TOP ENERGY
Te Puna Hihiko

ASSET MANAGEMENT PLAN 2026

CONTENTS

FOREWORD AND SUMMARY OF THE PLAN

SECTION 1

FOREWORD & SUMMARY OF THE PLAN

Top Energy's 2025 Network Asset Management Plan (AMP) has been prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024. **This document serves as the core asset management and operations plan for our electricity subtransmission and distribution network.**

The AMP outlines planned strategies for asset inspection, maintenance, development, and replacement, along with the targeted service levels intended for consumers. It covers the planning period from 1 April 2026 to 31 March 2036.

This plan's objective is to outline robust, coordinated management and investment strategies to protect and optimise Top Energy's assets as an integral part of the Far North's infrastructure. The plan recognises the key role the electrical distribution network plays in supporting growth and the Far North's potential.

Top Energy plays a crucial role in ensuring that the electricity subtransmission and distribution infrastructure serving the Far North continues to support communities into the future. This is important as electricity demand rises significantly with the decarbonisation of the economy.

Throughout 2025, a strategic review of the Top Energy Network Strategy has been conducted. This review included a comprehensive assessment of our 10-year programme and fleet investment strategies. We have reviewed our key network risks, the ongoing uptake of distributed generation, and slower-than-anticipated load growth across the network. As a result, there have been several key changes to where we are focusing our investment. Given the low level of growth in the area, along with the condition and criticality of our assets, we are placing greater focus on asset replacement and renewal rather than on system capacity, particularly during the DPP5 period. There has also been a significant impact on our capital investment due to our subtransmission line strategy. While we continue to maintain assets on our existing 110 kV Kaikohe-Kaitaia line for safety and reliability, as we prepare to commence the construction of a second 110 kV line from Wiroa substation to Kaitaia.

THE KEY AREAS OF FOCUS FOR OUR OVERALL NETWORK STRATEGY ARE:

Safety and reliability	Asset replacement and renewal	Distribution generation

[1.1] Capital Investment

Our network capital investment has significantly increased over the planning period to $311.6m, this increase is largely due to the required 110 kV line build, as summarised below.

AMP BUDGET FINANCIAL YEAR 2027-36

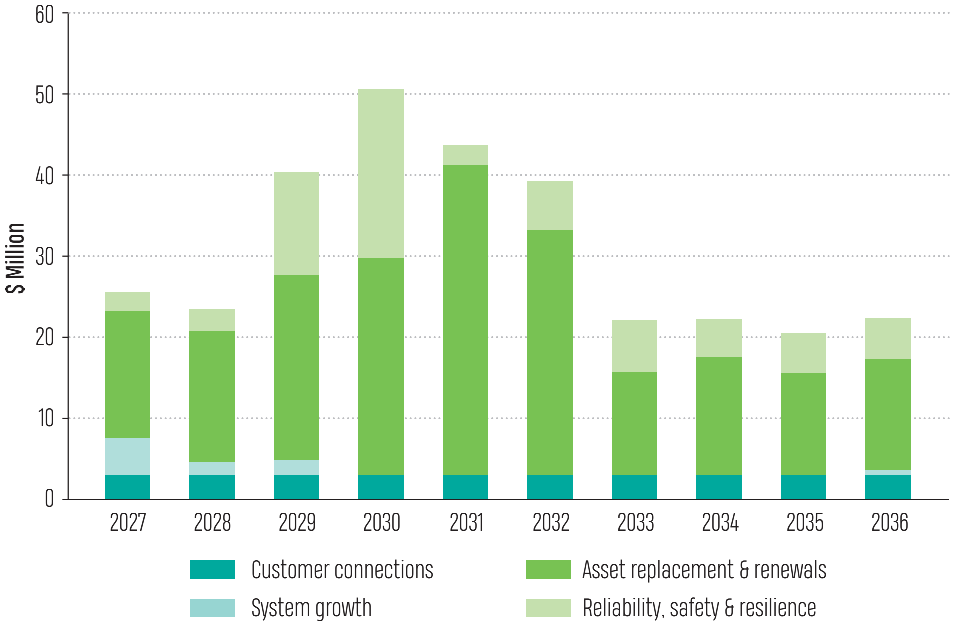

Figure 1-1 Distribution of Capital Expenditure by Financial Year

1.1.1 – ASSET REPLACEMENT AND RENEWAL

Asset replacement and renewal remain our largest investment areas. An ageing network, defective equipment issues and an increase in identified defects continue to affect our reliability and SAIDI performance. We have increased our defect management expenditure due to the higher rate at which we are identifying network risks through our inspection regime. Our overhead renewal programme has remained at a consistent level throughout the period.

Condition and risk assessments of our transformer fleet have accelerated our transformer replacement to ensure a resilient subtransmission network is maintained. This has been enabled by deferring growth projects in response to slower-than-expected load growth in the region. Other areas that have seen increases in expenditure or programme acceleration include distribution switchgear, due to type issues and the need for risk mitigation.

Our key Investment projects are:

110 kV Kaitaia-Kaikohe Line

Additional load from utility scale solar generation on our 110 kV Kaitaia-Kaikohe line means it may be loaded, at its peak, at 95% capacity. The increased thermal loading on the line has prompted us to consider the timing of reconductoring of the line, which is at end of life and showing signs of significant deterioration. This would include replacing a significant number of poor-condition structures, crossarms, and fixtures and fittings, with significant customer impact. As a result, the decision has been made to build the proposed new line from Wiroa to Kaitaia along the line route, secured in the 2022 Supreme Court judgement. These works are programmed for the end of DPP4 and into DPP5. It is expected to take several years to complete, with maintenance of the existing line continuing throughout to ensure a safe and reliable supply to the Kaitaia region whilst the new line is being constructed.

This solution will enhance resilience in the region by improving the reliability of our bi-directional energy transfer between Kaitaia and Kaikohe. However, due to the age and condition of the existing line and the additional stress from increased generation-related loading, it cannot be used as a parallel line. As such, the new line will not increase network capacity.

A decision regarding the future of the existing line will be made in the following years. Given the high reconductoring costs and a small customer base, the line is being considered for decommissioning. This is influenced by the fact that the primary users (embedded generation sites) do not contribute to the maintenance and upkeep of these assets.

The line shares assets with the planned 33 kV line to provide resilience and security to Kaeo substation, and it is proposed that these works are undertaken in tandem in order to gain efficiencies and further minimise customer impact for those properties the line utilises. This line is included in the overall works programme.

We anticipate that the total amount for these works, including the Kaeo security project, will cost around $90 million. A detailed programme estimate will be developed over FY 2027 and FY 2028. Work is planned to commence in FY 2029 and continue for the following three years. This will result in a significant increase in our capital expenditure over DPP4 and DPP5.

Funding for additional capacity by building Wiroa-Kaitaia as a second line was being sought through the Energy Bridge project, in conjunction with Transpower and Northpower. This would have allowed us to build the new line and reconductor the existing line once commissioned. However, Top Energy have now withdrawn from this, as significant regulatory reform is required to:

- enable investment in areas to increase capacity, and
- promote further generation in the region without unfairly burdening consumers who will not benefit from the expenditure.

Power Transformers

An external consultant's condition assessment of our zone substation power transformer fleet has identified five transformers—Pukenui, Taipa, Kawakawa T1, and Kaikohe T2 and T5 – as being in an unreliable condition, with a further 11 considered fatigued.

To address this, we have developed a comprehensive power transformer fleet management strategy that sets out time-based refurbishment and replacement plans. However, declining reliability in our ageing Fuller and Ferranti tap-changer fleet (all over 38 years old) is increasing the urgency for replacements.

Wiroa 110/33 kV Substation

To provide sufficient network capacity to supply the high level of demand growth in the Kerikeri and Waipapa areas, we plan to construct a 110/33 kV injection point at our 33 kV switching station at Wiroa. The new substation will eventually have two transformers and will be supplied by two incoming circuits connected to Kaikohe.3F Space within the substation yard exists for 33/11 kV transformers. There is space for a new 11 kV switchboard, should a need arise for new points of injection into the 11 kV network. Construction began in FY 2026 and is expected to continue for three years. We have decided to incrementally develop this site by deferring the second transformer install until FY 2034.

This project provides strategic importance as it:

- remains a cornerstone project for future capacity expansion
- supports regional growth, and
- strengthens the subtransmission backbone for long-term resilience of supply to the eastern half of the network.

[1.2] Distributed Generation

The connection of small-scale behind-the-meter solar generation to our network continues apace, and the penetration of such generation, as measured by the proportion of consumers hosting such systems, is amongst the highest in New Zealand. We believe this high uptake of solar generation, with many applications including batteries, is a contributing factor to our slow load growth.

As the uptake of small-scale distributed energy resources (DER) continues and consumer injection increases from 5 kW per phase to 10 kW per phase, the need to curtail and manage these DER installations during peak times to balance generation with consumption grows.

Currently, we can only manage grid-scale generation to ensure a fair and equitable operating environment. To enable load-shedding and curtailment across all scales of generation, we encourage the development of a New Zealand standard for solar installations to enable control and curtailment of domestic solar as well as grid generation.

