SWER)	88	52	60
SWER	60	60	
LV	104	43	
Subtotal	**252**	**50**	**-**
Galvanized Steel			
Distribution (excluding SWER)	0.5	63	50
SWER	22	68	
Subtotal	**22**	**68**	**-**
Unknown			
All voltages	22	-	-
TOTAL	**4,064**	**36**	**-**

Note 1: Currently operating at 33kV

Table 3.4: Network Overhead Conductor Quantities

3.2.3 Underground Cable

Asset	Quantity (cct-km)	Average Age (yr)	Expected Life (yr)
33kV	21	6	55
Distribution	208	15	45-70
LV (excluding streetlight)	658	26	45-55
Streetlight	319	28	45-55
TOTAL	**1,206**	**24**	-

Table 3.5: Network Underground Cable Quantities

3.2.4 Other Assets

Asset	Quantity (No)	Average Age (yr)	Expected Life (yr)
Pole-mounted distribution transformers	5,219 (138MVA)	24	45
Ground-mounted distribution transformers	845 (147MVA)	17	45
Voltage regulators	40	8	45-55
Zone substation buildings	22	33	50+
Power transformers	40	40	45-60
Outdoor 110kV circuit breakers	10	Note 1	40
Indoor 33kV circuit breakers	44	5	60
Outdoor 33kV circuit breakers	34	16	40
Indoor 11kV circuit breakers	70	30	45-60
Outdoor 11kV circuit breakers	31	10	40
Outdoor 33kV switches	194	21	35
Sectionalisers	250	10	40
Reclosers	118	19	40
Ring main units	293	10	40
Overhead distribution switches	614	24	35-40
Distribution fuses	5,643	24	35
Underground service fuse boxes	12,065	25	45
Protection relays	288	Note 1	40
Capacitors	45	Note 1	55

Note 1: Insufficient data for an accurate estimate

Table 3.6: Other Network Asset Quantities

3.3 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 $251.5 million as at 31 March 2018; an increase of $13.7 million since 31 March 2017. This total was derived as shown in Table 3.4 and reflects the value of the assets commissioned in FYE2018 as part of our network development programme.

	$000
Asset Value at 31 March 2017	**237,830**
Add:	
New assets commissioned	19,745
Indexed inflation adjustment	2,616
Less:	
Depreciation	8,681
Asset disposals	22
Asset value at 31 March 2018	**251,488**

Table 3.7: Value of System Fixed Assets

The asset value shown in Table 3.4 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 $7.5 million as at 31 March 2018.

Table 3.5 disaggregates the value system fixed assets shown in Table 3.4 into its main asset categories.

	$000
Transmission and subtransmission lines	60,515
Subtransmission cables	9,378
Zone substations	38,060
Distribution and low voltage lines	50,541
Distribution and low voltage cables	37,671
Distribution substations and transformers	29,101
Distribution switchgear	16,539
Other network assets	5,256
Non-network assets	4,428
Total	**251,488**

Table 3.8: Disaggregated Value of System Fixed Assets as at 31 March 2018

Section 4 Level of Service

4 Level of Service

4.1 Introduction

When regulatory control over EDBs was introduced, our network started from a position of low reliability compared to similar New Zealand EDBs. 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 small dispersed population, spread over a large supply area with no dominant urban centre.

To address these disadvantages, Top Energy has made a significant investment in generation to reduce our dependency on grid supply. The current Ngawha expansion project and the Kaitaia backup diesel generation will ultimately provide independence from the grid if we need it in an extreme event, greatly improving our region's resilience. However, generation at Ngawha already exports energy that cannot be used within our supply area south over the transmission system and this export will increase substantially when the generation capacity at Ngawha increases. This energy export is reducing the share of cost our consumers pay for the use of transmission assets. Furthermore, we have received regulatory approval to complete a high capacity 110kV ring around our supply area. This will interconnect our Kaikohe GXP with Kaitaia and our developing load centre at Wiroa. This will be built after land use consents are finalised and before the existing 110kV line assets need renewal, which is expected to be some time after 2030.

Our existing grid connection and 110kV substations are no longer optimally located to serve the present load, since they were constructed during an era when the inland urban centres of Kaikohe and Kaitaia were the hub of both economic and population growth within our supply area. Over the last twenty years, there has been a steady decline in the growth of Kaikohe, whilst our supply area has experienced significant growth in Kerikeri, the Bay of Islands and the eastern coastal peninsulas.

Accordingly, over the last ten years we have concentrated our development on the redesign of our 33kV 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 strategy has seen a significant improvement in the supply reliability experienced by our consumers.

These improvements account for approximately $170 million of capital expenditure over the past 10 years. This has been a challenge to fund, as the requirement results from a shift in existing load rather than increasing demand (which would have generated revenue growth). However, we have managed to deliver these improvements within the regulatory price path set for us by the Commerce Commission.

At the 11kV distribution level, our network remains characterised by long, heavily-loaded distribution feeders supplying pockets of fringe development with sparse subtransmission support. To address these legacy issues and to improve security of supply, we will invest a further $180 million capital expenditure during the ten-year planning period of this AMP, as we continue implementation of the single largest development in the history of the network. To facilitate this development, we will focus on the following strategies:

- The connection of new generation from the Ngawha expansion project. This will repurpose the Kaikohe GXP as a grid injection point, as well as a GXP.
- The completion of our TE2020 110kV ring as a resilient high capacity backbone to our network.
- SAIDI improvement strategies, which will now focus on the 11kV network. This will include the construction of additional feeder interconnections, provision of standby generator support, 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.

The result of this further investment will be a significantly more secure and reliable network to support the future economic growth in our supply area.

Diesel generation is a key element in our transition from a distributor of energy sourced from the grid (and from Ngawha) to an operator of distributed generation and other energy resources dispersed across our network. Our diesel generation is justified by its flexibility in application, which will let us continue to improve the reliability of the supply we provide to our consumers and will increase our resilience to high impact events. For example, prior to the completion of the 110kV ring, diesel generation will be used to supply our northern area when the 110kV circuit from Kaikohe is out of service. It will also let us black start Ngawha and run islanded from the grid when the transmission connection to Maungatapere is out of service.

Not all our performance improvement will come from improvements to our network architecture. Improved maintenance will also increase 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, improving our organisational capability and the skill set of our staff, and the introduction of new technology to support our decision making.

To date, our investment in network reliability improvement has been effective. The average total minutes off supply per consumer due to faults and planned interruptions on our distribution network reached a high of 924 SAIDI minutes in FYE2009. In FYE2018, customers experienced a total of 658 minutes off supply[1]. However:

- The SAIDI impact of planned interruptions was 208 minutes due to a maintenance outage of our 110kV line and our decision to suspend live line maintenance work. The corresponding SAIDI impact in FYE2017, when there was no 110kV line outage and we were still carrying out live line maintenance, was only 43 minutes.
- The SAIDI impact of unplanned interruptions due to faults on our 33kV subtransmission network reduced from 198 minutes in FYE2017 to only 25 minutes in FYE2018. This reduction was in part due to the completion of the protection upgrades on our 33kV network, so that most 33kV faults no longer result in a supply interruption.
- Of the remaining 452 unplanned SAIDI minutes at total of 186 minutes (41%) were due to two events:
    - an unplanned interruption of our 110kV line in July 2017, which had a SAIDI impact of 87 minutes. The cause of this fault is unknown, but supply was not restored for safety reasons until the line had been patrolled. Unplanned interruptions of our 110kV line are rare; and
    - a subtropical storm in January 2018, which had a SAIDI impact of 99 minutes spread over two consecutive days.

  If these two events are excluded, the residual SAIDI impact, which would relate only to our 11kV distribution network in FYE2018 was 288 minutes, which is below our reset FYE2020 unplanned 11kV SAIDI target in Table 4.3.

In making comparisons of our current reliability with historic measures, it should be noted that our reported reliability prior to FYE2013 excluded any 110kV network interruptions, since the 110kV network only became part of our system on 1 April 2012.

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.

[1] This analysis uses raw outage data and takes no account of the impact of normalisation as provided for in the quality standard in the Commerce Commission's price-quality path regulatory framework.

4.2 Consumer Orientated Service Levels

The consumer service targets included in this AMP are limited to the normalised industry performance 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 don't reflect our targeted service level improvements.

The two measures that we use for the development of consumer service targets 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 as a result of faults and 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 as a result of 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.

The service level targets set out in this AMP relate to the performance of our transmission, subtransmission and distribution networks.

In measuring our performance for internal management purposes and setting our own targets, we use the normalising approach taken by the Commission in measuring the reliability of supply provided by all the EDBs that it regulates under the default price-quality path regime[2]. 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. 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, the impact of interruptions occurring on "major event days" is limited to SAIDI and SAIFI boundary values, which limit the SAIDI and SAIFI impact of any one extreme event. The Commission has determined the boundary values using a statistical analysis of the historic performance of the network. Boundary values are set because it has been found that interruptions occurring on only one or two "major event days" each year can have a substantial impact on the measured performance. These major event days correspond to days of severe storm activity or days on which another event occurs that we have not been able to manage effectively. By limiting the impact of interruptions experienced on major event days, the normalisation process produces a measure that is a better reflection of the overall network reliability to the extent that it can reasonably be controlled, given the resources available.

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 actual SAIDI of 1,837 minutes was reduced by more than 67% to 600 minutes after normalisation.

The Commission's 2015-20 price quality path determination changed the normalisation methodology. Salient features of the current methodology are:

- Only 50% of the SAIDI and SAIFI impacts of planned outages are included in the normalized SAIDI and SAIFI measures. This reflects the lower impact of planned interruptions as consumers

[2] 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.

receive advance notice of the interruption and are able to minimize their inconvenience and economic loss.

- Major event days, the actual SAIDI or SAIFI impacts are replaced by the boundary value for normalization purposes. Our boundary values are shown in Table 4.1. However, major event days can only be triggered by unplanned interruptions. This has put us at a disadvantage since a planned interruption of the 110kV transmission line cannot be treated as a major event, even though its SAIDI impact is higher than the boundary value even after the allowed 50% reduction is applied. We are not aware of any other EDB that is in a position where a planned interruption has a SAIDI impact that is higher than the boundary value set by the Commission. The generation we are installing at Kaitaia will address this issue.

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 FYE2016-20 regulatory period, but also include a margin to provide for volatility. Should we breach a threshold in any two of three consecutive years, the Commission is likely to investigate our management of the network and has the power to impose a civil penalty. Our current normalised SAIDI and SAIFI thresholds are also shown in Table 4.1.

	Threshold	Boundary Values
SAIDI	516.675	29.364
SAIFI	6.248	0.347

Table 4.1: Current Reliability Limits and Boundary Values

We set ourselves more challenging reliability targets then the Commission's thresholds to reflect the expected impact of our reliability improvement investment. While we met our internal targets in FYE2013, a year in which very benign weather conditions were experienced over most of the country, but in other years we have not met our targets as they have not adequately provided for the impact of the weather typically experienced in our supply area.

We have therefore reset our internal reliability targets at levels that we consider more realistic. Our new targets no longer provide for planned northern area interruptions to allow maintenance on our 110kV line, as these will not be required once we have completed our northern area generation project. We have assumed that the next planned 110kV line maintenance outage can be deferred until our new generation has been commissioned. Going forward, these targets have been incrementally reduced to reflect the improvements expected from our continuing investment programme.

Our reset targets 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. The measured reliability in FYE2015 was an extreme example of how weather conditions can impact network reliability.

- there are no unplanned outages of the 110kV Kaikohe-Kaitaia transmission line. The measured reliability of our network is very sensitive to the performance of this line, as an outage will affect all consumers in the northern region. While the installation of generation should limit the duration of any unplanned line interruption, supply will nevertheless be interrupted while the generators and started and brought on line. This will still have a material impact on both SAIDI and SAIFI, due to the number of consumers affected.

The indicators measure only interruptions that originate within our network. Interruptions that originate outside the network, such an 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 a 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.

The new SAIDI and SAIFI targets for each year of the planning period are shown in Table 4.2.

FYE	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SAIDI										
Planned 110kV	-	-	-	-	-	-	-	-	-	-
Planned 33kV	-	-	-	-	-	-	-	-	-	-
Planned 11kV	55	55	55	55	55	55	55	55	55	55
Unplanned 110kV	-	-	-	-	-	-	-	-	-	-
Unplanned 33kV	30	29	28	27	26	25	24	23	22	21
Unplanned 11kV	233	225	218	210	203	195	188	180	173	164
Total	**318**	**309**	**301**	**292**	**284**	**275**	**267**	**258**	**250**	**240**
SAIFI										
Planned 110kV	-	-	-	-	-	-	-	-	-	-
Planned 33kV	-	-	-	-	-	-	-	-	-	-
Planned 11kV	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Unplanned 110kV	-	-	-	-	-	-	-	-	-	-
Unplanned 33kV	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Unplanned 11kV	2.59	2.53	2.48	2.41	2.36	2.29	2.24	2.17	2.11	2.02
Total	**3.44**	**3.38**	**3.33**	**3.26**	**3.21**	**3.14**	**3.09**	**3.02**	**2.96**	**2.87**

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

The change in these targets over the planning period is shown graphically in Figures 4.1 and 4.2 below, which also compare the targets with the historical reliability. The graphs are indicative only, as the historical performance is not directly comparable to the performance targets going forward: firstly, performance prior to FYE2008 was estimated rather than directly measured; secondly, the reported actual performance prior to FYE2010 has not been normalised in accordance with the Commission's measurement methodology; and finally, the normalisation methodology changed from FYE2016 onwards.

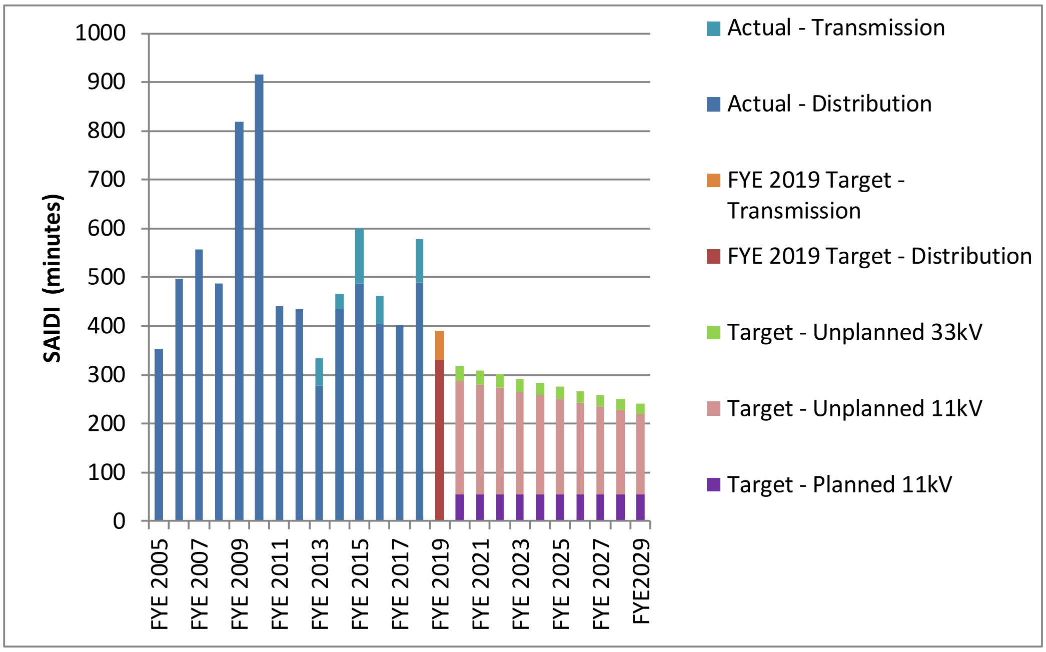

Figure 4.1: Historical and Target SAIDI

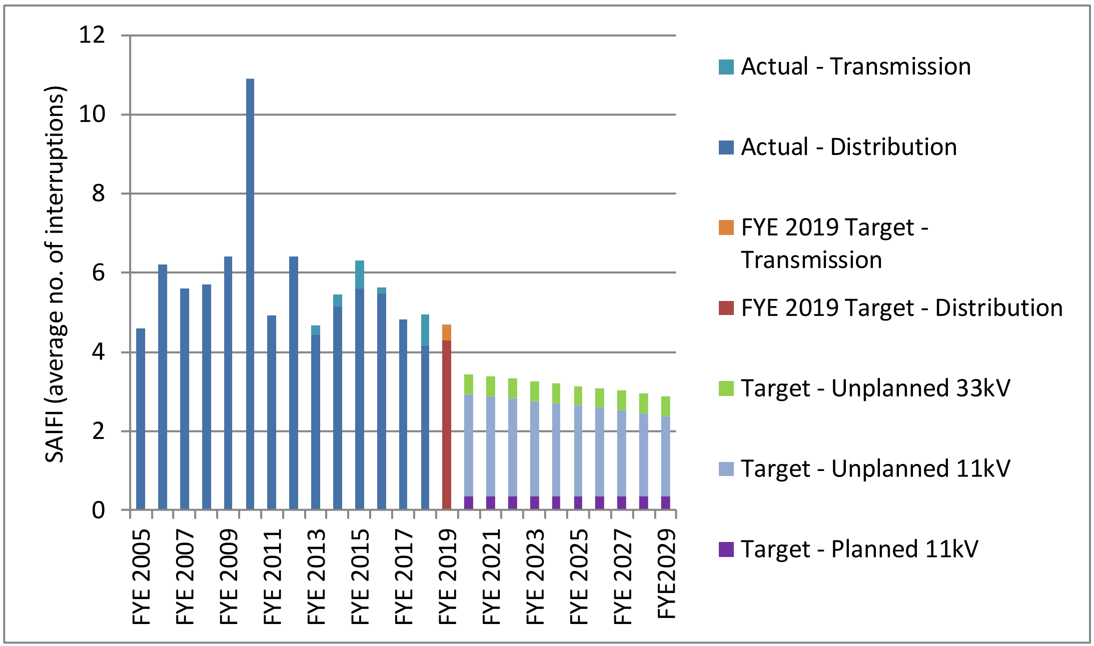

Figure 4.2: Historical and Target SAIFI

4.2.1 Outage Performance Reporting

The Commerce Commission's information disclosure requirements require us to disclose information on the reliability of the supply that we provide our consumers and the causes of supply interruptions. There is no industry standard as to how this information is to be measured and recorded. This results in EDBs setting their own rules, which means disclosures can be inconsistent if comparing one EDB with another. It is therefore important that consumers are aware of how we measure supply reliability and manage interruptions that affect them, particularly if they use our measure of the service levels we provide as a basis for determining their need for additional supply security (such as a back-up generator).

The ISO 55000 asset management standard requires performance indicators to measure the effectiveness of strategy against delivery on objectives. SAIDI and SAIFI are the main performance measures that we use to assess the effectiveness of our asset management strategy in delivering on TEN's strategic mission and objectives, given the need to balance reliability with cost and safety.

Application of these measures to drive short-term service delivery can conflict with long-term asset management objectives. Optimisation of the regulatory performance measure during fault response can lead to outcomes that are not in the best interest of consumers. For example, a fault on the LV network does not affect SAIDI as measured by the Commission. Notwithstanding this, it makes no sense to prioritise the repair of an HV fault (which has a SAIDI impact and affects a large number of consumers) over the repair of an LV fault that has interrupted supply to critical public infrastructure, such as a water supply or a hospital. We encourage the regulator to resolve this conflict in objectives, so EDBs are not penalised for prioritising public welfare.

There will a more scope for customising the level of service we provide to the cost a consumer is prepared to pay when we transition to a network hosting distributed energy resources, such as photovoltaics and batteries. For example, a group of consumers with photovoltaic generation and batteries may have several days resilience without any need for grid support and may be happy to trade delayed fault response for a lower cost of supply. The Commerce Commission's quality standards and the Electricity Authority's requirement for cost and service reflective pricing reform should provide for such flexibility.

4.3 Asset Performance and Efficiency Targets

We have developed targets to reflect our asset performance and efficiency in order 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, and the economics of building with large capacity conductors and high voltages. 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 high loss ratio was approximately 10%. In subsequent years, the loss ratio improved to between 8% and 9%. However, in FYE2013, the 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 maintained the FYE2019 target though to the end of the planning period, even though actual losses in FYE2019 exceeded our target. The targets for the planning period are shown in Table 4.3 and Figure 4.3 compares these targets with the recent historical performance.

FYE2019	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028
9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%

Table 4.3: Target Loss Ratios

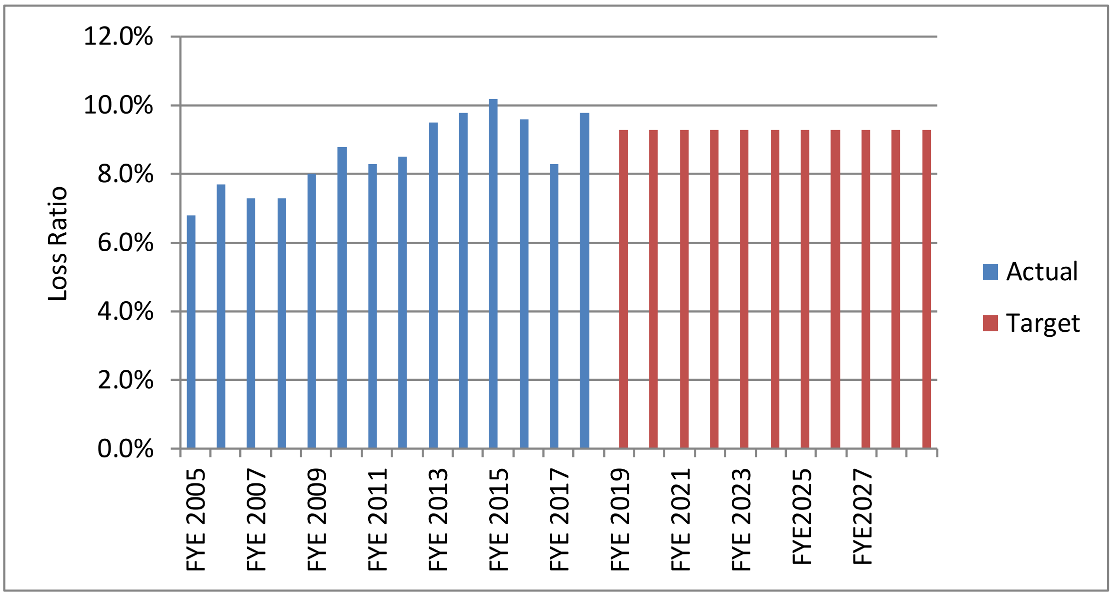

Figure 4.3: Loss Ratios of Top Energy since FYE2004

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 4.4.

FYE2019	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028
33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%

Table 4.4: Targets for Ratio of Total Operating Expenditure to Total Regulatory Income

Figure 4.4 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.

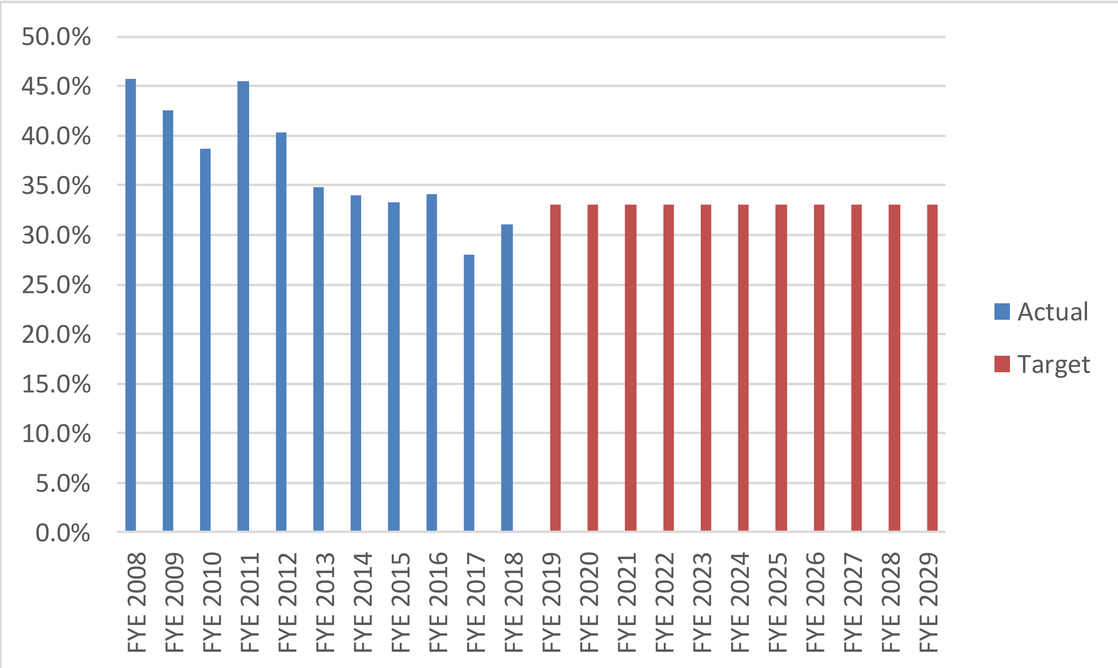

Figure 4.4: Ratio of Total Operating Expenditure to Total Regulatory Income since FYE2008.

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 are based on our normalised performance over the period 1 April 2015-31 December 2018 and have been derived as follows.

4.4.1.1 SAIDI

- We have assumed no planned or unplanned 110kV interruptions. The Kaitaia generation is designed to eliminate planned 110kV interruptions and it is assumed that the FYE2020 planned interruption will be deferred until all the generation has been commissioned. Unplanned 110kV interruptions are relatively rare and have not been included in our previous targets.
- We have assumed that there will be no planned 33kV interruptions, as generation will be used to avoid these on single circuit substation incoming circuits.
- The starting point of our planned 11kV SAIDI target is the normalized planned SAIDI achieved in FYE2018-19 after we stopped live line work. Our target of 55 SAIDI minutes reflects an increase over our historic SAIDI performance as we are planning to increase our expenditure on the renewal and replacement of 11kV assets and, with the suspension of live-line work, most of these replacements will require a supply interruption. We continue to look at a possible reintroduction of live-line work, but have not allowed for any change in resetting our targets.
- The starting point for the unplanned 33kV SAIDI target is the average actual unplanned SAIDI achieved over the period FYE2018-19, which was after the upgraded 33kV line and transformer protection had been fully commissioned. A marginal year-on-year improvement has been assumed to reflect the impact of the single-circuit 33kV line refurbishments and operational efficiencies.
- Our reliability improvement strategy is designed to achieve an overall reliability comparable to that of our peers[3] by the end of the planning period, primarily through improvements to the reliability of the 11kV distribution network. We have straight-lined this target over the planning period to achieve this outcome. As a sanity check on this approach, our unplanned 11kV SAIDI to the end of December 2018 was 167, albeit with relatively benign weather and no major event days. This escalates to 223 minutes at the end of FYE2019 on a pro-rata basis. Our FYE2020 target is 305 minutes, some 10% higher than what we expect to achieve in FYE2019. While this provides a buffer against more normal weather conditions, it is still lower than what we achieved in FYE2017 and FYE2018.

4.4.1.2 SAIFI

- Our planned 11kV SAIFI reflects what we achieved in FYE2018. This is not expected to improve over the planning period unless we recommence live-line maintenance.
- The unplanned 33kV SAIFI target reflects the actual FYE2018 outcome. Generation will be started after a fault occurs and will therefore have no impact on SAIFI. Any improvement over the panning period is likely to be small, so we have not provided for this in our targets.
- We have assumed an average time to restore supply (CAIDI)[4] following an unplanned 11kV interruption of 90 minutes, in setting our FYE2020 SAIFI target. While this is about 10% higher than we have achieved to date in FYE2019, it is lower than we achieved in either FYE2017 or FYE2018. For the following years, we have assumed that CAIDI will reduce by 1 minute each year and set our unplanned 11kV SAIFI targets accordingly.

Reliability is a key performance indicator for TEN and our performance against approved targets is reported monthly to the Board. The targets going forward are challenging and reflect the priority given by the business to reliability improvement. We note that the targets for FYE2021 and beyond may need to be changed to reflect any adjustments to the Commission's normalisation methodology to be applied during the FYE2020-25 regulatory period.

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[3] For comparison of performance, we have benchmarked our reliability against Alpine Energy, EA Networks, Eastland Network, Horizon Energy Distribution, Northpower, PowerNet and The Lines Company.

[4] The average time to restore supply after an interruption is known as the Customer Average Interruption Duration Time (CAIDI). Mathematically, SAIFI=SAIDI/CAIDI.

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 after the end of the AMP planning period. 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 the level achieved in FYE2018 throughout the planning period. There may be some reduction as we continue our transition to the revised asset inspection strategy discussed in Section 6.1.2, although much of the savings in asset inspection will be absorbed by additional expenditure on asset renewal. 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; and
- 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; and
- 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

Our security of supply standard is shown in Table 5.1. This drives the design of our network and determines when an intervention to increase the network supply capacity is required. Our transmission and subtransmission networks now meet or exceed this standard except for:

- Supply to the northern area. Compliance with the standard is contingent on the installation of standby diesel generation to provide supply when the incoming 110kV circuit is out of service. This project is currently being implemented and is due for completion in FYE2020.
- Supply to Omanaia. This is contingent on the installation of a diesel generator at the substation. An upgrade of the Omanaia substation is underway and will include a diesel generator connection point. We are planning to locate a generator at Omanaia while the incoming 33kV line is refurbished. Longer term we are considering relocating the generator within the 11kV network to provide increased resilience to 11kV faults as well as faults on the 33kV incoming substation supply.

Table 3.1 details the level of security we currently provide at each zone substation.

We own and operate a 7.5MVA mobile substation, which limits the maximum total outage duration should all transformer and generation capacity be lost at any substation. 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. The security standard assumes that the mobile substation is available for deployment and is not under maintenance or deployed to address a contingency elsewhere on the network.

At smaller substations with only one transformer, the mobile substation will need to be deployed before supply can be fully restored. In most cases it will be possible to partially restore supply at these substations before deployment of the mobile substation, using either standby diesel generation or distribution transfer from adjacent substations. The amount of energy that can be transferred though the distribution network will depend on network demand; more transfer capacity is available when demand is low.

The capacity of the mobile substation is insufficient to provide full supply restoration capacity at larger substations. However, our larger substations now all have full redundancy, so a complete loss of supply requiring deployment of the mobile substation would require the simultaneous loss of both transformers[5]. This is unlikely, but if it did occur, restoration using the mobile substation would only be partial and supply may need to be rotated at times of peak demand.

Our security standard, based on EEA guidelines, is shown in Table 5.1 and includes detail on:

- The number of affected customers in addition to demand;
- The intended voltage and distance;
- Contingent capacity targets;
- Targeted restoration times; and
- Preferred resilience measures

In addition to subtransmission security, Table 5.1 includes standards for the lower voltages and for consumer connections. However, these are our recommendations, as consumers can choose to pay us for the level of security they require or provide their own alternatives. Our standards provide consumers with a baseline against which they can assess their own security needs and then discuss investment options for customised solutions with us. New technology and a shift towards two-way energy flows at the edge of our network are providing consumers with more choice over opting in or out of network-centric security.

Adding standards for the distribution network is intended to drive reliability and resilience considerations in planning the development of the 11kV network, as distinct from pure security. These standards complement design standards around interconnection, excess capacity, generator support, automated restoration etc.

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5 The simultaneous interruption of both incoming circuits would also result in a complete loss of supply. If such an event occured, we would normally be able to repair at least one circuit before the mobile substation could be deployed.

Class	Group Peak Demand (MVA)	Asset Group	Customer Impact	Design Standards	Contingent Capacity	Security Level	1st Interuption	2nd interuption	Resilience Measures
Transmission									
T1	>60	Grid Exit Point - Kaikohe	>30000	80km @ 110kV	100% DG	n-1	Maintain 100% GPD	Repair time.	Dual circuits, islanding capability
T2	60 to 30	Main Load Centre plus its connection to GXP - Wiroa	<20000	300km @ 33kV	70% @ 33kV	n-1	Maintain 100% GPD	Repair time.	Dual circuits, off-road routes, H bus, bus sectioned,
T3	<30	Secondary load centre plus its connection to GXP - Kaitaia	<15000	100km @ 33kV	70% from generation	n-0.7	Maintain/Restore 70% GPD within 1h. 100% repair time.	Restore 70% GPD within 36hr 100% repair time	Start-up of deployed Standby DG. Disconnection of agreed non-essential load, rolling outages as required, emergency load management
T4	<60	Generation plus connection to GXP Ngawha	<10	Generation Plant	60% @ 33kV	n-1	Maintain 100% generation at 33kV	Restore 60% generation at 33kV 100% repair time	Interconnection to 33kV at Generator Bus,
Subtransmission									
S1	<30	**Line Segment of mesh**	<10000	75km	100% redundancy	n-1	Maintain 100% GPD	Best restore 100% switching time Worst 100%: repair time	33kV tie points, Dual or ringed circuits, 11kV tie capacity, load shifting
S2	12 to 25	**Urban/Industrial Zone Sub on Ring**: Kerikeri, Waipapa, NPL, Future Ngawha Energy Park	>5000	300km @ 11kV <3000 ICPs on 6 FDRs 2 x 23MVA Tfmrs	50% GPD of other 2 subs in group of 3	n-1	Maintain 100% GPD less interuptible industrial load	Restore 50% GDP within switching time Restore 100%: repair time	Indoor switchgear, higher component of UG network, higher level of interconnection, Load shifting, Interruptible load
S3	6 to 12	**Urban/Rural Zone Sub** Kaikohe, Okahu, Haruru, Future Wiroa	<5000	600km @ 11kV <4000 ICPs on 6 FDRs 2 x 11.5 MVA Tfmrs		n-1	Maintain 100% less holiday peak. Restore 60% GPD within 4h. Restore 100%: repair time.	Restore 60% GPD within 12h. Restore 100%: repair time	Extra contingent capacity for holiday peak load
S4	3 to 6	**Country Town Zone Sub** Kawakawa, Kaeo,	<2500	300km @ 11kV <3000 ICPs on 6 FDRs 2 x 9MVA Tfmrs		n-0.7	Restore 50% GPD within Switching Time, Restore 100%: repair time.	Restore 70% GPD within 12h. Restore 100%: repair time	Maintain 50% 11kV tie capacity
S5	1 to 3	**Rural Zone Sub** Pukenui, Taipa, Omanaia, Mt Pokaka	<1500	250km @ 11kV <3000 ICPs on 4 FDRs 5MVA Tfmr	Holiday peak demand	n-0.7	Restore 70% GPD within switching / genset startup tme	Restore 70% GPD within 12 Hr, Restore 100%: repair time	Intermediate or Mobile Sub 5/7.5MVA Standby Gensets
S5	< 5	**Rural Industry Zone Sub** Moerewa	<1000	200km @ 11kV <600 ICPs on 4 FDRs 2 x 3/5MVA Tfmr	Nil	n-1	Maintain 100% GPD less interuptible industrial load	Restore 70% GPD within switching time Restore 100%: repair time	Ring circuit 33kV, Dual TF,70% 11kV tie capacity.
S6	<30	**Spur to Rural Sub**	<1500	35km	Holiday peak demand	n-0.7	Maintain/Restore 70% GPD within switching/generator start up time. Restore 100%: repair time.	Restore 100%: repair time	Interconection to 11kV sections, Intermediate Sectionalising points, emergency load management
Distribution									
DC1	6 to 8	Feeder Cable	<1500	300mm2 Cable to first RMU Protected from adjacent cable faults	100% of 2 Tie feeders	n	Restore 100% within switching time	Repair Time	100% contingent capacity tie to other half of bus and/or other sub
DC2	4 to 6	Urban Cable Tie Points	< 1500	185mm2 feeder cable	100% of 2 Tie feeders	n	Restore 100% within switching time	Repair Time	Derated 30%, 100% contingent capacity tie to other half of bus and/or other sub
DC3	2 to 4	Urban Cable Spur	<500	185mm2 feeder cable	spare cable	n	repair time	Repair Time	
DC3	3 to 6	Overhead Main line Tie Points	<1000	Krypton	70% of tie feeders	n	Restore 70% in switching time	Repair Time	70% contingent capacity tie to other feeder, Sectionalising to reduce outage impact
DC4	4 to 6	Overhead Main line	<1200	Krypton	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC5	2 to 4	Overhead Spur Line	<500	Iodine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC6	1 to 2	Remote End of Line	<200	Fluorine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC7	< 1	2 wire	<200	Iodine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC8	<0.5	SWER	<100	Fluorine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
Transformers									
DT1	1 to 2	Ground Mount 3P	Major	Specific Design	customer may have standby generation	n	Repair time	Repair Time	May be LV tie points within Customer facility
DT2	0.5 to 1	Ground Mount 3P	Significant	Specific Design	customer may have standby generation	n	Repair time	Repair Time	spare unit in critical spares
DT3	0.1 to 0.5	Ground Mount 3P	<200	Specific Design		n	Repair time	Repair Time	spare unit in critical spares
DT4	< 0.2	Pole Mount	<80	Size based on connected ICPs		n	Repair time	Repair Time	spare unit in critical spares
DT5	<.2	Isolating, interconnecting	<80	Limited by earth bank		n	Repair time	Repair Time	spare unit in critical spares
Consumer									
C1	>5	Major Indusrial	>3GWh	Multiple 11kV feeders CB protected Closed rings	70% Cable and Transformer capacity	N-0.7	70% no interruption 100% within switching time	Repair Time	Duplication of supplies Ring feeds Customer owns TF and plant switchgear
C2	1 to 5	Medium Industrial	1 to 3GWh	Dual 11kV supply Dedicated <1MVA tfmrs on RMUs	50% excess cable capacity 30% excess transformer capacity	N-0.5	50% no interruption Restore 75% within switching time	Repair Time	Duplication of supplies Customer owns TFs and plant RMUs Customer provides essential supply backup
C3	0.5 to 1	Light Industrial	0.5 to 1GWh	RMU connected Single HV supply Dedicated transformer	0.3	N-0.3	30% supply from generator and UPS 100% restore: Repair time	30% supply from generator and UPS 100% restore: Repair time	Critical Spare TF Customer provides essential supply backup gen and UPS
C4	>100A	Large Commercial	<1GWh	RMU connected Single HV supply Dedicated transformer	0.3	N-0.3	30% supply from generator and UPS 100% restore: Repair time	30% supply from generator and UPS 100% restore: Repair time	Critical Spare TF Customer provides essential supply backup gen and UPS
C5	150A	Dairy Shed	35000	single HV service	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C6		Irrigation Pump		single HV service	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C7	60 to 100A	Medium Commericial	<100,000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C8	<60A	Std Commercial	<20,000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C9		Small	10000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C10	3x60A	Residential 3P	12000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C11	1 x 60A	Std Residntial 1P	7300	single phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C12		MUSH	As above according to demand		0.3	N-0.3	30% supply from generator and UPS 100% restore: Repair time	30% supply from generator and UPS 100% restore: Repair time	Critical Spare TF Customer provides essential supply backup gen and UPS

Table 5.1: Security of Supply Standard

5.1.3 Distribution Network Standards

It is not cost-effective to secure supply to consumers connected to the distribution network with a comprehensive N-1 full redundancy strategy. A more practical strategy is to limit the size and length of feeders to reduce the area affected by an outage, and enable faults to be found more quickly. Feeders should also be interconnected into rings or a mesh, with sufficient redundant capacity to allow the load to be supplied from the remote end to allow fast restoration of supply to areas not directly affected once a fault has been found. Ideally, the network should incorporate sectionalising points, so that the full impact of a fault requiring an extended repair is limited to a few consumers within a relatively small area, and supply to consumers outside this area can be restored before a fault is repaired. Sectionalising points can be as simple as a line break where disconnection requires the manual removal of bolted joints. Response and flexibility can be improved by sectionalising, using remote and locally operated switches, auto-restoring protection equipment and new technology such as an advanced distribution management system.

Our focus on improving the reliability of the distribution network will include the development of distribution system design standards that will define our standard network architecture. We anticipate these standards will specify:

- the maximum circuit length, peak demand, and number of connected consumers for distribution feeders supplying urban, rural and remote parts of the network;
- the standard conductor size and other line design parameters that define the capacity of the line, and the contingent load that a feeder must be able to deliver to interconnection points;
- criteria for determining the points at which a feeder needs voltage support, busing and sectionalizing;
- criteria for determining the type of sectionalizing equipment to be used at different sectionalizing points to ensure consistency of fault finding, isolation and supply restoration; and
- standard design solutions to address these issues.

These standards are expected to underpin operating practice and service delivery. Network design, particularly the system architecture, has a bigger impact on service delivery and life-cycle cost than other influencers, such as maintenance, effectiveness of fault response practices etc.

Table 5.2 summarises the architecture of the typical distribution feeder currently on our network.

	Urban	Rural	Remote
Total Feeder			
Peak demand (MW)	1.4	1.3	1.3
Annual energy delivered (MWh, excluding ICPs > 1GWh)	7,200	7,000	7,200
Total ICPs	720	750	950
Total length (km)	12	75	160
No. of transformers	35	150	300
Connected transformer capacity (kVA)	5,000	6,750	9,000
Average transformer size (kVA)	140	45	30
ICPs per transformer	23	7	3
Transformers per km	3	2	4
ICPs per km (connection density)	65	10	6
kWh per ICP	10,000	9,250	7,500
MWh per km (Load density)	650	90	45

	Urban	Rural	Remote
Feeder Backbone			
No of reclosers	0.3	1	1
No of sectionalisers	1	2	3
No of air break switches	4	7	9
Backbone length (km)	7	20	45
No of sections	7	11	16
Backbone length per section (km)	4	3	5
No of transformers per section	8	5	8
No of ICPs per section	365	90	400
Automated switch spacing (km)	-	8	13
Manual switch spacing (km)	1.2	2.6	3.1

Table 5.2: Typical Feeder Architecture

5.1.4 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.