Data access and network visibility are essential for managing load and outage processes. In 2025, we launched our Low Voltage visibility tool to monitor LV data at smart meter locations. Through FY 2027, we will continue developing this system and tie it to our Adaptive Distribution Management System (ADMS). We will look for ways to optimise our data-driven decision-making processes and drive efficiencies when looking at:

- consumer behaviour
- fault response, and
- voltage quality concerns.

We will continue to improve our LV asset data through our LV visibility programme, which now includes overhead assets and underground connections.

While we have modelled the potential impact of the injection limit increase, we continue to monitor the effects of any additional uptake to reassess our requirements for a Distributed Energy Resource Management System (DERMS).

This year, we have seen the construction of 41.1 MW of utility-scale solar generation in the Kaitaia region; the 24 MW Twin Rivers Solar Farm by Rānui Generation and the 17 MW Far North Solar Farm near Pukenui. At the time of writing, Twin Rivers is not fully commissioned, anticipated completion by the end of FY 2026. This is in addition to the 23 MW Kohirā Solar Farm by Lodestone Energy near Kaitaia, connected in 2023, bringing total solar generation in the region to 65 MW by the end of this financial year.

Interest in new generation connection remains high in the region. However, we are now constrained by the Kaikohe-Kaitaia 110 kV line, which is at capacity. Our maximum export is now beyond the line capacity of the Transpower line south of Kaikohe. Export capacity will increase once the Special Protection Scheme is implemented by the end of FY 2026.

[1.3] Safety and Reliability

In FY 2025, network reliability targets were achieved, with unplanned SAIDI and SAIFI both within target limits and only one major 110 kV interruption recorded.

Key points within our reliability outcomes are:

- Key contributors to 11 kV network outages included defective equipment (32%), vegetation (23%), and third-party interference (18%).
- Asset replacement and renewal of poor condition, high risk assets remains the focus of our expenditure,
- There remains a focus on vegetation strategy and delivery, moving to use a risk-based approach to prioritisation. This directs our focus on areas where customer impact is most significant and increasing expenditure accordingly.
- Strategic initiatives have led to notable reductions in outage durations and improved feeder performance.
- Areas where automation and fault passage indicator trials have been conducted have seen a decrease in fault location time and impact.
- Smart meter data integration and new feeder installations are improving fault management and network resilience.
- Focus continues on identifying unknown fault causes and advancing condition-based asset management.

Weather events, such as ex-cyclone Tam in 2025, indicate ongoing climate-related vulnerability across the network, with FY 2026 forecasting above our internal target. However, our internal and independent reviews of our progress show positive developments, showing a downward trend in SAIDI since our initial review in 2021.

[1.4] Decarbonisation

Decarbonising the economy presents significant asset management challenges for our network, particularly driven by a surge in solar generation and anticipated increases in electricity demand from transport electrification. Immediate network capacity issues, especially on the Kaikohe-Kaitaia 110 kV line, have prompted the planning of significant replacement to our subtransmission network, while longer-term uncertainties remain around planning for growth outside current subtransmission coverage.

Key highlights are:

- Utility-scale solar generation has reached network capacity limits, restricting new connections.
- Introduction of advanced distribution management systems (ADMS) and Distribution System Operation (DSO) roles to manage real-time operations.
- Rooftop solar demand is strong; ongoing improvements to monitoring and data collection are addressing voltage concerns.
- National electricity demand may rise up to 70% by 2050, mainly due to transport electrification.
- Current infrastructure supports 19 EV chargers, with expansion needed for heavy transport and airport charging.
- Most 33 kV assets can accommodate projected growth, but planning is challenged by uncertainty about new demand locations and timing.

[1.5] Significant Network Outages

In October/November 2025, we experienced two significant outages on the Southern Network from Kaikohe, both affecting 23,000 customers. At the time of writing, both incidents are under internal investigation to determine the root cause. We are also identifying areas for improvement.

The first incident was caused by an out-of-zone tree falling onto a 33 kV line, with the primary protection failing to operate as expected. Subsequently, the 110 kV breakers to the 110/33 kV transformers at Kaikohe operated, and we lost supply to all downstream substations and feeders.

A failure of a gas-insulated transformer circuit breaker caused the second incident. The arc protection operated, and all supply to downstream substations and feeders was again lost. This incident exceeded the limits for an extreme event under the electricity default price-quality path (DPQP). An investigation will be published in 2026, following submission to the Commerce Commission.

[1.6] Conclusion

In addition to managing our network assets, we continue to develop a safety and asset management culture within Top Energy as we transition to ISO 14001. We actively participate in industry safety initiatives that require staff engagement at all levels and offer the added benefit of sharing participants' experiences across the industry. To succeed, the Company and all staff maintain a proactive role in training, competency, peer support and guidance, and monitoring industry issues.

We hope that you find that this AMP demonstrates the continued prudent stewardship of our network assets for the long-term benefit of all our stakeholders. In particular, the electricity consumers who rely on our network to meet their energy needs.

Russell Shaw
Chief Executive, Top Energy Ltd

FEEDBACK

We welcome your feedback on our asset management plans or on any other aspect of Top Energy's business and performance.

Feedback can be provided through the Top Energy website at **www.topenergy.co.nz/i-want-to/get-in-touch/send-feedback** or emailed to **info@topenergy.co.nz**

BACKGROUND AND OBJECTIVES

SECTION 2
BACKGROUND AND OBJECTIVES

[2.1] Overview of Top Energy

Top Energy Ltd (TEL) 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 two divisions:

- **Top Energy Network** (TEN), which has responsibility for planning, design, operation, maintenance and customer project services on the electricity distribution Network throughout the Far North, and
- **Top Energy Contracting Service**s (TECS), which delivers field construction and maintenance services to TEN and other customers.

TEL is part of a Group that also includes Ngāwhā Generation Ltd (NGL), which owns and operates the 57 MW Ngāwhā geothermal power station.

TEL is 100% owned by the Top Energy Consumer Trust (Trust), which holds the business's shares 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 wellbeing and employs approximately 190 staff. It is one of the largest employers in the region and is uniquely placed as a major infrastructure owner and operator to act as a catalyst for developing the region's economic potential.

TEN's assets comprise a network of lines interconnecting approximately 34,618 individual connection points (ICPs) within our supply area, together with strategically placed backup diesel generation. These generators are employed to:

- minimise unplanned outage durations, and
- allow for specific parts of the network to be taken out of service while maintaining supply to customers, and
- assist Transpower in meeting its load obligations during grid constraints, thereby minimising or negating the need for Top Energy to disconnect customers in such events.

The network was constructed to supply consumers with electricity sourced from the national transmission grid and, more recently, the Ngāwhā geothermal power station. Recent developments in small-scale photovoltaic generation technologies have resulted in approximately 14.8 MW of localised generation, dispersed across more than 2,441 injection points, now connected to our network.

The Asset Management Plan (AMP) covers the management of TEN's assets, which had a regulatory asset value of $378 million at 31 March 2025. This figure does not include assets owned by Top Energy's other operating divisions, which are outside the scope of the AMP.

[2.2] Mission and Values

2.2.1 – GROUP

The Board has approved a Strategy Map for the Group that sets out the Group's purpose and values and underpins everything we do. This map is shown in Figure 2-1. Each operating division within the Group has developed its own strategic vision. This vision interprets the Group's purpose and values in the context of the business unit's core activity, while maintaining the Group's values and high-level corporate objectives.

OUR PURPOSE: DELIVERING SUSTAINABLE ENERGY TO FAR NORTH CONSUMERS

OUR VALUES: Safety | Together | Excellence | Integrity | Growth | Community

SCI	SAFETY	QUALITY & SECURITY OF SUPPLY	SHAREHOLDER RETURNS	BE RELEVANT TO CUSTOMERS	COST TO SERVE
OBJECTIVES	**PEOPLE** To develop and protect a diverse, high performing and highly engaged workforce	**QUALITY** To continually improve everything we do to enhance our resilience considering the price/quality trade-off	**FINANCIAL** To manage risks, secure long-term revenue, grow assets, operate efficiently	**CUSTOMERS** To understand and be responsive to the needs of our customer and stakeholder groups	**REGION** To support the growth of economic, sustainable and social development opportunites in the region
STRATEGIES	**P1** Encourage a learning culture in everything we do **P2** Attract, develop and retain key talent from diverse backgrounds **P3** Build leadership capability and depth **P4** Consult more on the things that matter most	**Q1** Define, measure and improve our service delivery standards and procedures **Q2** Nurture a culture that drive continual improvement **Q3** Create collaborative partnerships to achieve compliance and drive innovation	**F1** Identify and secure long-term revenue streams **F2** Grow our assets and profitability expand our services **F3** Operate efficiently, reducing costs **F4** Adopt risk management practices that protect and enhance the balance sheet	**C1** Proactively develop our understanding of their needs **C2** Enhance their understanding by providing guidance and information **C3** Respond their changing needs appropriately and effectively **C4** Deliver what we promise **C5** Be the voice of the customer	**R1** Create collaborative partnerships to drive economic development opportunities **R2** Operate sustainably and minimise our environmental impact **R3** Enhance community wellbeing through support of targeted events and initiatives **R4** Deliver sustainable electricity

↑ ↑ ORGANISATIONAL CAPACITY ↑ ↑

Figure 2-1: Group Strategy Map

2.2.2 – TOP ENERGY NETWORK

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

OUR GOAL

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

Since the Trust exists for the benefit of our consumers, our goal is well aligned with the Group's mission. While safety is not negotiable, our biggest challenges in delivering on our network goal are:

- finding the appropriate balance between security, reliability, and price for the services that we provide, and
- adapting to the challenges of emerging technologies to remain relevant to the consumers we serve.

OUR VISION

Enabling two-way power flow to deliver our consumers' evolving energy needs.

Electricity distribution has long been considered a natural monopoly, as consumers have historically had little choice but to source electricity from the grid. However, the declining cost of photovoltaic generation has led an increasing number of small-scale consumers to install their own generation, most typically rooftop solar, 'behind the meter'. This has blurred the distinction between a generator and a consumer. Many installations are now connected to our network:

- draw electricity from the network, and
- inject electricity back into the network at times when the output of their installed behind-the-meter generation exceeds their internal requirements.

Furthermore, the introduction of electronic time-of-use metering, along with continuing developments in communications and power control technologies, enables small consumers to become energy traders. They can sell their surplus electricity to retailers, to other users through peer-to-peer trading arrangements, or even to us for network support. Dynamic pricing and battery storage, including the utilisation of batteries in electric vehicles, enhance this arbitrage potential. Electricity generated when prices are low can be stored and injected back into the network during peak demand when prices are higher.

To remain relevant to the electricity users we serve, we must transition from an electricity distributor to a distribution system operator. Our role is to provide a network that facilitates the dynamic flow of power between interconnected electrical installations.

This transition 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 improving our service to consumers. We welcome:

- consumers and external parties introducing distributed generation and battery storage on our network, and
- opportunities to collaborate with stakeholders on how our network might be developed to better support the application of emerging technologies and strategies that are challenging our industry.

[2.3] Purpose of the Asset Management Plan

The purpose of the 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 current requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination.

[2.4] Asset Management Policy

Our network asset management policy guides this AMP. In summary, this policy requires us to develop an asset management plan that:

- gives safety our highest priority. We must:
  - act in accordance with industry standard safe working practices and, in consultation with our employees and contractors
  - develop and adopt systems and procedures that minimise the risk of harm to people and property, in accordance with the Health and Safety at Work (General Risk and Workplace Management) Regulations 2016, and
  - consider the impact of all that we do on our employees, contractors, consumers, and the general public
- develops a network that is resilient to high impact, low probability events. We do this by:
  - building in asset redundancy where this is appropriate, and
  - developing and improving plans and procedures for effectively responding to events that exceed our normal response capacity
- improves our network's security and reliability at a rate that is both financially sustainable to the business and affordable to our consumers. We also strive to continually improve the efficiency and cost-effectiveness of our asset stewardship to increase the value that we provide to our stakeholders
- monitors the technological changes affecting our industry, and are ready to modify our asset management strategies to remain relevant to the consumers that we serve.

We use the Commerce Commission's asset management maturity assessment tool (AMMAT) to assess the quality of the systems and processes that we use to implement this policy. Our current AMMAT assessment is shown in Schedule 13 of Appendix A.

[2.5] Asset Management Objectives

Our asset management objectives are grouped into five focus areas to align with the Top Energy Group's corporate objectives, as shown in Figure 2-1. In the sections below, we show how these corporate objectives are reflected in TEN's operations and in the way we manage our physical network assets.

2.5.1 – CONSUMERS AND OTHER STAKEHOLDERS

Our corporate objective is to:

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

We do this by:

- proactively developing our understanding of our consumer and stakeholder needs. We do this formally through regular consumer surveys and informally through less structured interactions with stakeholders in the normal course of business. This understanding will help us anticipate 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. We have increased the amount and timeliness of information to stakeholders through our website and other social media, including a real-time outage map.

Section 2.8 identifies our stakeholders, their interests, how we aim to accommodate those interests and how we attempt to resolve any stakeholder conflicts that may arise.

Our 2026 Asset Management objectives relating to Consumers and Stakeholders are:

- Meet our customer KPIs:
  - Shutdowns within advertised timeframe >80%
  - Customer response times within 2 days >80%

2.5.2 – QUALITY

Our corporate objective is to:

Continuously improve everything we do to enhance public safety and our service delivery performance.

We do this by:

- better defining, measuring, and improving our service delivery standards and procedures. We have successfully implemented and maintained an ISO 9001 certified quality management system.
- nurturing a culture that drives continuous improvement,
- Reviewing our work practices, such as through vegetation strategy reviews; and
- creating and maintaining collaborative partnerships to achieve compliance and drive innovation. We are actively involved with industry groups such as;
  - Electricity Networks Association (ENA) including involvement in working groups for future technology and vegetation management.
  - Electricity Engineers' Association (EEA), with representation on the Asset Management Group and Public Safety Working group
  - WorkSafe New Zealand,
  - Peer EDB's and lines businesses, sharing best practice, innovations and lessons learnt; and
  - Participating in the Business Health and Safety Forum.

The involvement in these groups helps us better understand our regulatory and legislative environment and work collaboratively towards achieving shared objectives.

Our 2026 Asset Management objectives relating to quality are:

- Reduce our SAIDI outcomes against the SAIDI glidepath, the glidepath figures set our internal SAIDI targets as found in Table 4 2
- Improve our fault record data to include cause, environmental condition and asset condition to review and improve our failure mode understanding and asset strategies
- Reach a maturity level of four in all four areas of the EEA Asset Information Maturity Framework by end of FY 2028.

2.5.3 – PEOPLE

Our corporate objective is to:

Develop and protect a high-performing and highly engaged workforce.

We do this through:

- our processes for the recruitment and retention of key talent
- building leadership capability and depth
- consulting more on the things that matter most, through the deployment of an annual employee culture survey and the provision of increased support and accountability for 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.

Our 2026 Asset Management objectives relating to people are:

- Develop cross-functional planning processes
- Continue our graduate engineering programme

2.5.4 – FINANCIAL

Our corporate objective is to:

Manage risks, secure long-term revenue, grow assets and operate more efficiently.

We do this by:

- securing our long-term revenue stream by implementing a pricing strategy designed to increase the certainty of our revenue levels
- 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 standardised project management and delivery framework
    - identifying procurement and cost-saving opportunities, and
    - providing operations and financial management training to managers to enhance financial decision-making.

Our 2026 Asset Management objectives relating to Financial are:

- develop a project management framework to improve efficiency and project outcomes
- initiate project governance committee to monitor and control project risks
- improve our vegetation management data to create an efficient, data-driven, fit for purpose, works programme and budget.

2.5.5 – REGION

Our corporate objective is to:

Support the growth of economic, employment and social development opportunities in the region.

We do this by:

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

Our 2026 Asset Management objectives relating to Community are:

- Complete the 110 kV line build to ensure resilience to the far north, and continue to review optionality to provide security.
- Increase domestic DER injection limits to 10 kW in order to support distributed generation for domestic customers .

[2.6] Annual Business Planning and the Asset Management Plan

Listed below are our key internal planning documents with a direct link to this AMP.

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

In addition, a range of internal and external documents and systems influences the content of the AMP. Listed below are these internal documents and systems.

- **Quality System:** Is certified as compliant with ISO 9001 and externally audited on a regular basis. It includes the policies, procedures, and work instructions that underpin everything we do.
- **Risk Register:** Identifies key risks that our business faces, given the architecture and condition of our network's 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:** 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:** Details the processes and procedures in place to ensure the safety of our employees and contractors working on the network.
- **Public Safety Management System:** Specifies the processes and procedures in place to ensure that our assets do not present a risk or hazard to the general public.
- **Northland Region Civil Defence Emergency Group Plan (NRCDEGP):** Describes procedures for the response to a civil defence emergency in the Northland region. It identifies interdependencies between our network and other lifelines, as well as Top Energy's role in responding to a civil defence emergency. The response procedures include operating injection equipment and supporting 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:

- legislative and regulatory requirements such as the Commission's Electricity Distribution Services Default Price-Quality Path Determination and
- technical standards relating to electricity supply, public safety, employee and contractor health and safety, and environmental protection.

2.6.1 – PREPARATION OF THE AMP

This AMP is both a strategic and an operational document. It is strategic, as it sets out our plans for managing our network assets over a 10-year planning period. It is operational in that the plans and budgets within the AMP for the forthcoming year form the basis for the Annual Plans that control our asset management expenditure. In subsequent years, the content becomes progressively more strategic. The Statement of Corporate Intent (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
- return that the shareholder requires, and
- need to maintain a prudent debt-equity ratio.

The SCI also sets target service levels 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 network's smooth operation and the need to plan for and mitigate them.

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 6 months before 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 electricity demand and the performance of the existing network asset base. As a result of this review, we prioritise our capex and opex requirements. These activities lead to the development of initial plans that consider operational constraints at a high level.