ASSET TYPE	CONDITION	PERCENT OF NOMINAL CURRENT RATING	
		Normal operation	Contingent operation
Transformers	Nominal	100	150
Overhead Conductors	Still Air 30 degrees	75	100
Underground cables	In Duct	75	100
Circuit Breakers	Nominal	75	100

Table 5.3: Design Capacity Limits

5.1.5 New Equipment Standards

In order 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[6] 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, this relatively small number of standard transformer ratings is justified, given the small number of power transformers in the fleet, as it reduces carrying costs and 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.

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 the network development plan, we expect the 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 the 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. However, long distribution feeders with high losses remain on parts of the network. We are planning to use relocatable generation to manage the load and voltage drop on these feeders by injecting energy and reactive power at the end of a feeder at times of peak demand, such as during holiday peaks. This will lead to more proactive, real-time management of the network, which in turn should result in both a more efficient use of our existing network assets and a reduction in losses.
- The Ngawha geothermal power station currently provides approximately 70% of the energy requirements of our consumers and this is anticipated to increase to 98% after the power station's generation capacity is increased in FYE2021. The power station displaces generation located south of Auckland and thus 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.
- As discussed in Section 5.11, 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

[6] The Kaikihe-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.

longer term our generators will 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 life-cycle. 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.

Priority 4: New Technology

Projects designed to pilot the impact of new and emerging technologies are included in this category.

Within this broad prioritisation framework, our capital expenditure can be further categorised into major projects and capital upgrades. Major projects are one-off, individually designed, major augmentations or upgrades of 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. 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.

Technology projects such as fibre communications or the ADMS installation are classified as secondary system or non-system expenditures. 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. The primary drivers for this work are:

- Top Energy's commitment to the Ngawha Expansion project and the benefits this will bring consumers, including self-sufficiency, improved resilience, reduced transmission costs and acceleration of the transition to a distributed energy system; this enables and supports consumers who choose to connect distributed energy resources to our network. Provisioning for the connection of this new generation triggers a sequence of projects that will lead to completion of the construction of a 110kV ring.
- Improvement of supply security to the northern region, which is currently constrained by the existence of only one 110kV circuit between Kaikohe and Kaitaia. We have engaged in an extended stakeholder consultation and a regulatory justification process that has culminated in agreement to a long-term plan to build a second line up the east coast to form a high-capacity 110kV ring that will service the entire network and provide uninterrupted N-1 supply security to the northern area. This includes the deployment of an interim generation alternative to manage reliability and resilience while the line is developed over the 10-year planning period of this AMP.
- The need to improve reliability of supply to deliver on our price-quality path commitments that justify the expenditure; and
- The introduction of new technologies to manage the operational requirements of our emerging distributed energy system, which is currently driven by consumers choosing to invest in their own generation, electric vehicles and modern appliances.

The introduction of new technologies makes the future industry landscape very difficult to predict. This favours the application of low-cost measures with short life cycles to address network constraints in preference to traditional solutions, at least as an interim measure until the future of the electricity supply industry is more certain. Nevertheless, it is necessary to keep development options open and not close off alternatives, particularly when it is unclear whether new technologies will deliver solutions that meet long-term requirements. The network is a platform on which new market services may be offered, so we are currently in an uncertain planning environment.

As signalled in our 2018 AMP, the new 110kV line between Wiroa and Kaitaia is the largest network development project that Top Energy has ever implemented and has been deferred to the end of this AMP planning period, due to delays experienced in securing easements for the planned line route. As an alternative, we are installing diesel generation to provide a higher level of supply security to the northern area by the end of FYE2020. The generation will allow supply to be restored following an interruption of the incoming network supply without waiting for the fault to be repaired. It will also a provide higher level of supply security to cover:

- An increased number of planned maintenance outages of the existing 110kV line due to the suspension of live-line work practices; and
- Low probability, high impact events, such as an extended outage of the 110kV line due to a tower failure in the Maungataniwha Ranges.

Some diesel generation will be located within the 11kV network to provide supply security following 11kV network faults.

5.4.2 Renewal and Upgrade Capital Programmes

These capital expenditure programmes generally have short 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. Projects that do not meet our VOLL test need to be justified in terms cost to serve.

The SAIDI model discussed in Section 8.1.2.3 is intended to demonstrate that the expenditure and improvement strategies can realistically be expected to deliver on the SAIDI targets presented in Section 4.2. These targets have been derived after benchmarking against our peer EDBs, analysing where our biggest SAIDI drivers are and the scope for improvement.

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; and
- Technology release and adaptation into society (e.g. photovoltaic cells, heat pumps etc.).

Demand growth is forecast down to the distribution feeder level.

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 used to determine contingent capacity requirements. The forecast incremental growth rates at each substation are based on historic trends for the substation, which in some cases are modified to take into account econometric or other factors that could reasonably be expected to impact the demand for electricity in each local area.

As the data we use are measurements of current, we assume a power factor of 0.98. We then overlay on this base forecast major new block loads that have been consented and are likely to proceed within a firm timeframe. Block loads where the timing is unclear are not included in the forecast, but are taken into account in planning any network augmentation where this does not have a material cost impact. We also consider the sustainability of development requirements to prevent hurdles to economic development by ensuring we have the capacity to deliver should new load accelerate.

We adopt a similar approach to forecasting the peak demand at our Kaikohe and Kaitaia transmission substations, and also our network peak demand. In each case, the diversity with the relevant undiversified zone substation demands is calculated to confirm that it is within what we consider a reasonable range. The observed peak demands in the previous year are used as the basis for the forecasts and the growth rates used are the growth rates of the undiversified aggregate demand of the relevant zone substations.

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 and Mt Pokaka feeders to the new 11kV injection point planned for Wiroa at the end of the planning period in FYE2029.

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 5.4 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. All our zone substations have winter peaks, so photovoltaics are unlikely to have a material impact on our peak demand until battery storage becomes economically feasible.

	Actual FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029
SOUTHERN AREA											
Kaikohe	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.3
Kawakawa	5.8	5.9	5.9	6.0	4.5	4.6	4.6	4.7	4.7	4.8	4.8
Moerewa	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Waipapa	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Omanaia	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Haruru	6.3	6.4	6.5	6.6	8.3	8.4	8.5	8.6	8.7	8.9	9.0
Mt Pokaka	2.5	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	2.2
Kerikeri	7.1	7.3	7.4	7.6	7.7	7.8	8.0	8.1	8.3	8.4	8.5
Kaeo	3.9	4.0	4.0	4.1	4.2	4.3	4.3	4.4	4.5	4.6	4.6
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	9.1	9.3
Taipa	5.5	5.5	5.5	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.7
NPL	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Pukenui	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8

Table 5.4: Zone Substation Demand Forecast – Winter (MW)

The demand forecasts for the transmission substations and for the total network are shown in Table 5.5 below.

	Actual FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029
Kaikohe	47.0	47.0	47.5	48.0	48.0	49.0	49.0	49.0	50.0	50.0	50.0
Kaitaia	23.0	23.0	23.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	25.0
NETWORK	70.0[1]	70.0	70.5	72.0	72.0	72.0	73.0	73.0	74.0	74.0	75.0

Note 1: Estimated from SCADA data. May not correspond to disclosed demand in FYE2019 information disclosure, which is derived from metered data.

Table 5.5: 110kV Transmission Substation and Network Demand Forecast – Winter (MW)

5.6.2 Capacity Constraints

This section considers emerging capacity constraints or other network vulnerabilities arising from the load forecast. To put the constraint issue into perspective, it should be recognised the loads in the forecast are peak demands, so in most cases any capacity constraint is likely to occur for no more than two hours a day and in most cases only during over winter. Secondly, there are no capacity constraints on the subtransmission network when all network elements are in service. A subtransmission constraint only arises when a network element is out of service. In most situations, when a constraint first emerges there are usually risk management strategies, such as transferring some load to a neighbouring unconstrained zone substation to avoid any loss of load. However, should the load continue to grow, the load at risk would continue to increase and therefore become more difficult to mitigate.

5.6.2.1 Kerikeri Area Demand

The Kerikeri area is supplied by the Kaeo, Waipapa, Kerikeri and Mt Pokaka zone substations. The load in this area continues to grow as shown by the forecast and there is no sign that this growth will reduce. Two substantial two- or three-storey buildings are currently under construction within the Kerikeri urban area. Our analysis indicates that, by FYE2024, a voltage constraint will emerge if the 110kV double circuit line Kaikohe-Wiroa line (which is operated as a single 33kV circuit) is unavailable at times of peak demand and all load is transferred to the remaining 33kV circuit supplying Wiroa from Mt Pokaka. One option for mitigating this would be to operate the existing direct line as two separate 33kV circuits, but our preferred option is to install a 110/33kV transformer at Wiroa. This option is preferred as the new transformer will be needed if one of the 110kV transformers at Kaikohe is taken out of service to accommodate the second incoming Ngawha circuit. Under this arrangement (shown in Figure 5.6), one of the incoming circuits on the 110kV line will continue to be operated at 33kV to provide the necessary incoming capacity, should the incoming supply on the 110kV line be interrupted.

5.6.2.2 Taipa Substation Demand

Taipa has a single incoming line and single transformer. Should the incoming supply be lost, the 4MW of generation capacity installed at the substation needs to supply a peak demand that is already as high as 5.5MW and there have been times when it was necessary to ration supply when the incoming network connection has been lost. The situation has been mitigated by the completion of the Kaeo substation and the installation of a voltage regulator at Mangonui, which will allow the load on the Mangonui feeder to be supplied from Kaeo. Should this be insufficient, a generator could be installed on the Tokerau feeder to provide additional support.

5.6.2.3 Russell Feeder

The load on the Russell peninsula is almost 3MW and is currently all being supplied through the Russell Express feeder from the Kawakawa substation. When the underground cable is installed from Okiato Point to the Rawhiti turnoff, the Joyces Rd feeder will also be capable of supplying the peninsula. Under normal operation the peninsula load will be shared between the two feeders, with Russell town being supplied from one feeder and the Rawhiti spur the other. However, in the event of a fault one of the feeders, the second feeder would be capable of supplying the full load.

The most likely fault is a boat dragging its anchor across one of the submarine cables, which may result in the cable being out of service for an extended period. As the load grows, reliance on a single feeder will also become marginal over the summer holiday peak and it will become necessary to place a generator on the peninsula over the summer to secure the load against this. Russell is currently our only summer peaking load.

5.6.3 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 transmission and subtransmission networks now have the capacity to accommodate additional block loads.

The largest potential new load is the Ngawha Energy Park, which is being promoted by Far North Holdings Ltd (FNHL), a business subsidiary of the Far North District Council (FNDC). This site is strategically located between our grid supply, the Ngawha power station and our Wiroa load centre. Certainty that this project will eventually materialise has improved over the past year with FNHL purchasing the land. The development is also linked to a potential water supply enhancement which is currently undergoing a feasibility study. We anticipate supplying the initial Energy Park electricity demand at 11kV from our Kaikohe zone substation, but 11kV only has 2-3MW of excess capacity. A load of up to 15MW is projected and this could readily be supported at 33kV. The new substation could be supplied from our existing subtransmission network and, if necessary, could be connected at 110kV.

The owners of the Carrington Resort at Matai Bay on the Karikari peninsula in our northern area have applied for resource consent to develop and expand the resort with the addition of approximately 800 rooms. We have been advised that the additional demand from this development would be approximately 5MW. The scale of the proposed development is such that we would not be able to supply the resort from the 11kV feeder currently serving the area. Local generation support at times of peak demand appears the most cost-effective option, since it can be installed relatively quickly and is scalable to match the actual load once the development is operational. Should the development proceed, we anticipate locating one of our generators (being purchased for the Kaitaia generation project) within the resort complex. Tourism ventures have a high value of lost load, so it is highly probable that a large resort in such a remote location will require a local backup supply using either diesel generation or battery storage, rather than being totally reliant on a grid supply with a single incoming circuit. When it is known that the development will proceed, we will liaise with the developer to negotiate a solution that best meets its needs.

A medium-sized industrial development next to our Wiroa switching station has also been consented, but it is not clear that this will proceed. This development could proceed when an 11kV injection point is developed at Wiroa.

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. Possible developments include wind generation north of Kaitaia, tourism development or new production facilities.

The area north of Kaitaia has seen recent avocado planting and irrigation installed to support it. We expect load to present as latent growth when the trees come into production. Irrigation is a great stimulator of growth and the lift in production justifies its cost. If the business case for avocado farming is proven, development could snowball.

We have not made any provision for the impact of emerging technologies on electricity demand. The government is encouraging the replacement of petrol and diesel fuelled vehicles with plug-in electrics and, as shown in Table 3.2, there are now more than 100 of these vehicles registered in our supply area. Increased uptake of these vehicles will increase electricity consumption, while the installation of additional solar generation and the probable reduction in the cost of battery storage (as well as increased community awareness of the benefits of energy conservation and efficiency) will likely reduce demand. The rate at which these competing trends will develop is still uncertain and any prediction of their impact on future electricity demand is highly speculative.

5.6.3.1 High Load Growth Forecast

Table 5.6 shows the network load forecast in a high load growth scenario, which assumes that the block loads discussed in Section 5.6.3 materialise. The high growth forecast has a high level of uncertainty, since even if the block loads do connect, their timing is uncertain.

	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029
Network – planning	70.0	70.5	72.0	72.0	72.0	73.0	73.0	74.0	74.0	75.0
Network – high growth	70.0	83.0	87.0	91.0	92.0	92.0	93.0	93.0	94.0	94.0

Table 5.6: Network High Growth Demand Forecast

5.6.3.2 Strategies to Supply Potential Block Loads

This section discusses how we think the possible block loads could be supplied and the network development that would be required. Any such consumer-driven development would be subject to an agreement between Top Energy and the proponent, and would likely require a capital contribution.

Ngawha Energy Park

As indicated above, this would require a new 33/11kV zone substation. A 33kV line runs adjacent to the site and could be diverted into the substation to provide a secure incoming supply.

Carrington Resort

The site is supplied by an 11kV feeder from Taipa which has limited spare capacity. Even if the supply was not capacity constrained, the proponent would likely want to install a generator to provide an alternative supply in the event of an interruption to the network supply. Should the development proceed, there are a number of solutions we would discuss with the proponent as to how a supply might be provided that both met the proponent's capacity and security requirements while providing us with network support. This is a situation where battery storage could be part of the solution.

Wiroa Industrial Development

The planned new 110/33kV transformer at Wiroa will have an 11kV tertiary winding, which could be used to provide supply.

Pukenui Irrigation Load

The existing network has adequate capacity to supply this load. While security requirements would be negotiated, in a worst-case scenario, a loss of supply for up to 12 hours while the mobile substation was relocated to Pukenui would be unlikely to have a material impact on an irrigators' operations.

5.7 Emerging Technologies

5.7.1 Background

In the past, consumers taking supply from a shared distribution network had little choice but to accept the level of reliability provided by their EDB at a cost set by a monopoly electricity supplier. The more recent introduction of retail competition has provided a limited ability to manage cost and have some control over service level, in that consumers can now choose whether loads such as water heating are controlled by their electricity suppliers. Technologies are emerging that will offer consumers the ability to actively manage the cost of the electricity they use and how it is sourced. This places a cap on the revenues that can be extracted from a centralised market for electricity supply, which is therefore no longer a monopoly business. Emerging technologies are providing alternatives to a grid connection if the cost and level of service provided by the EDB do not meet their requirements.

These new technologies are beginning to disrupt the traditional industry business model and, as their capability expands and costs decline, the extent of this disruption can only increase. We cannot control this trend, so must adapt by addressing the issues they present and deliver new services to the markets that this greater diversity will enable.

Emerging technologies include

- Photovoltaic generation;
- Battery storage and management systems;
- Microgrid inverters;

- Household energy management systems;
- Smart appliances, the internet of things and artificial intelligence;
- Electric vehicles, with their associated charger technology and ability to be used by the network for energy storage;
- Advanced network control systems;
- Advanced data acquisition and machine learning; and
- New business models and market solutions.

While such technologies form the building blocks, the major capability advances will arise from software upgrades able to be incorporated into base technologies. For example, electric vehicles, once a few sensors are added, may only need a software change to become autonomous. Microgrid inverters and vehicle chargers may converge and become capable of home energy management with software enhancements. These technologies now exist; their costs are declining and capabilities increasing very rapidly.

Accordingly, we face a high level of technology risk. In managing this risk, we should not try to pick winners and losers. We should remain agnostic to brands and sellers and not make investments that are better made by consumers. While we have no role to play in technology development, we will need to develop capabilities as system integrators in order to apply new technologies as alternatives to traditional network solutions and support consumers wanting to interface their in-house applications to our network.

Currently, more than 700 of our consumers have installed small photovoltaic generators capable of injecting power into our network. Our role is therefore already transitioning from managing a traditional electricity distribution system, where electricity moves in one direction, to managing a distributed energy system (DES), where connections are both generators and consumers and where electricity can flow in either direction. This transition will accelerate as more photovoltaic generators and battery storage systems are connected. External parties will become involved in the mining and processing of mega-data and its application to a DES.

Mobile computing, the internet, cloud resident business solutions, intelligent devices in the field, smart phones and the like have become mainstream within our business over the past decade. The next decade will see a shift from poles and wires to a technology and soft asset-based business. Artificial intelligence will perform many of the tasks currently performed by operational staff and our engineering capability will need to shift to a higher technology.

5.7.2 Small Scale Photovoltaics

We maintain a watching brief on the growth of new technology connected to our network, and management has set trigger points at which to review the potential for adverse impacts to emerge and the consequent need for asset management interventions. For photovoltaic installations, the trigger point is 5MW of installed capacity, which represents approximately 15% of our present summer midday demand.

In December 2018, there was 3.1MW of installed capacity and, given the rate at which new photovoltaic generation is being connected, we think the 5MW trigger point could be reached in 2020. When this happens, we may need to consider changes to our technical standards to prevent photovoltaic systems interfering with supply quality and to modify our pricing to make it more cost-reflective.

The technology growth factor, which is a combination of increasing capability and decreasing cost, is anecdotally reported to be about 18% p.a. This change relates to a doubling of the installed photovoltaic generation capacity every 4 years. If this trend is sustained at an exponential rate, there could be 24MW of connected photovoltaic generation on our network our network by 2030, which would represent up to 40% of our forecast summer peak demand. This level of penetration has already occurred in some parts of Australia, meaning this hypothetical possibility is potentially real.

The main problem with high levels of photovoltaic injection is the highly volatile nature of the generated output. For example, there will be a sudden drop in output of all adjacent photovoltaic 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 include sudden overvoltage or undervoltage swings when the generation output changes. The response of traditional voltage control assets, such as voltage regulators and transformer tap changers, is too slow to manage the speed and magnitude of the voltage transients that can occur.

A few power quality issues have already been experienced with photovoltaic connections to our network. These relate to the setup and capability of the equipment being sold to consumers and how it would react to conditions on our network or in nearby consumer installations.

The voltage stability problems associated with high levels of photovoltaic penetration can be mitigated by the connection of battery storage (including electric vehicles) to the network, as their associated power electronics react much faster than traditional voltage control devices. If the installation of batteries and purchase of electric vehicles by consumers does not keep pace with the connection of photovoltaic generation, there could be an interim period when quality of supply deteriorates to the point where we could find ourselves the investor of last resort.

Fortunately, we do not expect to encounter the issues that have been experienced in Australia as a result of high levels of photovoltaic penetration, as there are significant differences between the development path experienced in Australia and the New Zealand situation:

- Australia subsidized the installation of panels and supported owners with a feed-in tariff. This encouraged home owners to install more generation capacity than they could use. Battery installation was not subsidized and was not as economic as it is now.
- Australia's rural networks are significantly longer than in New Zealand and have a lower consumer density. They tend to be voltage constrained and generation distributed at the end of a feeder has a bigger impact on voltage volatility.
- Operating conditions with regard to temperature, sunlight, peak load are more extreme than here.

Due to the available subsidies, photovoltaic generation was installed in Australia much earlier than in New Zealand and well before complementary technologies such as electric cars, batteries, artificial intelligence enabled distributed energy resource management systems and other market solutions began to emerge.

Interventions to manage the voltage control issue could include the development of technical standards specifying minimum technical requirements for photovoltaic inverters and controls, and limiting the maximum output of inverters connected to different parts of the network. The average photovoltaic installation on our network is 4.4kW, which is closely matched to the 4kVA ADMD design capacity of the network. If we limit injection into the network to the same as its off-take capacity, there will be no need for network reinforcement.

A complementary approach would be to develop a pricing strategy where the cost of any investment we need to make to mitigate such issues is recovered from those consumers causing the problem and not spread across our consumer base.

There is also an equity concern related to photovoltaic installation. Photovoltaics are typically installed by wealthier, high-use consumers to reduce their grid offtake and electricity costs. It is argued that this leaves the less wealthy to fund sunk asset costs and the cost of network reinforcement. However, this proposition is not supported by initial findings of the cost-to-serve study discussed in Section 3.1.13. This found that the residential consumers that contribute the most revenue are those who have installed photovoltaics. There are several reasons for this:

- Without reticulated sewerage systems in our communities, section sizes are large and the houses that get built on them are large and have high value. These properties cover their future by installing network supplies with high capacities to meet relatively high loads, and then install a photovoltaic system to supplement their supply. They have paid up-front for capacity they are not using.
- Consumers with new large houses at the top end of the market are more likely to have also installed air-conditioning, spa pools and similar equipment with high electricity consumption.

- Retirees on fixed incomes often insulate themselves from the cost of electricity drawn from the grid; for example, they may install a spa pool or cool the house in summer if they can generate the electricity.

These consumers are more likely to use electric vehicles, supplement our energy management capability with batteries, and invest in their supply resilience in the longer-term and are our most attractive consumers. They have committed to investment in an all-electric future and will not present a burden to our network or the other consumers in our supply area.

5.7.3 Medium Scale Photovoltaics

Another emerging trend in Australia is the mounting of larger scale photovoltaic systems on commercial roof space. This model works where there are multiple tenants or where consumers can be aggregated into an efficient load block to host the quantity of installed generation. A building owner or a third party installs the generation and recovers its cost by selling the energy generated to the tenants. It then aggregates the individual tenant connections into a single load connection to the network. The tenants are better off because they pay less for their energy (e.g. reduced delivery costs), and the network benefits from a single connection to a diversified and more efficient load. The generator supplier exports any surplus energy to the network and retails it to other local consumers through a peer-to-peer trading arrangement. As low levels of investment capital are required, such businesses can proliferate quickly.

This model may work quite well in our network, where there are apartment buildings and retirement villages with Body Corporate facilities (e.g. heated swimming pools) that have a high energy demand. If these facilities install the maximum photovoltaic capacity that their connection can support, their low occupancy rates will result in a relatively high penetration of exported energy in certain pockets of the network. At this stage such developments remain hypothetical possibilities, but we are actively watching and interpreting developments in relation to our operation and service delivery.

For loads of about 2-3MW, the build cost of photovoltaic generation now has parity with the average spot price of 7c/kWh. Without transmission cost, this is an attractive alternative for a new load where a network connection would otherwise require subtransmission development. Capacity could be matched to load with batteries and security provided by a generator. The facility could be funded by the consumer or by a third party. We could develop a similar solution ourselves to supply summer peaking incremental loads at remote capacity-constrained locations such as Tokerau or Russell.

5.7.4 Network Implications and Opportunities of Emerging Technologies

There is a risk that emerging technologies will lead to reduced electricity consumption, although this trend could reverse in the medium-term as greater numbers of electric vehicles are charged through the network. Losing load to gas hot-water, for example, is a double negative, because it reduces energy storage and management capacity.

We can address the issue of declining consumption impacting our revenues by reforming pricing. Transmission pass-through costs, to be cost reflective should exclude energy generated and consumed locally. This would also provide an incentive for investment in local solutions that reduce reliance on the grid; investment in a battery, for example, not only increases resilience and reduces consumers' reliance on the grid, but also increases the energy management capacity and efficiency of our network.

Our consumers currently pay approximately 45c/kWh to draw energy from the grid. If energy can be generated locally, stored and then used at a lower cost than this, there is no justification for delivery via centralised generation and transmission development. Regions with potential for self-sufficiency expect fair treatment through market and transmission pricing reforms.

Batteries will be a major contributor to reducing our future network spend, and providing an asset platform on which future markets and solutions to system operating issues will develop. Cost-based pricing may need to reflect consumer investment in storage – including batteries, electric cars, freezers, hot water, thermal capacity and fuel resources.

The installation of high-capacity, fast car chargers behind existing meters is a self-limiting issue. If an installation's connection is smaller than the capacity required for the charger, it will need to be upgraded at the consumer's expense. Moving to a capacity levy based on the marginal cost of supply for the new load being added would recover the cost of any compounding network upgrade up-front as a one-off charge. The charge could also be calculated to recognise the value of storage added to an installation.

Internationally, the migration to electric vehicles is occurring faster than originally anticipated. European countries have announced a phase-out of sales of new internal combustion engines and manufacturers are adapting their research and production facilities.

Large retailers and businesses with company vehicle fleets can deploy photovoltaic supplied charging facilities in their car parks. Car batteries are able to be aggregated and applied to peak load management or absorbing excess generation from photovoltaics during off-peak times on sunny days. Developers of Distributed Energy Resource Management Systems (DERMS) already have this application on their development road maps and can demonstrate the use of artificial intelligence in this complex control process.

At a system level, it will be necessary to balance volatile renewable generation with more firm generation. South Australia has already installed a very large grid-scale battery to balance the high levels of photovoltaics and wind generation connected to its power system. On a much smaller scale, standalone microgrids are backed up with diesel generation and a battery for fast load following.

We already have 27MW of firm geothermal generation embedded in our network and have committed to purchasing a fleet of diesel generators that we can to deploy across our network to address capacity constraints. With the addition of batteries, we would have all the resources needed to deploy a DERMS when this level of energy management becomes necessary at system level. However, our preference will be for consumers to make their own choice about the level of security and resilience they require, and make informed investment decisions. Our pricing reform will need to support this strategy.

There is still a gap between smart meter deployment, and the data acquisition uses that a system operator might apply them to. For example, smart metering could be used to monitor load duration and therefore allow an annual update of capacity constraints on service connections, the required sizing of storage and the optimal load management strategy.

5.7.5 Adoption of New Technologies and Energy Supplies

Our network development plan, as set out in this AMP, will:

- Rationalize the 110kV bus at Kaikohe substation so that, with a target date of 2025, it will:
    - Provide a connection point to the transmission grid via Transpower's two Kaikohe-Maungatapere circuits;
    - Provide a grid connection for the 64MW of new geothermal generation to be constructed at Ngawha by Top Energy's subsidiary company, Ngawha Generation Ltd; and
    - Provide a point of connection of our network to the grid, rationalized to two 110kV circuit breakers.
- Provide a high capacity 110kV backbone ring interconnecting our three major load centres of Kaikohe, Kaitaia and Wiroa. This ring is targeted for completion in FYE2030 and will provide the points of injection into our 33kV subtransmission network. As the network develops beyond the planning period of this AMP, additional smaller substations can be added to provide further points of injection into the lower voltage network. A new substation at Mangamuka is envisaged.
- Provide for the connection of embedded generation that will supplement the new Ngawha generators to the point where our supply area is self-sufficient in generation capacity and could be operate independently of the transmission grid. This generation will include the existing 25MW Ngawha capacity, which will not be directly connected to the transmission grid (i.e. like the two new larger generators) as well as 15MW of diesel generation that can be moved around the network as required to relieve localized constraints.

These developments will provide a platform for our migration from a traditional grid-supplied distribution network to a distributed energy system, enabled with local generation, storage and new technology, which will meet future needs of our consumers with a lower cost and higher level of service than our current grid-centric system. We are therefore planning to minimise our consumer's use and dependence on the grid, which will primarily be used to export electricity from the new Ngawha generators when the electricity cannot be used within our supply area. Generation and network will then carry a proportionate share of the cost of our grid connection assets, restoring some balance to the allocation of transmission costs.

While centralised grid delivered energy may be more efficient for larger, higher-density loads closer to the country's main sources of generation, electricity supplied to small distributed loads remote from the grid is expensive and does not have the security and service levels that can be achieved with local generation supported by new technologies. Our decentralised approach will enable our services to be more readily customised to individual customer preferences. Consumers will be given more choice over whether they fund investment in our network or invest in solutions within their own installation. The services we can provide will be defined in standards, such as our security standard, and supported with opt-in or opt-out pricing. This work will be undertaken as part of a customer relationship management system project that will be incorporated into our 2020 pricing review.

The scale of generation that we now have in development is sufficient for the network to run islanded from the grid, given our current peak demand. As our demand increases, it will be desirable to sustain this ability by encouraging an increase in embedded generation and storage that will allow any additional generation to be utilised more efficiently. Top Energy does not need to invest directly but will need to take an active role in balancing the generation portfolio with demand and our network management capability. We will monitor both the mix and density of new technology and set boundary limits to define optimal technology deployment and signal opportunities through the Statement of Opportunities in Section 5.10 of this AMP. We will only invest as the provider of last resort.

Storage is currently the weakest element in the emerging distributed energy system of the future. This is due to the technology only now reaching an appropriate cost point and to the lack of a market signal rewarding investment. Traditional load management systems are becoming increasingly sub-optimal and no longer fit for the wider range of system management issues and opportunities that new technology introduces. We will develop a mix of technical standards and pricing options where these can be justified in terms of cost-to-serve and delivery of service. Whether Top Energy will need to invest in distribution scale batteries will depend on how quickly electric vehicles emerge as a significant load and what level of non-residential scale photovoltaics are installed for commercial retailing purposes. If market solutions to manage volatile supply from renewable generation do not develop at the same pace as photovoltaics, then batteries may be needed for system stability. Encouraging generation investors to firm their supplies with batteries and standby generators via connection standards will need to be considered and signalled before problems emerge.

We are also putting in place other strategies to manage our adaption to new technologies.

- We will regularly update our technical records and review our Connection Agreement, including its compliance with the Connection Standard and the terms on which we agree to supply. This is necessary to ensure we capture changes within consumer installations, so that we can ensure our system operation is optimal and our pricing is cost-reflective.
- The contracted connection capacity upgrade for new loads will be managed via a connection levy that will be based on the average cost for the network to deliver extra units of capacity. It will apply to all new load, not just new connections and replace the capital contribution mechanism. This will also be considered in the 2020 pricing review.
- We are introducing an Advanced Distribution Management System (ADMS) to facilitate more active management of the low voltage network. A DERMS will be added to the ADMS platform and start with the integration of our own embedded generation into our load management
- We will develop an information guide on new and emerging technologies. A major impediment to consumer uptake of new technology is understanding the available choices and their associated benefits, risks and costs.
- We will inform consumers in advance about our pricing plans going forward, based on our price/quality path for the 2020-25 regulatory period and the outcome of our 2020 pricing

review. Stability and predictability of pricing is important to consumers when making investment decisions.

In summary, new technology will drive change at a pace much faster than before. Preparedness for change is our best defence against disruption and will help us ensure maximum benefit for our owners, consumers and community as the technology emerges. Our watching brief will continue and be supplemented by the development of optimised responses at the technical and business process level.

This will include piloting new technologies and their associated systems engineering to determine their capability and applications as discussed in Section 5.7.6. These pilot projects are a learning process, as the technology and markets that will be available to ourselves and our consumers are still being developed. While the pilots carry a high technical risk, they are designed to help us better understand both the benefits and risks associated with the introduction of new technologies to reduce the risk of inappropriate or inefficient investment as we look to the future.

5.7.6 New Technology Pilot Projects

One conclusion from the above analysis of the potential impacts of emerging technologies is that battery storage is highly likely to be an integral component of future networks. While in the longer term, batteries are likely to be installed behind the meter by consumers or third parties, there may be a need for us to invest in batteries in the medium term to address volatility in power quality or as a component in the development of more cost-effective solutions to the provision of an electricity supply to consumers in remote parts of our supply area.

We therefore plan to trial the use of batteries in the following applications:

- Installation of batteries in a group of individual installations, to allow their consolidation to a larger single point of connection to the network. To achieve this, we will develop a low voltage microgrid supported by batteries behind the connection to our network in both a marae community scenario and a multi-occupied building complex. The objective will be to study the potential to reduce the capacity of the connection needed to supply loads by using batteries to smooth out fluctuations in demand.
- We plan to extend the above micro-grid and asset rationalization concept to the distribution network serving a rural township to determine whether re-optimization can deliver higher levels of service for a lower cost. We consider Rawene a candidate for this trial, as it has a consumer demographic that is representative of the wider network.
- We plan to compare the performance of a static voltage compensator (statcom) and battery, configured as a large, uninterruptable power supply with a voltage regulator, when supported by localized generation and used as a means of stabilizing voltage, managing peak demands and improving supply reliability on rural feeders. Our preferred location for the statcom is on the Russell feeder. We plan to reconfigure the Opononi voltage regulator to match the battery-statcom setup arrangement at Russell to compare the effectiveness of the two technologies.

5.8 Uneconomic Supply Management Strategy

As discussed in Section 3.1.13, the revenue we receive from consumers connected to remote parts of our network is generally sufficient to fund the operational expenditure incurred in providing supply. However, a problem can arise when the assets reach the end of their useful life and need to be renewed or replaced. Our policy is that we will fund the capital cost of replacing assets that have reached the end of their life only to an economic level. Any additional capital cost should be borne by the users of the assets, typically through a capital contribution or a differential pricing arrangement.

We are developing an economic supply test specific to our network. This will determine the amount of capital expenditure on asset replacement and renewal that the revenue we receive from an uneconomic supply will support. When we identify a part of our network where continuing to provide a supply will require expenditure over and above the economic level determined by applying the economic supply test, we will assess the capital expenditure required to maintain supply.

The capital expenditure assessment will consider the level of service required by consumers and potential trade-offs between capital and operational expenditure. For example, consumers could agree to fault repairs being undertaken only during normal working hours in exchange for a lower capital contribution or price adjustment. It would also consider the possibility of reconfiguring the network to better match current loads (e.g. reduce the number of transformers to cater for a lower population than when the network was first installed). It might also be possible to reduce consumer costs by utilising emerging technology (e.g. replacing a high voltage line with a low voltage micro-grid supported by batteries). The overall objective will be to develop a solution that meets the service level expectations of the community at a cost that they can reasonably afford, rather than perpetuate the use of an inefficient asset when there is a lower cost alternative.

5.9 Distributed and Embedded Generation Policies

Distributed generation (sometimes referred to as embedded generation) refers to electricity generation facilities that produce electricity for use at the point of location or supplies electricity to other consumers through the local distribution network.

Distributed generation connected to our network includes:

- The existing generation at Ngawha Power Station, which is connected to our 33kV subtransmission network. The two new Ngawha generators will bypass our network and be connected directly to the 110kV transmission grid, so will not be treated as distributed generation.
- Diesel generation installed to support the operation of the network by providing an alternative source of supply during a network outage or to offset localized shortfalls in network capacity. This includes the diesel generation at Taipa and the generation being installed to provide supply security to our northern area.
- Generation installed by users of the network for their own purposes. Currently all such generation in our supply area is small scale photovoltaic; we have a total of 3.1MW connected photovoltaic generation spread across approximately 700 different locations.

We welcome users wanting to connect larger generating units to our network, perhaps utilizing the significant wind resource that is available in parts of our supply area. Our Statement of Opportunities in Section 5.10 indicates where new distributed generation would contribute to efficient network operation.

Our approach to the connection of distributed generation to our network 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 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, the cost of any capacity upgrade needed to overcome the limitation would be funded by the proponent.

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

5.10 Statement of Opportunities

Distributed generation and new technology are potential alternatives to distribution lines for delivering electricity and providing capacity to meet peak demands, voltage support and network security. Such solutions do not need to be owned by Top Energy.

Top Energy encourages independent interests to consider the following opportunities:

- There is potential for installation of wind and photovoltaic generation at a commercial scale. Our network 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 2030. Access to this capacity would 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.
- The connection of dispatchable generation (most likely diesel) in areas supplied by radial 11kV feeders that cannot readily be interconnected to neighbouring feeders. Such areas include:
  - The north-east coast, where holiday and tourism ventures are driving development;
  - North of Kaitaia, where irrigation-driven load growth is occurring;
  - The Russell peninsula, where the load is approaching the limits of 11kV distribution;
  - Both North and South Hokianga; and
  - The Purerua peninsula.

5.11 Non-network Options

Demand side management (DSM) refers the management of a consumer's demand by shifting the consumer's peak away from the time of the network peak. This can help reduce the magnitude of peak network demand, deferring the need for capital investment to increase network capacity, and potentially also reducing our transmission charges. This could also reduce the need to install diesel generation for network support. The selection of a viable DSM option starts with identification of all appropriate alternatives, their cost and performance characteristics.

The development of a market-based system by Transpower to provide load reduction in the event of an emergency loss of generator 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 sufficient price incentive for them to modify their demand.

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

- **Direct Load Management (DLM):** 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. It has the advantage of being predictable and firm.
- **Under-Frequency Load Shedding:** In order to prevent a total power system collapse under major grid disturbance conditions, Transpower requires that automatic tripping of a percentage of each EDB's network load should occur 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 5.8 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 5.7: Emergency Load Shedding Specification

Block 1 equals approximately 35% of our network maximum demand and Block 2 equals approximately a further 20% of the maximum demand.

5.12 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 provide to enable smart meter data to be downloaded automatically and Contact Energy (our incumbent retailer) is replacing its mechanical meters with smart meters and 60% of our consumers now have smart meters installed.

From our perspective, smart meters can be programmed to automatically advise our control room when supply is lost. As noted in Section 5.14 we are planning to extend our ADMS functionality to include active real time management of the LV network and access to smart meter data would enhance this capability. Furthermore, the disaggregated demand data available using such meters should 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.

5.13 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.

5.13.1 Priority 1 - Asset Life Cycle Renewals

Assets that survive to the end of their lifecycle and that are still required to meet our service delivery targets need to be replaced. If the rate at which assets are replaced is insufficient, the average age of the asset base will increase and 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.

Depreciation gives an approximate level of renewal expenditure required to maintain the status quo across the asset base, in terms of condition and performance. In practice, expenditure categorised as asset renewal could be lower than depreciation, because some assets are removed from service early, for reasons such as a network reconfiguration or capacity upgrade. When this occurs, the cost of replacing the asset is absorbed by other capital expenditure categories.

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.

We are forecasting average expenditure of over $7 million per year[7] for asset renewal on a regulated asset base currently valued at $251 million. This forecast, which is categorised by what is driving the expenditure, is discussed in the sections below.

5.13.1.1 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 $1 million per year based on our historic capital expenditure on fault response. Our forecast fault driven capital expenditure over the planning period is shown in Table 5.8.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
Subtransmission	50	50	50	50	50	250
Zone substations						
Distribution and LV lines	600	600	600	600	600	3,000
Distribution and LV cables	50	50	50	50	50	250
Distribution substations and transformers	150	150	150	150	150	750
Distribution switchgear	150	150	150	150	150	750
Other network assets	-	-	-	-	-	-
Total	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**5,000**

Table 5.8: Fault Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.13.1.2 Defects

As described in Section 6.1.6, we operate a structured asset inspection 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 Section 5.13.1.4, 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 this situation. This is shown in Table 5.9.

[7] All expenditure forecasts presented in this AMP are expressed in FYE2020 constant prices, except where otherwise indicated.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
Subtransmission	117	128	127	129	131	683
Zone substations	59	64	63	64	65	342
Distribution and LV lines	622	677	672	682	692	3,620
Distribution and LV cables	59	64	63	64	65	342
Distribution substations and transformers	117	128	127	129	131	683
Distribution switchgear	176	192	190	193	196	1,025
Other network assets	23	26	25	26	26	137
Total	**1,174**	**1,278**	**1,268**	**1,287**	**1,306**	**6,830**

Note: Totals may not add due to rounding

Table 5.9: Defect Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.13.1.3 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 6.1.2.1) 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 their condition is such that they pose an elevated safety risk. Subtransmission lines fall into the first category, while the second category includes 11kV lines in poor condition.