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

[2.7] Planning Period

This AMP is dated 31 March 2026 and relates to the period from 1 April 2026 to 31 March 2036. The Board approved it on 24 March 2026 and replaces all previously published AMPs and AMP Updates.

[2.8] 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
- meetings with suppliers
- performance review and management for internal and external contractors
- papers and submissions
- website and social media, and
- local media.

Table 2-1 shows how the AMP incorporates stakeholders' expectations. Each year, the published AMP is made available to all stakeholders for their information. Feedback is welcomed.

When there is a conflict between our asset management requirements and stakeholder expectations, we engage the affected stakeholders and work 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, 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, and work towards a mutually acceptable solution. Our experience is that this will usually resolve the issue. However, if agreement cannot be reached, we will proceed in a manner that we believe is fair to all affected parties and is consistent with Top Energy's group values and objectives.

2.8.1 – STAKEHOLDER INTERESTS

Table 2-1 identifies our key stakeholders and their individual interests and summarises the processes Top Energy has in place to accommodate their expectations.

STAKEHOLDER	EXPECTATIONS	ACTIONS
NETWORK USERS	**Fair price**	• We set prices at or below the level consistent with the revenue cap determined by the Commerce Commission under its price-quality regulatory framework. • We continually strive to improve our operating efficiency, expecting that, over time, network users will benefit from lower prices for the services we provide. • Network losses are a cost to consumers. We measure these losses and expect they will decrease over time as our network develops. 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 through our water heater control system to minimise transmission connection costs without adversely affecting the quality of supply as perceived by consumers. • We minimise the cost of improving the reliability and capacity of our network by using new technologies and non-network alternatives, such as embedded generation, where practicable..
	Reliability	• We continually measure and review reliability against the SAIDI and SAIFI targets detailed in the AMP.
	Quality	• We identify areas within the network where supply quality 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 subtransmission network and have implemented augmentations to ensure these standards are met or exceeded. • We have a documented Emergency Preparedness Plan that sets out the procedures we will follow if an emergency arises from a low-probability event that exceeds our normal response capacity.
	Flexibility	• We facilitate the application of emerging technologies that enable consumers to use our network in new and innovative ways.
	Emerging technologies	• We facilitate the application of emerging technologies that enable consumers to use our network in new and innovative ways.
	Communications	• An external call centre has been contracted to ensure consumers are directed to the appropriate point of contact for quick and efficient service. • We closely monitor consumer expectations through regular surveys and other communication channels, and endeavour to meet them 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 where network capacity is available. We will negotiate with proponents to achieve an outcome that meets their requirements, without reducing the level of service we provide to other network users.

STAKEHOLDER	EXPECTATIONS	ACTIONS
RETAILERS	**Communications**	• We share information on network outages and other relevant issues with retailers in accordance with standard industry protocols.
	Use of system agreements	• We negotiate use-of-system agreements with retailers in good faith and in accordance with the Electricity Authority's requirements.
	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.

STAKEHOLDER	EXPECTATIONS	ACTIONS
BOARD	**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 monitor safety outcomes and report this monthly to the Board.
	Return on investment	• Our asset management activities align with a corporate strategic plan to ensure our operations are financially sustainable. • We report financial outcomes monthly to the Board. This report includes a comparison against the budgets in this AMP.
	Economic development	• Consistent with the objective of supporting economic development within our supply area, we negotiate with potential new industrial and commercial consumers to identify an economic supply solution that meets their specific requirements. This is done without disadvantaging consumers already connected to our network.
	Reliability	• Our reliability improvement expenditure is targeted at initiatives expected to enhance supply reliability. • We report the reliability of our network to the Board monthly. This includes a comparison of actual reliability against the reliability targets in this AMP.
	Accountability	• Our employees' key performance indicators are linked to achieving 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. We modify our asset management plans, processes and procedures as necessary to maintain compliance.
	Asset management	• We manage our assets in accordance with this AMP, which is prepared in accordance with the corporate strategy agreed with the Trust by the Board and reflected in the SCI.
	Social responsibility	• Our capital contribution scheme is designed to ensure equitable sharing of the costs of new construction installed for the benefit of individual consumers.

STAKEHOLDER	EXPECTATIONS	ACTIONS
COMMERCE COMMISSION	**Price**	• We set prices at or below the level consistent with the revenue cap determined by the Commerce Commission under its price-quality regulatory framework. We confirm compliance annually through our audited regulatory compliance statement.
	Quality	• We set internal reliability targets consistent with the Commission's standards under its price-quality regulatory regime. We monitor our performance against these targets monthly through our Board reports. • We compare our supply reliability with the Commission's standard 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. 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, guided by a formalised plan.
	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 in our network similarly to ensure the market operates on a level playing field in our area.
MINISTRY OF BUSINESS, INDUSTRY AND EMPLOYMENT (MBIE)	**Energy monitoring**	• We provide the 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 110 kV 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 110 kV assets. • We comply with Transpower requirements for the disconnection of load in emergency situations to ensure the security of the power system.

STAKEHOLDER	EXPECTATIONS	ACTIONS
TRANSPOWER	**Safety**	• We manage all work on our network in accordance with industry-standard safety requirements approved by WorkSafe. • We participate in industry forums to develop safety standards that protect 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 who 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.
	Training	• We regularly survey staff to monitor satisfaction with their work and working environment and to identify areas where skill development or support may be necessary. • This AMP reflects the skill set required of our workforce, which informs 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 vegetation expenditure to improve supply reliability.
	Safety	• We implement an NZS 7901 compliant public safety management system to ensure that the operation of our network assets does not pose a reasonably avoidable risk or hazard to the public. This is subject to regular audit.
	Land access rights upheld	• We comply with relevant regulations and consult with landowners and occupiers as appropriate before undertaking work that requires access to private property.

Table 2-1: Stakeholders and Their Interests

2.8.2 – STAKEHOLDER ENGAGEMENT

Top Energy engages with stakeholders across a range of topics using multiple communication channels to ensure timely, relevant, and accessible information. The approaches we take are listed below.

- **Public Safety:** Delivered year-round through print, radio, digital platforms, and targeted advertising placements such as local cinemas and radio stations. Direct communications are also issued to individuals directly affected.
- **Network Reliability:** Updates on capital works are provided biannually via newspapers and digital channels to keep communities informed about infrastructure developments.
- **Outage Notifications:** Planned and unplanned outages are communicated through newspapers, radio, digital platforms, direct email and SMS notifications.
- **Pricing Information:** Shared through newspaper publications to ensure transparency and accessibility.
- **Community Engagement:** Activities such as sponsorships and discount initiatives are promoted through newspapers and digital channels.
- **Land Access and Environmental Updates:** Direct communications are issued to landowners, iwi, and Heritage New Zealand regarding land access and environmental changes.
- **Company Performance:** Key performance updates are shared through annual reports, newspapers, and digital platforms.
- **Vegetation Management:** Tree regulation information is communicated to consumers and forestry stakeholders via newspapers, digital channels, and direct outreach.

2.8.3 – CUSTOMER ENGAGEMENT

Top Energy provides electricity to over 34,500 homes and businesses across the Far North. Our customer base comprises approximate:
- 83% residential consumers
- 17% small businesses, including those in agriculture, forestry, fishing, accommodation and food services, and real estate (including holiday accommodation), and
- two large industrial customers.

In addition to our customer network, Top Energy operates three large scale solar farms operate on the Top Energy Network, generating 65 MW of renewable energy.

Geographically, our customer distribution is as follows:
- 35% in the Northern region (Te Hiku)
- 45% in the Eastern region (Bay of Islands and Whangaroa), and
- 20% in the Western region (Kaikohe/Hokianga).

Figure 2-2: Network Sections

Because we service a large rural area, we are also mindful that in our service area:
- 10% of customers reside in remote locations
- 50% are in rural communities, and
- 40% are located in small towns.

Customer growth remains modest at less than 0.7% annually, with forecasts indicating this trend will continue in the near term.

As a consumer-owned trust, it is essential that we understand and respond to the evolving needs and priorities of our customers. In addition to the communication channels already outlined, we engage with our customers using the initiatives listed below.

- **Annual Customer Experience Survey:** This survey targets both residential and business consumers, regardless of whether they have interacted with us during the year. It covers key areas such as reliability, value for money, communication, and our image and reputation.
- **Transactional Feedback Surveys:** We gather feedback from consumers who have initiated services, such as new power connections, or who have reported faults, to assess their experience and identify areas for improvement.
- **Business Community Engagement:** We are active members of Far North business associations and aim to attend at least two meetings or events each year. These engagements help us connect with local businesses, understand their priorities, and stay informed about the challenges they face.
- **Consumer Panel:** Our Consumer Panel provides valuable insights into public perceptions and the impact of our services, helping us better understand how the community views Top Energy.
- **Customer Support Channels:** We operate a 24/7 call centre via our 0800 number for fault reporting and provide general enquiry support during business hours. Additionally, customers can share feedback through the dedicated section on our website.

Affordability

We operate within one of New Zealand's most economically challenged regions, where over 57% of our customers reside in areas classified as decile 9 or 10 on the Government's deprivation index—indicating limited access to material and social resources. The average household income across the Far North is approximately $65,500, which is 33% below the national average. Furthermore, 77% of our consumers are either experiencing energy hardship or are classified as low-income, low electricity-use customers.

We are committed to maintaining affordability by keeping our revenue per connection as low as possible. This is supported by leveraging Ngāwhā generation to offset the costs associated with operating our lines company. However, due to the extensive rural network and the absence of large industrial consumers, our electricity prices remain among the highest in the country.

To support our customers, we invest in targeted sponsorship programmes including Healthy Homes Tai Tokerau, EnergyMate, and the Energy Wellness Fund. These initiatives are designed to deliver local solutions that help alleviate energy hardship and improve household energy efficiency.

Large Load Customers

Top Energy services two large load customers in the Far North: a timber mill and a meat processing facility. These industrial operations account for approximately 12% of the region's total electricity consumption.

[2.9] Accountabilities and Responsibilities for Asset Management

2.9.1 – GOVERNANCE

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 shareholders' interests.

The Board governs our asset management effort through:

- the development of Top Energy's strategy
- the approval of this AMP, and
- individual project business cases for projects with an estimated cost of $500,000 or more.

It also actively monitors the ongoing operation of Top Energy Network (TEN) and Top Energy Contracting Services (TECS), and provides input into the development of the strategic performance targets in the SCI.

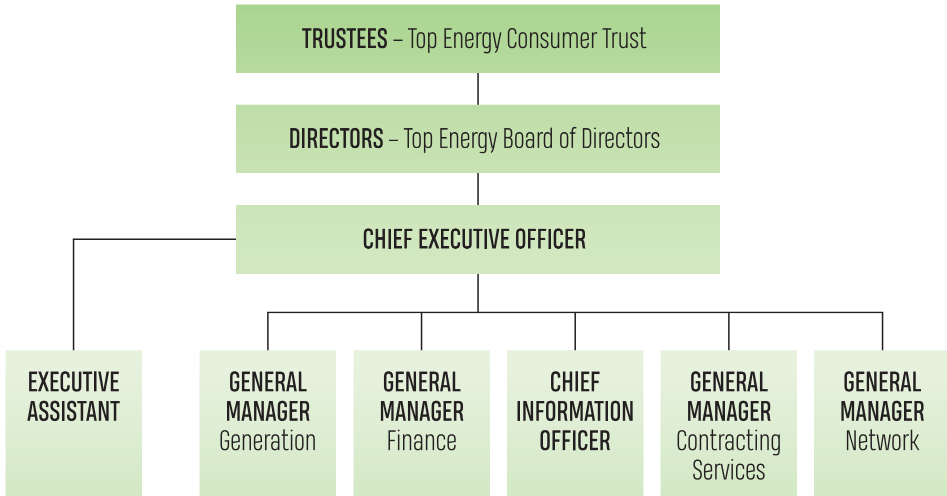

Figure 2-3 shows the Top Energy Group structure.

2.9.2 – EXECUTIVE

At the executive level, the Chief Executive Officer (CEO) is appointed by the Board and is responsible for our network asset management effort. TEN is responsible for managing the network assets covered by this AMP, which are 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.

2.9.3 – NETWORKS MANAGEMENT

The Networks Management Team 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 safely 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 both scope and finance, to the Board monthly, including those 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 upon by the General Manager Network and the CEO. They may be raised for Board approval if deemed significant.

TEN currently has a staffing establishment of 48 full-time equivalents. Figure 2-4 shows the structure of this team.

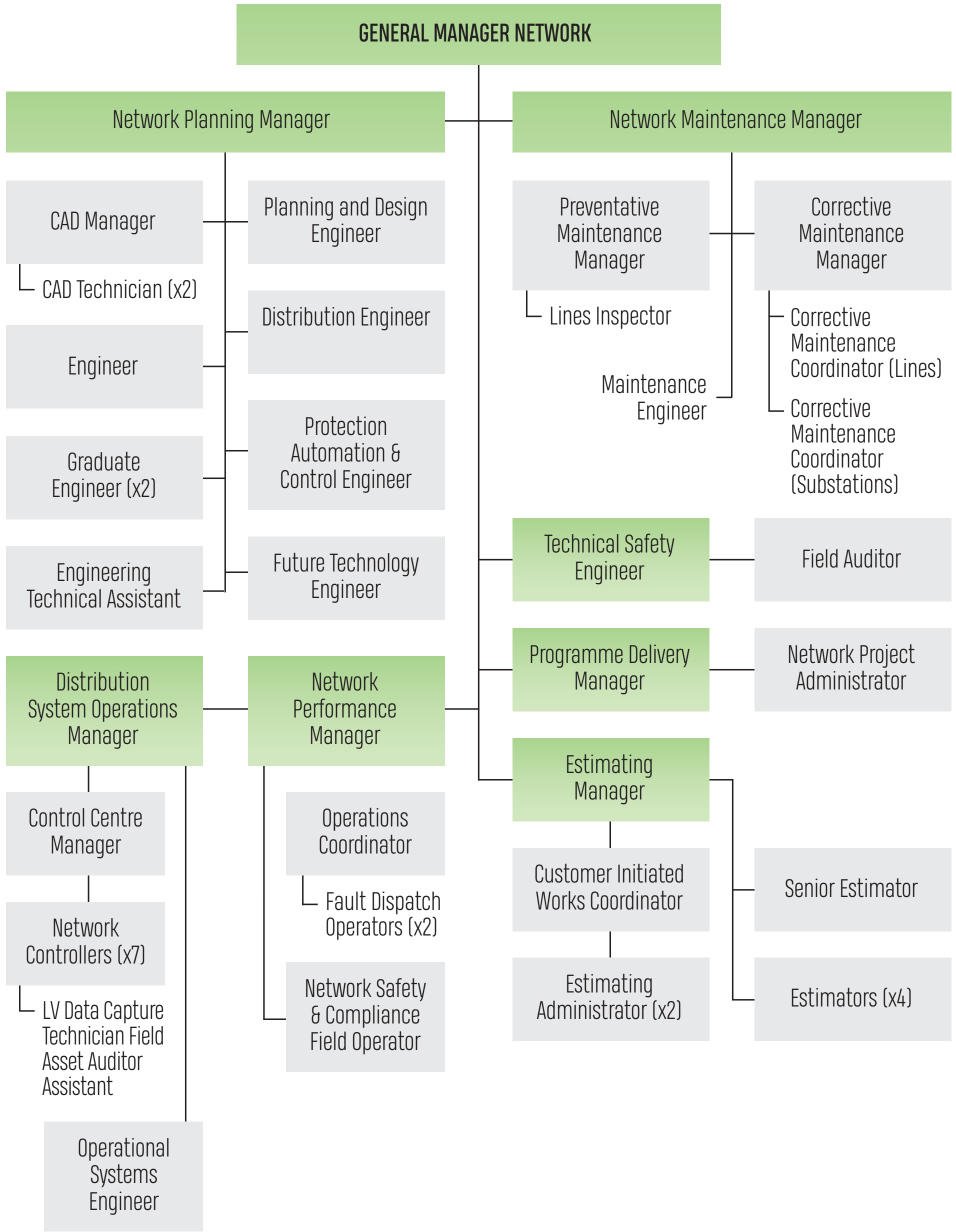

Figure 2-4: Top Energy Networks – Structure

The table below lists the key responsibilities of our Networks Management team.

POSITION	ACCOUNTABILITY
General Manager Network	To control the network budget that governs TEN's activities.
Network Maintenance Manager	To control the maintenance and renewal budget.
Network 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.
Technical Safety Engineer	To ensure compliance with regulations and to minimise the safety risk to staff, contractors, and the public.
Network Performance Manager	To manage dispatch, faults, and compliance, focused on the safety and reliability of supply.
Distribution System Operations Manager	To manage the real-time operation of the network, including power flow, consumer demand and generation.
Estimation Manager	To develop: • detailed customer-driven network extension designs, and • costs and work packages for customer, capital and maintenance works.
Engineers	Delegated authority to manage projects to individual budgets.

Table 2-2: Top Energy Networks Division Responsibilities

2.9.4 – FIELD OPERATIONS

Apart from specialist maintenance activities and larger construction projects subject to competitive tender, work on the distribution network is undertaken by TECS, which employs approximately 77 staff, including supervisors, technicians, and line mechanics.

TECS operates from purpose-built depots in Kaitaia and Puketona and delivers the works programme as defined by TEN. 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 does not include any margin or markup and is benchmarked against current industry costs to ensure the efficiency of works delivery is maintained. When work cannot be delivered internally, work is subject to a tender process for awarding works to external contractors, with Top Energy providing materials to ensure cost-efficient use. This may also include the appointment of specialist contractors, when skills are not available within TECS.

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

The Trust and the Board believe that this arrangement is in the best interests of the shareholder, as it aligns the interests of the asset manager and service provider.

2.9.5 – DELEGATED APPROVAL LEVELS

Individual order approval levels for Capital Projects within the Asset Management Plan are:

POSITION	DELEGATED APPROVAL LEVEL
CEO	$1 million
General Manager Network	$500,000
Section Managers	$50,000

Table 2-3: Top Energy Order Approval Levels

[2.10] Assumptions and Uncertainties

The Top Energy Board and executive management have worked 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 we can complete the investment programme described in this AMP.