Most recently, our line refurbishments have focused on our 33kV subtransmission lines. This work should be completed in FYE2020, except for the refurbishment of the Omanaia line and the replacement of the wooden poles on the Okahu Rd – NPL line. However, refurbishment work on 11kV and SWER lines in poor condition will be ongoing. Our forecast capital expenditure on line refurbishments is shown in Table 5.10. The FYE2020 expenditure in Table 5.10 includes $1.65 million 33kV line refurbishment expenditure carried forward from FYE2018.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
Subtransmission						
Moerewa-Haruru tower replacements	1,680	-	-	-	-	-
Kaikohe-Moerewa line refurbishment	218	-	-	-	-	-
Okahu Rd-NPL pole replacements	-	-	-	-	327	-
Kaikohe-Omanaia line refurbishment	1,136	423	423	-	-	-
Complete Kaitaia-Taipa line refurbishment	271	-	-	-	-	-
Total - Subtransmission	**3,306**	**423**	**423**	**-**	**327**	**-**
Distribution and LV Lines						
11kV reconstruction	776	723	612	507	622	479
SWER line rebuilds			312		287	1,927
Total - Distribution	**776**	**723**	**924**	**507**	**909**	**2,406**
TOTAL PROJECT DRIVEN	**4,082**	**1,146**	**1,347**	**507**	**1,236**	**2,406**

Note: Totals may not add due to rounding

Table 5.10: Project Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.13.1.4 Asset Health Driven Replacements

Our expenditure forecast for asset health driven replacements is shown in Table 5.11, disaggregated by asset type. Further information on the number of assets of each type that we are planning to replace is provided in Chapter 6. The FYE2020 expenditure shown in Table 5.11 includes $0.44 million carried forward from FYE2019 for the replacement of secondary assets.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
Subtransmission						
110kV poles and hardware	567	549	549	549	549	2,744
110kV tower refurbishment	161	161	161	161	161	803
33kV air break switches		43	43	43	43	215
Protection	173	-	-	-	-	-
Subtotal	**900**	**753**	**753**	**753**	**753**	**3,761**
Zone Substations						
110kV disconnectors	-	-	-	-	72	-
Subtotal	**-**	**-**	**-**	**-**	**72**	**-**
Distribution and LV Lines						
Conductor	-	196	322	669	689	2,339
Crossarms	-	3	200	247	247	1,237
Concrete poles	-	-	299	999	679	3,699
Wood poles	448	448	944	944	745	4,718
Subtotal	**449**	**647**	**1,764**	**2,859**	**2,361**	**11,993**
Distribution and LV Cables						
Pillars	-	79	79	79	79	394
Subtotal	**-**	**79**	**79**	**79**	**79**	**394**
Distribution Substations and Transformers						
Pole mount transformers	-	27	48	48	48	242
Pad mount transformers	120	57	77	77	77	387
Transformer earths	101	101	101	101	101	507
Voltage regulators	-	211	248	177		
Subtotal	**221**	**395**	**475**	**404**	**227**	**1,136**
Distribution Switchgear						
11kV capacitors	-	30	30	30	30	150
11kV fuses	-	48	108	129	129	645
Ring main units	321	319	319	324	324	1,618
11kV air break switches	-	74	74	74	74	370
Subtotal	**321**	**471**	**531**	**557**	**557**	**2,783**
Other network assets						
Communications	226	90	-	-	-	
SCADA	156	72	72	72	72	361
Subtotal	**382**	**162**	**72**	**72**	**72**	**361**
TOTAL HEALTH DRIVEN	**2,271**	**2,507**	**3,674**	**4,723**	**4,120**	**20,427**

Note: Totals may not add due to rounding

Table 5.11: Health Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.13.1.5 Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

Table 5.12 below consolidates the forecast asset renewal and replacement capital expenditure forecasts in Sections 5.13.1.1 – 5.13.1.4 into the asset categories used by the Commerce Commission for information disclosure.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
Subtransmission	4,373	1,353	1,352	931	1,260	4,694
Zone substations	59	64	63	64	138	342
Distribution and LV lines	2,446	2,647	3,961	4,648	4,562	21,020
Distribution and LV cables	109	193	192	193	194	985
Distribution substations and transformers	488	673	752	683	508	2,569
Distribution switchgear	647	813	871	900	903	4,558
Other network assets	405	187	98	98	98	498
Subtotal	**8,527**	**5,930**	**7,289**	**7,517**	**7,662**	**34,665**

Table 5.12: Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

5.13.2 Priority 2 - Network Capacity Augmentation

Our network capacity augmentation plan documents our expectations regarding demand growth, network extensions, and new connections. 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.

Our network development plan is driven by the following key objectives:

- Securing supply to our northern area. As an interim measure this is to be done through the connection of generation to Kaitaia. This project is in progress and some generation has already been installed.
- Connection of the new Ngawha power station generators. We currently own the 110kV bus at Kaikohe and will need to sell this back to Transpower, unless we are granted a rule change that would avoid the direct connection requirement. There is insufficient time available for this issue to be resolved and agreements finalized, and for Transpower to then construct a new line bay to accommodate a new generator connection by June 2020. We are therefore planning to release two existing line bays, which are currently used by our network, for the new generators, so that the existing 110kV bus arrangement will meet Transpower’s needs. When the Ngawha G5 generator is connected, there will be only two bays available to connect our network to the grid. These will be used to supply the planned 110kV ring that will feed Wiroa and Kaitaia. We will construct our own 110kV infrastructure to supply the 110/33kV Kaikohe transformers from this ring.
- Construction of a new 110kV substation at Wiroa. This will relieve a potential capacity constraint in the Kerikeri area and will allow the load in the eastern Bay of Islands, including the tourist areas of Paihia and Russell, to be supplied from either Kaikohe or Wiroa.
- Construction of the new 110kV line between Wiroa and Kaitaia to complete the 110kV ring.
- Construction of a new 110/11kV substation at Taipa to replace the existing substation, which is poorly located, and exposed to flooding and contamination risks.

Our plans to achieve these objectives are discussed in the following sections.

5.13.2.1 Kaitaia Generation

In February 2018, we conducted a telephone survey of 400 randomly selected consumers in our northern area on the acceptability of using diesel generation to provide supply security to our northern area, as an alternative to constructing the planned second 110kV circuit. The surveyed consumers were from the following consumer groups:

- Domestic;

- Industrial and commercial;
- Tourism and hospitality; and
- Essential services (schools, marae, ambulance, police etc.).

While the response rate was only 30%, some very clear views emerged. In particular:

- 78% of respondents said that the planned nine-hour planned maintenance interruption on Sunday 26 November 2017 caused no more than minor inconvenience.
- 59% of respondents considered that diesel generation was not an acceptable permanent alternative to a second line. 41% considered diesel generation to be an acceptable long-term solution, while slightly more (47%) thought that diesel generation was only acceptable as a short-term approach. 67% of industrial and commercial consumers considered that diesel generation should only be a short-term solution, whereas the other consumer segments were evenly divided between a short- and long-term.
- 79% of respondents considered that three days was the longest acceptable unplanned power interruption, given that the existing line crosses some rugged country that gets a lot of storms. Unfortunately, shorter periods were not given as alternatives to this question, so it cannot be assumed that a three-day interruption would be considered acceptable by all these respondents.

We conclude from this that our decision to secure supply in our northern area through the installation of diesel generators has the support of a majority of our consumers. While the occasional planned interruption lasting eight or nine hours on a Sunday is acceptable, it is not clear that this would still be the case if the frequency of such interruptions increased. Furthermore, we have been given a very clear message that unplanned interruptions with an extended duration are not acceptable to most consumers.

Now that we no longer undertake live-line maintenance on the 110kV line, more frequent planned outages of this line will be required. In addition, the tower failure that occurred in December 2014 showed that an extended unplanned outage of this line is a real possibility. Our plan to install diesel generation in the Kaitaia region addresses both concerns.

We have had two 2MW generators installed at Taipa for a number of years and late last year we installed three 1MW generators at our northern construction and maintenance depot next to the Juken Nissho mill, north of Kaitaia. These generators were all operated during the planned 110kV line maintenance outage in November 2018 to mitigate the impact on consumers by 21 SAIDI minutes. We have also purchased a site for a generator farm in Bonnetts Rd, west of Kaitaia, which has been consented for this purpose. We are committed to the purchase of a further twelve 1MW generators in FYE2020. The 1MW generators will be packaged in 20ft containers so they can be deployed across the network to support holiday peak loads or to provide resilience against faults on long rural 11kV feeders.

In the short-term, one of the generators is to be deployed at Omanaia to provide supply when the Kaikohe-Omanaia line is taken out of service for refurbishment work. When this project is completed in FYE2022, the generator will be relocated; possibly to the site of the Opononi regulator as part of the voltage regulation and generation support pilot project discussed in Section 5.7.6.

Figure 5.1 shows the consented generator locations during a 110kV line interruption. Resource consents are not required for a generator to be deployed across the network for intermittent operation in a network support role. Figure 5.2 shows how the generators could potentially be deployed to provide network support. We are likely to take a cautious approach, initially aggregating generators in the consented locations and then deploying them more widely as we gain experience in the remote operation of generators providing network support.

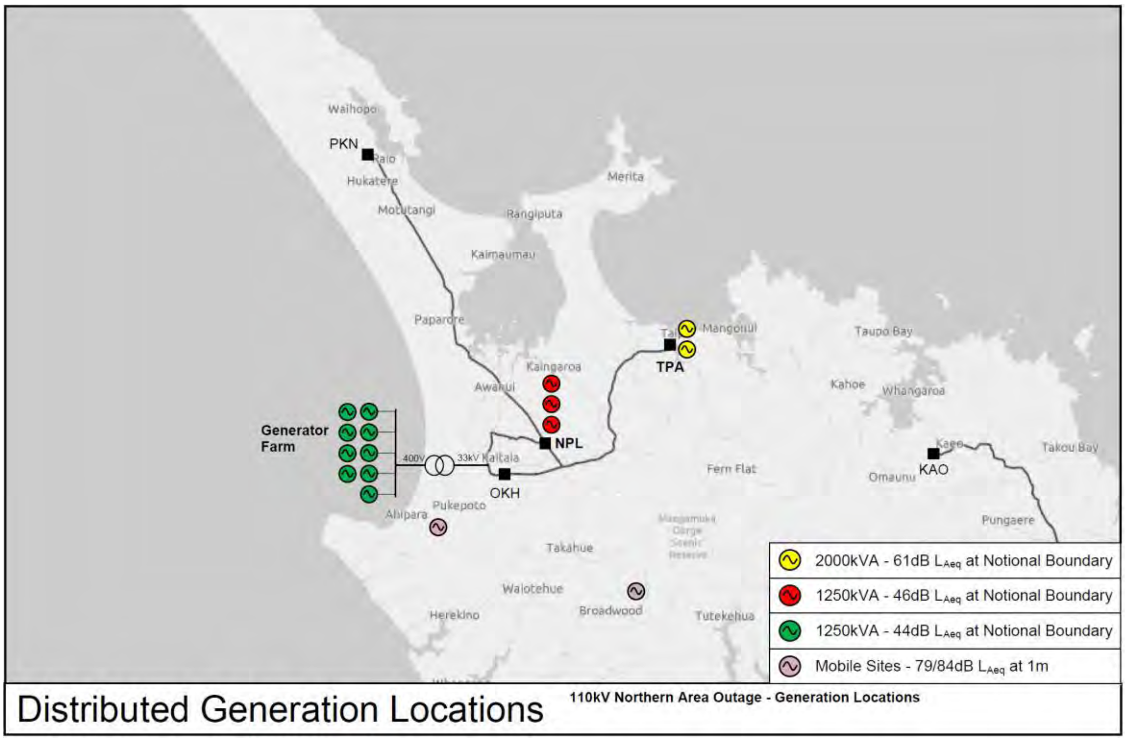


Figure 5.1: **Consented Generator Locations**

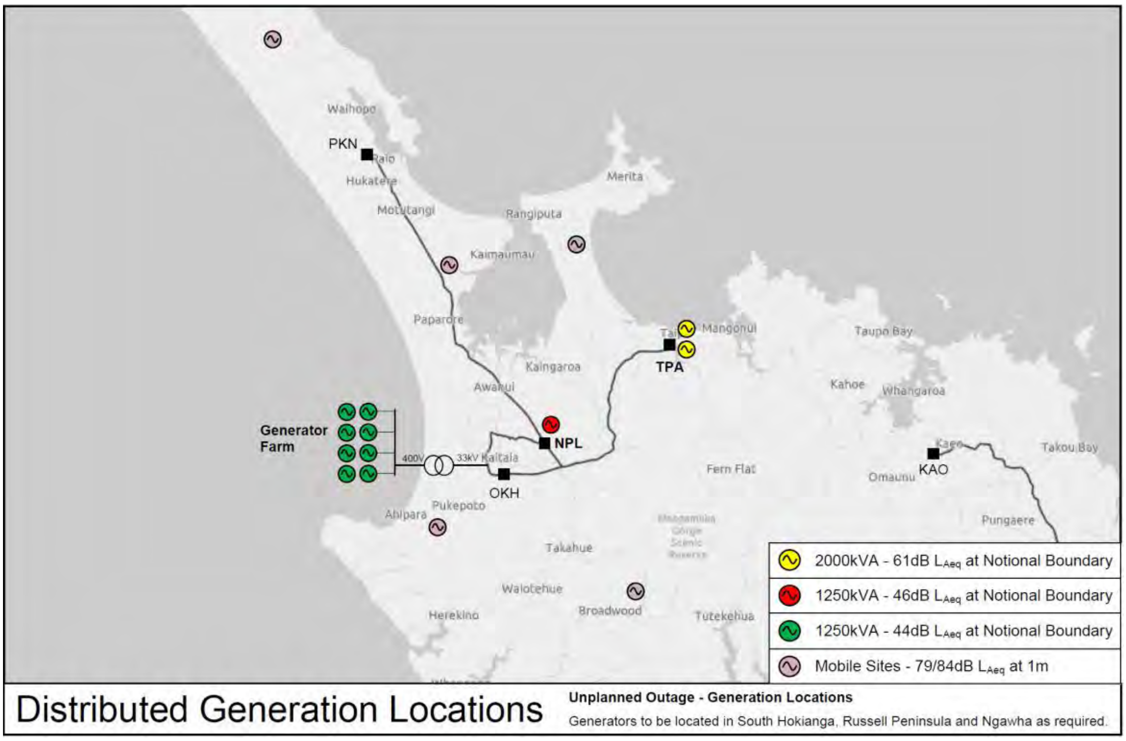


Figure 5.2: **Potential Remote Generator Deployment**

5.13.2.2 Subtransmission Development Stage 1 – Connection of Ngawha 4 Generator

The first stage of our development plan is the connection of the first of the two new Ngawha generators to the Kaikohe110kV bus. To achieve this, we will construct a new double circuit 110kV line between the new power station switchyard and the Kaikohe-Wiroa double circuit line, which is insulated to 110kV. Part of this line will be constructed over the route of the 33kV line connecting the existing Ngawha switchyard to our Worsnops 33kV switching station.

The new 110kV circuit will then comprise one circuit of the new 110kV line and one circuit of the Wiroa line, which will be operated at 110kV over part of its length and terminated in one of the line bays currently used for the Kaitaia line. The second new 110kV circuit will, as an interim measure be operated at 33kV and form part of the circuit between the Ngawha 33kV switchyard and Worsnops.

Fig 5.3 shows the existing southern area subtransmission arrangement and Figure 5.4 shows the arrangement after completion of this Stage 1 development. This stage must be completed in time for the commissioning of Ngawha 4 generator in FYE2021. It will be funded by the Ngawha project and most of the expenditure is budgeted for FYE2020.

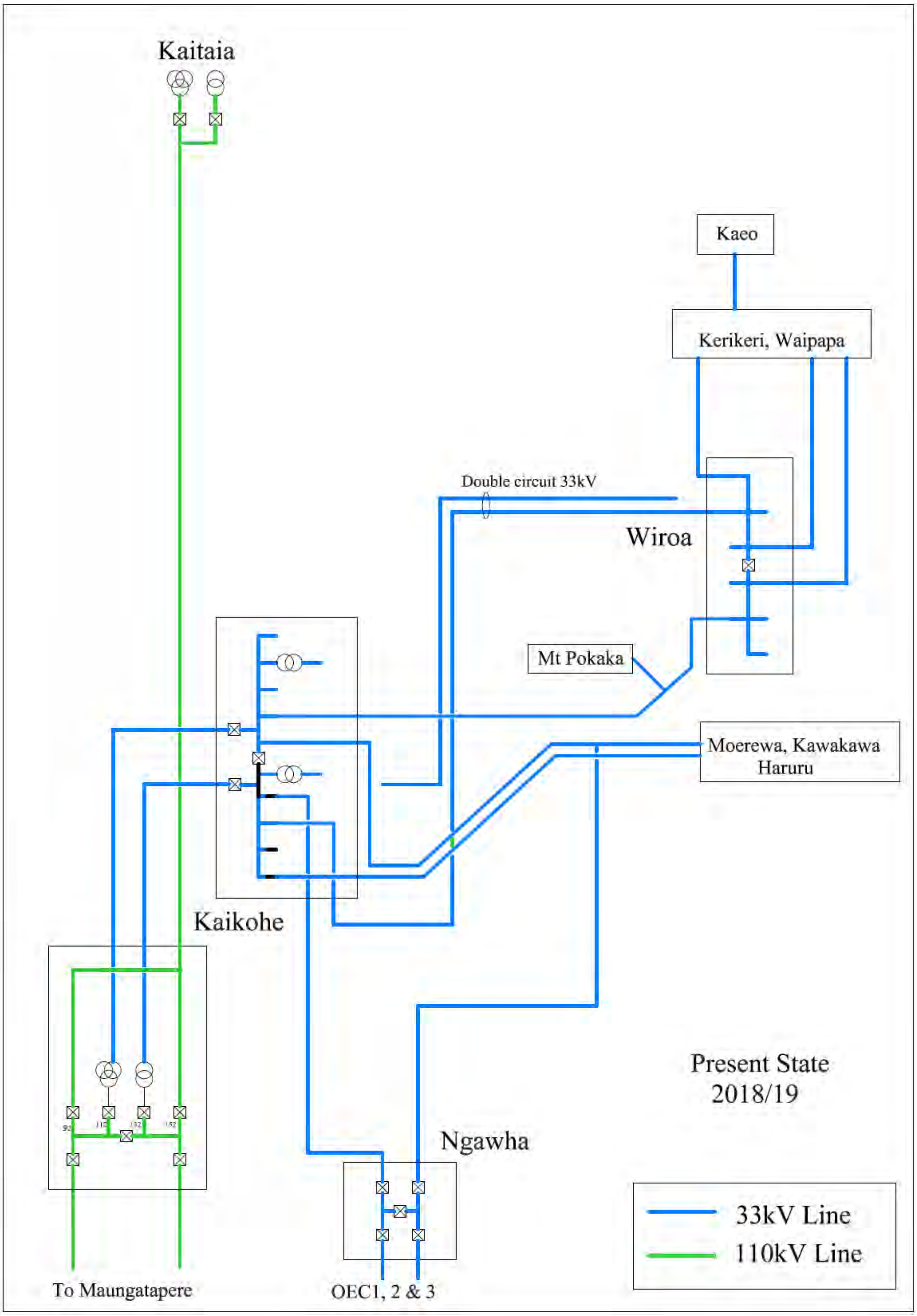


Figure 5.3: Current Southern Area Subtransmission Arrangement

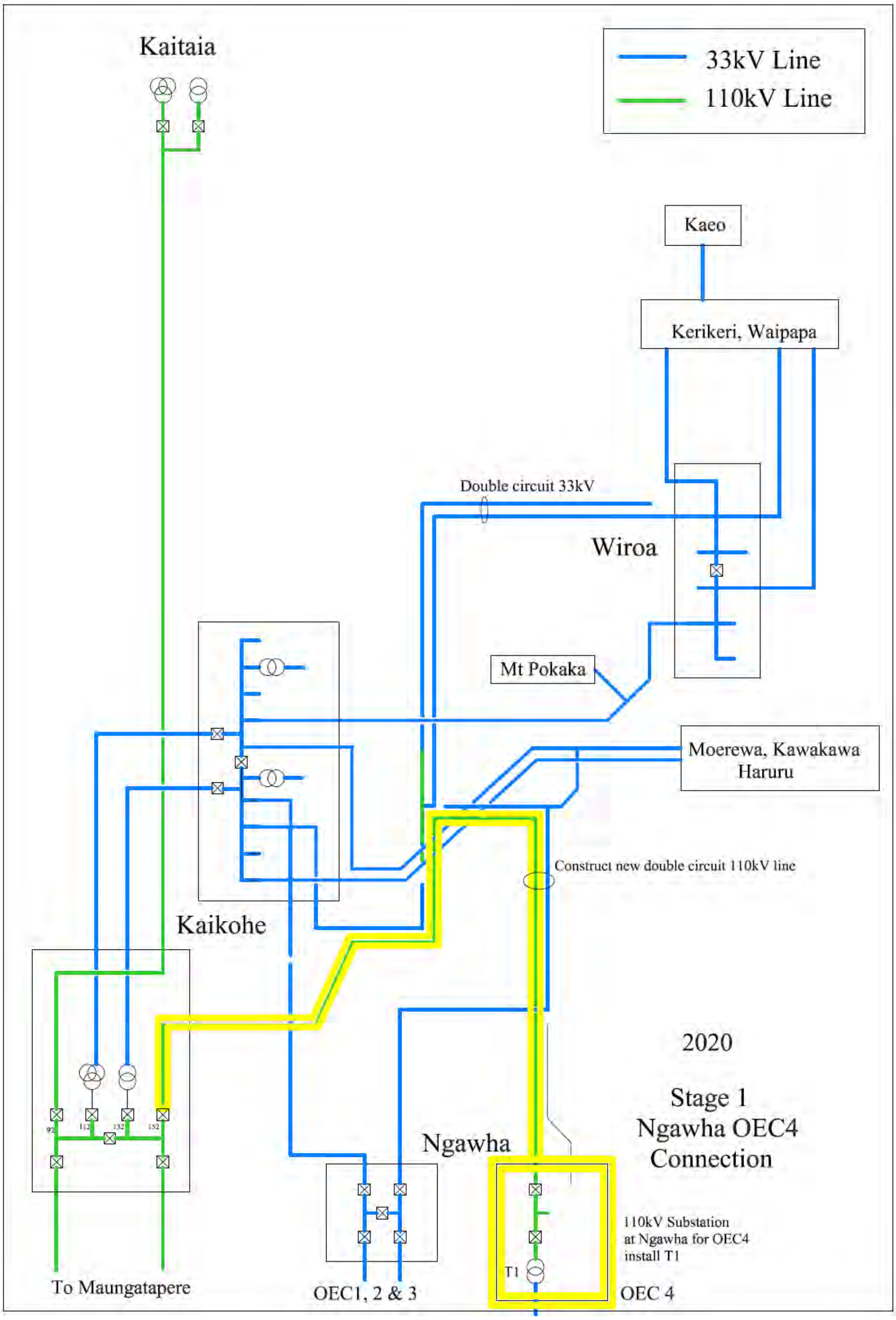


Figure 5.4: **Southern Area Subtransmission Network Development – Stage 1**

5.13.2.3 Subtransmission Development Stage 2: Kaikohe 110/33kV Transformer Replacement

Stage 2 of our subtransmission development plan is the replacement of the 30MVA 110/33/11kV transformer at Kaikohe with a new 40/60MVA unit, similar to the unit recently installed at Kaitaia. The high voltage supply to the replacement unit will be a tee connection to the Kaikohe-Kaitaia line, which will become a three-terminal circuit. The transformer will have an 11kV tertiary winding, which can be used to directly supply the Kaikohe 11kV bus when one of the existing 33/11kV transformers at Kaikohe needs to be replaced. The work is programmed for completion in FYE2023.

This arrangement is shown in Figure 5.5. Figure 5.5 also shows a 33kV connection to proposed new Energy Park at Worsnops. However, the timing of this development is uncertain and, as the substation will be largely funded by a capital contribution, it has not been budgeted for. Network development can proceed as we currently plan if this substation does not proceed.

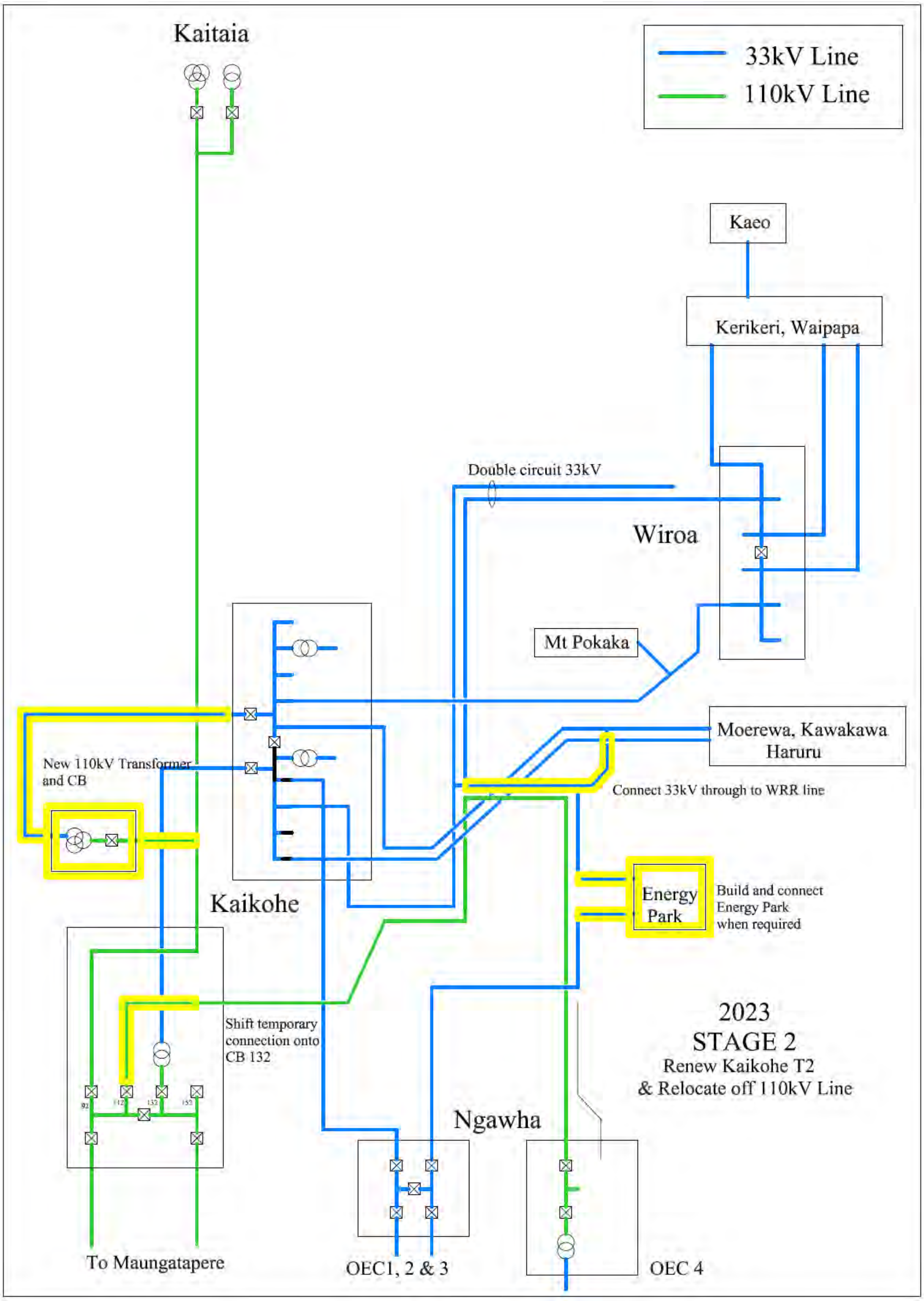


Figure 5.5: **Southern Area Subtransmission Network Development – Stage 2**

5.13.2.4 Subtransmission Development Stage 3: Wiroa 110/33kV Substation

Stage 3 of our subtransmission development plan is the construction of a new 110/33/11kV single transformer substation at Wiroa, as shown in Figure 5.6. A three winding transformer is planned to provide for a future new point of injection into the 11kV network. The substation will initially be energised from Kaikohe by terminating the second circuit of the 110kV Wiroa line into the spare 110kV line bay. This is programmed for FYE2024.

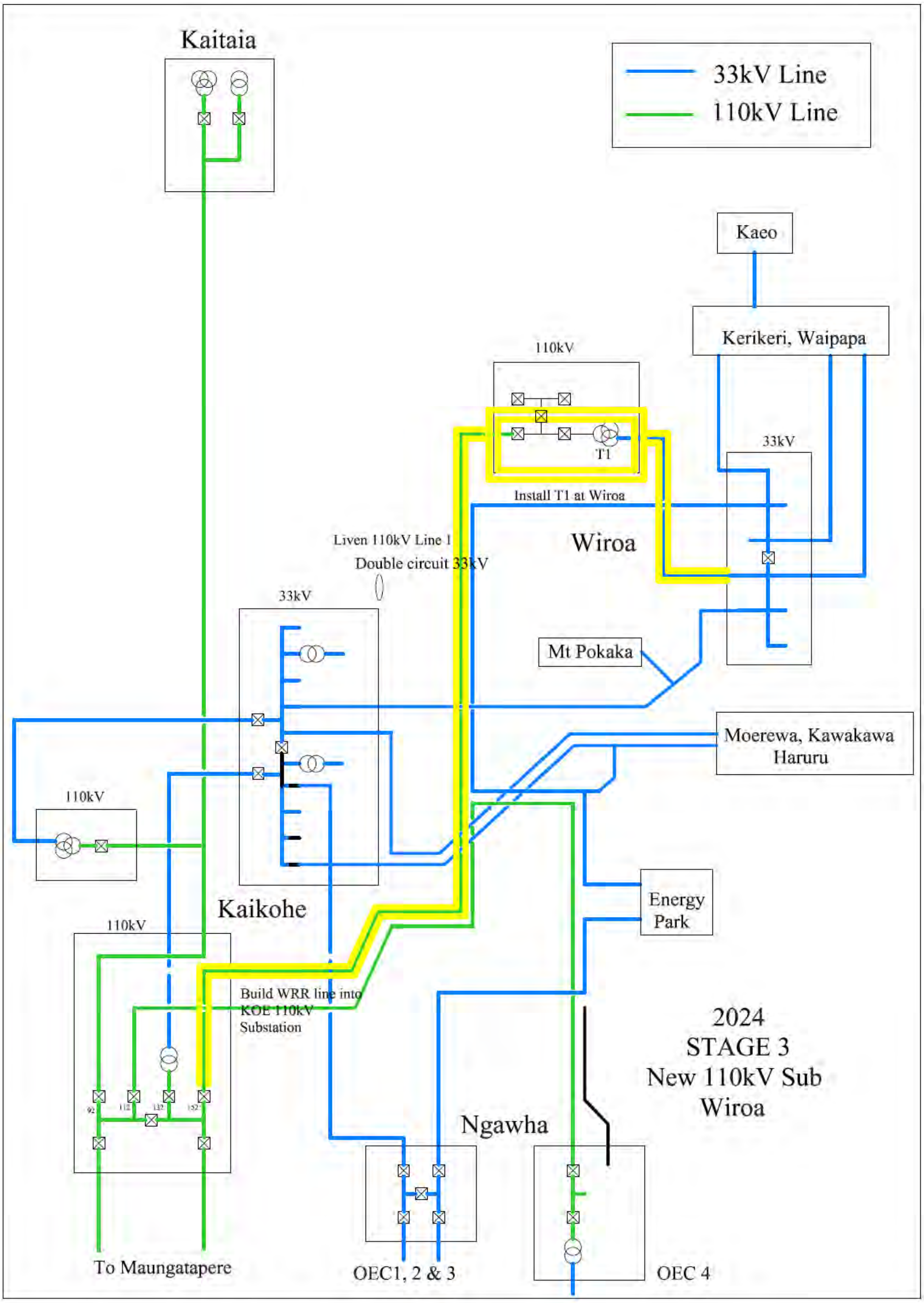


Figure 5.6: Southern Area Subtransmission Network Development – Stage 3

5.13.2.5 Subtransmission Development Stage 4 – Connection of Ngawha 5 Generator

We plan to connect the Ngawha Unit 5 generator to the Kaikohe 110kV bus as shown in Figure 5.7.

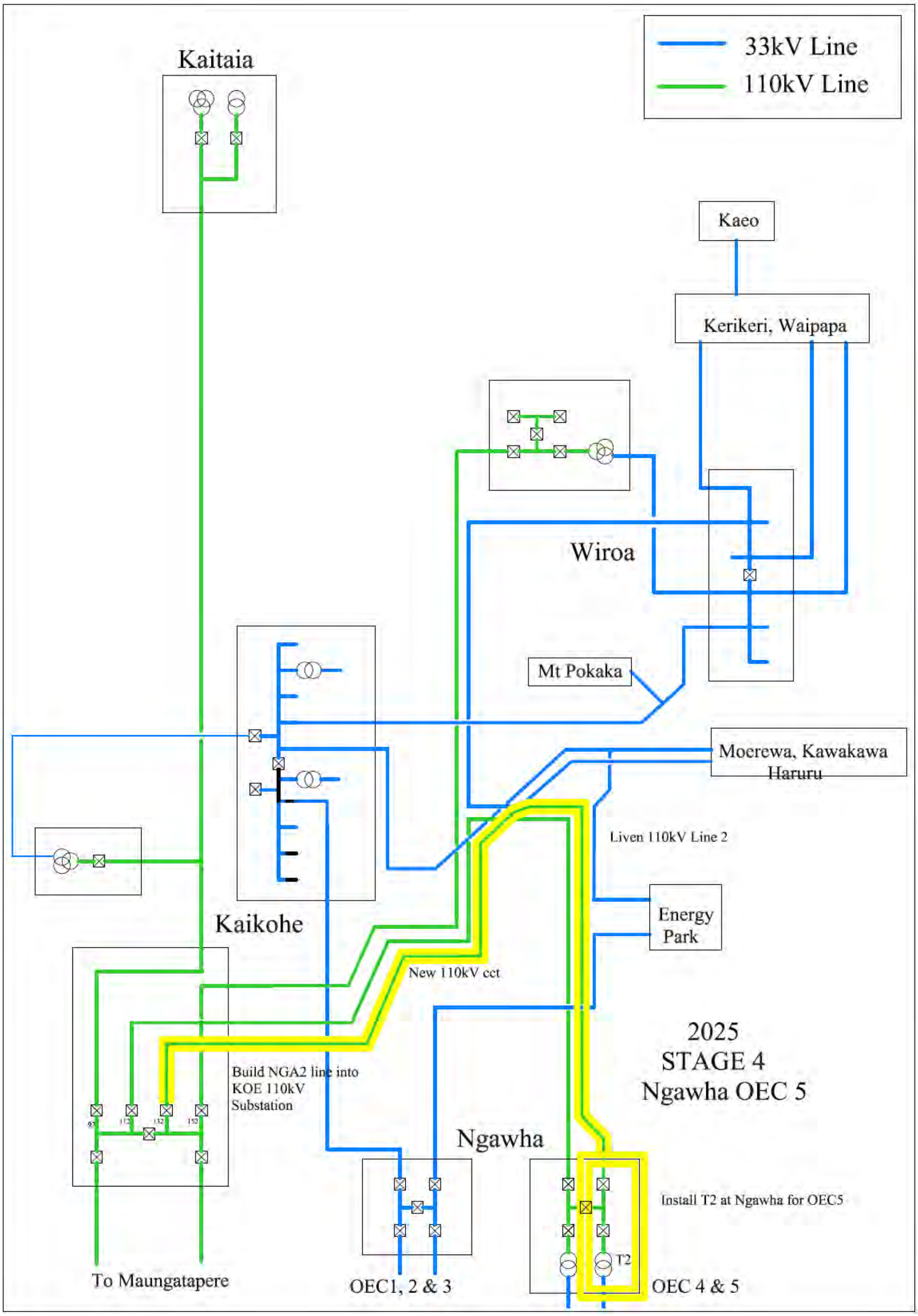


Figure 5.7: Southern Area Subtransmission Network Development – Stage 4

This will involve constructing a new 110kV circuit using the route of an existing 33kV circuit between Kaikohe and the Worsnops switching station, and terminating it in the line bay currently used by the 50MVA 110/33kV transformer at Kaikohe. This will be funded by the Ngawha generation project. The section of circuit on the Wiroa line, which is not required to be energised at 110kV, will remain energised at 33kV to enable the Bay of Islands area to be supplied from either Kaikohe or Wiroa. Our expenditure forecast provides for completion of Stage 4 in FYE2025 to coincide with commissioning of Ngawha Unit 5. Once this stage is implemented, rationalisation of the 110kV Kaikohe bus, as discussed in Section 5.13.2 will be complete.

5.13.2.6 Stage 5 – Completion of the 110kV Ring

The remaining components of our network development plan, including construction of the Kaitaia-Wiroa circuit to complete the 110kV ring, are shown in Figure 5.8.

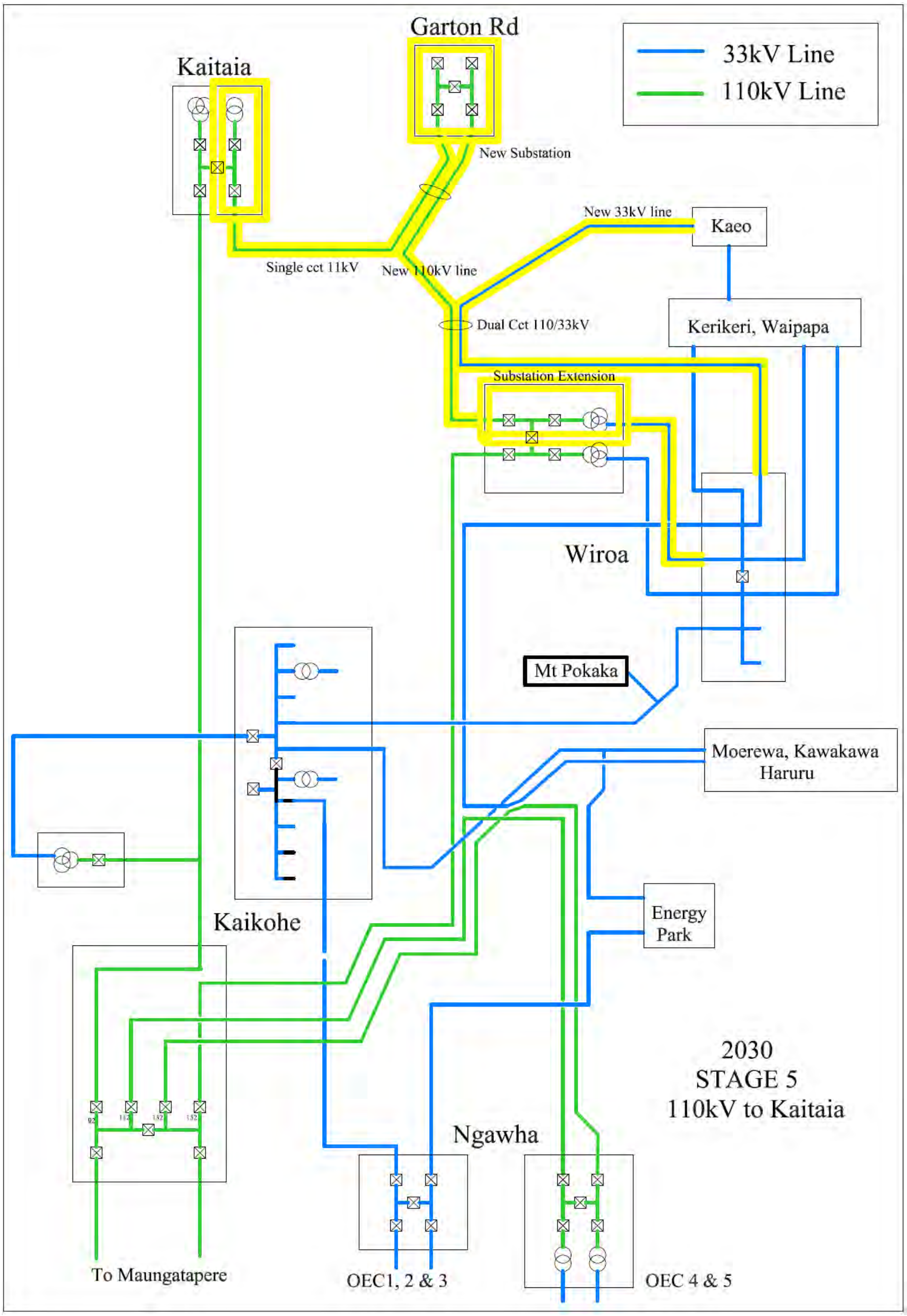


Figure 5.8: **Southern Area Subtransmission Network Development – Stage 5**

We are planning to have the 110kV ring in place by FYE2030, in time for the replacement of the conductor on the Kaikohe-Kaitaia 110kV circuit, should this be required. Our network development expenditure forecast provides for the Stage 5 development to be implemented over the period FYE2026-2030. However, there are a number of components of this development that are not critical to the completion of the ring and could be deferred or modified should funding constraints merge, or if it is found that the expenditure could be better utilised elsewhere. In particular:

- The second 110/33kV transformer at Wiroa will replace the 50MVA Kaikohe transformer that will need to be removed during Stage 4 to accommodate the second 110kV Ngawha circuit. It may be that this transformer would be better located at the Ngawha Energy Park, should this development proceed. We will keep this under review.
- While it is normal to have two incoming circuits to zone substations to provide supply security, a second incoming circuit to Kaeo is unlikely to reduce SAIDI as much as a new 110/11kV substation at Mangamuka. A Mangamuka substation would feed into the South Rd and Rangiahua feeders, allowing our two longest distribution feeders to be divided into a number of shorter feeders with fewer consumers on each. This would improve the reliability of supply to consumers in the North Hokianga and north of Okaihau. It may be that we defer construction of the second Kaeo circuit to provide funding for the Mangamuka project.
- The new substation 110kV substation at Garton Rd will replace the existing Taipa substation, which is on a poorly located site at risk of flooding and contamination. The substation is supplied by a single 33kV line built over difficult terrain and supplies the Doubtless Bay tourist area, which is a load that could continue to grow. While there are strong drivers for its construction, its timing could possibly be deferred until after the 110kV ring has been completed to ease funding constraints.