Notwithstanding this, the strategies and action plans are predicated on a range of assumptions. As with all major investment programmes, some risks and uncertainties may affect the timely completion of the action plans as described in this AMP. These issues are covered in the table 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.	We have developed a funding plan based on a combination of increased bank borrowings and electricity sales revenues. 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.	As we are subject to a revenue cap, we can increase prices to offset revenue shortfalls resulting from lower energy delivery volumes. However, the extent to which we can do this is limited. Our supply area includes some of the most socio-economically deprived areas in the country. We expect to encounter significant consumer resistance to high price increases. The current economic environment exacerbates this risk. The connection of new block load that are not provided for in this AMP may also change our network development plans. We will work with proponents seeking to connect to our network to meet their requirements cost-effectively.
REGULATORY CONTROL	Regulatory controls will continue to encourage investment in infrastructure, asset replacement, and the maintenance of existing assets to provide target service levels and an adequate return on investment.	The assumption aligns with the government's energy policy, which aims to encourage efficient infrastructure investment.	Our network development plan can only be implemented as schedule in this AMP if the line charge increases required to fund the investment are permitted by the Commerce Commission. The Commission has been supportive of our network development initiatives, and we expect this support to continue.
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. Retailers will offer pricing structures that penalise low-power-factor loads and discourage electricity use during peak demand.	Power systems must be designed to meet peak demand. Increased power system efficiency and minimised investment largely come 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 when power factors are close to unity, and demand is controlled. Hence, an industry structure that does not incentivise demand management will increase the required network capacity.	If our ability to effectively control peak load is reduced, we may need to increase the capacity of the parts of the distribution network to address voltage issues on long rural feeders. This would utilise funds currently budgeted for other activities. This medium-term risk is particularly related to the uptake of electric vehicles. Incentives will be needed to encourage vehicle charging during periods of low electricity demand. This will help minimise the investment in the distribution network to accommodate the new electric vehicle load. While we do not own the control relays installed across our network, recent activity within industry forums has been encouraging. We are confident that regulators recognise the importance of demand management.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
ASSET CONDITION	Assumptions have been made in forecasting asset replacement and renewal expenditure beyond the first five years of the planning window.	The forecasts are largely based on defect rates gathered during routine asset inspections. These are then adjusted, where necessary, to accommodate estimated changes in failure rates driven by 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 enabled the collection of more useful information on the condition of individual assets. It also allows asset maintenance (including replacement and renewal) expenditure to be better targeted at assets known to require renewal or replacement.	Equipment failures cause approximately a quarter of our unplanned supply interruptions and a quarter of our unplanned SAIDI. However, it is a fault cause that can be difficult to target through a reliability improvement programme since these faults can occur anywhere on the network in a largely random fashion. 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. These measures will be less effective in improving overall network reliability. We are confident that the forecast asset replacement expenditure in this AMP is sufficient to prevent a significant deterioration in the overall health of our asset base.
FAULT AND EMERGENCY MANAGEMENT	The weather is the biggest factor in fault and emergency maintenance. Storms with wind speeds greater than 75km/h have been shown through post-fault analysis to have a significant effect on our network.	Post-fault analysis following major storm events. We think the frequency and intensity of major storm events are increasing, and this is impacting the reliability of supply through our network.	Variability in weather conditions inevitably leads to 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. The reliability targets in this AMP reflect the average level of reliability the network has delivered over a 10-year reference period.
UTILITY SCALE PHOTOVOLTAIC GENERATION	The volatility of the output of connected utility-scale solar farms will not generate voltage stability problems.	System studies undertaken by our external engineering consultant have confirmed that the solar farms for which connection agreements have been signed can be operated without impacting other network users.	If the findings of these studies are not reflected in practice, we may need to fund remediation measures.
SMALL-SCALE PHOTOVOLTAIC GENERATION	The output from behind-the-meter small-scale photovoltaic generation will not cause voltage stability issues on the low voltage network.	While the penetration of photovoltaic generation is high compared to other New Zealand EDBs, it remains low compared to Australia. While some localised issues have emerged on our network, their impact has been minor and readily corrected.	We may need to fund localised corrective measures if significant issues arise.
CONTRACTOR AVAILABILITY	Contractors are available to augment TECS capacity.	The capital projects incorporated into the 11 kV reliability improvement plan are labour-intensive and exceed TECS's delivery capacity. We plan to engage external contractors to complete the work programme.	There appears to be a shortage of external contracting capacity with the required skills. If we are unable to recruit the contractors we need, the rate at which we can implement this plan will reduce.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
INFLATION	Except where otherwise shown, cost estimates in the AMP are presented in real New Zealand dollars in FY 2025. Where these cost estimates are expressed in nominal New Zealand dollars, an annual inflation rate of 4% for capital expenditure and 5% for operational expenditure is assumed for FY 2026. We assume an inflation rate of 3% for FY 2027 and 2% thereafter for both expenditure categories.	2% is the mid-point of the Reserve Bank's long-term target consumer price index (CPI) inflation rate of 1-3%. Cost increases have been well above 2% over the last three years due to the impact of Covid-19, labour shortages and supply chain issues. These increased costs have been incorporated into the expenditure forecasts in this AMP. Inflation appears to be trending down, Treasury and the Reserve Bank expect it to moderate over time and fall back within the Reserve Bank's target range by about the end of FY 2026. The variance in the assumed FY 2026 inflation rates is due to operational expenditure having a higher labour cost component. In the short term, we expect labour costs to increase faster than material costs. Nevertheless, we see little value in developing a more accurate forecast, given the length of the planning period and the high uncertainty in other elements of the AMP.	If actual costs exceed the forecast, the volume of work we can undertake in a financial year may decrease. This could delay the implementation of the capital and maintenance plans outlined in this AMP. The Incremental Rolling Incentive Scheme (IRIS) that is incorporated into the default price-path determination may mitigate some of this impact.

Table 2-4: AMP Assumptions and Uncertainties

2.10.1 – DECARBONISATION

Decarbonisation of the economy is presenting a range of asset management challenges and uncertainties for our network. In the short term, the primary challenge is the rapidly increasing demand for connections of photovoltaic (PV) generation. Over the medium term, we anticipate the need to expand the network in response to a significant increase in electricity demand, principally driven by the electrification of the transport fleet. The following sections outline how these changes are influencing our asset management planning.

Impact on Network Capacity and Renewable Generation Connections

Historically, network capacity constraints have been a consequence of growing consumer demand, and demand forecasts have been the principal input for determining the need for network expansions. However, the main driver of network constraints has shifted from consumer demand growth to the demand for connecting renewable generation. For instance, the current 110 kV Kaikohe-Kaitaia line is rated at 55 MW for summer and supplies a peak consumer demand of 25 MW, which is more than sufficient to cover foreseeable growth. Nevertheless, we have already connected 40.8 MW of utility-scale solar generation in the northern area, with an additional 24 MW plant commissioned recently.

This fully utilises the capacity of the Kaikohe-Kaitaia line, and also impacts the capacity limits on the Kaikohe-Maungatapere connection to the Transpower grid. As a result, while applications for renewable generation connections continue unabated, we are currently unable to accept further applications for utility-scale solar generation connections.

Changes in Real-Time Network Management

The increased integration of photovoltaic generation is altering the way we manage the network in real time and process new generation connections. To address this, we have deployed a state-of-the-art advanced distribution management system (ADMS) and restructured our Operations department to include a Distribution System Operation (DSO) function. The DSO now supports the existing Distribution Network Operator (DNO) function and is responsible for:

- Managing the Control Centre
- Real-time operation of the network
- Developing the architecture to support future consumer needs and implementing management systems for orchestrating flexible services and load management

Small-Scale Solar Integration and Low Voltage Network Management

There is continued strong demand for connecting small-scale rooftop solar generation to the low voltage network, resulting in over 14.8 MW of small-scale solar generation now embedded in our network. While Australia has experienced challenges with voltage management in areas of high rooftop solar penetration, we have not faced these issues to the same extent. Nevertheless, we have had to tap down distribution transformers in response to overvoltage complaints resulting from power injection on the low-voltage side of transformers.

The ADMS enhances our visibility of the low voltage network, which will help us manage these issues. However, our current ability to fully leverage this visibility is constrained by insufficient accurate data on our low voltage assets. To address this, our LV monitoring roadmap includes projects to install transformer monitors, and we are in the process of procuring access to smart meter data services.

Future Demand Growth Driven by Electrification

Transpower projects that national electricity demand could increase by approximately 70% by 2050, driven largely by the decarbonisation of industrial process heat and the electrification of transport. In our area, most industrial process heat is already powered by biomass, so anticipated growth will primarily stem from transport electrification. This will include organic growth from increased home charging of electric vehicles (EVs) and concentrated loading at fast DC charging stations.