Depending how the east coast load develops, there is scope for alternative sequencing between 33kV and 110kV development, and more optimal zone substation location.

5.13.2.7 Kaitaia Substation Upgrades

The staged development plan discussed in the above sections does not include the planned upgrades to the Kaitaia 110kV substation that have been included in the capacity expansion forecast. These include the construction of a new line bay 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.

5.13.2.8 Network Capacity Augmentation Expenditure Forecast

Our capital expenditure forecast for network capacity augmentation project is shown in Table 5.13. Forecast expenditure in FYE2020 includes a total of $3.7 million carried over from FYE2019, relating to Kaitaia generation, property rights for the Wiroa-Kaitaia line, the connection of Ngawha generation and the Omanaia substation reconstruction. The table does not show all expenditure for the final section of the 110kV line, the Garton Rd substation and the second transformer at Wiroa, which will all be completed beyond the end of the planning period.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
11kV consumer driven upgrades	1,636	1,636	1,636	1,636	1,636	8,177
11kV network upgrades	260	260	260	260	260	1,302
Kaitaia generation	7,094	-	-	-	-	-
Ngawha generation connection	11,463	854				508
110kV Wiroa-Kaitaia line – property rights	1,127	222	360	46	46	-
110kV Wiroa-Kaitaia line – construction						28,223
110kV Garton Rd spur[1]						608

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
110kV Garton Rd substation						3,518
33kV Omanaia substation upgrade	230					
Kaikohe transformer reconfiguration		493	1,007	2,306		
110kV Wiroa substation				1,451	3,936	3,199
Wiroa ripple injection plant				74	708	
Kaitaia 110kV bus reconfiguration				530	154	700
Kaitaia T2 transformer						3,603
33kV Kaeo incoming circuit		61				2,385
Other						58
Total	**21,810**	**3,526**	**3,263**	**6,302**	**6,740**	**52,281**

Note: Totals may not add due to rounding

Table 5.13: Network Capacity Augmentation Forecast

5.13.3 Priority 3 – Reliability Safety and Environment

Improvement of supply reliability improvement, measured by network SAIDI, 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. Once the new generators at Kaitaia have been commissioned, the SAIDI impact of transmission and subtransmission faults will only drive a small proportion of our total network SAIDI. Reliability improvement initiatives over the planning period will therefore focus on reducing the SAIDI impact of the 11kV distribution network.

We are analysing our faults database to identify the parts of the network with high SAIDI contributions and develop solutions to improve their robustness to network faults. We use our SAIDI model (discussed in Section 8.1.2.3) to estimate the SAIDI minutes saved by potential reliability improvement solutions and to prioritise projects on the basis of cost per SAIDI minute saved. Having invested in backup generation as an alternative to conventional approaches to security improvement, we are now reassessing where generators might be able to address a wider number of issues and where they, combined with new technology, could address security and peaking problems on the distribution network.

The generation purchased to manage the lack of N-1 security in the northern network can be relocated onto the distribution network. Initially, we are targeting the Herekino and South Rd feeders. We plan to use generators to provide fault cover on these long, remote, high SAIDI feeders as well as being used in the event of a 110kV supply interruption. Nevertheless, we have also allocated expenditure to network projects targeted at reducing the SAIDI impact of fault on the 11kV distribution network. These are discussed in Section 5.13.3.1.

Deferral of SAIDI improvement projects to provide funding for higher priority asset renewal and network augmentation projects would forego opportunities for reliability improvement, but would not result in a deterioration of supply reliability below existing levels.

This category also includes capital expenditure driven by safety and environmental considerations to mitigate risks that are currently being otherwise managed. Safety remains our highest priority and capital expenditure to reduce a major safety risk to a level that cannot be effectively managed operationally would be escalated to Priority 1. Currently we have no such projects and our safety management systems are appropriate to manage all known safety risks.

However, we are planning to upgrade our Waipapa zone substation between FYE2021 and FYE2026. This 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.

Reliability projects improvement projects included in our capital expenditure forecast are discussed in the sections below.

5.13.3.1 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.

We have allocated a total of $7.3 million for capitalised 11kV network reliability improvements. This will fund the capital expenditure component of our 11kV fault reduction strategy discussed in Section 8.1.2.4. The focus will be on improving the performance of our least reliable feeders, which are shown in Table 8.4.

5.13.3.2 Russell Reinforcement

While we have two feeders (Russell Express and Joyces Rd) capable of supplying the load on the Russell peninsula, there is only a single circuit between Okiato Point and the Rawhiti turn-off, which prevents the load being shared between the two feeders. This project will install an underground cable under the existing line so that the peninsula load can be shared, with one feeder supplying Russell town and the second supplying the Rawhiti spur. The project also includes the installation of an 11kV remote controlled switching station at the turn-off and the installation of an additional voltage regulator.

While the primary driver of the project is reliability improvement, it will also increase the supply capacity to the peninsula, since the peak holiday load will be shared between the two feeders during normal operating conditions and the regulator will maintain voltage standards when all the load must be supplied from one feeder.

5.13.3.3 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 discussed in Section 5.14. 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, which has been carried over from FYE2018. 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.

5.13.3.4 Reliability Safety and Environment Expenditure Forecast

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
Quality of Supply						
11kV network reliability improvements	86	1,145	2,156	1,910	830	1,142
Russell reinforcement	-	682	678	-	-	-
Protection improvements	357					
SCADA	219	-	-	-	-	-
Kaitaia 11kV interconnection						868
Subtotal	**662**	**1,828**	**2,834**	**1,910**	**830**	**2,010**
Other Reliability, Safety and Environment						
Waipapa substation upgrade	31	2,709	-	-	-	1,717
Relocate Mt Pokaka protection cabinets	42					
Subtotal	**73**	**2,709**				**1,717**
Total	**735**	**4,537**	**2,834**	**1,910**	**830**	**3,727**

Note: Totals may not add due to rounding.

Table 5.14: Reliability Safety and Environment Capital Expenditure Forecast

5.13.4 Priority 4 - Technology Development

This expenditure forecast provides for implementation of the pilot projects described in Section 5.7.6, the upgrade of our GIS to one incorporating more modern technology and the extension of the ADMS functionality to include the management of the low voltage network. The forecast also includes a small annual provision for the introduction of technology upgrades into our zone substations.

A breakdown of our emerging technology expenditure forecast is shown in Table 5.15. Expenditure on the ADMS integration is carried forward from FYE2018 and relates to the validation of the data required to enable extended ADMS functionality.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29
New technology pilot project	66		744			413
GIS upgrade using latest technology	415					-
Low voltage monitoring	265	520	520			-
Substation technology Improvements	33	33	33	33	33	168
ADMS data validation	85					
Total	**865**	**554**	**1,298**	**33**	**33**	**581**

Note: Totals may not add due to rounding.

Table 5.15: Emerging Technology Expenditure Forecast

5.13.5 Consolidated Capital Expenditure Forecast

Table 5.16 presents our consolidated capital expenditure forecast. The high network development expenditure is driven by expenditure on the Ngawha connection in FYE2020 and expenditure on the construction of the 110kV Wiroa-Kaitaia line in the final three years of the planning period.

$000	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025-29	Average Annual
Asset renewal	8,527	5,930	7,289	7,517	7,662	34,665	7,159
Asset development	21,810	3,526	3,263	6,302	6,740	52,281	9,392
Reliability improvement	735	4,537	2,834	1,910	830	3,727	1,457
New technology	865	554	1,298	34	34	581	337
Total	**31,937**	**14,548**	**14,683**	**15,763**	**15,266**	**91,254**	**18,345**

Note: Totals may not add due to rounding.

Table 5.16: Consolidated Capital Expenditure Forecast.

The allocation of our capital expenditure forecast to our internal capital expenditure drivers is shown in Figure 5.9.

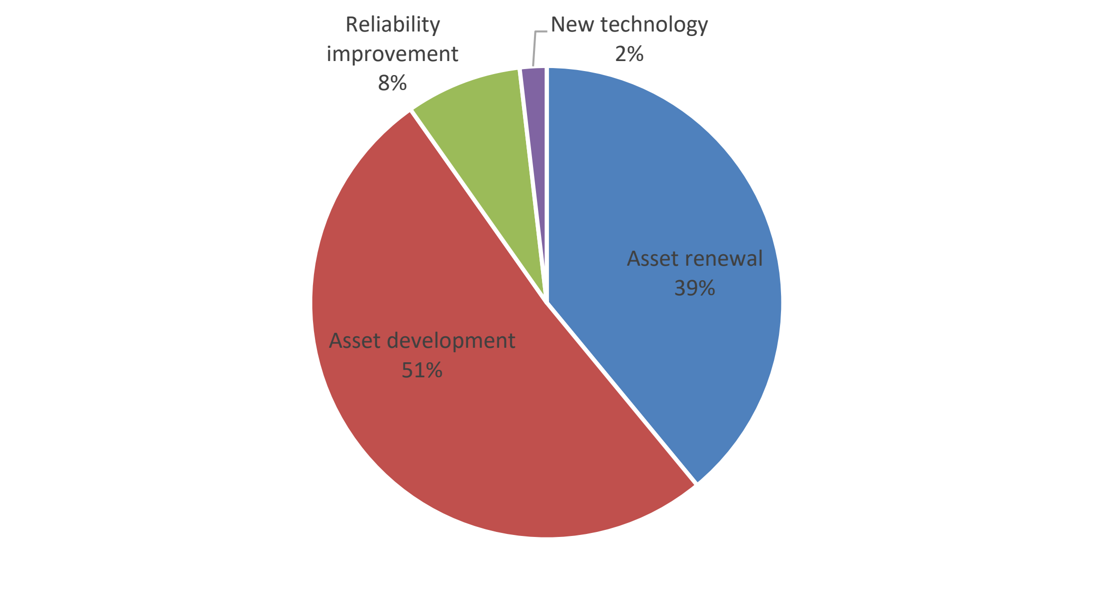


Figure 5.9: Allocation of Capital Expenditure to Expenditure Drivers

We have developed the capital expenditure forecast shown in Table 5.17 based on our internal management drivers. In preparing our capital expenditure disclosure (Schedule 11a of Appendix A), we have mapped this forecast into the Commerce Commission's standard asset categories as shown in Table 5.18 below.

TEN Expenditure Driver	Commerce Commission Asset Category
Renewal	Asset Replacement and Renewal
Development	Consumer Connection
	System Growth
Reliability Improvement	Quality of Supply
	Other Reliability, Safety and Environment
New Technology	Quality of Supply

Table 5.17: Expenditure Asset Category Mapping

5.14 Advanced Distribution Management System

During FYE2019-20, we are upgrading our network control operation through the installation of an advanced distribution management system (ADMS) for a budgeted capital cost of $2.6 million. The initial deployment will include a new SCADA master station and an automated outage management system

(OMS). The OMS will combine real-time inputs on the state of the network from our SCADA system with the customer connectivity information in our GIS to predict the location of faults and to automatically calculate the SAIDI and SAIDI impact of supply interruptions. This will provide more timely and accurate management reporting.

Distribution management system (DMS) functionality will then be added. This will overlay the above systems with a real-time model of the network, using inputs from SCADA, the GIS and our SAP asset management system (AMS). It will provide a decision support system for the operation of the network by making real-time information on network status and asset condition available to operators through a user-friendly graphical interface (with the architecture shown in Figure 5.10), automatically producing switching schedules, ensuring that all required isolation procedures are undertaken before operators issue field staff a permit to work and in many other ways. This will reduce operator error, support the enhanced safety procedures that we are introducing and optimise the operation and management of the network.

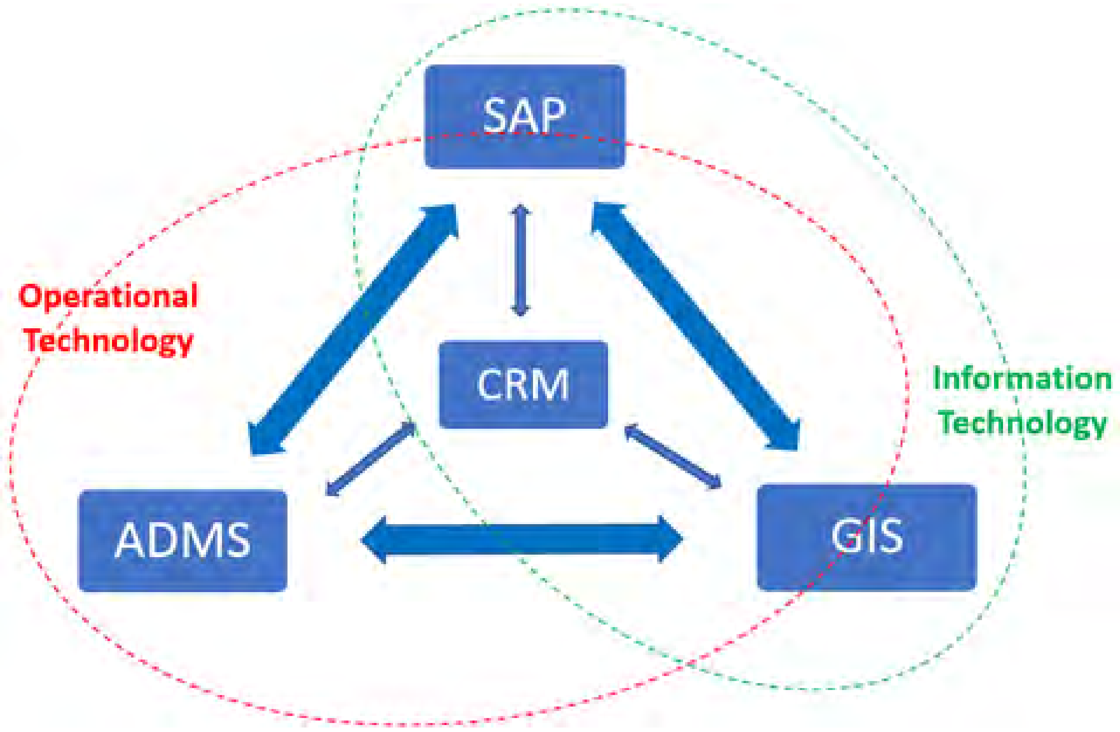


Figure 5.10: ADMS Architecture

The installation of the ADMS is timely, as our network will become significantly more complex and challenging to operate with the installation of new diesel generation. The ADMS can potentially be configured to optimise the use of this plant by automatically starting relevant generators following an interruption or when needed to alleviate localised network constraints.

We are also planning to use the ADMS to actively monitor the low voltage network. Currently the control room actively monitors the network only as far as the distribution transformer and only becomes aware of a low voltage fault when a consumer calls in to advise that it has no power. As shown in Table 5.15, our capital expenditure forecast includes a provision of $1.3 million to provide this low voltage monitoring functionality. This includes the cost of updated our data on the LV network to provide the low voltage connectivity model that will be needed before this function is activated.

The ADMS will also have the potential to access and control in real-time smart meters connected to our network. Restoration times should reduce, as we anticipate that smart meter data will often provide our control room staff with sufficient information to accurately predict the cause of a fault before a repair crew is dispatched. The system will also have the potential to prevent the unnecessary dispatch of fault staff, as the control room will be able to determine whether a consumer reporting a fault has power to its meter (in which case the consumer will be advised to call an electrician). Disconnections and reconnections could be undertaken remotely without the need to visit the site.

The installation of the ADMS will be a key tool in the operation of a network that is open to the use of new technologies and in 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) have already been developed by ADMS vendors, and can be added as required. This is shown in Figure 5.11.

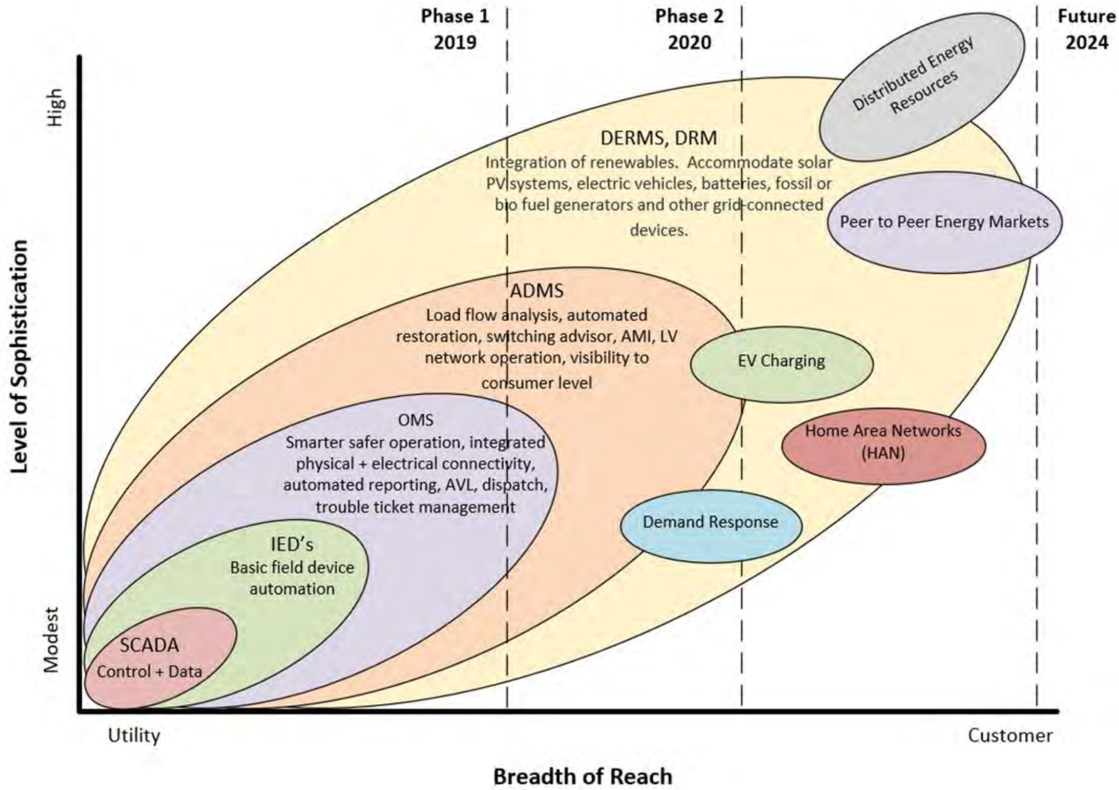


Figure 5.11: Features of an ADMS

The implementation of the ADMS is being managed by the Group's IT department and its implementation cost, apart from the costs incurred by TEN in validating input data, is included in the non-network capital expenditure forecast.

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 optimal 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 of assets requiring immediate and unplanned intervention 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 sudden asset component failures. The forecast is based on the reactive maintenance costs incurred in previous years.

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 total 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

The failure rate of typical assets across their life cycle is consistent with a standard bathtub curve. Newly constructed and commissioned assets may have an elevated failure rate as manufacturing and installation defects can affect performance. This is followed by a period of high reliability during the middle period of an asset's life, when the failure rate is generally low. Asset health over this period is initially H5, transitioning to H4 once minor age-related degradation, which does not affect an asset's performance in service, becomes apparent.

As an asset approaches the end of its expected service life, the degradation becomes more severe and the asset enters a period of unreliability where a failure in service is possible. When this occurs, the asset is considered to have reached its "onset of unreliability" and its AHI transitions from H4 to H3. We have assessed the performance of our assets to identify the age at which a particular asset type can be expected to reach its onset of unreliability. At this point, the degradation of an individual asset will vary across the asset class and the level of degradation can be used to assess the remaining life of a particular asset.

Our approach to asset inspection and maintenance under our planned risk-based strategy therefore depends on the age of the asset relative to its expected onset of unreliability:

- Newly constructed assets are inspected and checked for compliance with relevant regulatory requirements around five years after commissioning. For critical line assets, this includes a pole-top inspection and tightening as required.
- Following this initial maintenance inspection, assets can be expected to perform with a low risk of failure. No formal asset inspection is needed over this period and any maintenance is reactive; assets are only repaired or replaced following an event. Where the cause of an event is not understood, the assets concerned will be inspected or tested to ensure they remain in a serviceable condition. "Drive-by" safety inspections and ad-hoc observations from staff working in the field are relied on to identify any unusual situation where a premature maintenance intervention is required.
- Assets are inspected and their remaining life estimated about the time their age reaches the expected onset of unreliability for the relevant asset class. Across an asset class, the remaining life from that point can be represented by a bell-shaped failure curve. Some assets will fail early, most will fail about the median point of this failure curve and some will last longer. The objective of the risk-based inspection approach is to determine the point on this failure curve that an individual asset is likely to fail and to time the maintenance or replacement of the asset to avoid an in-service failure.

  This condition assessment determines:

  - The expected remaining life of each individual asset;
  - Any changes in operating practice necessary to keep staff and public safe, but still get the optimum service life out of the asset. An example might be to avoid climbing a pole once it has deteriorated to the point where a pole's strength has reduced to below a prescribed level; and
  - Any temporary life extending techniques that might economically be applied to align an asset's remaining life with that of similar assets surrounding it. This ensures that assets are renewed as a group as opposed to spot replacements, which are less efficient in terms of cost and service disruption.

  Following this onset of unreliability assessment, we create a population priority list ranking all assessed assets in terms of their relative condition and serviceability. This is a dynamic list that may change as every new asset assessment record is completed. Our objective is to replace each asset slightly ahead of its predicted failure. This is discussed further in Section 6.1.2.3.

A small percentage of assets in a population may survive beyond the life of the rest of the population. These are most likely assets that have been repaired or maintained prior to their initial condition assessment or assets where age was inaccurately recorded during their initial condition assessment.

- After an asset reaches its onset of unreliability, it is subject to more frequent, time-based inspections as the probability of an asset failure is greater.

The outcome of this approach is a reduction in inspection costs, as assets are not inspected where there is a low probability of a serious defect being found. These savings are being used to accelerate the rate of asset renewal and end-of-life replacement. Over time, this is expected to lead to an improvement in the overall condition of the asset base and a corresponding reduction in the incidence of interruptions caused by equipment failure.

Assets are installed in accordance with the prescribed design and safety conditions of the day and are certified as compliant during the commissioning process, and recertified for the scope of that work every time safety critical work is undertaken. However, assets are not normally retrospectively upgraded to new standards until they are replaced at the end of their service life. Such assets are classed as "unsafe" as defined in the legislation and managed in accordance with our NZS7901 certified public safety management system. In this context, the term "unsafe" is a legal definition, which does not imply that the asset cannot remain in service. This is discussed further in Section 7.4.

6.1.2.3 Asset Replacement Strategy

At an asset's onset of unreliability inspection, its health is categorised as H1 to H3 in accordance with the asset health categories in Table 6.1. This categorisation is updated at subsequent inspections. Our SAP asset condition database is therefore able to produce, at any time for each asset category, a schedule of assets categorised by health indicator. The tables in Section 3 show the numbers of assets in each health category for each asset fleet, as derived from this data.

Over time the condition of each asset will deteriorate and the health of each individual asset is therefore reassessed at each inspection following its onset of unreliability. The average rate at which assets deteriorate will differ by asset category (e.g. wooden poles will generally deteriorate from H3 to H1 much faster than concrete poles).

Our asset replacement strategies for each asset category are described in Section 6.3. The number of assets we have assumed will need to be replaced within the first five years of the planning period is based on the premise that assets currently categorised as H1 should be replaced within two years. The rate at which assets are subsequently replaced beyond this has been determined by the rate that we expect assets currently categorised H2 will transition to H1 over this time. As this is higher for wooden than for concrete poles, we have been able to reduce the rate of replacement of concrete poles to meet budgetary constraints.

This approach has allowed us to quantify the numbers of assets requiring replacement over the first five years of the planning period and consequently develop a capital expenditure forecast for the renewal of each asset category (shown in Table 5.11). For some categories, the forecast expenditure in the table is lower in the first two years of the planning period, because we expect assets to be replaced as part of a targeted refurbishment project. In these cases, the replacement costs are included in the replacement project expenditure forecast in Table 5.10.

The priority given to the replacement of individual assets within a category will depend on an asset's condition and its criticality, and the consequences of an unexpected in-service failure. Assets with a high criticality might be replaced when their health is assessed as H2 or even H3, whereas assets with low criticality might be left to run to failure even with an H1 health assessment.

6.1.3 Vegetation Management

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

Vegetation contacting our electricity assets presents two main hazards:

- A risk of electrocution if handling vegetation through which electricity is leaking to ground. Wet vegetation is more prone to leakage and, fortunately from a safety perspective, quicker to activate our protection. Nevertheless, clearing vegetation in this state presents an elevated safety risk.
- A fire risk. Vegetation growing slowly into live conductors can burn away at the tips without interrupting supply. Dry or windy conditions creates an elevated risk of starting a fire.

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

1. 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.
2. 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).
3. 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 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 in order 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 is defined as serious and, for safety reasons, requires specialist competencies to remedy. We necessarily must be involved. When we discover a tree contact, we are required to urgently attend to its elimination.

Our vegetation management strategy is discussed in greater detail in Section 6.2.

6.1.4 Replacement and Renewal Maintenance

Replacement and renewal maintenance is proactive condition-based maintenance triggered by the findings of the inspection and condition assessment programmes described in Section 6.1.2. Our renewal maintenance philosophy entails performing maintenance only when safety, reliability or performance are compromised, as discussed in Section 7.4.3 for our line assets. The objective of the renewal maintenance programme is the prevention of unexpected, in-service failures with unacceptable safety or network performance consequence. Our maintenance objective is to keep assets serviceable until they reach the end of their life-cycle.

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). Our replacement and renewal maintenance forecast includes a capex component that is integrated into our capital expenditure forecast.

6.1.5 Capital Replacement

Overlaid on the replacement and renewal maintenance programme described in Section 6.1.4 is a separate proactive capital replacement programme, where assets are replaced early to mitigate critical safety or reliability risks. Examples of these programmes are:

- the accelerated replacement of wooden and "T" and "L" shaped concrete poles to mitigate elevated safety risks;
- the refurbishment of 33kV lines supplying zone substations with a single incoming circuit to mitigate the elevated risk to supply reliability; and
- the replacement of crossarms close to the zone substation point of supply on selected 11kV distribution feeders, to reduce the probability of 11kV equipment defects that have a high SAIDI impact.

The cost of such programmes is included in the capital expenditure forecast.

6.1.6 Defect Management

Following the asset health assessment when an asset inspected at its onset of unreliability inspection, the asset enters a defect management phase. The objective is to ensure that:

- The asset is re-inspected at appropriate intervals;
- Maintenance is undertaken as necessary to extend the life of the asset; and
- The asset is 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 will be replaced early to minimize the risk of an in-service failure whereas non-critical assets may be allowed to run to failure.

The defect management process is shown in Figure Z.Z.

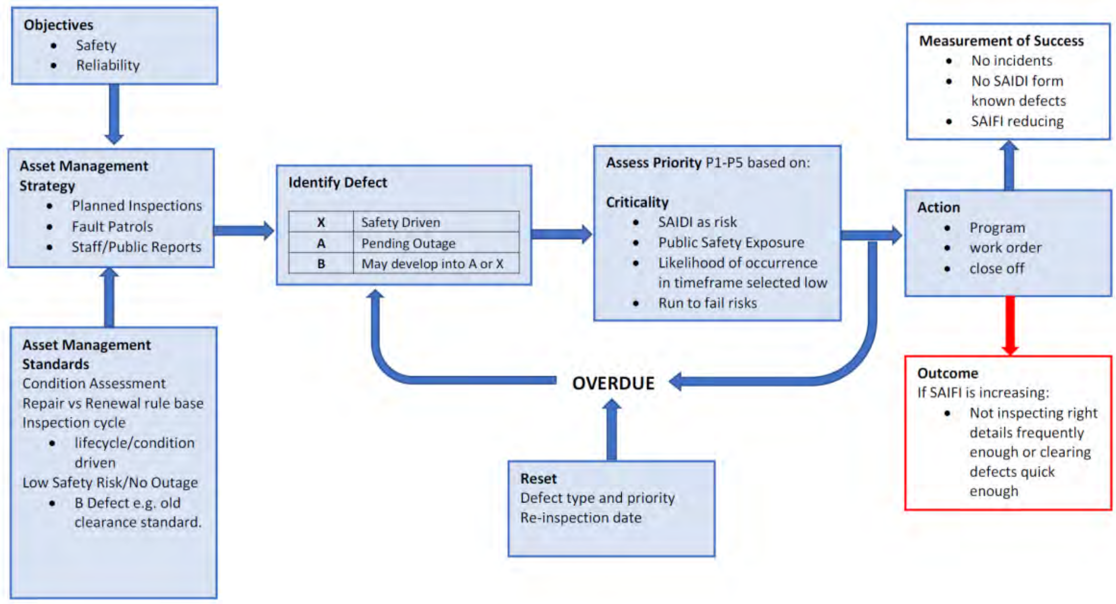


Figure 6.1: Defect Management Process

When the asset is inspected at its onset of unreliability, or earlier if a defect is identified, it is assigned a defect priority as follows:

- X defects are considered safety critical and must be made safe within 30 days;
- A defects are limited to subtransmission assets and other assets where a failure n service will result in a supply interruption or where the failure mode represents a safety risk. These defects are prioritized to determine the repair timeframe – from 3 months through to 2 years.

- B defects are considered unlikely to fail within two years or are low risk if they do (e.g. assets that can run to failure). These are on the register to capture any issues that are likely to escalate before they reach end-of-life to ensure that an appropriate inspection regime is in place. Reinspection is assigned as two-, three-, or five-year but the repair may be bundled in with planned work and addressed sooner on an opportunistic basis.

If an X or A defect is not repaired by the end of its assessed repair time, it is re-inspected and recategorized as appropriate. This approach ensures that the defect list is actively managed, and that defects are addressed in a timely manner consistent with the rate of asset deterioration. 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 programme, so we don't repair defects shortly before an asset is to be renewed. Situations may also arise where a number of 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 budget for a proactive crossarm replacement programme.

6.2 Vegetation

6.2.1 Risk Management

Lack of awareness of safety issue and tree owner 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 achieve a forced cut within three months.

Other vegetation risks include:	Our risk management strategies include:
• Ascendable trees growing close to power lines allowing access to a public zone. • Vegetation growing close to power lines presenting a future risk to power lines and public safety. • Trees at risk of falling that are within 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.	• Liaising with vegetation owner 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 using contracted resources. • Negotiation of formal agreements with tree owners on future management of the site and safety coordination. This applies particularly to commercial plantings.

6.2.1.1 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; and
- 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. Section 6.2.3 provides 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.

6.2.2 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.

6.2.3 Summary of Tree Management Practices

General.	• All lines are surveyed regularly for vegetation interference in accordance with inspection frequencies in Section 6.2.2. • 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 organise their own contractor to trim their hedges with a regular trimming cycle. • Hedge owners are encouraged to remove high hedges or reduce height to allow hedge trimmers to trim hedges without violating the regulatory minimum approach distances to live lines. • Reminder notices are issued regularly to encourage the 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 high growth rate and their potential for being pulled into lines at ground level. Notices are issued more frequently for these. 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 this option 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 responsibilities for the management of identified hazards and safe access on a 24/7 basis. Tri-partite felling plans are required for harvesting.
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 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 specific 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 affected units are 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.	• Wood poles are treated as unsafe and given a below ground inspection to determine they are safe before they are climbed. • We are ultrasonically checking all wood poles on the network for residual strength and this programme will be completed in FYE2020. The results are used to identify poles that must not be climbed and 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 restriction 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 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 13 steel tower steel towers were installed about 1966 as they were used to support the now-dismantled 50kV line that originally supplied Kaitaia. These have been well maintained and are still in serviceable condition.

Steel Poles

The 39 steel poles have all been installed since we acquired the line from Transpower in 2012. They are all in new condition.

Concrete Poles

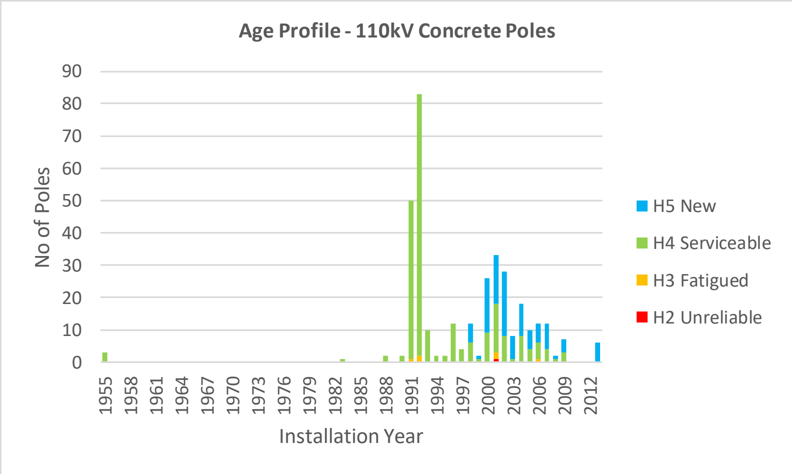


Figure 6.2: Age Profile – 110kV Concrete Poles

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 scheduled for replacement.

Concrete Poles

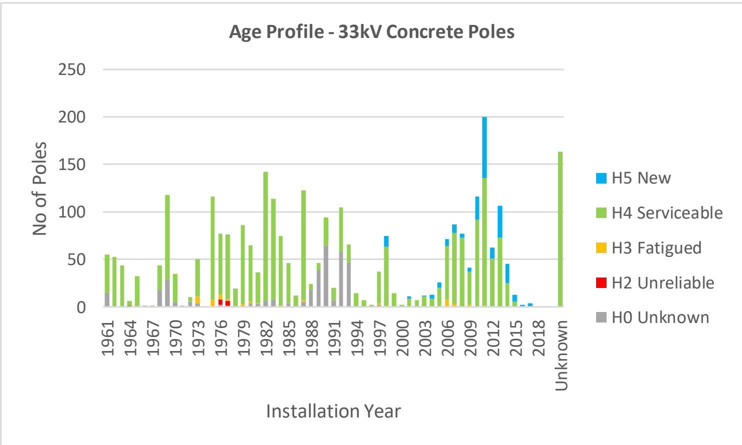


Figure 6.3: Age Profile – 33kV Concrete Poles

6.3.5.3 Distribution - Concrete

Two and Three Wire Lines

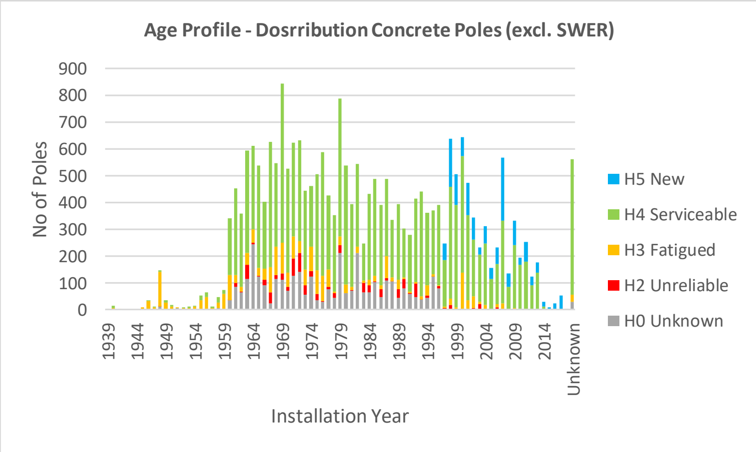


Figure 6.4: Age Profile - Distribution Concrete Poles (excl. SWER)

SWER

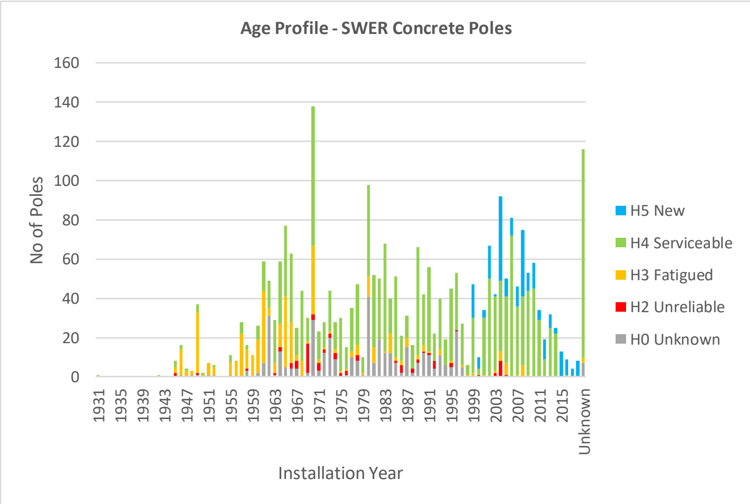


Figure 6.5: Age Profile - SWER Concrete Poles

6.3.5.4 Low Voltage

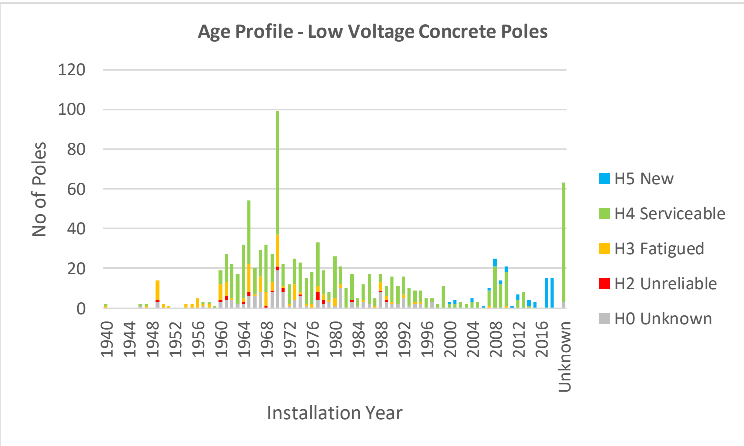


Figure 6.6: Age Profile – Low Voltage Concrete Poles

6.3.6 Wood

6.3.6.1 Subtransmission-110kV

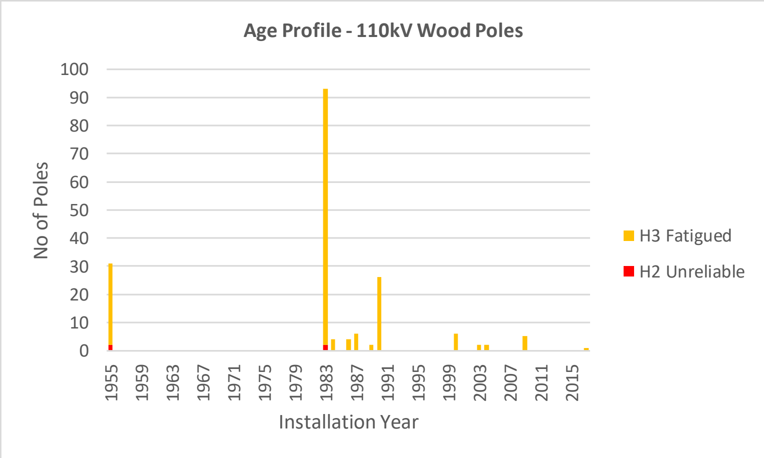


Figure 6.7: Age Profile – 110kV Wood Poles

6.3.6.2 Subtransmission-33kV

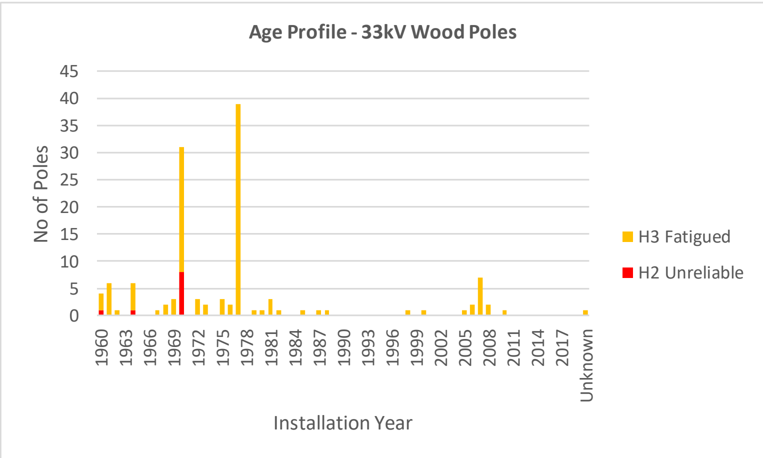


Figure 6.8: Age Profile – 33kV Wood Poles

6.3.6.3 Distribution

Two and Three Wire Lines

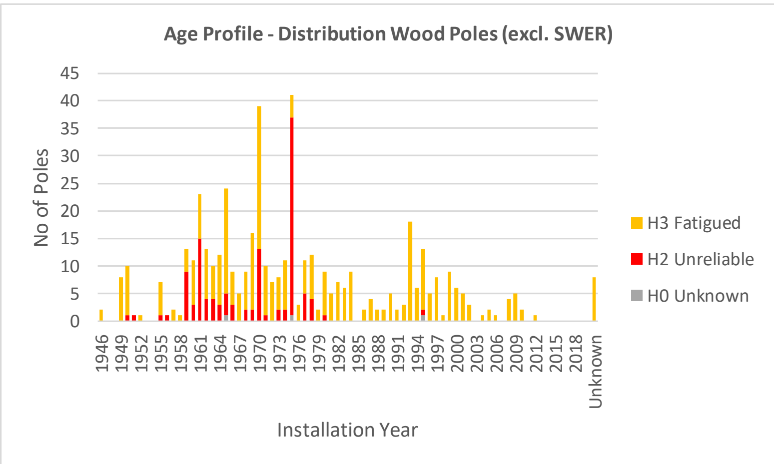


Figure 6.9: Distribution Wood Poles (excl. SWER)

SWER

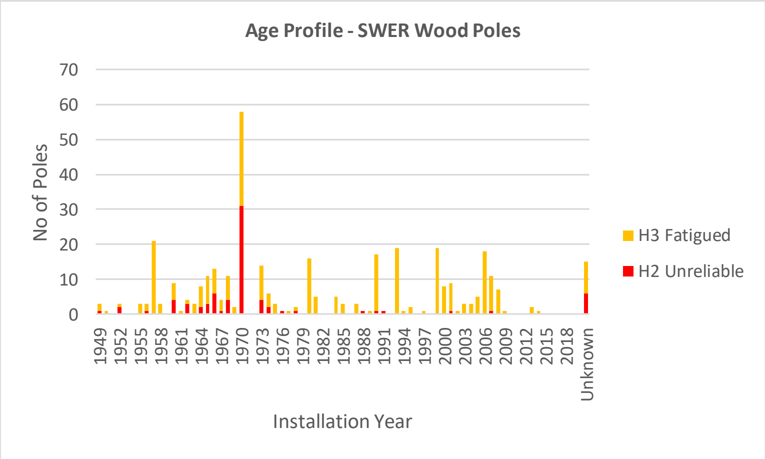


Figure 6.10: Age Profile – SWER Wood Poles

6.3.6.4 Low Voltage

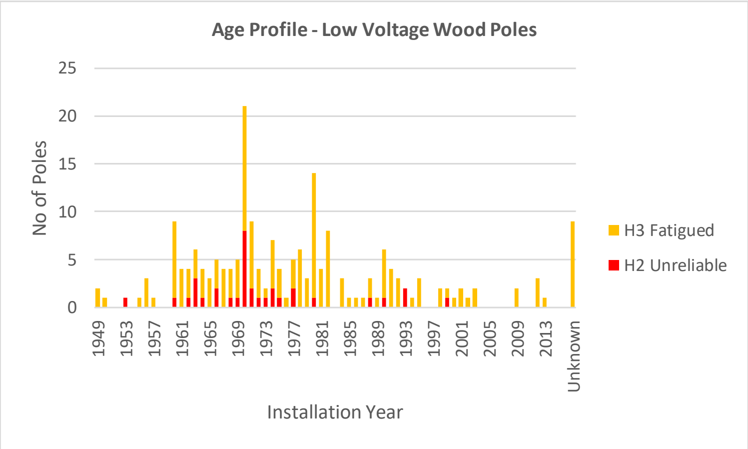


Figure 6.11: Age Profile – Low Voltage Wood Poles

6.3.7 Pole Health Summary

6.3.7.1 Steel Poles

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV	-	-	-	-	13	40	53
33kV	-	-	-	10	22	51	83

Table 6.2: Health Summary – Steel Poles

6.3.7.2 Concrete Poles

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV	-	-	1	6	233	107	347
33kV	350	-	12	46	2,376	215	2,999
11kV 2 and 3 wire	3,334	-	775	2,347	16,358	1,468	24,282
11kV SWER	379	-	80	392	1,655	230	2,736
LV	147	-	23	137	671	56	1,034
Total	**4,210**	**-**	**891**	**2,928**	**21,293**	**2,076**	**31,398**

Table 6.3: Health Summary – Concrete Poles

6.3.7.3 Wood Poles

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV	-	-	4	178	-	-	182
33kV	-	-	10	118	-	-	128
11kV 2 and 3 wire	3	-	118	355	-	-	476
11kV SWER	-	-	77	289	-	-	366
LV	-	-	34	165	-	-	199
Total	**3**	**-**	**243**	**1,105**	-	-	**1,351**

Table 6.4: 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, since pole deterioration is often internal and can be hard to detect. We are planning for the proactive replacement of over 120 poles per year, which will see all wood poles on the network replaced over the next 12 years. We also have an ultrasonic test programme in place to assess the integrity of all wood poles on the network and are prioritizing replacements using the results of this 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

In FYE2018, equipment failures accounted for 24% of the total SAIDI impact of unplanned interruptions. A total of 43% of this impact was due to 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.