Currently, our network supports 19 public DC EV chargers, totalling over 575 kW of capacity, and we have received enquiries about supplying higher-capacity charging stations in locations such as Kawakawa, Waipapa, and Kerikeri. Recently, three 250 kW Tesla chargers were installed at the Waipapa Warehouse. With the electrification of heavy transport, demand for future charging stations is expected to exceed 1 MW, and there is also potential for a charging station at Kerikeri Airport to support electrified aircraft under consideration by Air New Zealand. This could be supplied at 33 kV or 11 kV from the nearby Wiroa substation.

Network Expansion Requirements and Planning Uncertainty

Our 33 kV subtransmission network, with the exception of the capacity constraint into the Kerikeri area (to be addressed by the Wiroa substation) and a potential voltage constraint in the Bay of Islands, has sufficient capacity to accommodate expected demand growth through to 2050. However, anticipated new demand may arise in areas such as Opononi/ Omapere and the Russell, Karikari, and Purerua peninsulas, which are not currently served by the subtransmission network and rely on the more limited 11 kV network. Meeting demand growth in these areas may necessitate extending the 33 kV network by constructing new subtransmission lines and zone substations. The precise location and timing of this growth remain uncertain, which presents planning challenges.

We expect that the need for, and timing of, network capacity expansion to accommodate demand increases driven by decarbonisation will become clearer as these trends continue to evolve.

[2.11] Asset Management Strategy and Delivery

2.11.1 – ASSET MANAGEMENT STRATEGY

Top Energy does not yet have a separate documented Asset Management Strategy, in the absence of this our Asset Management plan contains our Asset Management Strategy, including our Asset Management Objectives and Strategic Plans. Work is ongoing over the coming two years to develop our strategy further and formalise in a stand alone document.

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

- implementing an 11 kV network development plan to improve reliability of the 11 kV network expanding into overall network reliability. This involves a stream of incremental upgrades to the distribution network, aimed at reducing the number of consumers affected by a fault and the time required to locate a fault. It also supports faster restoration of supply to consumers outside the faulted switching zone, as well as a targeted approach to asset replacement to reduce outage event numbers.
- accelerating the 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 on those parts of the network where vegetation has the most impact on supply reliability, and
- improving the efficiency of the maintenance effort by focusing on high criticality assets that are most likely to fail in service, due either to their age, or to their condition, as assessed by our maintenance inspections. This includes assets with high SAIDI, safety, or operational impacts.

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 aligns with the overarching corporate mission statement and underpins the long-term development of the economically depressed Far North region. While the bulk of asset management capital expenditure has historically been on network development, our focus is now shifting, with expenditure on maintenance and, particularly, asset renewal increasing.

2.11.2 – CONTINGENCY PLANNING

Our Control Centre staff have developed system operating procedures that document the optimal response to potential faults with a high SAIDI impact.

Since publishing it in 2013, Top Energy has utilised a version of the Emergency Preparedness Plan (EPP) as the guiding document to manage events that cause significant disruption to the network. During a 2023 review of the EPP, the plan was split into two parts: the Emergency Preparedness Plan (EPP) and the Emergency Response Plan (ERP).

The purpose of splitting the EPP was to differentiate the two key functions of the original plan for ease of use. However, both newer plans reference each other to maintain cohesion between maintaining capability and response management. Both plans reference and align with the Top Energy Business Continuity Plan. The EPP maps the processes to measure and confirm Top Energy's capabilities, i.e. systems, processes, and resources are in place to reasonably manage sustained major events affecting the network.

The ERP sets out the processes and resourcing structures required to trigger and respond to significant, extended network disruption events. This plan structure is based on the National Coordinated Incident Management (CIMs) model. It is designed to ensure that:

- Top Energy's capabilities, i.e., systems, processes, and resources, can be mobilised to manage sustained major events affecting the network reasonably, and
- Top Energy meets its obligations to the community, including fulfilling Civil Defence Emergency Management requirements.

Following major network disruption events such as Cyclone Gabrielle and ex-tropical Cyclone Tam, these plans have been activated. After each event, a debrief and lessons learned are conducted, with outcomes recorded in the quality management system to ensure the actions and improvements identified are implemented.

As part of Top Energy's emergency management approach, we routinely participate in the Northland lifeline group and National Emergency Management exercises to test the effectiveness and integration of our plans with external emergency agencies and stakeholders.

2.11.3 – ASSET MANAGEMENT IMPLEMENTATION

The General Manager Network has overall responsibility for asset management implementation and controlling expenditure on network development and maintenance. Asset management procedures are documented in our ISO 9001-certified quality system and our NZS 7901-certified public safety management system. Apart from 110 kV asset maintenance and some major construction projects, most network work is undertaken by TECS. A documented Service Level Agreement, discussed further in Section 2.15 and based on the asset manager-service provider model, defines 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. Both internal and external resources undertake asset inspections.

2.11.4 – CORRECTIVE AND PREVENTIVE ACTION

Our ISO 9001 certified quality management system defines the business processes in place for determining preventive and corrective actions. When an unexpected asset problem is identified, the process owner:

- undertakes a root cause analysis
- determines appropriate corrective actions, and
- tracks these through to close-out.

The process works well during a major incident. We continue to develop a culture that encourages our staff to identify issues and proactively implement incremental process improvements.

[2.12] Asset Management Data and Information Management

2.12.1 – OVERVIEW

Top Energy Networks recognises that management of the existing asset portfolio and the ability to adapt to changes in the electricity industry depends upon fit for purpose asset information.

To achieve this, Top Energy Networks have committed to an Asset Information Maturity journey aligned with the EEA Framework. Our objectives include:

- Establishing a strong foundation for improving asset information across Top Energy Networks.
- Mandate direction, principles and requirements to guide the collection, use, maintenance and retiring of Top Energy Networks asset information
- Outline the requirements for data governance and stewardship to meet Top Energy Networks asset management objectives
- Drive continuous improvement of how Top Energy Networks manages its network data
- Assigning clear roles and responsibilities for Top Energy Networks data ownership.
- Provide the framework to ensure data is meaningful so that it delivers actionable information and insights for Top Energy Networks.

A key target for the Asset Information Strategy is that Top Energy Networks will reach a maturity level of four in all four areas of the EEA Asset Information Maturity Framework by end of FY 2028. The Asset Information Governance Group will oversee the development and implementation of this Strategy. Originally planned for FY 2026, this was delayed due to resourcing constraints. This group will represent key stakeholders and ensure improvements align with Top Energy's objectives.

2.12.2 – ASSET MANAGEMENT DATA AND INFORMATION REQUIREMENTS

Top Energy is moving towards an increasingly structured approach to identifying asset management data and information requirements. The following processes are currently in place to identify data and information requirements of the asset management system, covering the whole life cycle of the assets:

- When any changes are introduced to the asset management system the data and information requirements to support and sustain the change are considered. This includes the data and information management implications of introducing new equipment, or making changes to maintenance and inspection programmes.
- For critical data and information requirements, the DataFrame tool is used to link data held in information systems with the processes that require that data. This also provides reporting on the quality of the data.
- When incidents and non-conformances occur, including asset failures, the review considers data and information that could prevent future recurrence.

2.12.3 – ASSET MANAGEMENT DIGITAL SYSTEMS

We use a range of 'best of breed' digital and telecommunications systems to:

- improve safety through consistent, reliable and easily accessible hazard identification and reporting
- support the continuous improvement of existing and future business functions and processes
- maximise flexibility to meet future system operator and customer expectations. External integration capability will be fundamental
- measure and improve performance through data analytics and visualisation
- improve accuracy, relevance, and quality of records
- improve end-to-end customer service, and
- support the asset management process to ensure we deliver efficient and effective outcomes.

Top Energy uses a five-year roadmap for each digital system to ensure the digital system strategy and plans are aligned with business objectives, and this is communicated effectively to the business.

Advanced Distribution Management System

An Advanced Distribution Management System (ADMS) is a software platform that integrates various operational tools to reduce risk and improve the efficiency and reliability of electricity distribution networks. It provides real-time monitoring, analysis, and control capabilities, enabling utilities to manage outages, optimise grid performance, and integrate renewable energy sources effectively.

Top Energy went live with the GE PowerOn ADMS in December 2020. It includes capabilities for outage management, distribution optimisation, and advanced analytics, allowing utilities to enhance grid reliability, operational efficiency, and customer service.

Since then, additional supporting software, such as EDNAR (Electricity Distribution Network Access Register), Peek ADMS diagram viewer, and additional PowerOn modules and capabilities, have been implemented, and many functional issues have been resolved.

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

The ADMS delivers:

- Supervisory Control and Data Acquisition (SCADA) of applicable network assets
- Outage Management System (OMS)
- Distribution Management System (DMS), and
- Vehicle tracking integration.

The OMS combines real-time inputs on the state of the network from our SCADA system with the customer connectivity information in our Geographic Information System (GIS) to:

- predict the location of faults, and
- automatically calculate the SAIDI and SAIFI impact of supply interruptions.

This has resulted in improved reliability reporting. The OMS also provides data for our web-based Outage Centre, where customers can view current planned and unplanned outages and subscribe to future outage notifications.