From FYE2022, we will be 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 therefore capitalised.

Our capital expenditure forecast provides for the proactive replacement of 200 crossarms in FYE2022 and 250 crossarms per year after that.

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).
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 competent 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 planning a follow-up assessment in 2019 to determine the rate of any deterioration. We are also installing vibration dampers when any structures on the line are replaced. Nevertheless, the age of the conductor is such that it is likely to need replacement after 2030, by which time it will be more than 60 years old.

We also have 36km of AAAC conductor on our Kaikohe-Wiroa 10kV line, which is currently operating at 33kV. This was installed between 2011 and 2015 and is in new condition.

6.5.6 Subtransmission-33kV Conductor

Most of our 285km of 33kV subtransmission conductor is AAC, although ACSR has been used over about 33km where extra strength is required. Approximately 20km of recently installed conductor is AAAC. An age profile of our 33kV subtransmission conductor is shown below.

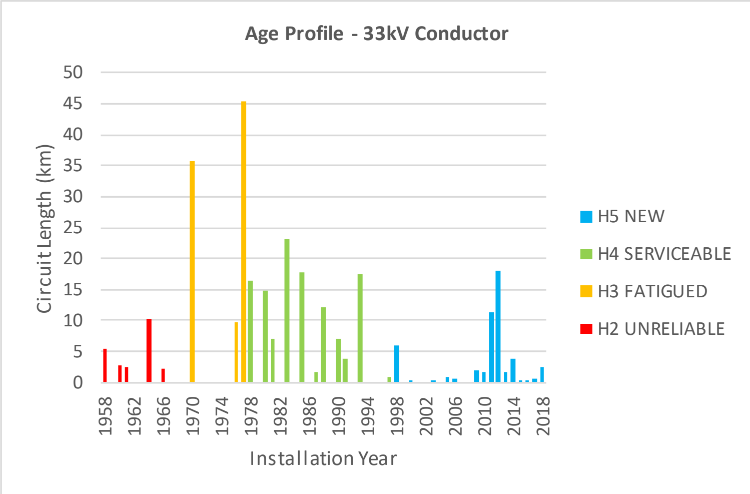


Figure 6.12: Age Profile – 33kV Conductor

6.5.7 Distribution Conductor – Two and Three Wire Lines

6.5.7.1 Aluminium and ACSR

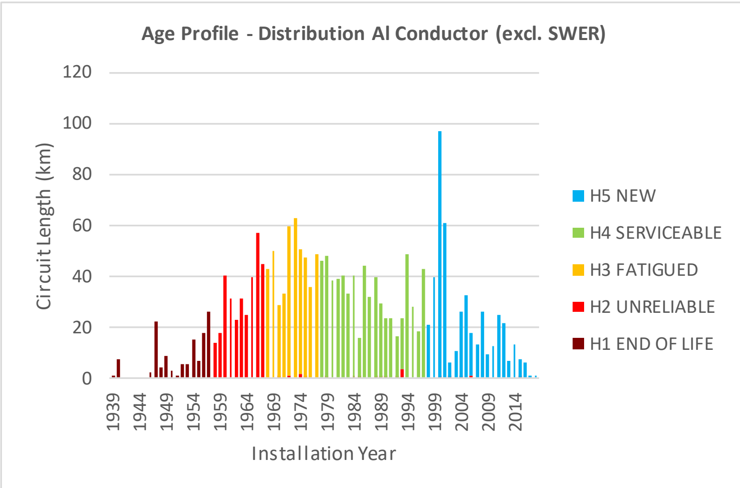


Figure 6.13: Age Profile – Distribution Aluminium and ACSR Conductor (excl. SWER)

6.5.7.2 Copper

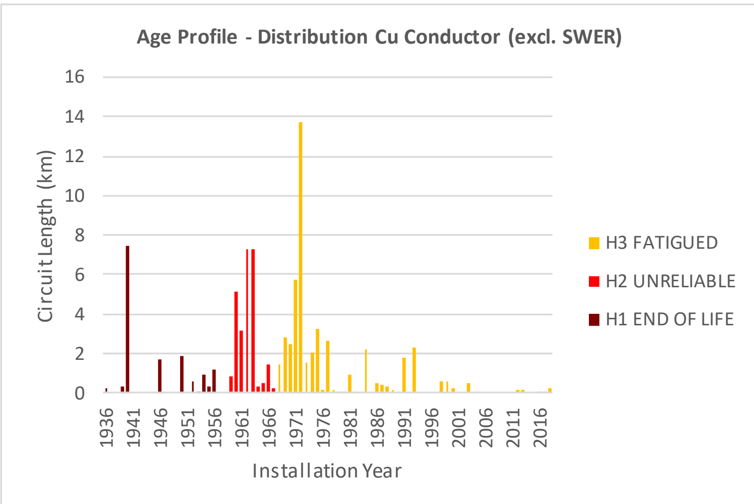


Figure 6.14: Age Profile - Distribution Copper Conductor (excl. SWER)

6.5.7.3 Steel

There is less than 1km 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

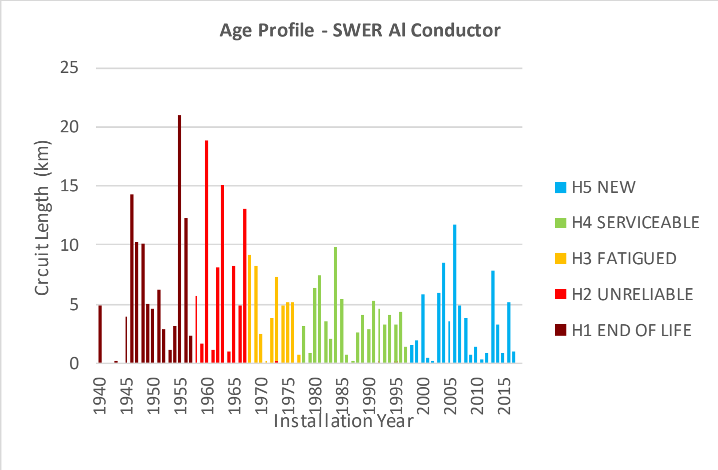


Figure 6.15: Age Profile – SWER Aluminium and ACSR Conductor

6.5.8.2 Copper

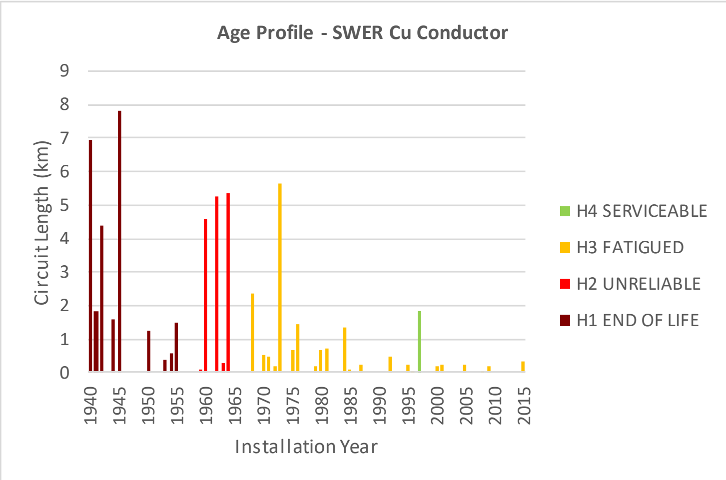


Figure 6.16: Age Profile – SWER Copper Conductor

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

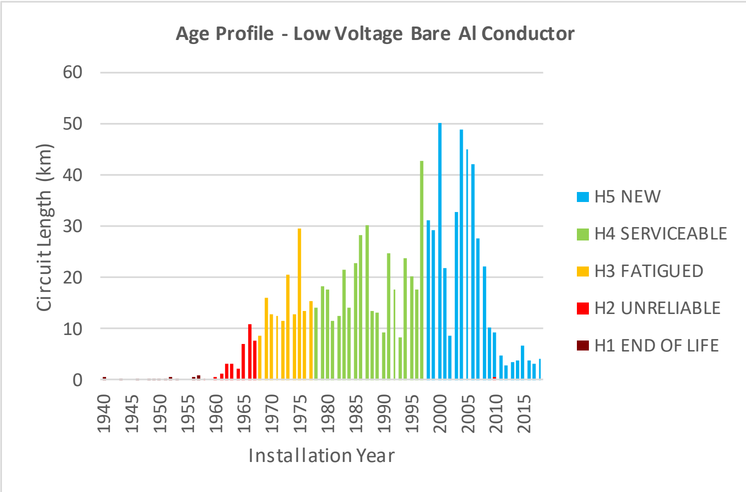


Figure 6.17: Age Profile – Low Voltage Aluminium and ACSR Conductor

6.5.9.2 Copper

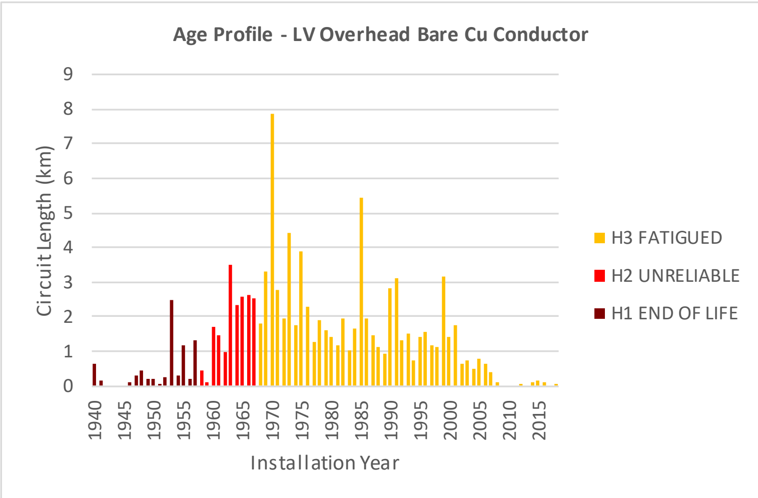


Figure 6.18: Low Voltage Copper Conductor

6.5.10 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	-		23	91	121	49	284
11kV 2 and 3 wire	-	125	332	458	665	452	2,032
11kV SWER	-	102	78	47	75	70	372
LV	-	3	36	153	382	411	985
Total	**-**	**231**	**469**	**749**	**1,243**	**983**	**3,675**

Table 6.5: 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 and 3 wire	-	15	26	47	-	-	88
11kV SWER	-	26	16	16	2	-	60
LV	-	8	18	78	-	-	104
Total	**-**	**49**	**60**	**142**	**2**	**-**	**252**

Table 6.6: 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		2	3	3	4	10	22

Table 6.7: Health Summary – Conductor (Unknown Material)

6.5.11 Replacement Programme

Between April 2015 and December 2018, conductor faults accounted for 21% of the SAIDI impact of unplanned interruptions resulting from equipment failure. From FYE2021, we are planning to replace up to 10 cct-km of conductor per year. This will be 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 250km 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 following an event.

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 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 as new condition.

6.6.6 Distribution (XLPE/PVC)

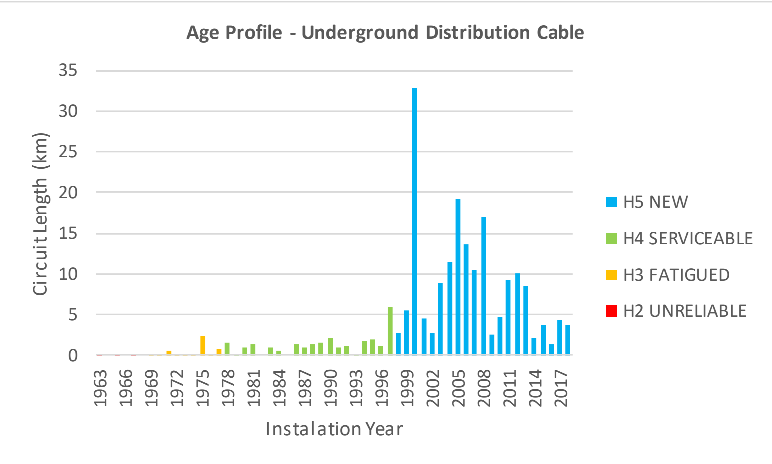
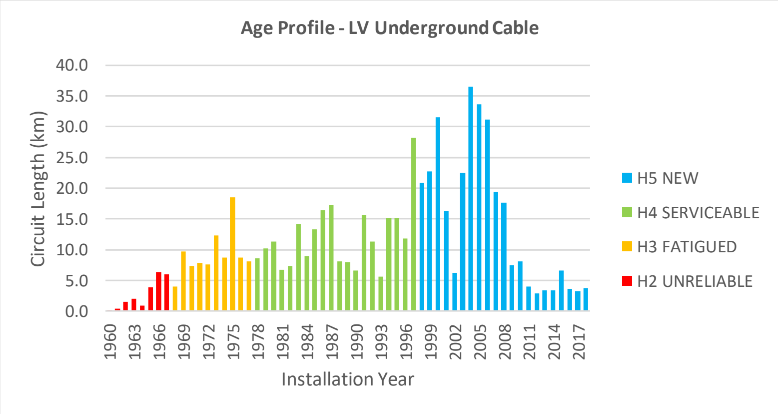


Figure 6.19: Age Profile – Underground Distribution Cable



Note: Excludes streetlight cable

Figure 6.20: 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	-	-	-	-	-	21	21
Distribution	-	-	0.1	4	25	179	208
LV	-	-	21	93	240	305	971
Total	-	-	21	96	265	505	887

Table 6.8: Health Summary – Underground Cable

6.6.8 Replacement Strategy

The small quantity of cable classified as unreliable 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

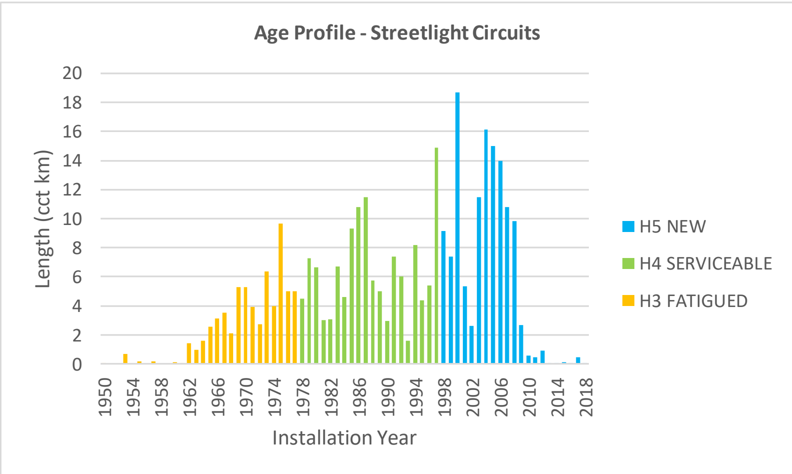


Figure 6.21: Age Profile – Streetlight Circuits

6.7.2 Streetlight Circuit Health Summary

cct-km	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	-	64	129	126	319

Table 6.9: 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 risk-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

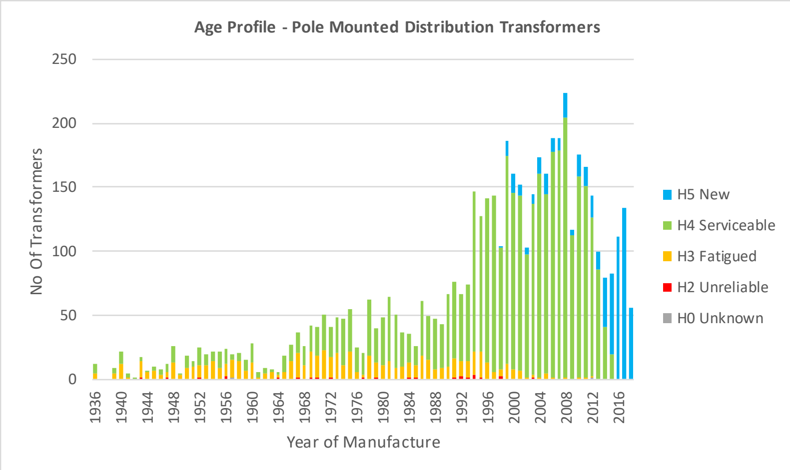


Figure 6.22: Age Profile – Pole Mounted Distribution Transformers

6.8.3.2 Ground Mounted Distribution Transformers

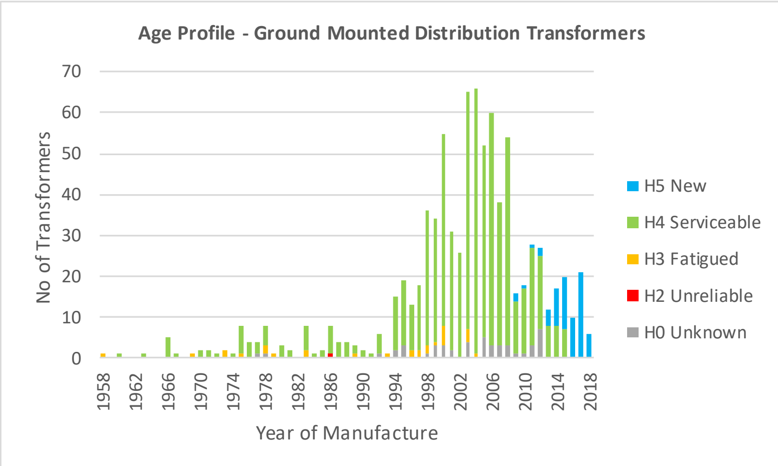


Figure 6.23: Age Profile – Ground Mounted Distribution Transformers

6.8.3.3 Ground Mounted Substation Housings

We have only five distribution substations situated in our 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	2	-	25	691	3,912	589	5,219
Ground mounted	47	-	1	28	700	69	845
Total	**49**	**-**	**26**	**719**	**4,612**	**658**	**6,064**

Table 6.10: Health Summary – Distribution Transformers

6.8.5 Replacement Strategy

Our distribution transformer fleet is generally good condition with only 0.4% considered unreliable. 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.

Our forecast allows for the replacement of four pole mounted transformers and two ground mounted transformers annually.

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; or • 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

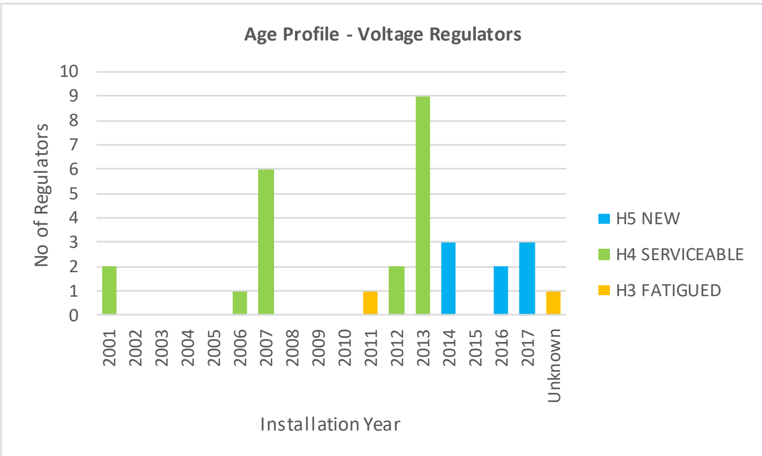


Figure 6.24: Age Profile – Voltage Regulators

6.8.6.7 Voltage Regulator Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	-	2	30	8	40

Table 6.11: 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. Nevertheless, our forecast allows for the proactive replacement of the two voltage regulators in fatigued condition during the planning period.

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 around 1940 and remains in a serviceable condition.

Waipapa Substation will be upgraded during the planning period. A new switchgear building will be constructed, new indoor 11kV switchgear installed and the transformers lowered to ground level in FYE2021. New 33kV switchgear is to be installed in FYE2026.

Asbestos is present at some substations. This asbestos is non-friable and low risk, and 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 unauthorised persons.	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 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, waste water), pests, leaks (e.g. building, water pipes, waste water 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 110kV Substations

We have two 110kV substation buildings; one constructed in 1939 and the other in 1945. Both remain in a serviceable condition.

6.9.1.7 Age Profile – 33kV Substation Buildings

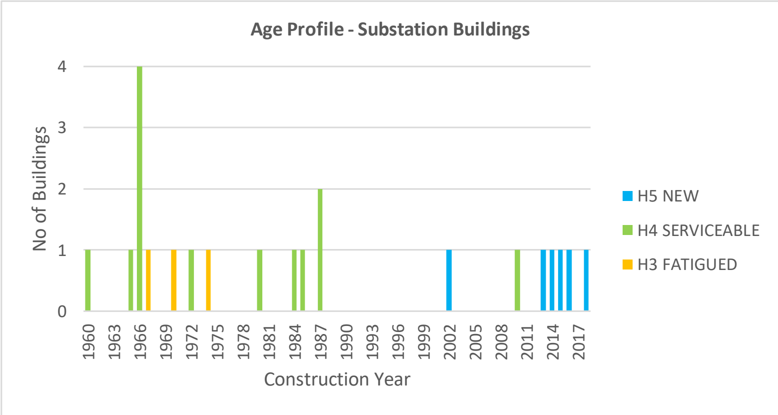


Figure 6.25: Age Profile – Substation Buildings

6.9.1.8 Substation Building Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	-	**3**	**13**	**6**	**22**

Table 6.12: Health Summary – Substation Buildings

6.9.1.9 Replacement Strategy

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

6.9.2 Power Transformers

6.9.2.1 Age Profile

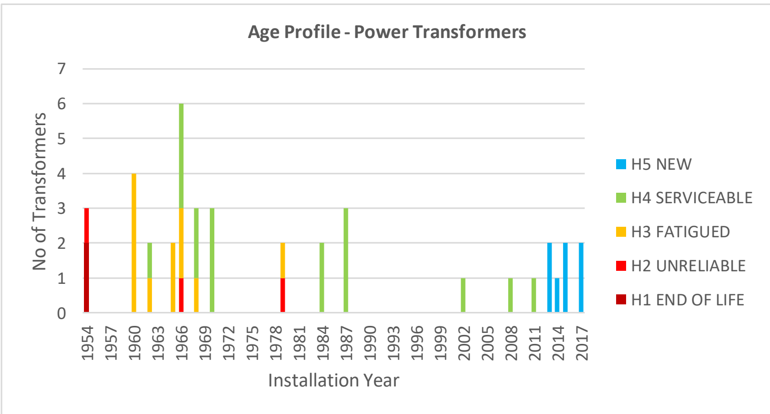


Figure 6.26: Age Profile – Power Transformers

6.9.2.2 Power Transformer Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV	-		1	7	5	1	14
33kV	-	2	2	4	12	6	26
Total	-	**2**	**3**	**11**	**17**	**7**	**40**

Table 6.13: Health Summary – Power Transformers

6.9.2.3 Power Transformer Replacement Strategy

An H2, 110kV transformer is located at Kaitaia and is scheduled for replacement in FYE2029. This is a single-phase bank with each phase winding contained in a separate tank. As the old transformer, which was also a single-phase bank and replaced in FYE2016, has not been removed, there are a total of seven identical single-phase tanks located at the substation, only three of which need to be in service. The new transformer at Kaitaia has ample capacity to carry the full substation load and we are confident of being able to keep a second bank in service over the medium-term, by swapping out single-phase tanks if required.

Three of the four H1 and H2, 33kV transformers are located at Omanaia. This bank is being replaced with a new three phase transformer. The other 33kV, H2 transformer is a three-phase bank at Okahu Rd, which is categorised as unreliable due to low insulation test results. A second transformer, with sufficient capacity to carry the full substation load, is in service. Should the H2 transformer fail unexpectedly, we would replace it with the mobile substation as an interim measure. A proactive replacement of the unit is not warranted at this point.

6.9.3 Circuit Breakers

6.9.3.1 Outdoor 110kV Circuit Breakers

We have ten outdoor 110kV circuit breakers, but the age of two of these is not shown in our records.

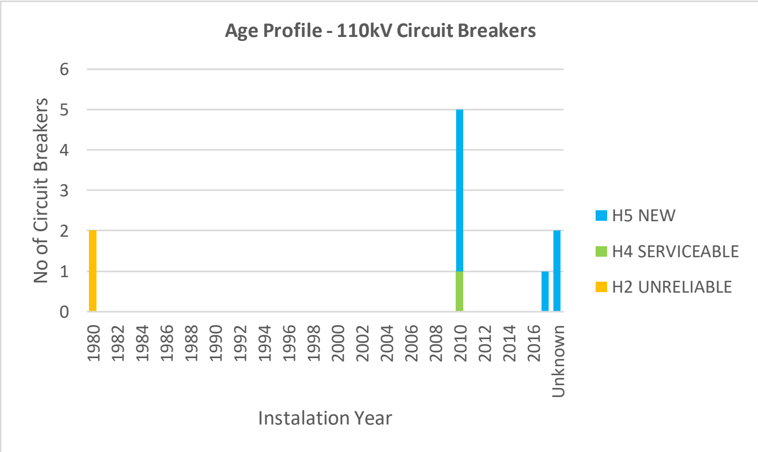


Figure 6.27: Age Profile – 110kV Circuit Breakers

6.9.3.2 Indoor 33kV Circuit Breakers

We have a total of 44 indoor 33kV circuit breakers on the network installed between 2013 and 2017. All are in new condition.

6.9.3.3 Outdoor 33kV Circuit Breakers

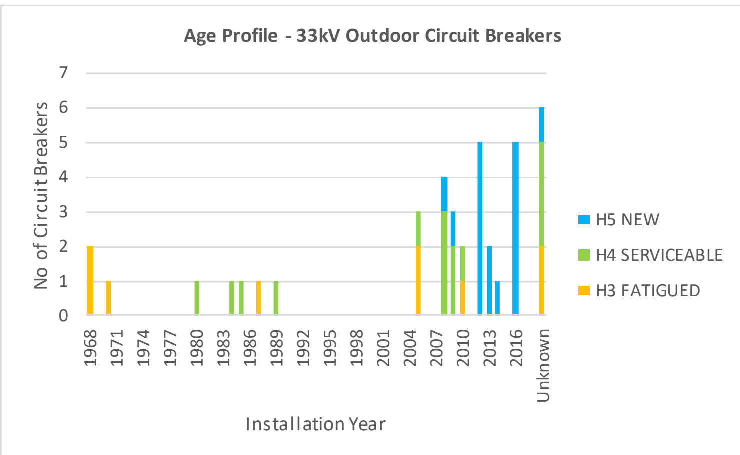


Figure 6.28: Age Profile – 33kV Outdoor Circuit Breakers

6.9.3.4 Indoor 11kV Circuit Breakers

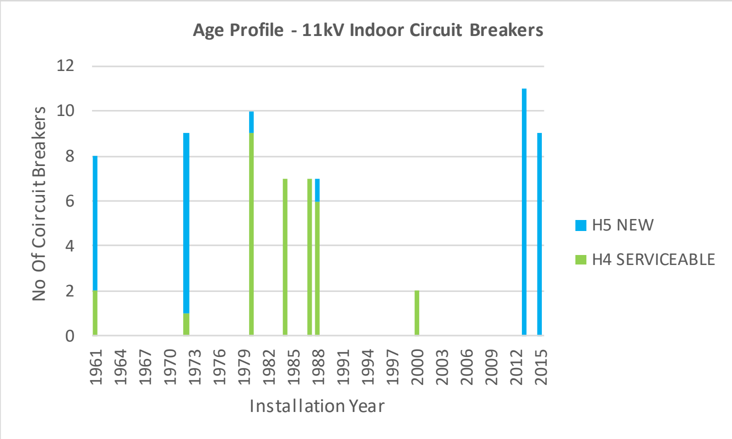


Figure 6.29: Age Profile – 11kV Indoor Circuit Breakers

6.9.3.5 Outdoor 11kV Circuit Breaker

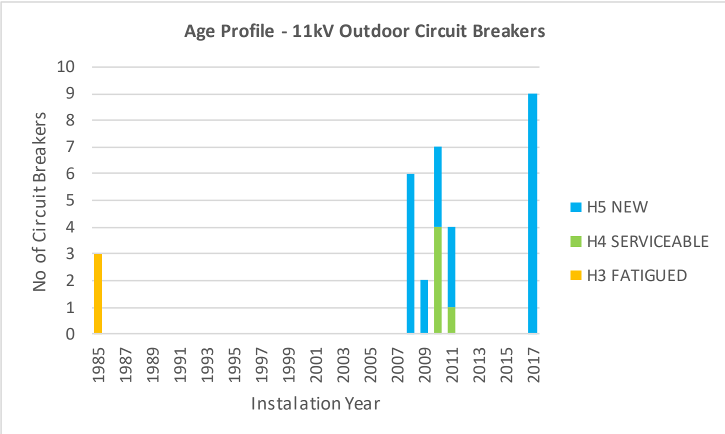


Figure 6.30: Age Profile – Circuit Breakers

6.9.3.6 Circuit Breaker Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV Outdoor	-	-	2	-	1	7	**10**
33kV Indoor	-	-	-	-	-	44	**44**
33kV Outdoor	-	-	-	8	12	14	**34**
11kV Indoor	-	-	-	-	34	36	**70**
11kV Outdoor	-	-	-	3	5	23	**31**
Totals	**-**	**-**	**2**	**12**	**54**	**126**	**194**

Table 6.14: Health Summary – Circuit Breakers

6.9.3.7 Circuit Breaker Replacement Strategy

We plan to replace the two 110kV, H2 circuit breakers located at Kaitaia by FYE2025. Refurbishment of the Waipapa substation will release six outdoor 33kV circuit breakers and nine outdoor 11kV breakers. Some of these are in good condition and will be available to replace fatigued circuit breakers elsewhere. The three fatigued 11kV units are at Omanaia and will be replaced during the substation refurbishment.

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 mediums 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; and
- 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 requirements;
- Flammability in certain failure conditions; and
- 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; or • 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 enables 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. Six-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

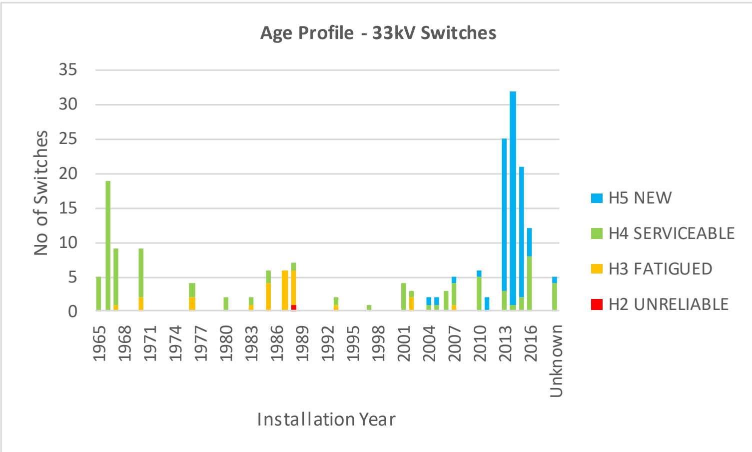


Figure 6.31: Age Profile – 33kV Switches

6.10.6.2 Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	1	25	85	83	194

Table 6.15: Heath Summary – 33kV Switches

6.10.7 Overhead Distribution Switches

6.10.7.1 Age Profile

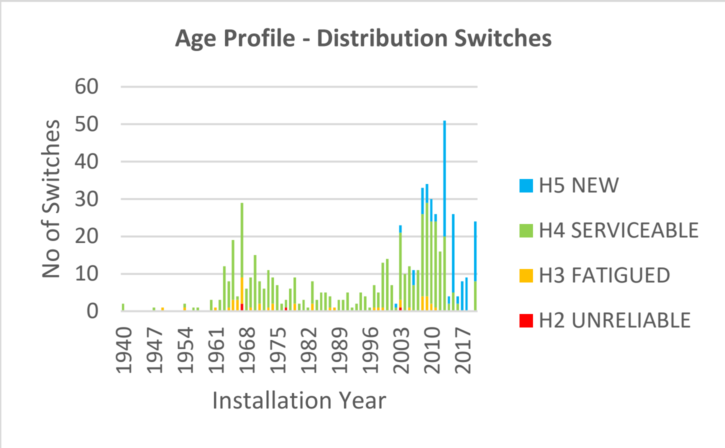


Figure 6.32: Age Profile – Overhead Distribution Switches

6.10.7.2 Overhead Distribution Switch Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	4	46	448	116	614

Table 6.16: Health Summary – Distribution Switches

6.10.8 Sectionalisers

6.10.8.1 Age Profile

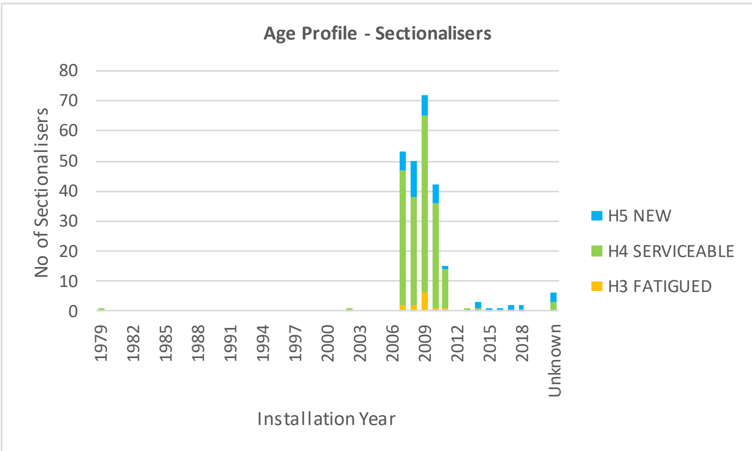


Figure 6.33 Age Profile - Sectionalisers

6.10.8.2 Sectionaliser Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	-	12	195	43	250

Table 6.17: Health Summary – Sectionalisers

6.10.9 Reclosers

6.10.9.1 Age Profile

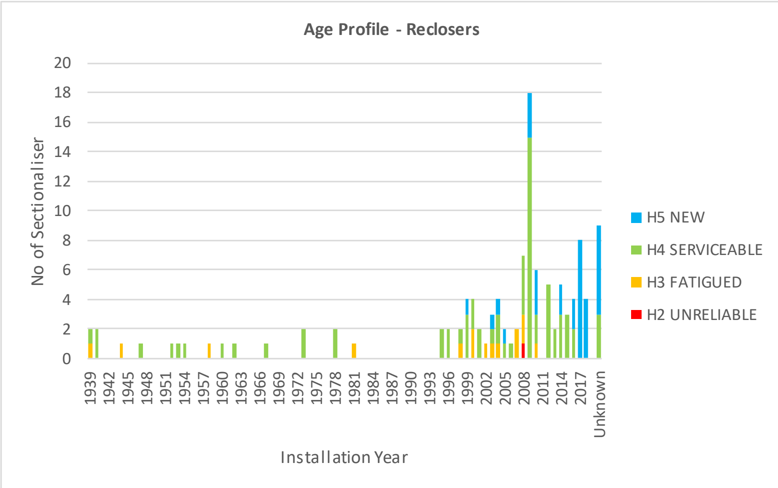


Figure 6.34: Age Profile - Reclosers

6.10.9.2 Recloser Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	1	15	70	32	118

Table 6.18: Health Summary - Reclosers

6.10.10 Ring Main Units

6.10.11 Age Profile

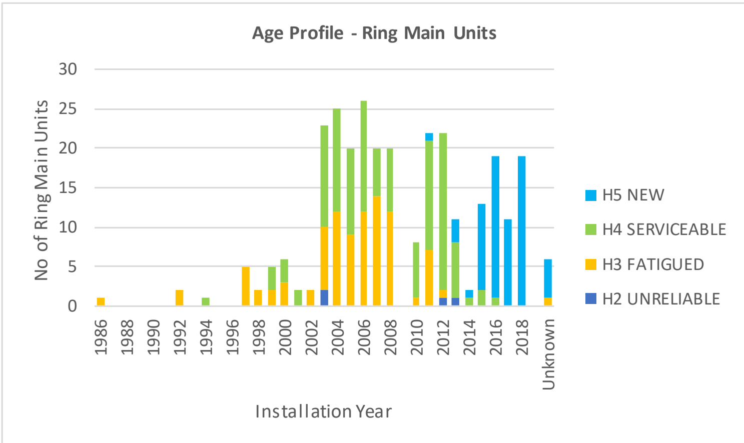


Figure 6.35: Age Profile – Ring Main Units

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	94	126	69	293

Table 6.19: Health Summary – Ring Main Units

6.10.12 Distribution Fuses

6.10.12.1 Age Profile

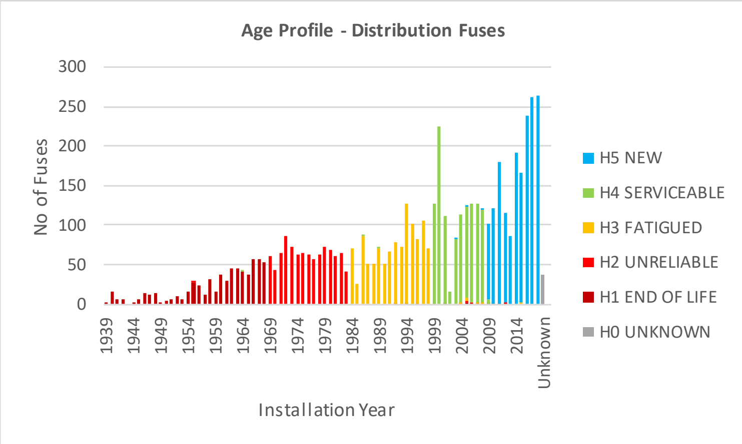


Figure 6.36: Age Profile – Distribution Fuses

6.10.12.2 Distribution Fuse Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	37	641	957	1,120	1,167	1,721	5,643

Table 6.20: 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. Nevertheless, our capital expenditure forecast allows for the proactive replacement of approximately 25 fuses per year.

6.10.14 Underground service fuse boxes

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

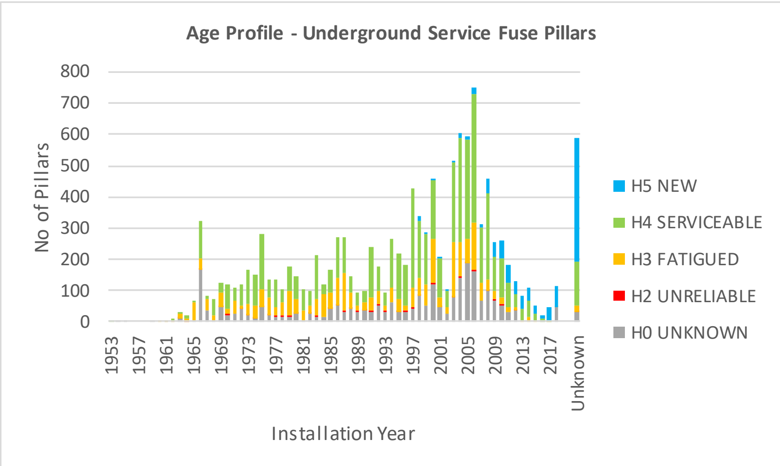


Figure 6.37: Age Profile – Underground Service Pillars

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	**2.548**	**-**	**87**	**2,526**	**6,033**	**961**	**12,065**

Table 6.21: 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 proactively 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; or • 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 are 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

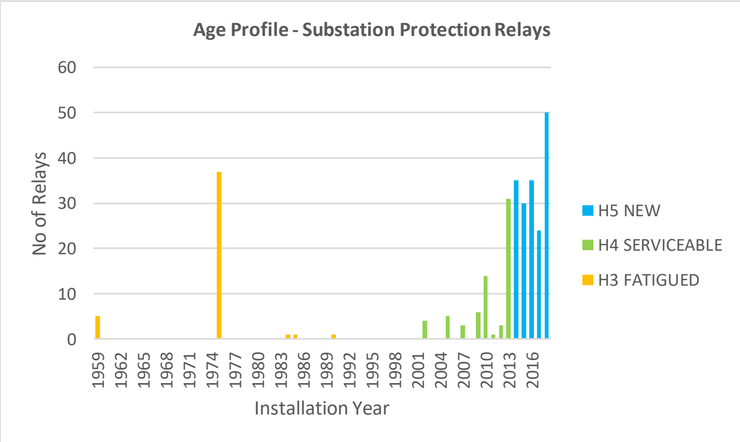


Figure 6.38: Age Profile – Substation Protection Relays

6.11.1.6 Protection Relay Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	-	1	45	67	175	288

Table 6.22: 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 are replacing our SCADA system 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; or • 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	Communication systems are routinely checked and tested. These systems are often self-monitoring and provide warnings if conditions indicate a problem.
Server failure	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[8] 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.

[8] 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.

6.11.3.2 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

6.11.3.5 Age Profile

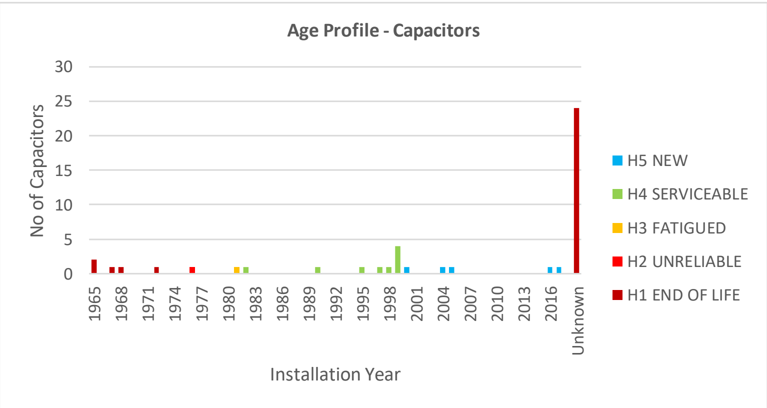


Figure 6.39: Age Profile - Capacitors

6.11.3.6 Health Summary

Condition information is presently age-based. Defect reports do not support the number of units identified as 'end-of-life', indicating the actual condition is better than what the age profile suggests. As the quality of this information is improved the true condition profile will emerge.

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Totals	-	29	1	1	9	5	45

Table 6.23: 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, many units have now reached end-of-life. We are planning to replace one unit per year from FYE2021.

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 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 6.1.5, is shown in Table 6.27.

6.12.1 Service Interruptions and Emergencies

($000, real)	FYE									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Lines and poles	416	407	398	390	381	372	364	355	346	338
Cables and pillars	227	222	217	212	208	203	198	194	189	184
Transformers	20	19	19	18	18	18	17	17	16	16
Buildings and grounds	1	1	1	1	1	1	1	1	1	1
Switchgear and protection	239	234	229	224	219	214	209	204	199	194
Secondary systems	297	291	285	279	272	266	260	254	248	241
Total	**1,199**	**1,174**	**1,149**	**1,124**	**1,099**	**1,074**	**1,049**	**1,024**	**999**	**974**

Note: Totals may not add due to rounding

Table 6.24: Service Interruptions and Emergency Maintenance OPEX by Category

6.12.2 Routine and Corrective Maintenance

($000, real)	FYE									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Routine maintenance & inspection	**2,071**	**1,994**	**2,020**	**2,034**	**1,974**	**1,926**	**2,076**	**2,060**	**2,023**	**2,067**
Vegetation	**1,787**	**1,787**	**1,787**	**1,787**	**1,787**	**1,787**	**1,787**	**1,799**	**1,812**	**1,824**
Asset replacement & renewal										
Lines and poles	461	461	461	461	461	461	461	461	461	461
Cables and pillars	181	181	181	181	181	181	181	181	181	181
Transformers	192	192	192	192	192	192	192	192	192	192
Buildings and grounds	142	142	142	142	142	142	142	142	142	142
Switchgear and protection	106	106	106	106	106	106	106	106	106	106
Secondary systems	24	24	24	24	24	24	24	24	24	24
Subtotal – replacement & renewal	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**	**1,106**
TOTAL	**4,963**	**4,887**	**4,913**	**4,926**	**4,867**	**4,818**	**4,968**	**4,965**	**4,940**	**4,997**

Note: Totals may not add due to rounding

Table 6.25: Breakdown of Routine and Corrective Maintenance

6.12.3 Summary of Maintenance Opex Forecast

($000, real)	FYE									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Service interruptions and emergencies	1,199	1,174	1,149	1,124	1,099	1,074	1,049	1,024	999	974
Routine maintenance and inspection	2,071	1,994	2,020	2,034	1,974	1,926	2,076	2,060	2,023	2,067
Vegetation	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,799	1,812	1,824
Replacement and renewal	1,106	1,106	1,106	1,106	1,106	1,106	1,106	1,106	1,106	1,106
Total	**6,162**	**6,060**	**6,061**	**6,050**	**5,965**	**5,892**	**6,017**	**5,988**	**5,938**	**5,970**

Note: Totals may not add due to rounding

Table 6.26: Breakdown of Maintenance Opex Forecast

6.12.4 Breakdown of Maintenance Capex Forecast

($000, real)	FYE									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Transmission and subtransmission lines	4,373	1,353	1,352	931	1,260	935	935	939	941	943
Transmission and zone substations	59	64	63	64	138	66	67	68	69	70
Distribution lines	2,446	2,647	3,961	4,648	4,562	4,431	4,377	3,966	4,188	4,058
Distribution cables	109	193	192	193	194	195	196	197	198	199
Distribution substations and transformers	488	673	752	683	508	510	512	514	516	518
Distribution switchgear	647	813	871	900	903	905	908	911	915	918
Other network assets	405	187	98	98	98	99	99	99	100	100
Total	8,527	5,930	7,289	7,517	7,662	7,142	7,095	6,695	6,926	6,806

Note: Excludes accelerated asset replacements with safety and supply reliability drivers

Table 6.27: 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 described in Section 5.14. This situation is not expected to change over the planning period and, apart from the new ADMS, expenditure is 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 the ADMS and other 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; and

  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 2.3; and
- 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 6.8 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									
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**20298**
System operations and network support	6,029	6,149	6,272	6,398	6,526	6,421	6,435	6,563	6,695	6,828
Business support	5,198	5,302	5,408	5,516	5,626	5,739	5,854	5,971	6,090	6,212
Total	**11,227**	**11,451**	**11,680**	**11,914**	**12,152**	**12,160**	**12,288**	**12,534**	**12,785**	**13,041**

Table 6.28: 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 commits the Group to undertaking 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 authorities;
- 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; and
- 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; and
- 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 Networks Risk Management Committee

TEN has its own specialised network risk committee consisting of the following personnel:

- General Manager Network;
- Network Maintenance Manager;
- Network Operations Manager;
- Network Planning Manager; and the
- Network Project Delivery Manager.

One member is nominated to manage the committee, organise four-monthly meetings, second other internal expertise as required and be responsible for updating the risk register.

The network risk committee is responsible for reviewing and maintaining 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; and
- 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: 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.

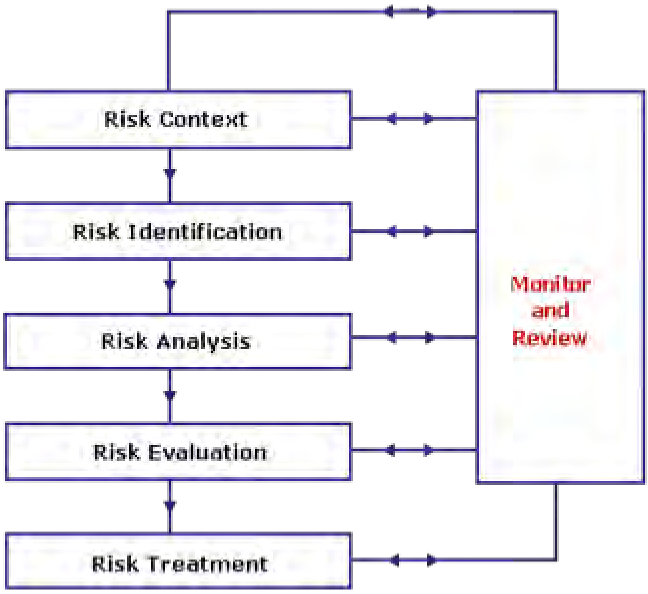


Figure 7.1 Network risk management process

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:

GENERAL MANAGEMENT	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.
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 TEN to recognise, assess and manage 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 and/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 delivers 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 each risk that is 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.

7.2.4 Risk analysis outcome

Table 7.3 schedules our top network risks, together with the existing controls associated with these risks and further risk mitigation actions to be implemented. High impact faults with a very low probability of occurrence, such as a complete loss of supply from a zone substation, are not included in the table. Should such an event arise, the Emergency Preparedness Plan discussed in Section 7.3.2 would be activated.

No.	Risk	Probability	Consequence	Mitigation/Comment
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 NZS7901 in place. Current focus areas include improved protection coordination, pre-livening safety checks and testing, and cutting trees in contact with lines.
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 as best practice standard. • Assessment of asset management capability and maturity, and continuous improvement as per the standard. • The use of external consultancy when inhouse capability insufficient. Asset management is TEN's core responsibility. Current focus areas include provisioning for new technology and increased distributed generation, installation of an ADMS, upskilling staff, and aligning to industry practice guides (such as the use of asset health indicators).
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. Current focus areas include the development of 110kV line construction and conductor renewal capability within TECS.
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. Current focus areas include integration of generation fleet into the wider network, development of islanding capability following the Ngawha expansion, identification of network vulnerabilities and the development of documented fault response plans.

No.	Risk	Probability	Consequence	Mitigation/Comment
19.	Loss of incoming grid supply for more than 24 hours.	Moderate, mitigated to low.	Loss of grid supply to all consumers.	At present, Ngawha cannot be run islanded due to technical limitations, so consumers would lose supply until the grid connection is restored. However, the new unit at Ngawha (Unit 4 - to be commissioned in 2020) will be capable of islanded operation and will be used as an alternative source of supply, supported by the new Kaitaia generation in a load following/frequency keeping role during any loss of grid connection. The network currently has 7MW of diesel generation it can deploy to critical load locations in the event of sustained loss of grid supply. Current focus areas include increasing local generation (including Ngawha) to achieve self-sufficiency and reviewing Transpower's contingency and conductor renewal plans.
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.
Risks Derived from TEN's Network Risk Register				
1.	Public safety – line and field located assets.	Moderate.	Potential fatality or serious injury.	All network assets accessible to the public are a potential public safety risk. We operate a public safety management system certified to NZS 7901 to mitigate this risk.
2.	Public safety – substation assets.	Low.	Potential fatality or serious injury.	All substation assets are located in a locked building or a locked fenced enclosure. Substations have intrusion alarms, and closed-circuit television monitored from our control room to guard against unauthorised access.

No.	Risk	Probability	Consequence	Mitigation/Comment
3.	Unplanned interruption of Kaikohe-Kaitaia 110kV line.	About once every two years.	Loss of grid supply to northern area consumers.	We are installing sufficient generation in the northern area to restore supply to all northern area consumers, apart from the Junken Nissho mill, without waiting for the line fault to be repaired. With the commissioning of the Kaeo substation and the installation of a voltage regulator at Mangonui, there is also a limited amount of grid support capacity available from the southern network. We have agreed with Junken Nissho that, in the event of a fault, we will provide sufficient diesel generation capacity for a managed plant shutdown, but restoration of a full supply would be delayed until the fault is repaired.
4.	Fault on 33kV Kaikohe-Omanaia line or failure of Omanaia transformer.	Line fault: about once a year. Transformer fault: unlikely.	Loss of supply to South Hokianga area.	This line is in poor condition and requires refurbishment. We are planning to temporarily locate a generator at Omanaia substation to provide a supply during line refurbishment outages. The generator will also be used during unplanned interruptions. The transformer is being replaced with a new unit. In the event of this failing, the transformer will be replaced by the mobile substation as a medium-term solution.
5.	Fault on 33kV Kaitaia-Taipa line or loss of Taipa transformer.	Line fault: about once a year. Transformer fault: unlikely.	Loss of supply to Taipa/Doubtless Bay.	This line is currently being refurbished to reduce the fault probability. Taipa generation and support from the Kaeo substation will be used to restore supply before repair time. The mobile substation will be relocated to Taipa as a medium-term solution in the event of a transformer failure.
6.	Fault on 33kV Kaitaia-Pukenui line or loss of Pukenui transformer.	Line fault: about once a year. Transformer fault: unlikely.	Loss of supply to Cape Reinga peninsula.	There is sufficient distribution transfer capacity to supply the Pukenui South feeder after a short interruption and we are planning to locate a mobile generator on the Ta Kao feeder if required. The mobile substation will be relocated to Pukenui as a medium-term solution in the event of a transformer failure.
7.	Failure of the Mt Pokaka transformer.	Unlikely.	Loss of supply to Mt Pokaka mill, and small-use consumers in Puketona and south-west of Kerikeri.	There is sufficient distribution transfer capacity to restore supply to small-use consumers after a short interruption. Restoration of supply to the mill will not occur until after the mobile substation has been relocated to the site. The reduced security of supply to the mill has been agreed with the consumer.

No.	Risk	Probability	Consequence	Mitigation/Comment
8.	Fault on the Waipapa-Kaeo line.	About once a year.	Loss of supply to Whangaroa consumers.	There is sufficient distribution transfer capacity from Waipapa and Taipa substations to supply the load in this event. Kaeo substation has two transformers.
9.	Faults on other 33kV lines or transformers.	Lines: less than once a year per line. Transformers: low.	No loss of supply.	There is sufficient redundancy in the network to prevent any loss of supply when such events occur.
10.	Loss of supply from Waipapa substation.	Unlikely.	Loss of supply to consumers in the Waipapa, Purerua, Takao Bay, Riverview and Puketi areas.	This substation is old and is scheduled for refurbishment in FYE2021, primarily for safety and environmental reasons. In the meantime, a complete loss of supply is unlikely, as the substation has two incoming lines. In such an event, supply to most consumers could be provided from the Kaeo, Kerikeri and Mt Pokaka substations. It might be necessary to locate a generator on the Purerua feeder to support the load at times of peak demand.
11.	Failure of Kaitaia T5 transformer.	Moderate.	No loss of supply.	This is an old bank of single-phase units and the loss of one phase is a possibility. In this event, supply would be provided by the new lightly-loaded T1 transformer with generation as backup. There is a spare single-phase unit on site and the old T4 bank, while no longer energised, is still in place. Therefore, there are four single-phase units on site that could be used to replace the faulted phase.
12.	Failure of new Kaitaia T1 transformer.	Unlikely.	Possible loss of supply to some consumers.	This transformer is new, lightly-loaded and fault levels in the Kaitaia area are low. In the unlikely event of a failure, supply could be restored to all consumers using the T5 bank with generation support. The T4 bank could also be recommissioned to provide additional grid support. Transpower has spare transformers available that we could lease, if necessary, until the transformer was repaired or replaced.
13.	Failure of Kaikohe 110kV transformers.	Unlikely.	No loss of supply.	In the event of a failure of one of the Kaikohe 110kV transformers, there could be insufficient transformer capacity to supply the southern area from the grid. The existing generators at Ngawha feed directly into the 33kV network and would prevent any loss of supply.

No.	Risk	Probability	Consequence	Mitigation/Comment
14.	11kV distribution network fault.	An unplanned interruption of the 11kV network occurs about four times a week on average.	Loss of supply to consumers. The number of consumers affected will vary and depend on the location of the fault.	There are still a significant number of long distribution feeders with high numbers of consumers serving rural and remote parts of our supply area with low population densities. The diesel generation fleet that will supply the northern area during planned 110kV line interruptions will include mobile generators that can be positioned on low-reliability feeders to provide backup during unplanned interruptions. This AMP also provides for increased expenditure on 11kV asset renewal, the installation of additional fault location indicators, improvements in protection along 11kV feeders and the installation of additional interconnections between feeders.
15.	Low voltage fault.	Frequent.	Loss of supply to a small number of consumers.	Supply is restored in repair time.

Table 7.3: Profile of Network Risks

7.3 Network Risk Management Processes

7.3.1 Health and Safety

The safety of our employees, contractors and the general public is of utmost importance in the operation, maintenance and expansion of the network. 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 general 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; and
- Management of contractors and subcontractors.

Further, a high standard is being 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); and
- Control room operator.

This demonstrates our commitment to employee development and increases our ability to maintain the network efficiently.

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 unsupervised on and around the network. This assessment process ensures the safety of employees as they only work within their proven competency.

To reinforce this, the Group launched a company-wide “values programme” and the current AHC system has been updated to integrate the EWRB’s competency-based refresher classes. We maintain a proactive role in staff competency, monitoring industry safety issues, and implementing training and guidance where required.

7.3.1.1 Transmission Risks

Transmission risks are relatively high, because the transmission system carries high loads and a loss of supply due to a failure of the transmission system affects large numbers of consumers. The acquisition of transmission assets in April 2012 transferred much risk from Transpower to Top Energy. We manage this additional risk exposure through the following measures:

- An investment in staff training, and a willingness to optimise fault response and minimise the duration of single circuit transmission outages;
- A comprehensive condition assessment of our 110kV assets (completed in December 2014);
- Contracting the maintenance of 110kV line and substation assets to an experienced external service provider;
- Establishment of a programme to develop in-house 110kV skills for both emergency response, construction and maintenance activities;
- A plan to provide prioritized remediation of identified defects;
- A commitment to facilitate regular site visits and engagement with owners of property over which our 110kV assets are situated; and
- Installation of additional generation in our northern area. When this project is completed in FYE2020, there will be no need for planned transmission system interruptions and supply will be restored more quickly following unplanned interruptions.

7.3.1.2 Network Critical Spares

We maintain an inventory of critical spares where there could be long delivery times in the event of network equipment failure.

Our electrical network is mainly overhead construction. In most cases, the equipment is of modular design and can be relatively easily replaced using our inventory of equipment held to maintain and expand the network. However, we maintain a regularly reviewed level of specialised spares and have joined a cooperative group of other EDBs to provide mutual risk mitigation in this area.

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.

7.3.1.3 Defect Management

Defects identified during our asset inspection programme are risk assessed and repair is prioritised as follows:

- X – asset has a high safety risk. It must be made safe on the spot and the issue must be resolved within 30 days either by replacement or by the implementation of a formal operational risk management strategy.
- A – repair is prioritized by SAIDI risk and included in a planned maintenance strategy.
- B – maintenance is required if asset is to live an optimum service life. The defect is remedied within our normal maintenance programme and generally within five years.

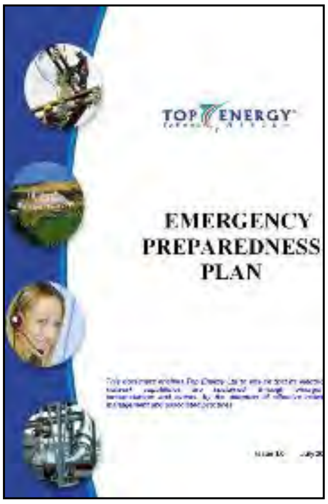
7.3.1.4 Vegetation Management

Our ongoing vegetation management programme is described in Section 6.2. Our current vegetation management focus includes the prevention of trees growing into our line, which is treated as an X defect during periods of high fire risk. We are working with commercial plantation owners to develop vegetation management agreements and we are also campaigning to remove bamboo growing in the vicinity of our lines.

7.3.1.5 Asset Criticality

We have developed an asset criticality model, where asset criticality is defined by the number of consumers affected if the asset fails and the SAIDI impact of the failure. Application of the design standard set out in Table 5.1 is prioritised by asset criticality.

7.3.2 Emergency Preparedness Plan



We have well-established disaster readiness and emergency preparedness plans. Our formal Emergency Preparedness Plan ensures 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. The plan ensures 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 objectives of this plan and associated arrangements are:

- To provide general guidelines that can be combined with sound judgment, initiative and common sense in order to address any emergency, irrespective of whether that particular set of circumstances has been previously considered. 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 general public;
    - Protection of property and network assets;
    - Protection of the environment;
    - Ongoing integrity of the electricity network; and
    - 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; and
    - 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 addresses the management of emergencies related to:

- Our electricity network management facilities and capabilities for our network, Transpower's supply to Top Energy, and the coordination of responses and communications; and
- Our major consumers, and the coordination of responses and communications.

The plan addresses major emergencies to electricity supply addressing the following 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 outages; and

- *Recovery* following response, to restore full normal services and functions.

The plan is a comprehensive document, which 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 and subsequently reviewed to capture the lessons learnt from our management of that event. It was also activated when insulators on Transpower's Maungatapere-Kaikohe 110kV grid connection were damaged by bullets in 2016, causing an extended outage to our whole supply area.

7.3.3 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; and
- 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 voluntarily 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; and
- The protocols for testing and reporting of system failures.

7.3.4 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 - each block being a minimum of 16% of the total pre-event demand at that grid exit point - when the power frequency falls below specified minimum requirements.

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. This is discussed further in Section 5.11.

7.3.5 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 operations centre at the Ngawha Power Station, and our training programmes provide for regular operator familiarisation and testing activities.

7.3.6 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.

This unit can also be used to facilitate maintenance on zone substations and therefore reduce planned consumer outages.

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. Regulation 48(1) of the Electricity Safety Regulations 2010 (ESR) allows us to do this rather than comply with the prescriptive requirements of Regulation 49 and 50 of the ESRs. 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.

We have adopted a new strategy to separate out inspections undertaken to manage asset life cycle (discussed in Section 6.1.2.2) from work supporting safety management, as the two workstreams have different drivers. We think that treating safety separately from condition assessment will lead to better safety outcomes. For example, managing close approach to live assets by checking clearances prior to work, and advising staff and contractors before they work on the network of the hazards that we are aware of and that should be considered in their safety plan, is a more proactive and safety-focussed approach than simply trying to capture relevant data during asset condition assessments.

7.4.1 ESR Driven Safety Management Practices

Regulatory requirements related to the design of a safe network are prescribed in Part 4 of the ESR. The essential elements are:

- ESR 34 Protection: from both short circuit and earth fault;

- ESR 41 Structural loading: more specifically, compliance with AS/NZS 7000 and NZECP 34;
- ESR 42 Earthing Systems: more specifically, compliance with NZECP 35; and
- ESR 43 Isolation: provisions for the disconnection of works from energy sources.

Safety of consumer installations is prescribed in Part 5 of the ESR, which is focused on compliance with the Wiring Rules specified in AS/NZS 3000. Part 5 covers assets that do not supply multiple consumers, including service lines and street lighting systems.

Part 3 of the Regulations covers safe systems of supply, prescribing voltage and quality standards which relate to the design of connection provisions. For example, ESR 31 requires compliance with New Zealand Electricity Code of Practice 36 (NZECP 36) relating to limiting the potential interference from electrical harmonics. There are also requirements relating to the interaction of live networks with other utilities (e.g. telecommunications) and also to special scenarios such as grid tie inverters, hospitals, marinas and generation.

Our practices that address the key requirements of safety regulations are described below:

7.4.1.1 Network Safety Checks

ESR 39 specifically provides that compliance with our NZS 7901 certified PSMS is an approved approach to meeting our obligation to ensure that our network is maintained in a safe condition. We use this approach as an alternative to compliance with the prescriptive default requirements of the ESRs and associated NZECPs. Our ongoing compliance with our PSMS is regularly audited externally.

7.4.1.2 Protection

Our network protection scheme relies largely on expulsion fuses. This has the following limitations:

- Fuses are an over-current device that has limited effectiveness in protecting against earth faults. In places, our network may not have sufficiently high earth fault levels to operate the fuse.
- Fuses operate individually for each phase. Hence, fuse operation may not isolate all three phases to provide full isolation.
- Correct operation of a graded fuse protection system[9] is dependent on the appropriate size fuse being used in a particular location. Network configuration changes affect the fault level and the required grading.
- Fuse protection systems can trigger fires when a fuse expels molten metal or when contact with vegetation fails to create a sufficiently solid fault to operate the fuse.
- Fuse operating curves are extremely inverse, making them difficult to coordinate with modern protection equipment, such as reclosers.
- Using a fuse as an isolation point may result in the effective removal of all protection on the circuit being worked on.

The primary protection devices on our 11kV distribution network are the feeder circuit breakers at our zone substations; these need to be coordinated with the downstream protection equipment on each 11kV feeder. This feeder protection may not detect low resistance faults at the end of a feeder or correctly grade with expulsion fuses. To address these limitations, we have circuit breakers, or reclosers and sectionalising devices, along our 11kV feeders. The protection on these devices is designed to coordinate with upstream devices and the feeder circuit breakers.

Maintaining accurate coordination is therefore vital to the effective operation of overall distribution network protection scheme. When this is wrong, there can be a high level of unreliability due to the spurious tripping of feeder sections not affected by a fault. A protection scheme that isn't working effectively generally indicates the following design issues:

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[9] In a graded system, fuse sizes are selected to ensure that only the affected section of a network is isolated in the event of a fault.

- The application of a protection device is sub-optimal in respect where the device is positioned in the network, how it is connected, configured etc. This requires competent engineering; or
- The protection settings or fuse sizes are not correct, perhaps because a device has been shifted, the network has been reconfigured, or fuse links have been inadvertently replaced with the wrong size.

Therefore, there is a need to:

- Model the protection coordination whenever there is a network design change;
- Review the system fault levels on which protection design is based every five years, or when significant new growth occurs or new block loads are added;
- Check devices are programmed and function correctly as part of their regular maintenance cycle. This should include secondary injection trip testing as a minimum; and
- Regularly check fuse sizes against system records.

Our protection safety management system consists of the following:

- Maintaining a power flow model of the network. As indicated in Section 2.9.4, our power flow model uses the DigSilent power system analysis software. All our subtransmission networks have been modelled as having feeder backbones, but some spurs have been simplified as lump loads. While modelling to this level meets most needs, we are working with the software provider to create a power flow model directly from our GIS system, which will mean that the model will be automatically updated as the network configuration changes.
- Maintaining a full-set of protection coordination diagrams for every feeder. This information is currently available in various forms, but not as a collated set. We are undertaking a full feeder protection review, where this information is being properly collated.
- As part of the asset management process, we regularly review equipment selection criteria in respect of equipment technology, standardisation, application and obsolescence. Similarly, the overall protection scheme is regularly reviewed to ensure it remains fit for purpose. Our 33kV line protection has recently been upgraded as part of our network development plan.
- Undertaking trip testing and programming checks as part of the maintenance cycle.
- Logging all fault events attributed to protection system coordination/design issues for follow-up review and assessment of the need for design improvements. Currently, protection issues on the 33kV subtransmission network are prioritized and resolved quickly. Protection problems on the 11kV distribution system are also logged, but resolution can be slower.
- We also intend to check fuse sizes on a regular basis and maintain a history of dates when they were changed or checked. We will include this process in the next review of our PSMS.

The low voltage system has a different set of safety issues.

- The ability to isolate from high voltage is the most significant long-term design issue, which is being addressed through asset management and safety-by-design.
- Low voltage distribution fuses are typically sized to protect cables from overload and therefore may not clear faults. Specifically, they do not provide earth fault protection.
- Service line fuses may not operate effectively due to voltage drop and poor earthing conditions which can result from aging and load growth in a consumer's installation. Regulations currently do not require periodic checking and compliance upgrades of low voltage systems, as they do for high voltage. There is also a demarcation issue regarding who owns and operates these assets, and who has the responsibility for managing safety.
- There remain some assets, such as rewireable fuse bases, which are defined as "unsafe" in the ESR, but are not required to be retrospectively brought-up to compliance.

Our asset management and safety-by-design processes now use the following practices for delivering safe low voltage protection in new and upgraded installations:

- Use of insulation piercing connectors and a policy of replacing replace all “unsafe” fittings on discovery.
- Installation of incoming pillars with full shrouding and ganged fuses to distribution frames.
- Service line safety assessments and, where necessary, requiring consumers to upgrade the service line to compliance with current safety requirements, when reconnection to the network is required following faults, connection upgrades etc. This is a public safety management process.
- We also plan to initiate a data capture project to progressively gather information on service lines to manage the above safety initiatives and maintain updated records.

7.4.1.3 Structural Loading

The ESR requires all structures to be designed to AS/NZS 7000, which is a structural design standard for overhead lines; and NZECP34, which addresses issues of electrical clearances. We are required to keep records of design and to use these to determine whether their physical condition is adequate to meet the minimum strength requirements of the design. Our challenge is that we have no historical records of structure design and therefore, limited ability to assess remaining strength against the original design requirement. Further, condition assessment techniques tend to deliver results based on an assessment of remaining strength, which is relative to whatever the installed strength was and not an absolute measure that can be compared directly with an assessment of what the required design strength was.

Our structure design and pole condition management practices are based on the following:

- Wooden poles are required by EEA practice guides to be treated as unsafe to climb until an action has been undertaken to prove they are safe to climb. We are planning to implement a new safety management process that will require any wooden pole, that cannot be accessed by a bucket or held with a crane, to receive a below ground inspection, an assessment of pole-top load and a permit to climb. We are also planning to eliminate this hazard within 12 years by replacing all wood poles remaining on our network.
- Structures have been standardised to a limited set of pole-top assemblies, allowing tighter control of materials specifications and coordination of component strength. Component approval is subject to a “safety-by-design” assessment and selection process. These assemblies are then able to be modelled as elements in structural design tools.
- We use CATAN as our distribution line design tool. This assesses the strength of structures as an integral part of a line; that is, their strength requirements in terms of the pole-top loadings presented by conductor size, span and angle, and the resolution of strength issues via stays, foundations and structure modifications. Transmission and subtransmission lines are designed by external consultants.
- CATAN is informed by our Overhead Line Design Manual, which identifies the key assumptions for local environmental conditions; for example, the maximum wind speed we design structures to withstand.
- CATAN also provides information on potential conductor clashing, clearance to ground etc.
- To address the lack of design records for old structures a set of typical structures has been modelled and tested to determine a benchmark strength.
- There is a large population of concrete poles that have replaced hardwood poles over the past 20 years and for which there are no design records. These may be under-designed or overloaded in some locations, because a concrete pole generally has lower strength than a hardwood pole. This is because a concrete pole can be manufactured to more homogenous and consistent standards. Accordingly, concrete poles are not designed to high safety factors. Concrete poles also perform differently under certain loading conditions so generally require better staying and foundation design.

- The other weakness (in regard to historical practice) that specific design can resolve is conductor tensioning and sagging.

7.4.1.4 Earthing

We operate a multiple earth neutral (MEN) system. Earthing at multiple points lowers the earth loop impedance. It ensures a lower resistance path for fault current and a higher probability that the fault current will be sufficient to operate fuses and other protection devices.

The MEN is less effective when there are fewer earthing points; for example, in rural areas with minimal low voltage interconnection, where the earth electrodes have a high resistance to earth, or where the conductor is small and long with a high resistance. We provide an earthing point at every item of high voltage equipment, every transformer, every high voltage cable termination, every metal clad installation, and at the end of every low voltage distribution line. Every main switchboard in consumer installations also has an earth.

The earthing system is also required to limit touch and step potentials resulting from earth potential rise[10] during fault events. We engage external consultants to design the earthing systems within our zone substations, and all earthing points elsewhere on our network are designed and installed in accordance with standard industry practice. The resistances of high voltage earths are now tested at the time of installation and measures are taken to lower the earth resistance where necessary. We also have a programme in place to periodically test earths for their continuing integrity and to remediate where necessary.

Earthing issues:

- Past design of earthing may not meet modern requirements, particularly in respect of the need to keep earth potential rise below a hazardous level. Modern design keeps the high voltage earth fault path separate from the low voltage earthing system. Further, the condition of old earths may have deteriorated since new.
- Load growth or modifications to consumer installation may have resulted in earthing systems no longer being adequate for effective protection.
- Past practice was poor in regard to the management of step and touch potentials and potential hazards may remain on the network as a result. There was a lack of bonding of operating mechanisms and conductive material not intended to carry fault current may not be effectively isolated. An example of this is a failure to install an insulator on stays. There may be fortuitous earthing connections that could exhibit a hazardous earth potential rise during faults. This is a public safety matter if the public can access the assets involved.
- The power supply to telecommunication cabinets may have insufficient barrier to prevent high voltage fault currents using the copper communications network as a return path.

Our approach to managing these issues, which are not unique to Top Energy, and ensuring compliance with earthing requirements is:

- We assess the strength of the MEN – the number of earthing points connected and combined earth impedance. Where a high earth test is discovered, we will upgrade the system to modern standards and, if necessary, add additional earthing points to achieve an acceptable outcome;
- We ensure that all new ground mounted equipment is either earthed metal clad with an equipotential earth mat or loop, or insulated. The design standards to which we build incorporate compliant earth systems, and inspection and testing at commissioning ensure that the installed earth systems are effective.
- Earths are visually inspected as part of all asset inspections and a programme is in place for testing the resistance of older earths. Funds for the remediation of substandard earths have

[10] During a fault event the current flowing to earth can be very high. If the earth resistance is high, the voltage of metallic material connected to earth will rise and, in extreme cases, the magnitude of this rise can be dangerous to people and stock nearby.

been allocated in the asset replacement and renewal budget for earth remediation, prioritised by earthing test results and defect status.

7.4.1.5 Isolation

The ESRs require that we provide the capability of isolating our works from their source of supply. To prevent disruption to others and make day-to-day operation of the network pragmatic, the network is designed with specific switching points that also provide isolating capability.

The main legacy issue is the demarcation between service lines and works. Historically, we owned all high voltage assets connected to our network. Regulatory change has now dictated that high voltage assets (except transformers) on a consumer's property are now owned by the consumer, who is responsible for the management and maintenance of these assets. A consequence of this change is that there may not be isolation and protection at the boundary between our works and a consumer's dedicated supply assets. All new high voltage service connections to our network now require a set of drop out fuses at the ownership boundary providing both protection and an isolation point. These fuses replace the ones that have traditionally been installed on the transformer pole.

We also adhere to the following design standards:

- Switchgear is rated for load break, fault make duty, so that it can be safely operated under all loading conditions; and
- We maintain a visual air gap requirement for high voltage isolation, and do not rely on the insulation rating of circuit breakers and other equipment.

The majority of our isolation points are drop-out fuses. These require special consideration when being used for load breaking, as each phase is individually operated. Specifically:

- In some situations, earth fault protection could operate during phase-by-phase isolation. This would cause the feeder circuit breaker to operate, disconnecting the feeder.
- There is a potential for ferroresonance to be initiated between cables and larger ground-mounted transformers. This could damage the equipment.
- Restrike might occur when breaking loads with high levels of stored energy.

Such occurrences are rare. If they were identified, we would supplement the drop-out fuses with a three-phase, load-breaking device, such as a load-break switch or an air-break switch fitted with a load-breaking head.

Low voltage isolation in the distribution system is limited. For example, historically we have not installed incoming links between a transformer and its low voltage distribution frame. Fortunately, there is limited LV interconnection between distribution substations, so low voltage distribution fames can generally be isolated by isolating the transformer. Nevertheless, as these substations do not meet current safety requirements, the ESRs class them as "unsafe" and they are managed accordingly. These non-compliances are addressed when the ground-mounted transformers and their associated LV networks are upgraded.

7.4.2 Integrated Safety Management

We use our NZS 7901 certified PSMS as the basis for managing the risks that our network poses to the public, to our employees and contractors, and to ensure compliance with ESRs. We are revising our PSMS to reduce the reliance on condition assessment as a safety measure and to put in place additional proactive measures to keep our employees, contractors and the public safe. These measures include:

- A requirement that wooden poles are treated as unsafe to climb until they have been inspected below ground level, consistent with the EEA guide to work on poles and pole structures, and a permit to climb has been issued;
- A requirement that all new work has a formal inspection record or certificate of compliance that confirms compliance with the ESRs and the Wiring Rules before the work is livened;

- A requirement that all repair work is tested for safety before livening and that completion of these tests is formally recorded;
- A system of recording and processing defect, safety and compliance issues reported by staff and the general public outside of formal PSMS processes; and
- A requirement that assets be patrolled after a fault has occurred where supply has subsequently been restored without the fault cause being found.

7.4.3 Management of Pole and Structure Condition

7.4.3.1 Regulatory Background

We manage pole and structure condition in accordance with the ESRs. The following regulations are applicable:

- Regulation 40 (ESR 40) Safety Checks of Works
- Regulation 41 (ESR 41) Structural Loadings on Works

These two regulations have prescriptive requirements, particularly in relation to periodic asset inspections and the management of overhead line poles. However, as noted above in Section 7.4, ESR 48(1) states that compliance with ESR 40 and ESR 41 is not mandatory if there is an accredited safety management system such as an NZS 7901 certified PSMS in place that provides equivalent outcomes.

At present our PSMS largely mirrors ESR 40 and 41 in that it provides for asset inspections irrespective of asset age and the replacement of poles in poor condition within predetermined timeframes. We are revising this to require inspections at reasonable intervals. These intervals will be determined by the stage of an asset's life cycle and any specific condition issues known about an asset that our safety management must adapt to. Unnecessary inspections devalue the quality of the inspections through "safety fatigue" and waste resource that could otherwise focus on meaningful safety management. This is discussed further in Section 6.1.2.2.

Poles with the strength to withstand the loads to which they are subjected can remain in service. The increased use of elevated platforms and the ability to support poles with mobile truck-mounted cranes means that the ability to climb an unsupported pole need not be the criterion that determines whether a pole can remain in service, provided alternative strategies are in place to ensure worker safety. Our new safety procedures will require workers to undertake an onsite assessment of structural integrity and obtain a permit to climb from the control room before climbing any wooden pole. This is consistent with the EEA guide for work on wood poles and pole structures, which states that all wood poles should be deemed unsafe to climb until their structural integrity has been confirmed. All of our poles are uniquely numbered and poles approaching the end of their expected life will have a detailed assessment of pole condition in our asset management database. This information, as well as the mandated onsite assessment of structural integrity, will be used by control room staff in deciding whether to issue a permit to climb.

The sections below describe our proposed new approach to pole management in more detail. There will be a transitional period while our procedures are modified, and the new arrangements are put in place.

7.4.3.2 Application

The ESRs and our NZS 7901 accredited PSMS apply only to assets that we own[11]. They exclude service line assets which are categorised as installations, as these are owned by the consumer from the point of connection to our works; which is generally the point where the assets are both dedicated to, and contained within, a consumers' property or property over which they have property rights (i.e. an easement).

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[11] Regulations prescribing requirements to ensure electrical safety distinguish between assets owned by a lines business ("works") from assets owned by a consumer ("installations"). The ESRs specify requirements for the safety of "works" while the Wiring Rules (AS/NZS 3000) specify requirements for the safety of "installations".

The demarcation point between our works and a consumer's installation has changed during the industry reforms over the last twenty years and is not consistent for both high voltage and low voltage assets. We limit management of service line condition to matters that impact public and worker safety. Specifically:

- We check pole condition before our staff or contractors are permitted to climb or work on service line poles;
- At the Network Manager's discretion, we address urgent non-compliances with the relevant safety regulation, such as line clearance clearances over roadways. In exercising this discretion, the Network Manager considers the public risk from an in-service pole failure;
- We notify service owners of any discovered regulatory non-compliances; and
- We ensure a service line is safe to liven before connecting it to our network or reconnecting it following a fault repair.

Hence our PSMS extends our sphere of influence beyond the management of our own works. However, we do not:

- Provide an inspection service for privately owned service lines; nor
- Have a database or other record of consumer-owned service line assets, or design, or inspection records as a basis for managing these assets.

7.4.3.3 Structural Loading and Design

We design our poles and other supporting structures to AS/NZS 7000 requirements. Transmission and subtransmission structures are designed by external consultants and distribution structures are designed internally using the CATAN design tool. The Standard specifies material standards, seismic and environmental assumptions such as the relevant extreme wind loading event assumption. These are recorded in our Overhead Line Design Manual. Lines are designed as integral of conductor, poles, foundations, stays and any equipment adding load to the pole-top such a transformer. Pole-top load capacity is greatly increased when supported by conductor, stays and the poles either side.

However, we cannot assume that legacy structures are compliant with the Building Code even if the structure is in good condition (e.g. the wood treatment of hardwood poles may not meet current code requirements). Where a wooden pole has been replaced with a legacy concrete pole, the replacement pole may not have had the required strength; historically, hardwood poles were used in situations where additional strength was required, as hardwood poles when new were stronger than the concrete poles historically used.

Pole deterioration will weaken a structure, but not necessarily to the point where it becomes unserviceable. In an extreme situation, the conductors and stays supporting the top of a pole could contribute sufficient support to keep a pole in service even though it is completely broken at ground level. A deteriorated pole carrying light conductor may have sufficient strength to remain in service, if the structure was originally built to a standard design intended for a heavier conductor.

The objective of pole condition management is to ensure that structures retain sufficient strength, before they are replaced, to support the loads imposed by the operating conditions they are exposed to. This does not mean that a structure should routinely be replaced once a defect or deterioration is found if other means are available to keep the structure in service without compromising worker or public safety. The service life of a pole can be extended by changing the conditions under which it operates or by managing safety through changed operating practice. An example would be not allowing a suspect pole to be climbed and supporting it with a mobile crane when changing pole-top loading. Public safety can be ensured by re-checking condition before deferring replacement for a limited period.

7.4.3.4 Risk Based Inspections

Our pole management process is:

- Poles will be designed and installed in accordance will all relevant structural and safety requirements. They will be certified as compliant and records updated to "as built" following construction.

- A pole will be closely inspected and fittings tightened approximately five years after installation. This inspection will also confirm safety compliance.
- There will be no further planned asset management inspections of a pole until its population is demonstrating, through defect and condition monitoring, that it is approaching its onset of unreliability, which is the age at which experience has shown that rates of failure start to increase (see Section 6.1.2.2). Over this period, any outage and defect reports will be analysed for unfavourable trends that could be indicators of premature failure. An example might be binder failure related to a specific make of component or vibration damage. If necessary, the timing of the onset of unreliability inspection will be adjusted.
- The onset of unreliability inspection will closely examine each pole to identify those poles that have the highest probability of early failure. The inspection will also look for the presence of other issues, such as rot, that may be accelerating its end-of-life. This assessment will include below ground testing at the point on the pole where the maximum bending moment acts. The results of this inspection will be a determination of remaining strength relative to required strength, from which an engineering judgement can be made of the expected remaining life of the structure. This is not an exact science. The objective is to make an informed judgement about how quickly a pole's strength is deteriorating over the end-of-life period during which failure can be expected. The asset management output of this process is a ranking that determines which poles need replacing and prioritises the replacement of these poles. It will also identify poles that can be left in service to be reassessed at a subsequent inspection. For wooden poles, ultrasound inspections are already being used to provide more consistent and reliable assessments of a pole's strength.
- We follow a Safe Operating Practice where all wooden poles are assumed to be unsafe for climbing until assessed for structural integrity to determine under what set of safety measures the pole can be climbed. This will require each pole to be inspected before it is climbed. We will control this process by requiring a Permit to Climb to be issued for every wooden pole climb, should auditing determine that staff or contractors are failing to comply with the Safe Operating Practice. Hence the inspection regime for wooden poles will be overlaid with an operational regime of mandated inspection, regardless of age and wood type, which will alert us to the presence of poor condition or unclimbable poles that we have not identified. These poles will be tagged as a warning to others, logged as a hazard and given a public safety risk assessment.
- Similarly, poles may be given a higher replacement priority for reasons other than pole strength. Such reasons could include proximity to trees, public safety risk or the criticality of the pole location. We would anticipate, for example, that replacement of poles on feeder backbones close to their zone substation will be prioritized for replacement over a pole on a spur line close to the end of a rural feeder.

7.4.3.5 Pole Tagging

We have changed our system of pole tagging so that tags will used as a warning to others.

Red tags indicate an issue such as the presence of rot that may be accelerating the deterioration of the pole. This signals the need for more vigilant monitoring and condition assessment. They will no longer mean that the pole is "condemned" (a legacy industry term rather than a regulatory definition) as field assessment is too subjective to determine this status.

Yellow tags mean that it is suspected that the pole has insufficient strength to be safely climbed without additional pole support. These would typically be poles that have significant loss of diameter or are carrying high loads, such as a transformer or terminating structure. A yellow tagged pole will require a formal inspection to be initiated and a safety management system put in place.

The industry is currently investigating a standardised tagging system.

7.4.4 Pole Replacement Programme

The pole management programme discussed in Section 7.4.3 will be overlaid with a work program to replace every wood pole on the network within the next twelve years. Pole replacements will be prioritised based on the assessed pole condition and remaining life, and will have the following structure:

- Poles that require attention more urgently than others in the line segment that they are part of, will be replaced on a spot pole replacement basis.
- Where time allows, it is preferable to rebuild entire line segments, as this allows for line design improvement, relocation to more accessible/suitable sites etc. Spot pole replacements may be deferred where the remaining line supporting that structure has sufficient integrity, provided that the risks associated with failure are low and closer monitoring is put in place. Alternatively, the line rebuild may be brought forward, resulting in an earlier than planned renewal of the other poles in the line; this would normally be triggered by the closer monitoring of the poor condition poles.
- Replacement of service line poles owned by us may also be deferred where there is an issue with the condition of the poles on the same service lines that are owned by a consumer. If the consumer's line has a compliance issue, then this needs to be resolved before that service can be reconnected. In practice, consumer lines tend to be in poorer condition, less well maintained, built to lesser design standards and therefore drive the urgency of pole replacement. Where we identify an issue with our poles on such a line, we will then check the consumer-owned assets and notifying them of non-compliances.
- Where it is not our intention to rebuild a line at the end of its service life, it may be uneconomic or in an inaccessible location, poles may be left to fail in service. Affected property owners will be informed of this and of any hazard issues.

Urgent pole replacements may sometimes be deferred where access conditions present a bigger risk than in-service failure.

7.4.5 Other Pole Management Issues

Not all structure strength issues are pole condition related. Some are design related (e.g. overloaded, missing stays etc.) and some are hardware related (e.g. crossarm condition). These issues will also be captured by inspection and recorded in defect registers, and may drive early pole replacement.

Poles get replaced opportunistically as part of other asset management work programmes and maintenance (e.g. replacement of a pole with a heavier pole on which to hang a transformer).

Softwood poles occasionally fail as a result of preservative system failure, causing them to rot significantly earlier than expected. We will not approve service line designs for connection to our network where softwood or other non-approved poles are involved.

Concrete poles may suffer cracking as result of an incident such as a traffic accident. Where this does not adversely affect the integrity of the line and any critical contribution the pole makes to the line design, then they are programmed for replacement at the next opportune time in the work programme. Given that the approximately 80% of pole structures are only providing a simple propping function, damage to the pole would need to be severe and obvious to demand urgent replacement. This may involve refining the design to reduce the probability of a repeat incident.

Section 8 Evaluation of Performance

8 Evaluation of Performance

This section presents a review of our financial and service level performance for FYE2018, the most recent period for which a full year's results are available. Discussion is centred on the various factors that influenced our performance and comparisons are made with industry benchmarks where appropriate.

Detailed discussion of performance measures and targets is included in Section 4 of this AMP.

8.1 Reliability

8.1.1 Review of Network 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 the FYE2016-2020 regulatory period, the Commerce Commission changed the methodology to be used in normalising the raw SAIDI and SAIFI measures before assessing regulatory compliance. No corresponding change has been 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.

As discussed in Section 4, for internal management purposes, we now set our reliability targets using the default price-quality path normalisation methodology, and this approach is assumed in setting the forward service level targets shown in Table 4.3.

The most recent disclosure year for which complete reliability measures are available is FYE2018, when there was a total of:

- 423 unplanned supply interruptions (409 in FYE2017); and
- 237 planned interruption (207 in FYE2017).

Table 8.1 shows the reliability of our network over the period FYE2011-17, with all measures normalised according to the Commerce Commission's information disclosure requirements. The table shows interruptions arising from within the network only; interruptions due to a loss of grid supply are not included.

FYE	2011	2012	2013	2014	2015	2016	2017	2018
SAIDI	440	435	333	465	600	516	465	579
SAIFI	4.9	6.4	4.7	5.8	6.4	6.3	5.4	5.3

Note 1: Interruptions of the 110kV transmission system acquired from Transpower are not included in the above table prior to FYE2013.

Table 8.1: Network reliability – normalised using information disclosure methodology

Table 8.2 shows SAIDI and SAIDI normalised in accordance with the requirements of the Commission's default price-quality path regulatory regime and compares our performance with our internal management targets and the relevant threshold denoting a potential quality path breach[12]. The measures normalised for price-quality path assessment are lower than the corresponding measures normalised for information disclosure, primarily because the weighting of planned interruptions is reduced by 50% under the price-quality path methodology. We did not set separate targets for planned and unplanned interruptions were not set prior to FYE2020.

12 As this methodology was first introduced in FYE2016, measures for prior years are not available.

	Threshold	FYE2016		FYE2017		FYE2018		FYE2019	
		Target	Actual	Target	Actual	Target	Actual	Target	Actual[1]
SAIDI									
Unplanned	-	-	369.1	-	378.4	-	369.1	-	209.5
Planned			91.7		21.5		104.2		90.4
Total	**517**	**324**	**461.8**	**350**	**400.9**	**345**	**483.3**	**390**	**299.9**
SAIFI									
Unplanned	-	-	5.30	-	4.68	-	4.55	-	2.42
Planned			0.34		0.14		0.40		0.41
Total	**6.25**	**4.20**	**5.64**	**4.60**	**4.82**	**4.50**	**4.95**	**4.90**	**2.83**

Note 1: Performance to 31 December 2018

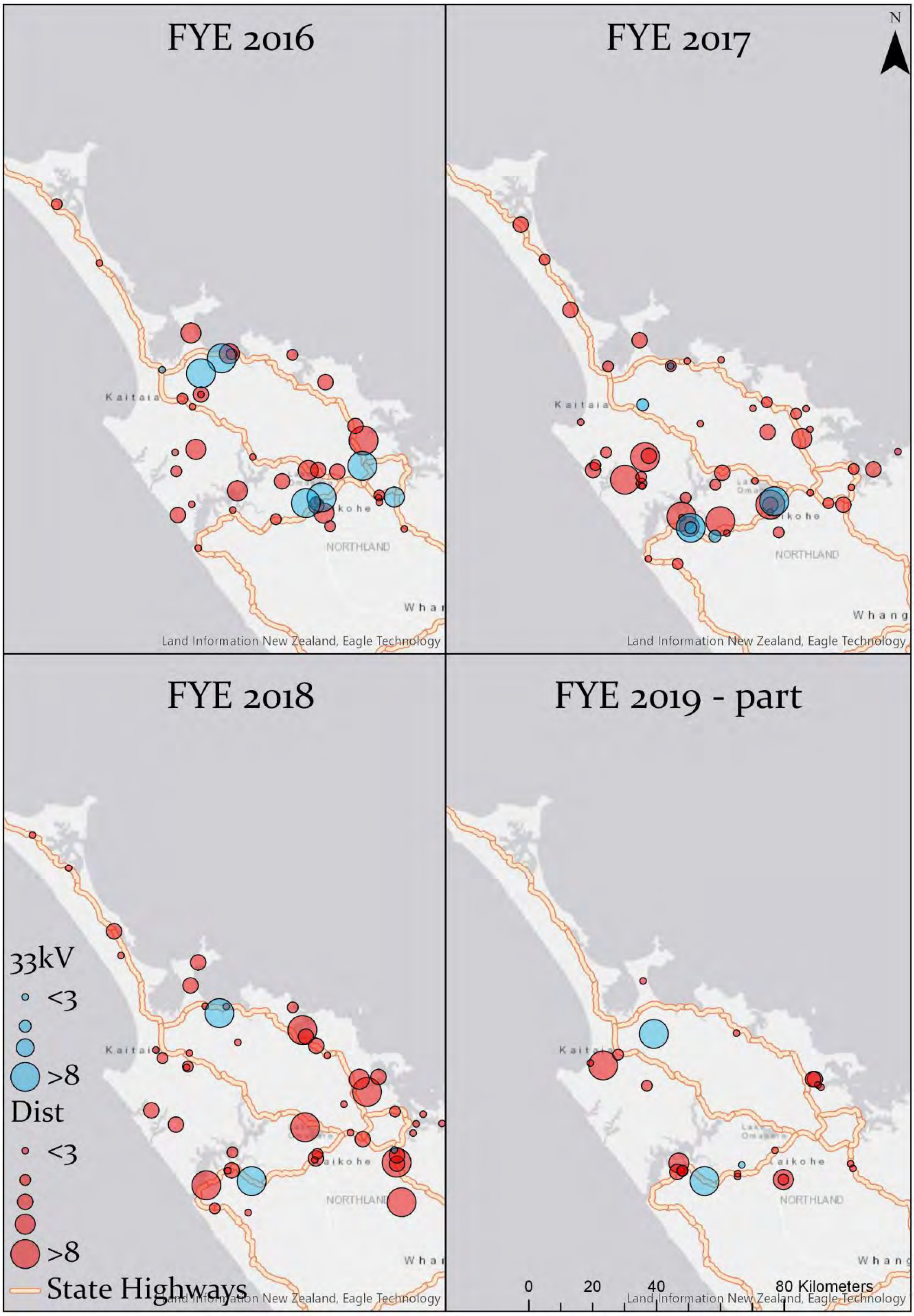
Table 8.2: Network reliability – normalised using price quality path methodology

Table 8.1 shows that our network reliability was highest in FYE2013, a year in which weather was abnormally benign across the country. Our worst reliability was recorded in FYE2015, a year in which our network was hit by the remnants of Tropical Cyclone Ita in April 2014, a severe weather event that lasted more than three days and caused a slip that closed State Highway 1 south of Kawakawa for almost a week in July 2014, and a slip in the Maungataniwha Ranges in December 2014 that caused a tower on our 110kV transmission line to move more than 10 metres and required two planned line outages to undertake repairs. In other years, our normalised reliability has hovered between these two extremes.

Table 8.2 shows that our reliability has been comfortably below the Commerce Commission threshold for each year of the current regulatory period. The table further shows that our reported network reliability is very sensitive to the impact of planned maintenance interruptions. Until this year, when we were able to mitigate the impact by running generation recently installed within our Kaitaia depot, a planned maintenance interruption of our 110kV line had a normalised SAIDI impact of 60 minutes. Over the three-year period FYE2016-18, the normalised SAIDI impact of unplanned interruptions showed little variation from year-to-year and the volatility of the overall SAIDI was almost entirely due to the impact of planned interruptions. The low normalised reliability reported in FYE2017 was due to the lack of a planned maintenance interruption of the 110kV line over the period.

Our network reliability is steadily improving. This can be seen from the unplanned interruption maps in Figure 8.1, which track the number and location of unplanned interruptions within the 33kV and 11kV networks that have had a SAIDI impact of more than two minutes. Of note is the reduction in the number of large interruptions, particularly at 33kV, the frequency of significant faults in the Hokianga area and the reduction in the number of large faults in the Whangaroa–Matauri Bay area following the commissioning of the Kaeo substation at the end of FYE2018.

Our reliability to date in FYE2019 is much improved on previous years, assisted by relatively mild weather and we are on track to meet our internal SAIFI and SAIDI targets. Going forward, our reliability indicators should improve with the commissioning of new generation at Kaitaia, which will mean that 110kV line maintenance outages will no longer interrupt supply to consumers in the northern area; with the exception of the Juken Nissho mill, where an agreement is in place with the consumer. Nevertheless, our efforts to improve the reliability of our network must continue, both by improving the architecture of the network to limit the impact of faults that do occur, and by increasing the effectiveness of our maintenance and asset renewal expenditure. This is discussed in the sections below.



Note 1. Excludes all planned and 110kV unplanned interruptions
Note 2: FYE2019 includes April – December only

Figure 8.1: Area Fault Maps (FYE2016 – FYE2019)

8.1.2 Reliability Improvement Strategies

8.1.2.1 Background

A major focus of our SAIDI improvement strategy has been to reduce the impact of interruptions caused by faults on our 33kV network. To achieve this, we have installed differential protection on the 33kV lines supplying our larger zone substations with two incoming circuits so that these circuits can be operated in parallel. We are also refurbishing our other 33kV circuits to reduce the incidence of vegetation and equipment failure faults. This programme, which is now almost complete, has been successful; the SAIDI impact (prior to normalisation) of 33kV faults in FYE2018 was just 25 minutes, compared 152 minutes in FYE2016 and FYE198 minutes in FYE2017. The corresponding 33kV SAIDI impact in FYE2019, though to the end of December 2018, was 42 minutes; higher than in FYE2018, but still well below the levels of previous years.

Our reliability improvement efforts going forward will focus on our 11kV distribution network.

Table 8.3 shows the SAIDI impact of unplanned 11kV interruptions disaggregated by substation. The average SAIDI for Waipapa over the period FYE2016-18 is not shown as performance of this substation has been improved by the commissioning of the Kaeo substation at the end of FYE2018. While the substation still shows up as a poor performer in FYE2019, this is largely due to the relatively poor reliability of the long rural Purerua feeder, which was not improved by the Kaeo build.

Substation	Average Annual SAIDI (FYE2016-18)	Total SAIDI FYE 2019 (Apr-Dec 2018)
Kaikohe	77.3	39.3
Okahu Rd	64.3	32.2
Taipa	30.5	5.8
Omanaia	28.9	26.8
Kawakawa	28.3	10.6
Pukenui	20.4	6.4
Kerikeri	9.7	5.3
Moerewa	8.6	0.9
NPL	8.0	1.2
Haruru	6.1	3.4
Mt Pokaka	5.6	3.4
Waipapa	-	25.0
Kaeo	-	7.7

Table 8.3: SAIDI Impact by Substation

Table 8.4 shows our 20 least reliable 11kV feeders ranked on their average annual contribution to unplanned SAIDI over the three-year period FYE2016-18, together with the average number of unplanned 11kV faults on each feeder over the same period. Almost all the feeders on the list are rural or remote feeders, with limited interconnection scope and supplied by substations that have not been the focus of our subtransmission system upgrade. The table also shows the FYE2019 SAIDI contribution and number of unplanned 11kV faults through to 31 December 2018.

Rank	Feeder	Substation	Average Performance (FYE2016-19)		Performance FYE2019 (to 31 December 2018)	
			SAIDI	No of Faults	SAIDI	No of Faults
1	South Rd	Okahu Rd	37.1	36	6.8	24
2	Rangiahua	Kaikohe	19.0	24	12.0	31
3	Opononi	Omanaia	18.2	18	24.9	20
4	Towai	Kawakawa	15.3	20	8.9	8
5	Awarua	Kaikohe	15.3	18	10.8	10
6	Te Kao	Pukenui	14.9	11	3.6	9
7	Horeke	Kaikohe	13.9	13	6.4	9
8	Oruru	Taipa	12.3	17	1.5	5
9	Herekino	Okahu Rd	12.1	12	19.0	8
11	Oxford St	Okahu Rd	11.7	14	4.5	9
12	Taheke	Kaikohe	11.5	13	7.0	9
13	Rawene	Omanaia	10.7	11	1.9	5
14	Russell Express	Kawakawa	10.6	9	1.5	5
15	Kaikohe	Kaikohe	9.2	9	-	-
16	Inlet Rd	Kerikeri	9.2	7	1.5	3
17	Purerua	Waipapa	8.7	11	15.1	7
18	Ohaeawai	Kaikohe	8.4	15	3.0	6
19	Awanui	NPL	7.1	17	0.8	6
20	Mangonui	Taipa	6.3	5	0.4	1

Table 8.4: Lowest Reliability 11kV Feeders

Further improvement in SAIDI will require expenditure in the less economic end of the network and, given our expenditure constraints, solutions that are less capital intensive. The optimal solutions are likely to come from:

- Reconfiguring feeders with a more optimal overlay of automation and technology, and improved coordination and operation of automation, isolation and protection systems;
- Prioritising the maintenance of critical assets at the front end of a feeder;
- Improved targeting of asset renewal and maintenance through the application of asset health data, criticality and risk models, and fault analysis. The application of machine learning to these tasks is on our roadmap;
- Better location and coordination of generation into our distribution network and load management system;
- More sophisticated operating to exploit new technology such as batteries, distributed energy resource management systems etc.; and
- Correct coordination and operation of automation, isolation and protection systems.

8.1.2.2 Causes of Unplanned Interruptions

Cause	Average Annual SAIDI	Percent	Average Annual No. of Interruptions	Percent
Equipment Failure	118.4	24%	129	32%
Foreign Interference	116.7	24%	64	16%
Tree Contact	85.9	17%	76	19%
Unknown	83.4	17%	35	9%
Adverse Weather	78.5	16%	73	18%
Lightning	4.8	1%	7	2%
Human Error	4.4	1%	9	2%
Adverse Environment	1.2	0%	3	1%
Total	**493.3**	**100%**	**396**	**100%**

Table 8.5: Causes of Unplanned Interruptions FYE2016-18

Table 8.5 disaggregates the number of unplanned interruptions by cause and their SAIDI impact averaged over the three-year period FYE2016-18. It shows that equipment failure has caused almost a third of the total interruptions and a quarter of the total unplanned SAIDI over the three-year period.

Equipment Failure

Figure 8.1 shows the shows the main causes of equipment failure faults over the period 1 April 2016 to 31 December 2018.

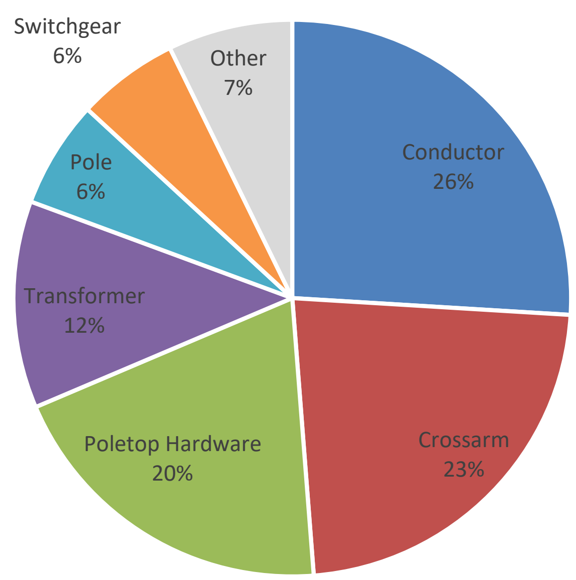


Figure 8.2: 11kV Equipment Failures by SAIDI Impact

Figure 8.2 shows that equipment failure faults having the most SAIDI impact are:

1. *Crossarm and pole-top hardware failure* – Pole top hardware failures cause 43% of the SAIDI impact of 11kV equipment failures, with crossarms being the most troublesome component. Wooden crossarms have half the expected life of a concrete pole. As we do not consider crossarms and their associated

hardware to be a complete asset, we have not had a proactive crossarm maintenance management strategy. This has been corrected and our forecast asset renewal expenditure now has a separate line item for crossarm replacement. Our initial strategy will be to replace crossarm at the zone substation end of our most unreliable feeders, where a pole-top fault will have the biggest SAIDI impact. Crossarm replacement will include the replacement of any associated pole-top hardware showing end-of-life condition symptoms.

2. *Conductor failure* – Conductor failure is the cause of 26% of the SAIDI impact of equipment failures. Our more in-depth analysis of conductor failures indicates that our galvanised steel conductor is in poor condition and at the end of its service life. Copper conductor, which is prone to work hardening and also features frequently in our conductor failure statistics. We have limited data on conductor condition and therefore will concentrate renewal on these conductor types over the next five years. In the meantime, we will assess the condition of other conductor types.

3. *Transformer failure* –Transformer failure accounts for 12% of the SAIDI impact of equipment faults. We have a run-to-failure policy on small pole-mounted transformers, since there is no economic way of assessing the condition of transformer windings in the field. Transformer tanks showing end-of-life condition symptoms (e.g. significant rust or oil leaks) are replaced when they are found.

Figure 8.3 shows that the SAIDI impact of equipment failures is reducing, from 139 minutes in FYE2016 to 95 minutes in FYE2018, and then to only 51 minutes in the first three quarters of FYE2019. However, the number of equipment failures is not decreasing at a similar rate. We are experiencing more frequent outages with a lower SAIDI impacts, which suggests that our maintenance strategies are accurately targeting the most critical assets.

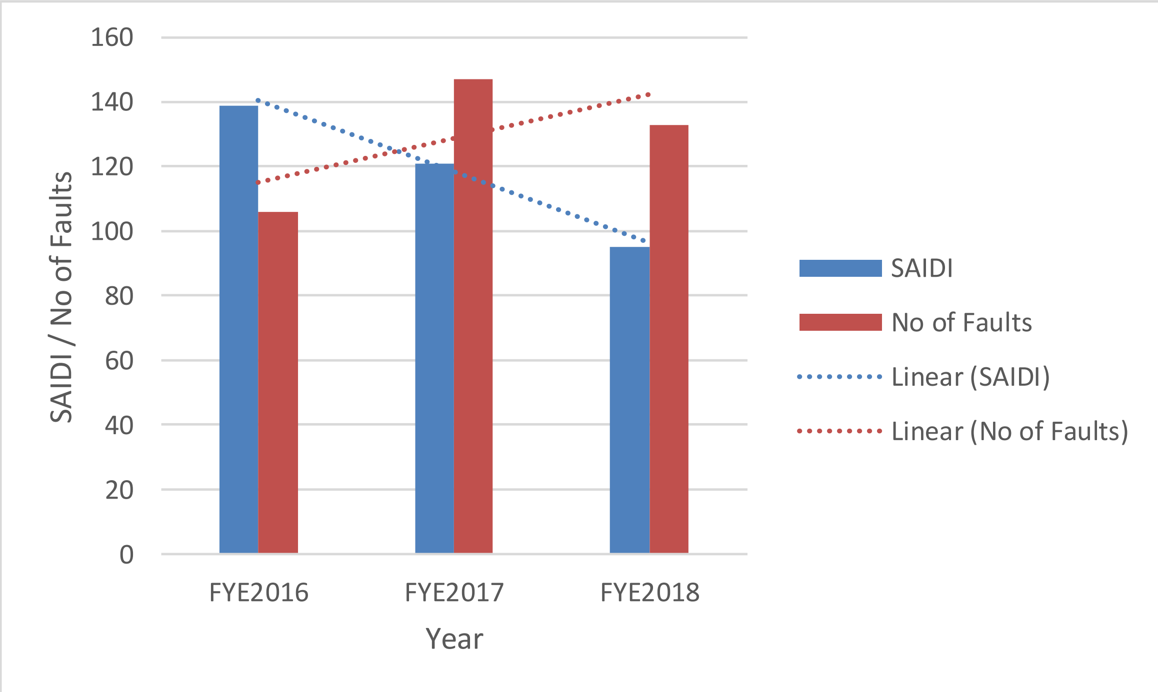


Figure 8.3: Impact of Unplanned Equipment Failures

Foreign Interference

Table 8.4 shows that foreign interference has a similar SAIDI impact to equipment failure and, as can be seen from Figure 8. 3, 60% of the impact of such 11kV faults from 1 April 2016 to 31 December 2019 were caused by a car hitting a pole. This type of event occurs often on our network because our pole spans are short and the roads are winding, with often only a limited berm on the edge of the seal. Our options for reducing the SAIDI impact of such events are improved change-out response and the provision of a contingent supply downstream from known hot spots. The contingent supply could be a generator, in situations where a downstream interconnection to an adjacent feeder is not available.

Faults on consumer premises have a SAIDI impact where a consumer's private line is fused at the transformer, rather than at the connection point to our network. We now require private lines to be fused at the network connection point. Outages due to external tree works are often associated with commercial plantings and we are prioritising the establishment of formal vegetation management and safety coordination agreements with plantation owners.

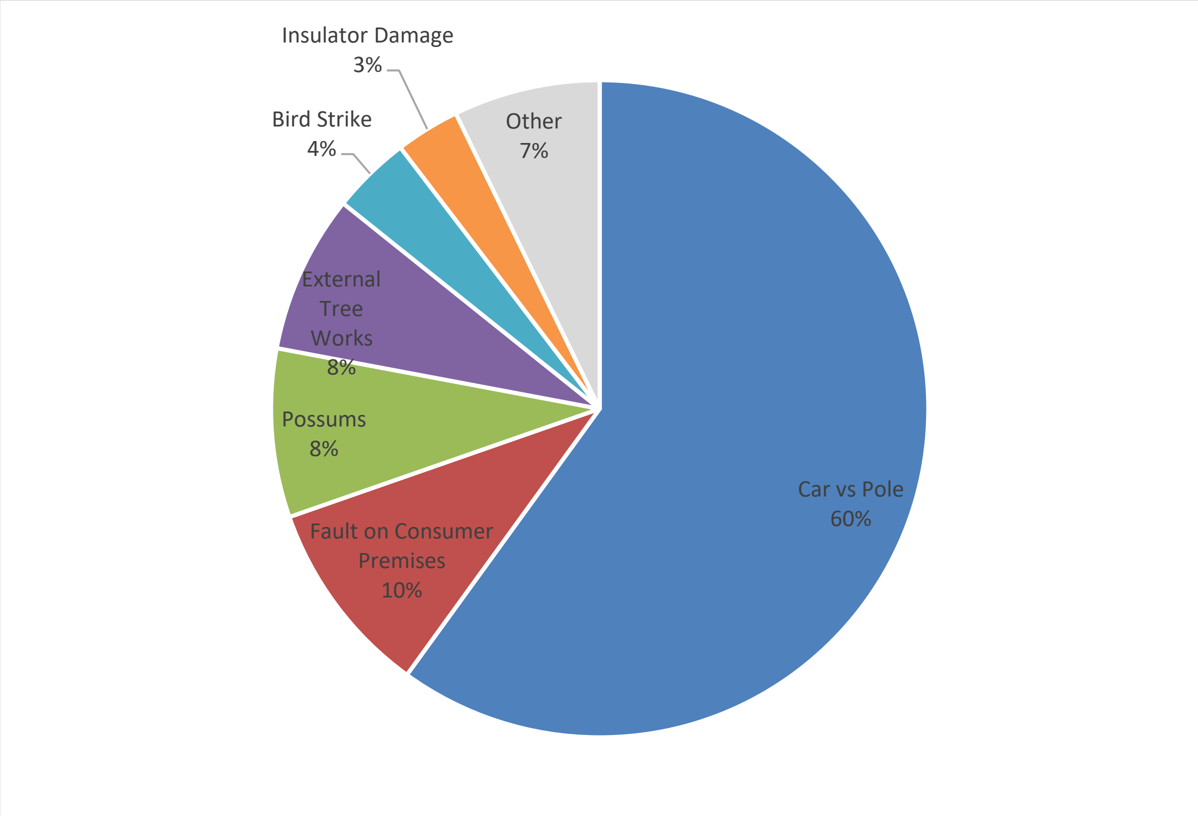


Figure 8.4: SAIDI Impact of 11kV Foreign Interference Faults

Environment

Table 8.5 shows that 50% of the SAIDI impact of unplanned interruptions are caused by the external environment. These include tree contact, adverse weather, lightning and faults where the cause cannot be established (which are generally related to the environment). Figure 8.5 shows the impact of such interruptions over the three-year period FYE2016-18. This shows that the total SAIDI impact of faults due to the external environment is higher than that of equipment failure and of foreign interference, and has increased year-on-year over the period. The number of environmental-related faults is also increasing, but at a significantly slower rate than their SAIDI impact.

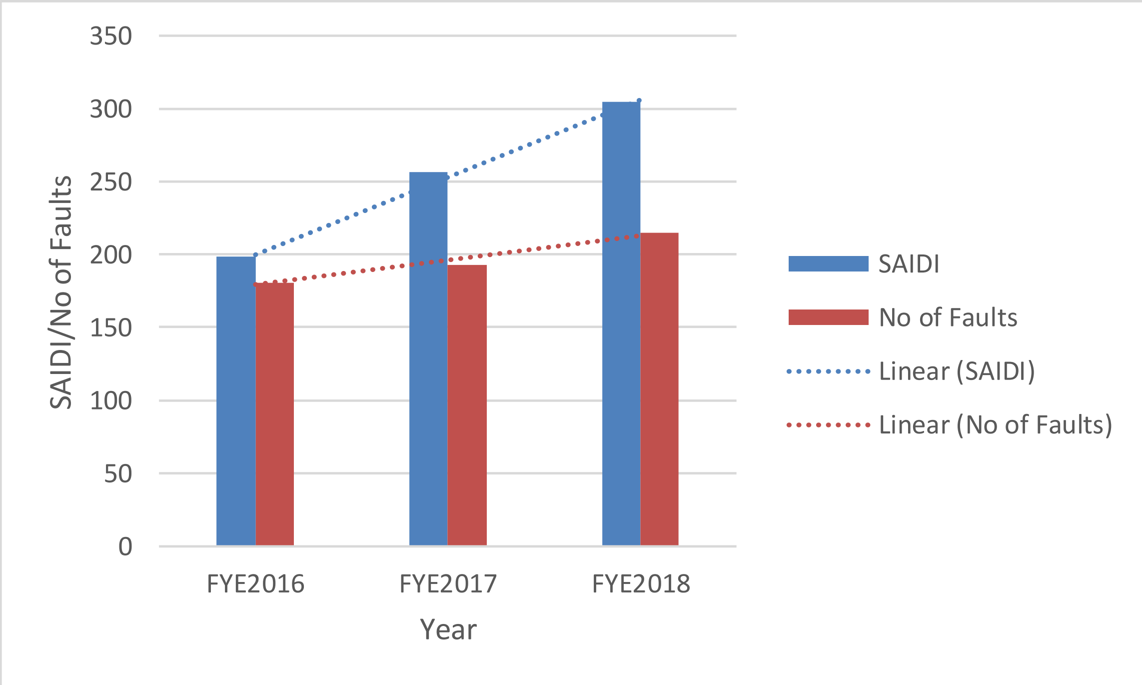


Figure 8.5: Unplanned Interruption caused by External Environment

Our vegetation management programme (see Section 6.2) is being retargeted at applying all available resource to high-hazard sites where actual tree contact is evident. Unknown faults are transient, such as a branch falling across a line and then blowing off again. The high SAIDI impact of unknown faults is, in part, a failure of protection and automation systems that are intended to clear transient faults or isolate the fault at its closest protection device. This is an operational matter that should improve once we have implemented our programme to better coordinate the protection along a feeder.

Faults are categorised as "adverse weather" when our fault response resources are overwhelmed due to multiple and widespread events occurring during a severe wind or lightning storm. Such situations arise because it is not economic to carry the response capacity that would be needed if our response to such extreme events was to be fully effective. Improved debriefing and follow-up will provide more useful information on how we might improve our response to such situations with our available resources. Weather conditions rarely exceed the design standards of our assets.

8.1.2.3 SAIDI Model

We have developed a model to estimate the SAIDI minutes saved by potential reliability improvement capital investments and to assist us in prioritising interventions on the basis of cost per SAIDI minute saved. It is a spreadsheet application that can present data sets in a flexible range of perspectives. The model can:

- Model the impact of changes in expenditure allocations on cost both through the budgeting process and within a financial year;
- Compare the potential reliability improvement benefits of larger reliability improvement projects in terms of cost per SAIDI minute; and
- Analyse projects by strategic driver.

Our SAIDI improvement strategy has three key components:

- Ensuring that asset renewal and maintenance is sustained at a level that results in no overall deterioration in asset condition and therefore performance. The shift from age and condition-based renewals, to renewal based on asset health and criticality is expected to deliver better outcomes. Increased attention is being given to crossarms and conductor renewal.
- Specific projects such as feeder interconnections. Where the improvement in SAIDI does not meet the VOLL test, these projects need to be justified by other criteria such as consumer consultation and

agreement on the cost-to-serve implications. There are diminishing returns in these projects, as we have targeted the biggest gains first in the 33kV network.

- Other small capital projects and operations and maintenance initiatives. Not all SAIDI improvement can be achieved through capital project expenditure. Our operations and maintenance processes will need to improve if we are to meet our SAIDI improvement targets. For example, we are targeting improvement in the coordination of our protection and network automation. We also think we can improve our management of adverse weather events through better resource management and operational preparedness. Our vegetation management must target the elimination of potential problems and must adapt as vegetation issues emerge.

The network reliability data that underpins this model is being updated and the model will be used to prioritise interventions from the range of possibilities discussed in Section 8.1.2.4.

We have used the model to assess the SAIDI impact of the different strategies we will use to improve our normalised reliability from the target of 390 minutes in FYE2019 to our new target of 240 minutes in FYE2029. This is shown in Figure 8.6 below.

Our FYE2019 target of 390 minutes included a normalised 110 minutes of planned interruptions, including 60 minutes due to the annual planned interruption of the 110kV line and an aggregate 50 minutes from planned interruptions at other voltages. In FYE2020, the installation of generators in Kaitaia prior to the line maintenance outage will mean that the maintenance outage will not result in a supply interruption. However, we expect the impact of planned interruptions at 11kV to increase by a normalised five minutes, since we have budgeted for additional asset renewals and, now that we have suspended live-line work, most 11kV asset renewals will require a planned interruption. The other SAIDI reductions will come from capitalised reliability improvement projects, smaller capitalised investments and operations and maintenance process efficiencies.

Note: Other includes small capital projects and operations and maintenance initiatives.

Figure 8.6: Impact of Reliability Improvement Strategy Components.

The cost per SAIDI minute saved of different capital projects targeted at SAIDI improvement is shown in Table 8.6. This shows that we have identified a potential total saving of approximately 60 planned and 40 unplanned SAIDI minutes from capital projects. After allowing for the increase in planned SAIDI at 11kV, we must find savings of 95 unplanned SAIDI minutes between FYE2020 and FYE 2029. Assuming we find 40 minutes from major capital projects, we will need to find 55 minutes from other initiatives, including minor capital expenditures and operational and maintenance initiatives. Potential reliability improvement strategies fitting into into this category are described below for feeders supplied from our different zone substations.

Many of the long rural feeders with high SAIDI contributions supply consumers that are the least economic to serve. We will therefore undertake further analysis of candidate projects that will consider issues such as cost-to-serve and the VOLL before a final decision to proceed is made. We have calculated an average VOLL for the network of $59.18 per kWh (see Appendix F) but the value we use for the analysis of a specific project will depend on the mix of consumers affected.

Project	Total Cost ($000)	SAIDI Reduction (min.)	Cost per SAIDI minute ($000)
Kaitaia generation.	12,260	60.0[1]	204
Rangiahua- South Rd feeder interconnection.	1,079	11.7	92
Rangiahua-Horeke feeder interconnection.	1,223	6.9	177
Mobile generator implementation.	496	6.0	83
Herekino-South Rd feeder interconnection.	1,142	3.7	311
Tokerau feeder refurbishment	363	2.4	149
Purerua feeder refurbishment	125	2.3	55
Matauri-Bay-Whangaroa feeder interconnection	1,245	2.1	587
South Rd recloser and sectionaliser installation	143	1.7	85
Rawene feeder reconstruction	479	1.7	285
Opononi feeder rebuild	342	1.1	304
Omanaia generation	1,612	1.0	1,612
Russell reinforcement	678	0.7	983
Total	**21,187**	**101**	-

Note 1: Planned SAIDI after normalisation. All other savings are unplanned.

Table 8.6: Cost per SAIDI Minute of Capital Expenditure Projects.

8.1.2.4 Potential 11kV Network Reliability Improvement Strategies

Improvement in SAIDI will require expenditure at the less economic end of the network and, given our expenditure constraints, solutions that are less capital intensive than the projects shown in Table Y.Y. These solutions are likely to come from:

- Reconfiguring feeders with a more optimal overlay of automation and technology, and improved coordination and operation of automation, isolation and protection systems;
- Prioritising the maintenance of more critical assets and/or their components at the front end of a feeder;
- Improved targeting of asset renewal and maintenance through the application of asset health data, criticality, risk models and fault analysis. The application of machine learning to these tasks is on our roadmap;
- Better location and coordination of generation into our distribution network and load management system;
- More sophisticated operating to exploit new technology such as batteries, distributed energy resource management systems etc.; and
- Correct coordination and operation of automation, isolation and protection systems.

The potential for these strategies to be applied to different parts of our network is discussed in more detail below

Kaikohe Substation Feeders

All feeders supplied from the Kaikohe substation, except NRCF, which is entirely underground, are shown in Table 8.4. However, the urban Kaikohe feeder has not experienced any faults in to date in FYE2019.

In the medium term, the construction of a new substation at the proposed Ngawha Energy Park and an 11kV point of injection at Wiroa will allow two Ohaeawai feeder to be split into two and would also supply the Puketi/Wiroa spur on the Rangiahua feeder. We are investigating the use of the mobile substation to provide an additional injection point into the Taheke feeder (which would be fed from the Kaikohe-Omanaia 33kV line), and the installation of an interconnection between the ends of the Rangiahua and Horeke feeders is shown in Table 8.6. Beyond this AMP planning period, a new 110/11kV substation at Mangamuka would allow the Rangiahua feeder to be split into three or four smaller feeders.

The Awarua feeder has few realistic opportunities for interconnection with other feeders and needs a similar low technology solution to address reliability improvement. This could include the provision of fault indicators and optimising the location of isolating switches to speed up the location of faults after they occur.

Okahu Rd Feeders

In addition to the feeders supplying local load close to Kaitaia, Okahu Rd supplies three long rural feeders; South Rd, Herekino and Oxford St, all of which are shown in Table 8.4. In November 2018, two remote sectionalisers and a recloser were installed close to Broadwood to improve the reliability of the South Rd feeder.

In the long term, an optimal solution would be to split the South Rd feeder into a number of smaller feeders fed from the proposed 110kV substation at Mangamuka and potentially a new 33kV substation at Broadwood. In the interim, an 11kV bus arrangement comprising remote controlled circuit breakers and supported by a generator would reduce the impact of faults near the ends of the feeder, and also allow supply to be restored more quickly to the ends of the feeder when a fault occurs between Broadwood and Okahu Rd. A similar arrangement is being considered at Herekino.

The Oxford St feeder already has more remote interconnections with other feeders, but could benefit from additional fault indicators and possibly further optimisation of the location of isolation points.

Kawakawa Feeders

Towai and Russell Express are shown in Table 8.4. Both are long feeders with limited interconnections to other feeders.

The reliability of the Russell Express feeder is a major concern, due to the load, the number of customers on this feeder and the fact that Russell is a significant tourist town. We have two submarine cables supplying the Russell peninsular, and the recent completion of an 11kV cable between Te Haumi and Opua means that the Russell load could also be supplied from the Haruru substation using the Joyces Rd feeder. However, a new 11kV cable between Okiato Point and the Russell Rd junction is needed before the feeder could be split in two. A bussing point at the Russell Rd junction supported by generation would also assist. Outside the planning period an 11kV cable between the Russell Rd junction and the north end of Russell would provide a more secure supply to the town.

The Towai feeder is challenged by difficult geography and locating faults has proved difficult. Fault Indicators located at direction decision points and more isolation points to facilitate the segregation of the feeder to prove line sections after a fault occurs would speed the response. This is a low-technology, low-cost option appropriate to the economics of the feeder.

Omanaia Feeders

This substation supplies the long rural Opononi and Rawene feeders, both of which are shown in Table 8.4.

Protection and automation on the Opononi feeder are not performing reliably. This results in a delayed fault response if the switches need to be operated manually as the feeder is remote from our Puketona depot. It is a maintenance issue that we should be able to resolve without significant capital investment. Furthermore, the Opononi and Rawene feeders interconnect adjacent to a voltage regulator. This arrangement could be reconfigured so that either feeder could supply the regulator, while the other could be back-fed from the voltage-corrected side of the tie point. The voltage-corrected bus could be further secured by the connection of a generator.

There is also an interconnection opportunity between the Rawene and Horeke feeders, which could potentially provide a useful SAIDI reduction.

Taipa Feeders

Taipa supplies the Oruru, Tokerau and Mangonui feeders shown in Table 8.4. The construction of the Kaeo substation and installation of voltage regulators at Manganui in FYE 2019 has provided some tie capacity with the southern network. This will allow some load to be supplied from Kaeo in a contingency situation, which should improve the reliability of both the Mangonui and Oruru feeders.

Development of the Carrington resort on the Karikari peninsula will necessitate supply reinforcement, which may be an opportunity for network scale distributed generation. If this development materialises, a generator will be located on the peninsula, possibly within the resort. This will to provide 11kV security, which will improve the reliability of the Tokerau feeder.

Pukenui Feeders

The Te Kao feeder, which supplies the area north of Pukenui, is shown on Table 8.4. It has poor reliability due to its remoteness and its location on the network extremity, which precludes interconnection with other feeders. It is planned to locate a generator mid-way along the feeder to provide support in the event of a fault.

Other Feeders

The two remaining feeders shown in Table 4.4 are Inlet Rd (Kerikeri substation), Purerua (Waipapa substation) and Awanui (NPL substation). These feeders are all in the most reliable quartile of the feeders in the table and potential reliability improvements have still to be reviewed for possible reliability improvement initiatives. Purerua and Inlet Rd are long rural feeders that could benefit from the installation of fault indicators to assist with fault location and possibly also from the location of generators near the remote ends of the feeders.

8.1.3 Benchmarking

We have also benchmarked our FYE2018 network operations and maintenance expenditure against that disclosed by other New Zealand EDBs with largely rural supply areas. This is shown in Appendix F, where our expenditure has been normalised by circuit length. The results show that we differ from our peers in our operational focus, but we are confident that our asset management expenditure is appropriate for our network and supply area, and will enable us to be agile in our response to changing consumer needs and economic development initiatives. We are in the middle of a major modernisation cycle and are transitioning to a network enabled by distributed energy resources.

This exercise has shown that:

- Our total maintenance expenditure per km is approximately 36% higher than the average of our peers. We are well resourced to cope with the wide variations in operating conditions that our environment can throw at us.
- Our expenditure on vegetation management per km is 114% higher (on average) than our peers for a similar level of vegetation-driven SAIDI. This reflects the challenge of recovering costs under the existing tree regulations, which are to be reviewed in late 2019. The gains from our past strategy have stabilised and we are maintaining our position. New strategies are being implemented to improve the safety outcomes that underpin the need for vegetation control without additional expenditure.
- We are spending on average 39% more than our peers on routine maintenance. Most of this is on inspection and condition assessment. We are gathering the improved asset condition data needed to develop more efficient condition and reliability centred maintenance strategies. This is a shift from age-driven to condition- and lifecycle-driven management strategies. Data gathering will continue with a focus on crossarm and conductor condition. We are also gathering the data to better control and monitor the low voltage network and to apply ADMS and DERMS technology.
- Our expenditure on asset renewal is 30% above the average. This is related to our defect management. Performance issues are frequently related to a specific component such as the crossarm, which do not warrant renewal of the entire structure.
- Our reactive (fault and emergency) maintenance expenditure is 5% lower than the average of our peers.

The key messages from this analysis are that our total network operations and maintenance expenditure is not a limitation on performance and that the network is being adequately resourced and maintained for our current and foreseeable future needs.

8.2 Asset Performance and Efficiency

Table 8.7 compares our achieved asset performance and efficiency measures in FYE2018 with the target levels set out in the 2017 AMP update.

PERFORMANCE MEASURE	FYE2018 TARGET	ACTUAL PERFORMANCE	VARIANCE
Loss Ratio	9.3%	9.8%	0.5%
Operational Expenditure to Total Regulatory Income	33%	31.0%	(2.0%)

Table 8.7: Comparison of actual asset performance and efficiency with target levels for FYE2018

As indicated by the table, our loss ratio was marginally higher than our target in FYE2018. Our operational expenditure ratio was 2% better than out target. Our assessed performance against both measures is taken from our audited FYE2018 information disclosures.

The relatively high loss ratio is a reflection of the current network architecture. It includes transmission losses, so is not directly comparable with many other EDBs. We expect the Kaeo substation to drive a small reduction in loss ratio and the completion of the second 110kV circuit to Kaitaia should have a significant impact.

8.3 Financial and Physical Performance

A comparison of our actual expenditure in FYE2017 for both network capital expenditures and network maintenance with the budgeted expenditures, as presented in the 2016 AMP, is provided in Table 8.8. While there are variances between the difference expenditure categories, total spend over the year was within 3% of budget.

Variances between actual and budgeted expenditures are discussed in detail in Sections 8.3.1.1 and 8.3.1.2 below.

EXPENDITURE CATEGORY	AMP BUDGET FYE2018	ACTUAL SPEND FYE2018	VARIANCE	
Network capital expenditure ($000)				
Consumer connection	1,486	2,115	629	42%
System growth	4,694	7,978	3,284	70%
Asset replacement and renewal	7,278	5,439	(1,839)	(25%)
Reliability, safety and environment	3,883	4,775	892	23%
Asset relocations	-	-	-	-
Subtotal – network capital expenditure	**17,341**	**20,307**	**2,996**	**17%**
Maintenance expenditure ($000)				
Service Interruptions and emergencies	1,200	1,371	171	14%
Vegetation management	1,730	1,591	(139)	(8%)
Routine and corrective maintenance and inspection	2,122	2,233	111	5%
Asset replacement and renewal	1,088	1,108	20	2%
Subtotal – maintenance expenditure	**6,140**	**6,303**	**163**	**3%**
TOTAL DIRECT NETWORK EXPENDITURE	**23,481**	**26,610**	**3,129**	**13%**

Table 8.8: Comparison of actual and budget network capex and network maintenance opex in FYE2018

8.3.1.1 Network Capital Expenditure

As shown in Table 8.5 actual capital expenditure in FYE2018 was 17% higher than forecasts with material variations from budgeted levels in all expenditure categories. The more significant variations from budget are summarised below.

Consumer Connections

This is an area where we have little control over expenditure and there was more consumer-driven activity than expected in FYE2018. The additional expenditure was largely offset by an increase in consumer contributions.

System Growth

The new Kaeo substation and the refurbishment of the Omanaia substation (which included the installation of a larger transformer) went over budget for the following reasons:

- The line builds for the Kaeo Substation were significantly more complex than anticipated due to unforeseen landowner and archaeological issues. The final line routes were over more difficult terrain and involved the use of stronger structures, structure relocations and longer more complicated construction; and
- We decided that a complete refurbishment of the Omanaia substation, including a new larger transformer, rather than a simple transformer replacement with a relocated unit. While much of this cost fell into FYE2019, equipment procurement and site preparation expenditure in FYE2018 was significantly higher than budgeted.

Asset Replacement and Renewal

- Refurbishment work on the 33kV lines supplying Taipa and Omanaia substations was deferred due to inclement weather and the limited availability of contracting resources.
- This expenditure reduction was partially offset by cost overruns on the refurbishment of Kawakawa substation. Problems included damaged switchgear on arrival, parts not fitting, contractor difficulties and transformer mount anchoring for earthquake resilience being more complicated than envisaged.

Reliability, Safety and Environment

During FYE2018, the Board decided to defer construction of the Wiroa-Kaitaia 110kV circuit and to secure supply to the northern area with diesel generation. There was earlier than planned expenditure on diesel generators in preparation for the implementation of this project. These generators were deployed during November 2018 to reduce SAIDI impact of the 110kV maintenance outage. One generator will be shared with the Omanaia project.

8.3.1.2 Network Maintenance Expenditure

As shown in Table 8.4, network maintenance expenditure in FYE2018 was 5% below budget. We reduced expenditure on vegetation management, and service interruptions and emergencies (over which we have limited control) also came in lower than expected. These expenditure reductions were partially offset by additional expenditure on asset inspections and routine maintenance.

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 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.

We now have both a public safety management system and a quality system that are both externally certified and subject to regular external audits. These are process-orientated total quality management systems. Our asset management system, of which this AMP is an output, has adopted the ISO 55001 standard, and our asset management maturity is assessed against prescribed criteria derived from this standard. This assessment is presented in Schedule 13 of Appendix A.

Our asset management improvement programme will continue to focus on improving those areas that we have identified as weak and are impediments to our overarching goal of meeting stakeholder expectations as efficiently as possible. As with any relationship, there are still opportunities for improvement at the interface between TEN and TECS, and efforts to improve communication will continue. Furthermore, we plan to shift our asset management focus from regulatory compliance to that of meeting consumer expectations, particularly in the management of supply reliability and network maintenance.

As discussed elsewhere in this AMP, our asset management goals for FYE2019-21 include:

- the installation of more diesel generation within our network to secure supply in the northern area when our 110kV transmission line is out for maintenance, improve supply reliability during both planned and unplanned interruptions and also to manage localised and seasonal network constraints;
- the installation and implementation of an ADMS to improve the effectiveness of our management of service interruptions and emergencies, and to manage the increased embedded generation within our network. We anticipate that this new operations management system will prove a key tool in our transition from that of a distributor of electricity to that of a manager of a distributed energy system, utilising a network that interconnects embedded electricity generators and consumers;
- developing and operating a network that is open to the use of new and emerging technologies by both consumers and generators. This will include trialling the use of these technologies in situations where they have the potential to reduce the cost of network development and operation, or to better meet the expectations of consumers and other network users in the efficient utilisation of electricity;
- increasing the efficiency of our network maintenance by focusing expenditure on assets that are nearing the end of their expected life and therefore have a higher probability of failing in service; and
- mitigating the risk of reducing the level of monitoring of assets that are less likely to fail in service by introducing enhanced safety management systems that are not reliant on asset condition.

8.5 Further Work

8.5.1 Cost of Service, Value of Lost Load and Reliability

We are progressing further work to establish the cost of service under our new strategic direction for network development. Specifically, we are:

- Continuing to develop our cost to serve model to provide resolution down to load groups and network segments. This model will also support the cost and service reflective pricing initiatives that all EDBs are currently engaged in, at the behest of the Electricity Authority. It will also have relevance to the development of preferred solutions for addressing uneconomic line renewal and the application of new technologies.
- Utilising a model that allows us to estimate the SAIDI impact of different reliability improvement interventions in a consistent and quantitative manner. We are using this model to prioritise reliability improvement projects on the basis of cost per SAIDI minute saved and use the results to optimise our reliability improvement expenditure.
- We are initiating a programme to document vulnerabilities in our network and develop formalised response plans for faults with an identified high SAIDI risk.

8.5.2 Resilience

Resilience has emerged as a key issue for our consumer and regulator stakeholders. We are undertaking a review of how these interests are addressed in our development plans, security, standards, contingency provisions etc.

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

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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 19**	**31 Mar 20**	**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**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		3,400	1,636	1,669	1,702	1,736	1,771	1,806	1,842	1,879	1,917	1,955
11	System growth		2,486	20,174	1,929	1,693	4,953	5,525	5,900	6,270	9,369	9,269	20,467
12	Asset replacement and renewal		7,921	8,527	6,049	7,583	7,977	8,294	7,885	7,990	7,691	8,115	8,134
13	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:												
15	Quality of supply		5,277	1,527	2,430	4,299	2,063	936	1,298	503	39	39	1,078
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		-	73	2,763	-	-	-	-	1,934	-	-	-
18	**Total reliability, safety and environment**		5,277	1,600	5,193	4,299	2,063	936	1,298	2,437	39	39	1,078
19	**Expenditure on network assets**		19,084	31,937	14,839	15,277	16,729	16,525	16,889	18,540	18,977	19,341	31,635
20	Expenditure on non-network assets		1,478	850	408	520	531	541	552	563	574	586	598
21	**Expenditure on assets**		20,562	32,787	15,247	15,797	17,260	17,066	17,441	19,103	19,552	19,926	32,232
22													
23	*plus* Cost of financing		100	100	100	100	100	100	100	100	100	100	100
24	*less* Value of capital contributions		2,000	1,202	1,226	1,251	1,276	1,301	1,327	1,354	1,381	1,408	1,437
25	*plus* Value of vested assets		75	100	75	50	25	25	25	25	25	25	25
26													
27	**Capital expenditure forecast**		18,737	31,785	14,196	14,697	16,109	15,890	16,239	17,874	18,296	18,643	30,921
28													
29	Assets commissioned		16,850	29,763	12,515	12,917	14,301	14,028	14,320	15,897	16,259	16,544	28,757
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 19**	**31 Mar 20**	**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**
32			**$000 (in constant prices)**										
33	Consumer connection		3,400	1,636	1,636	1,636	1,636	1,636	1,636	1,636	1,636	1,636	1,636
34	System growth		2,486	20,174	1,891	1,627	4,667	5,104	5,344	5,568	8,156	7,911	17,126
35	Asset replacement and renewal		7,921	8,527	5,930	7,289	7,517	7,662	7,142	7,095	6,695	6,926	6,806
36	Asset relocations		-	-	-	-	-	-					
37	Reliability, safety and environment:												
38	Quality of supply		5,277	1,527	2,382	4,132	1,944	864	1,175	447	34	34	902
39	Legislative and regulatory		-	-	-	-	-	-					
40	Other reliability, safety and environment		-	73	2,709	-	-	-		1,717			
41	**Total reliability, safety and environment**		5,277	1,600	5,091	4,132	1,944	864	1,175	2,164	34	34	902
42	**Expenditure on network assets**		19,084	31,937	14,548	14,684	15,764	15,267	15,297	16,463	16,521	16,507	26,470
43	Expenditure on non-network assets		1,478	850	400	500	500	500	500	500	500	500	500
44	**Expenditure on assets**		20,562	32,787	14,948	15,184	16,264	15,767	15,797	16,963	17,021	17,007	26,970
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			66		744							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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*
50												
52	for year ended	**31 Mar 19**	**31 Mar 20**	**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**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	33	66	100	135	170	206	243	281	319
55	System growth	-	-	38	66	286	421	556	702	1,213	1,358	3,341
56	Asset replacement and renewal	-	-	119	294	460	632	743	895	995	1,189	1,328
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	-	-	48	167	119	71	122	56	5	6	176
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	54	-	-	-	-	217	-	-	-
62	**Total reliability, safety and environment**	-	-	102	167	119	71	122	273	5	6	176
63	**Expenditure on network assets**	-	-	291	593	965	1,258	1,592	2,077	2,456	2,834	5,164
64	Expenditure on non-network assets	-	-	8	20	31	41	52	63	74	86	98
65	**Expenditure on assets**	-	-	299	613	995	1,300	1,644	2,140	2,531	2,919	5,262
66												

67		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	All types	3,400	1,636	1,636	1,636	1,636	1,636
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**	3,400	1,636	1,636	1,636	1,636	1,636
77	*less* Capital contributions funding consumer connection	2,400	1,202	1,202	1,202	1,202	1,202
78	**Consumer connection less capital contributions**	1,000	434	434	434	434	434
79	**11a(iii): System Growth**						
80	Subtransmission	571	12,821	1,138	360	46	46
81	Zone substations	1,629	-	493	1,007	4,361	4,798
82	Distribution and LV lines	41	260	260	260	260	260
83	Distribution and LV cables						
84	Distribution substations and transformers	245					
85	Distribution switchgear						
86	Other network assets		7,094				
87	**System growth expenditure**	2,486	20,174	1,891	1,627	4,667	5,104
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	2,486	20,174	1,891	1,627	4,667	5,104
90							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
92		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94		Subtransmission	2,225	4,373	1,353	1,352	931	1,260
95		Zone substations	1,307	59	64	63	64	138
96		Distribution and LV lines	1,908	2,446	2,647	3,961	4,648	4,562
97		Distribution and LV cables	390	109	193	192	193	194
98		Distribution substations and transformers	632	488	673	752	683	508
99		Distribution switchgear	894	647	813	871	900	903
100		Other network assets	565	405	187	98	98	98
101		**Asset replacement and renewal expenditure**	7,921	8,527	5,930	7,289	7,517	7,662
102	*less*	Capital contributions funding asset replacement and renewal						
103		**Asset replacement and renewal less capital contributions**	7,921	8,527	5,930	7,289	7,517	7,662
104								

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
106		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
122	**11a(vi): Quality of Supply**							
123		*Project or programme**	**$000 (in constant prices)**					
124		11kV network reliability improvements		86	1,145	2,156	1,910	830
125		Russell reinforcement		-	682	678	-	-
126		ADMS implementation - network costs		569	520	520		
127		New technology trials		66		744		
128		GIS upgrade		415				
129		**include additional rows if needed*						
130		All other projects or programmes - quality of supply	5,277	391	34	34	34	34
131		**Quality of supply expenditure**	5,277	1,527	2,382	4,132	1,944	864
132	*less*	Capital contributions funding quality of supply						
133		**Quality of supply less capital contributions**	5,277	1,527	2,382	4,132	1,944	864
134								

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Waipapa substation upgrade		31	2,709			
154	Relocate Mt Pokaka protection cabinets		42				
155	[Description of material project or programme]						
156	[Description of material project or programme]						
157	[Description of material project or programme]						
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	-	73	2,709	-	-	-
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	-	73	2,709	-	-	-
163							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	ADMS implementation	1,360	450	-	-	-	-
170	Vehicles	75	75	75	75	75	75
171	Misc Items	43	325	325	425	425	425
172	[Description of material project or programme]						
173	[Description of material project or programme]						
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	1,478	850	400	500	500	500
177	**Atypical expenditure**						
178	*Project or programme**						
179	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	[Description of material project or programme]						
183	[Description of material project or programme]						
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	1,478	850	400	500	500	500

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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 19**	**31 Mar 20**	**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**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,300	1,199	1,197	1,195	1,193	1,190	1,186	1,181	1,176	1,170	1,164
11	Vegetation management	1,700	2,071	2,034	2,102	2,158	2,137	2,126	2,338	2,366	2,370	2,470
12	Routine and corrective maintenance and inspection	1,600	1,787	1,823	1,859	1,896	1,934	1,973	2,012	2,066	2,123	2,180
13	Asset replacement and renewal	700	1,106	1,128	1,151	1,174	1,197	1,221	1,246	1,270	1,296	1,322
14	**Network Opex**	5,300	6,163	6,182	6,307	6,421	6,458	6,506	6,777	6,879	6,960	7,136
15	System operations and network support	5,522	5,934	6,149	6,272	6,398	6,526	6,421	6,435	6,563	6,695	6,828
16	Business support	5,025	5,198	5,302	5,408	5,516	5,626	5,739	5,854	5,971	6,090	6,212
17	**Non-network opex**	10,547	11,132	11,451	11,680	11,914	12,152	12,160	12,288	12,534	12,785	13,041
18	**Operational expenditure**	15,847	17,295	17,634	17,987	18,335	18,610	18,666	19,066	19,414	19,745	20,176

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 19**	**31 Mar 20**	**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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,300	1,199	1,174	1,149	1,124	1,099	1,074	1,049	1,024	999	974
23	Vegetation management	1,700	2,071	1,994	2,020	2,034	1,974	1,926	2,076	2,060	2,023	2,067
24	Routine and corrective maintenance and inspection	1,600	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,799	1,812	1,824
25	Asset replacement and renewal	700	1,106	1,106	1,106	1,106	1,106	1,106	1,106	1,106	1,106	1,106
26	**Network Opex**	5,300	6,163	6,061	6,062	6,051	5,966	5,893	6,018	5,989	5,940	5,971
27	System operations and network support	5,522	5,934	6,029	6,029	6,029	6,029	5,816	5,714	5,714	5,714	5,714
28	Business support	5,025	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198
29	**Non-network opex**	10,547	11,132	11,227	11,227	11,227	11,227	11,014	10,912	10,912	10,912	10,912
30	**Operational expenditure**	15,847	17,295	17,288	17,289	17,278	17,193	16,907	16,930	16,901	16,852	16,883
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	310	344	344	344	344	344	344	344	344	344	344

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 19**	**31 Mar 20**	**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**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	23	46	69	91	112	132	152	171	190
43	Vegetation management	-	-	40	82	124	163	200	262	306	347	403
44	Routine and corrective maintenance and inspection	-	-	36	72	109	147	186	225	267	311	356
45	Asset replacement and renewal	-	-	22	45	68	91	115	140	164	190	216
46	**Network Opex**	-	-	121	245	370	492	613	759	890	1,020	1,165
47	System operations and network support	-	-	121	244	369	497	605	721	850	981	1,115
48	Business support	-	-	104	210	318	428	541	656	773	892	1,014
49	**Non-network opex**	-	-	225	454	687	925	1,146	1,377	1,622	1,873	2,129
50	**Operational expenditure**	-	-	346	698	1,058	1,417	1,760	2,136	2,513	2,893	3,294

Company Name **Top Energy**
AMP Planning Period **1 April 2019 – 31 March 2029**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					Asset condition at start of planning period (percentage of units by grade)							
8												% of asset forecast to be replaced in next 5 years
9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	
10	All	Overhead Line	Concrete poles / steel structure	No.	-	3%	10%	79%	8%	13%	2	2%
11	All	Overhead Line	Wood poles	No.	-	18%	82%			0%	3	44%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	8%	32%	43%	17%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	100%	-	-	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					100%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	5%	68%	26%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.			67%		33%	-	3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	24%	35%	41%	-	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	1%	13%	44%	43%		3	5%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	20%	-	10%	70%	-	3	20%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	49%	51%	-	3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.			10%	16%	74%		3	39%
35												

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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												
36					**Asset condition at start of planning period (percentage of units by grade)**							
37												
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5%	8%	28%	43%	18%	-	3	8%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	7%	17%	24%	31%	21%	-	3	-
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	30%	22%	15%	18%	16%	-	3	9%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0%	0%	6%	93%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	0%	5%	43%	52%	-	3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	50%	50%	-	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	0%	7%	72%	20%		3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11%	17%	20%	22%	31%		3	3%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.		1%	32%	43%	24%		3	12%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	0%	13%	75%	11%	0%	3	0%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0%	4%	88%	9%	6%	3	0%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	5%	75%	20%	-	3	3%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.				100%			3	-
55	LV	LV Line	LV OH Conductor	km	1%	5%	21%	35%	38%	-	3	-
56	LV	LV Cable	LV UG Cable	km	-	3%	14%	36%	46%	-	3	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	20%	40%	40%	-	3	-
58	LV	Connections	OH/UG consumer service connections	No.	-	1%	26%	63%	10%	21%	2	1%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	0%	16%	23%	61%	-	3	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot				100%			3	20%
61	All	Capacitor Banks	Capacitors including controls	No.	64%	2%	2%	20%	11%		3	11%
62	All	Load Control	Centralised plant	Lot				50.00%	50.00%		3	-
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km							N/A	

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Kaikohe	10	17	N-1	1	59%	17	59%	No constraint within +5 years	
10	Kawakawa	6	7	N-1	3	91%	7	72%	No constraint within +5 years	1.5MW to be transferred to Haruru in FYE2022.
11	Moerewa	3	5	N-1	2	67%	5	67%	No constraint within +5 years	
12	Waipapa	8	23	N-1	6	34%	23	34%	No constraint within +5 years	3.2MW to be transferred to Kaeo in FYE2019.
13	Omanaia	3	-	N-0	1	-	-	-	Transformer	Transfer capacity provided by onsite generation
14	Haruru	6	23	N-1	1	28%	23	37%	No constraint within +5 years	
15	Mt Pokaka	3	-	N-0	1	-	-	-	Transformer	Mobile transformer available. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	7	23	N-1	6	31%	23	35%	No constraint within +5 years	
17	Kaeo	4	10	N-1	4	40%	10	44%	Subtransmission circuit	New substation. 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	9	12	N-1	4	75%	12	79%	No constraint within +5 years	
19	Taipa	6		N-0	4	-	-	-	Transformer	Transfer capacity is standby diesel generation installed at the substation site. There is also a single incoming subtransmission circuit
20	NPL	11	23	N-1	4	48%	23	48%	No constraint within +5 years	
21	Pukenui	2	-	N-0	-	-	-	-	Transformer	Mobile transformer available. There is also a single incoming subtransmission circuit
22	Kaikohe 110kV	48	30	N-1	25	160%	50	100%	Transformer	Transfer capacity is Ngawha generation, which is connected to the 33kV subtransmission network and which is normally in operation.
23	Kaitaia 110kV	23	25	N-1	9	94%	25	98%	Subtransmission circuit	Transfer capacity is diesel generation. Firm capacity limited by single incoming 110kV circuit.
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 2019 – 31 March 2029**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*				**Number of connections**		
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**						
12	[EDB consumer type]	480	480	480	480	480	480
13	[EDB consumer type]	10	10	10	10	10	10
14	[EDB consumer type]						
15	[EDB consumer type]						
16	[EDB consumer type]						
17	**Connections total**	490	490	490	490	490	490
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	100	105	110	116	122	128
21	Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25	GXP demand	45	45	58	62	66	67
26	*plus* Distributed generation output at HV and above	25	25	25	25	25	25
27	**Maximum coincident system demand**	70	70	83	87	91	92
28	*less* Net transfers to (from) other EDBs at HV and above						
29	**Demand on system for supply to consumers' connection points**	70	70	83	87	91	92
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	175	178	235	250	270	275
32	*less* Electricity exports to GXPs	15	15	5	-	-	-
33	*plus* Electricity supplied from distributed generation	200	200	200	200	200	200
34	*less* Net electricity supplied to (from) other EDBs						
35	**Electricity entering system for supply to ICPs**	360	363	430	450	470	475
36	*less* Total energy delivered to ICPs	325	328	389	408	426	431
37	**Losses**	35	35	41	42	44	44
38							
39	**Load factor**	59%	59%	59%	59%	59%	59%
40	**Loss ratio**	9.7%	9.6%	9.4%	9.4%	9.3%	9.2%

Company Name	**Top Energy**
AMP Planning Period	**1 April 2019 – 31 March 2029**
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								
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		210.8	110.0	110.0	110.0	110.0	110.0
12	Class C (unplanned interruptions on the network)		251.2	283.0	274.0	266.0	257.0	249.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		1.10	0.35	0.35	0.35	0.35	0.35
15	Class C (unplanned interruptions on the network)		3.30	3.09	3.03	2.98	2.91	2.86

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2019 – 31 March 2029**
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?	2	We have an approved management policy consistent with PAS 55 requirements. However it still has to be formally communicated throughout the organisation.		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 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 are implementing a network development programme that is focused on improving reliability over time and adapting to the application of emerging technologies. This is guiding our investment in the creation of new assets. 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.		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 for described in the AMP. 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 was certified as ISO 9001 compliant in May 2015 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.		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 was certified as ISO 9001 compliant in May 2015 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 was certified as ISO 9001 compliant in May 2015 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 7.2.3 and 7.2.4 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. This was activated for the July 2014 storm and the Plan has been reviewed and revised to incorporate the lessons learnt during that event. 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.

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
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.

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
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	Our quality system was certified as ISO 9001 compliant in May 2015 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.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	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 amount of work we have successfully completed over the last two years is documented in our AMP (see Section 5.12.2) and is testimony to our ability to deliver on a challenging work programme.		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	We have developed documented criteria and processes for the accreditation of external suppliers and contractors and implementation of these is well in hand. We also transferred responsibility for some asset management activities, in particular asset inspection and maintenance programming, from Top Energy Contracting Services (TECS) to Networks. The formal relationship between TECS and Networks is based on the asset manager - service provider model, but implementaton of this model has still to fully mature.		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 availability 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.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	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.		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	This 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 some 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?	3	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 but we are in the process of developing an electronic link between GIS and SAP. Getting "as built" information back from the field can be a problem. We have written an "as built" standard but compliance is still weak.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	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 relatively new and its implementation is still being optimised to effectively meet our requirements.		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. However these systems tend to be managed independently and we still have some way to go to develop a risk management system that is fully integrated with our asset management and corporate business processes.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	We have a Public Safety Management system that is certified to NZS 7901 and externally audited. We operate a risk register that is updated on an ad-hoc basis. We are also developing systems to identify and record design and operational risks. However these systems tend to be managed independently and we still have some way to go to develop a risk management system that is fully integrated with our asset management and corporate business processes.		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 Corporate Services is responsible for identifying our legal obligations. However he is unlikely to capture all changes to our technical obligations. Our involvement with industry organisations such as the Electricity Networks Association and Electricity Engineers Association is increasing to the extent that it is unlikely changes in 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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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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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
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?	2	As previously described, we have a formal asset inspection programme in place and defined standards for recording and measuring asset condition. However these processes are reactive and we have not developed score cards or other leading indicators of the health of our asset base.		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 part of 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.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2019 -31 March 2029**
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
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Our ISO 9001 quality system and our NZS 7901 Public Safety Management System are audited in accordance with their certification requirements. Our measurement of supply reliability is also externally audited in accordance with the Commission's requirements. However we do not have a structured internal audit process that covers the whole of the asset management system.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	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. However, in the absence of a structured internal audit process that covers the whole of the asset management system, there is no formal process within TEN for instigating and monitoring the implementation of corrective actions that apply directly to the asset management system.		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, but our involvement with industry interest groups such as the EEA could still have more traction. 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.

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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
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.

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	2.8.3	
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 supprt 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;	3.1.5, Table 3.1	
4.2.2	- the extent to which individual zone substations have N-x subtransmission security;	3.1.5 Table 3.1	
4.2.3	- a description of the distribution system including the extent to which it is underground;	3.1.6	
4.2.4	- a brief description of the network's distribution substation arrangements;	3.1.6	
4.2.5	- a description of the low voltage network, including the extent to which it is underground; and	3.1.7	
4.2.6	- an overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems.	3.1.8 3.1.9	
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	

Handbook Reference	Requirement	AMP Ref	Comment
4.5.1	Subtransmission	6.3.1 6.3.2	
4.5.2	Zone substations	6.9	
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	5.14	
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	3.1.11	
4.5.11	Other generation plant.	3.1.11	
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 indiators by feeder to assist us mange network reliability. This is discussed in Section 8.2.1.1
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

Handbook Reference	Requirement	AMP Ref	Comment
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			
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 5.3	
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.	5.6.3	
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	5.6.2	

Handbook Reference	Requirement	AMP Ref	Comment
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		
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:	5.12	
11.9.1	- the reasons for choosing a selected option for projects where decisions hae been made;	5.13	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-netowrk 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	5.13.2.1	Our major initiative is the installation of diesel generation in the Kaitaia area, which is discussed extensively in this section.
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;	5.13	
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.	5.9	
11.12	The AMP must include a description of the EDB's policies on non-network solutions including:	5.9 5.10 5.11	

Handbook Reference	Requirement	AMP Ref	Comment
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:		
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 maintianing 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;		

Handbook Reference	Requirement	AMP Ref	Comment
12.3.3	- a description of the projects currently underway and planned for the next twelve months;	5.13.1	The capex forecasts in section 5 include a provision for incremental maintenance CAPEX such as miscellaneous pole replacements. The maintenance CAPEX component of these forecasts is extracted and disaggregated in Table 6.6
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;	5.14	We do not consider our expenditure on non-network assets to be material, apart from expenditure on the new ADMS.
13.2	development, maintenance and renewal policies that cover them;		
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.	7.3.2-7.3.6	
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	

Handbook Reference	Requirement		AMP Ref	Comment
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 8.5	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:			
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 – Benchmarking

9.5.1 FYE2017 Operations and Maintenance Expenditure per km of Circuit

$000 (real 2017)/km	Top Energy	Peer Group Performance								
		EDB A	EDB B	EDB C	EDB D	EDB E	EDB F	EDB G	EDB H	Average
Service Interruptions	338	408	248	321	598	268	231	346	436	356
Vegetation Management	392	101	93	270	276	177	86	299	167	183
Routine Maintenance and Inspection	551	589	294	232	407	334	319	477	430	396
Asset Replacement and Renewals	273	164	497	394	376	34	0	388	87	210
Total	1,555	1,261	1,132	1,218	1,657	814	636	1,511	1,120	1,145

Table F.1: Benchmarking of Network Operations and Maintenance Expenditure

9.5.2 FYE2017 SAIDI

SAIDI (by cause)	Top Energy	Peer Group Performance								
		EDB A	EDB B	EDB C	EDB D	EDB E	EDB F	EDB G	EDB H	Average
Lightning	2.7	3.1	0.1	6.5	8.6	10.9	2.1	1.5	3.1	4.5
Vegetation	83.2	1.0	4.0	107.7	20.5	57.5	4.6	16.2	9.9	27.7
Adverse Weather	103.0	22.9	15.2	155.6	31.7	30.0	7.0	19.9	16.4	37.3
Adverse Environment	0.0	2.0	0.0	0.8	0.0	4.5	0.0	1.0	0.3	1.1
3rd Party Interference	65.4	12.1	8.3	23.9	30.0	15.9	19.5	18.9	15.9	18.1
Wildlife	5.7	17.6	16.8	12.5	1.6	3.6	6.5	6.3	7.0	9.0
Human Error	6.1	1.6	6.2	0.4	0.4	0.0	0.0	1.1	0.3	1.3
Equipment Failure	94.9	17.5	28.0	46.8	76.8	86.7	33.4	24.8	103.6	52.2
Unknown	116.0	8.0	16.1	15.8	33.6	16.7	6.5	7.0	15.2	14.9
Planned	208.3	59.8	162.5	41.8	77.3	77.7	87.9	65.6	96.3	83.6
Total	**685.3**	**145.6**	**257.2**	**411.8**	**280.5**	**303.5**	**167.5**	**162.3**	**268.0**	**249.6**

Table F.2: Benchmarking of Network SAIDI (prior to normalisation)

9.6 Appendix F - Value of Lost Load

We have calculated a customised value of lost load (VOLL) for Top Energy using the University of Canterbury's Centre for Advanced Engineering model developed in 2004 for the Electricity Authority's determination of the national VOLL to be applied to transmission grid investment tests. The original model calculated $17.17 per kWh of unserved energy based on transmission system reliability and was a weighted average figure across the residential, agricultural, commercial and industrial sectors.

In our analysis we have made the following input changes to the model:

- The sector weightings have been changed to those related to kWh consumption on our network. We have a higher proportion of residential (46% vs 34%), higher agriculture (8% vs 4%), higher commercial (25% vs 22%), but lower Industrial (22% vs 41%). Industrial users have a typically lower VOLL ($8.19 in our case). This change increases VOLL from $17.17 to $21.32, which increases to $29.00 when inflation adjusted.

- We have adjusted the cost of a loss of supply. A supply interruption affects consumers in different ways and they have different durations for which an outage becomes critical in terms of incurring a loss and then irrelevant in terms of a direct cost to the economy. These costs were determined by customer survey to derive the normalised value and our model has been calibrated against a similar survey in Australia. Our modelled costs have been checked to allow for way businesses change with technology (e.g. cloud services, customers putting in their own resilience measures like a generator etc.).

- We have not adjusted the reliability figures in the original model, which is based on the performance of the national grid, because the 110kV ex-Transpower asset forms the backbone of our network. However, our assets are regional and non-core grid and therefore their reliability is likely to be worse than the national average. The model can be reworked to reflect actual reliability trends, which can be adjusted for any voltage level and limited to specific feeders, zones, assets under test, etc. While we have not made any such adjustment for this high-level analysis, we would do so when using the model to estimate the appropriate VOLL to be used in the analysis of a specific project.

- Energy volumes and sector proportions change more widely the further down into the network leading to decoupling and divergence from the national position. We have updated consumption figures and applied finer resolution of customer sectors, using the Australian and New Zealand Standard Industrial Classification (ANZSIC) code to more accurately reflect the makeup of our commercial load. We don't have the high finance high risk commercial activity (with the highest VOLL at $111/kWh) but we do have a strong accommodation and food sector (which has a higher VOLL than retailing for example).

- In 2015 PricewaterhouseCoopers (PWC) was engaged by the Electricity Authority to update the VOLLs for different customer sectors in the North Island. We have these sector VOLLs to derive the weighted average VOLL across our consumer base.

These adjustments have resulted in an estimated average VOLL of $59.18 per kWh of unserved energy. This much higher figure is expected on our distribution network because of the more direct impact distribution assets have on reliability that consumers experience.

Update CAE VoLL	CPI factor	Residential	Agricultural	Commercial	Industrial	All Sectors
TEL Sector Weighting		46.0%	8.0%	24.6%	21.5%	
Sector Weighted VoLL CAE Model		$7.40	$3.90	$9.07	$0.95	$21.32
CPI Adjustment	1.36	$10.06	$5.31	$12.34	$1.29	**$29.00**
Application of PWC VoLLs 2015						
PWC Sector Av Nth Island		$15.88	$8.09	$24.59	$7.80	$56.36
CPI Adjustment	1.05	$16.67	$8.49	$25.82	$8.19	**$59.18**

PWC 2015 VoLLs	kWh weight	PWC 2015	By ANZSIC
Commercial VoLL by ANZSIC			
Accommodation	0.134	$31.87	$4.28
Administrative and support services	0.009	$37.15	$0.32
Arts and recreation services	0.016	$16.58	$0.27
Education and training	0.076	$6.99	$0.53
Financial and insurance services	0.026	$111.64	$2.92
General	0.178	$37.15	$6.60
Health care and social assistance	0.040	$4.48	$0.18
Information media and telecommunications	0.148	$6.64	$0.98
Other services	0.077	$37.15	$2.85
Professional, scientific and technical services	0.021	$44.67	$0.95
Public administration and safety	0.075	$3.82	$0.29
Rental, hiring and real estate services	0.023	$37.15	$0.85
Retail trade	0.125	$22.67	$2.83
Transport, postal and warehousing	0.039	$11.50	$0.45
Wholesale trade	0.013	$22.67	$0.28
Commercial Weighted Average			**$24.59**
Industrial VoLL by ANZSIC			
Wood product	0.670	$5.94	$3.98
Food product	0.330	$11.57	$3.82
Industrial Weighted Average			**$7.80**

9.7 Appendix G – 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 Gregory Mark Steed, 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 clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Top Energy Limited's corporate vision and strategy and are documented in retained records.

E R Krogh

G M Steed

26 March 2019

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