The DMS modules deliver significant additional functionality. Additional modules we have already implemented include:

- Advanced Meter Interface (AMI): Utilises the data and capability of smart meters, Optical Network Terminals (ONT) and Transformer loggers to improve the OMS outage status, coverage and prediction accuracy and performance.
- Distribution Power Flow Analysis (DPF): This provides a real-time capacity and constraints model of the network, using inputs from SCADA, the GIS and potentially our SAP Asset Management System (AMS). It provides a predictive load-flow modelling function for network planning by making real-time network status information available to operators. DPF is functioning in ADMS, however we are currently populating this module with more accurate system data.
- Adaptive Network Management: Leverages DPF to automate control of embedded generation plants based on current network conditions and constraints. The need for this capability will be driven by customer demand.

Our five-year ADMS development roadmap is predominately focused on optimising the utilisation and operation of our network, preparing for and testing DERM systems and enabling our evolution to a DSO.

GIS System

Geospatial Information Systems (GIS) are vital for managing and analysing geographical data and visually representing spatial information. This technology is essential for utilities as it enables the mapping, modelling, and managing of infrastructure assets and networks. We went live with GE Smallworld Electric Office (EO) in March 2022. We replaced our previous Hexagon GIS with EO. EO is a GIS solution tailored for the electric utility industry. It offers detailed modelling of electric networks, enhanced data accuracy, and efficient asset management. Integrating with other systems supports planning, design, and operations, helping utilities maintain high service and reliability standards.

EO primarily masters the physical and electrical connectivity data for our ADMS, as well as much of the asset attribute data for our Enterprise Asset Management (EAM) and Condition-Based Risk Management (CBRM) systems. It is therefore important that the data held within the GIS receive the utmost attention to veracity. The current GIS roadmap is predominately focused on supporting the ADMS and improving the veracity of all GIS data.

Our GIS is currently integrated with the business applications listed below.

- Advanced Distribution Management System (ADMS): The GIS is the master for all network electrical and physical connectivity data. Each relevant change in the GIS is automatically sent to the ADMS using the Common Information Model (CIM) standard. This ensures the ADMS is constantly and consistently kept up to date.
- Permissions and Easements: SharePoint is used to store details and agreements related to easements and general property access rights.
- ICP Management: Axos Registry Manager integrates with the national registry to manage and report on moves, additions, and changes to consumers' Installation Control Points (ICPs).

Further integration development is underway to align our asset maintenance and finance system (SAP) and our power system analysis software (DigSilent PowerFactory).

Network Analysis System

We use the DigSilent PowerFactory power systems analysis package for load flow, voltage profile and protection design. Digsilent PowerFactory is a leading power system analysis software application that analyses generation, subtransmission, distribution, and industrial systems. It covers the full range of functionality from standard features to highly sophisticated and advanced applications, including:

- wind power
- distributed generation
- real-time simulation, and
- performance monitoring for system testing and supervision.

PowerFactory requires an accurate model of our electricity network derived from the EO GIS data. Integration with our GIS is to be delivered in two stages. These stages aim to significantly improve how this model is derived and ensure we achieve maximum functionality and accuracy in PowerFactory. Stage 1, the delivery of the current-state network model from GIS to PowerFactory with regular automated updates, is complete. Stage 2 will provide more comprehensive integration.

Enterprise Resource Planning and Asset Management

Enterprise Resource Planning (ERP) and Enterprise Asset Management (EAM) systems are essential for organisations to manage their resources and assets efficiently. ERP systems integrate various business processes, including finance, human resources, procurement, and supply chain management, providing a unified platform for data and process management. EAM systems focus on managing physical assets throughout their lifecycle, from acquisition to disposal, ensuring optimal performance, cost-effectiveness, and compliance with regulatory standards.

We migrated on-premises SAP ECC to SAP Cloud in 2025 with go-live on 1 October. SAP Cloud provides real-time data processing, advanced analytics, and streamlined workflows, enhancing decision-making, operational efficiency, and business agility. Its EAM functionality includes:

- comprehensive asset lifecycle management
- predictive maintenance, and
- advanced analytics, enabling organisations to maximise asset performance, reduce downtime, and improve overall operational reliability.

The cloud-based platform ensures scalability, flexibility, and continuous innovation, making it a valuable asset for businesses seeking to stay competitive in a rapidly evolving market.

The Group uses:

- SAP Cloud for the management of expenditure, capital accounts, estimating capital jobs, inventory, orders, accounts payable and accounts receivable, and
- 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 company's performance.

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 asset is assigned to a maintenance and inspection plan in SAP Cloud, based on its type, required inspection frequency, and location. Asset inspections are undertaken both internally by TEN and externally by contractors. Our asset inspectors work systematically through each inspection plan. As each asset is inspected, its condition and other relevant data (such as defects requiring remediation) are entered directly into the SAP database using handheld data input devices.

Assets are inspected according to a time-based inspection regime. The frequency of inspection under this programme is based on the expected rate of asset deterioration and a risk-based assessment of the consequences of an asset's failure. When an asset is assessed as potentially requiring replacement before its next scheduled inspection, it is:

- transitioned into our defects management system, and
- inspected more frequently until the asset is replaced.

Our inspection and defects management regimes are discussed further in Section 6.

Our five-year ERP and EAM roadmap is primarily focused on improving our job resource planning and leveraging SAP AI's evolving technology to enhance our modelling capability.

Customer Relationship and Service Management

Customer Relationship Management (CRM), Customer Information Management (CIM), and Service Workflow Management are integral to ensuring high customer satisfaction and operational efficiency. CRM and CIM systems help organisations collect, organise, and analyse customer information, enabling a better understanding of customer needs and the delivery of personalised experiences. On the other hand, Service Workflow Management focuses on automating and optimising service processes to ensure customer issues are resolved promptly and effectively.

Salesforce Service Cloud stands out in this domain with its robust capabilities to enhance customer service operations. It offers comprehensive case management tools that enable service agents to efficiently track, manage, and resolve customer inquiries. Salesforce Service Cloud also provides powerful analytics and reporting features, giving organisations valuable insights into service performance and areas for improvement.

TEL started our Salesforce Service Cloud journey in 2019 when we built our first customer-facing workflows on the platform. Since then, as we have learned the capabilities and flexibility of the Salesforce platform, we have built many more workflows on it, both internal and customer-facing. We contract an external call centre to handle consumer calls to our 0800 number. The call centre uses our Salesforce Cloud system to load new cases and provide details about consumer calls and call statistics.

Our five-year CRM, CIM, and Service Workflow Management roadmap is primarily focused on building process workflows in Salesforce that currently lack a supporting digital system or would benefit from moving the workflow to Salesforce.

Enterprise Field Mobility

Enterprise field management (EFM) systems are designed to automate and streamline field operations, enhancing productivity and efficiency for organisations with significant field service components. These systems enable real-time tracking of field personnel, efficient scheduling and dispatching, and comprehensive management of work orders. By leveraging mobile technology, field workers can access essential information and tools on the go, ensuring timely, accurate task execution. The benefits of enterprise field management systems include:

- improved resource utilisation
- reduced operational costs
- enhanced customer satisfaction, and
- better compliance with service-level agreements (SLAs).

Univerus Unity (also known as FieldGo or FRED) is an advanced enterprise field management solution tailored for organisations with extensive field service operations. Unity offers comprehensive features, including real-time communication, GPS tracking, and seamless integration with existing enterprise systems. It provides field workers with mobile access to work orders, asset information, and customer data, enabling them to complete tasks efficiently and accurately. Unity's robust analytics and reporting capabilities help organisations:

- gain valuable insights into field operations
- identify areas for improvement, and
- make data-driven decisions to optimise performance and service delivery.

TEL started our enterprise field mobility journey with the original FieldGo product in 2017. Since then, the product, developed initially in NZ, has been procured by Univerus, a large Canadian-based company, which has continued to evolve and expand its capabilities. Over that time, we have configured most of our field paper-based forms, field job dispatch, and asset data capture in the product. It also provides a map of our area with an asset overlay that includes hazard locations, details, and asset defects. Unity is at the forefront of our efforts to improve the quality of field-captured asset data.

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.

Intelligent Automation and Artificial Intelligence

Artificial intelligence (AI) is the simulation of human intelligence in machines, enabling them to perform tasks such as learning, reasoning, and problem-solving. By utilising machine learning and natural language processing, AI systems can adapt to new data and optimise operations, enhancing productivity and decision-making across industries.

Intelligent automation combines artificial intelligence (AI) and automation to streamline processes, enhance decision-making, and improve efficiency. Intelligent automation enables systems to:

- perform complex tasks
- adapt to new data, and
- continuously optimise operations by leveraging technologies such as machine learning, natural language processing, and robotics.

This leads to increased productivity, reduced operational costs, and the ability to respond swiftly to changing business demands.

We have developed an AI Strategy, which is formed by a five-year roadmap, the 5- and 10-year budget, and six individual strategic plans:

- Managing AI Risk, Ethics and Social Licence
- Generative AI
- AI Strategy and Controls: Machine Learning for Asset Management Operations
- Robotic Process Automation and Conversational Artificial Intelligence
- Augmented Reality Overview for Top Energy, and
- ERP AI Assisted Modelling.

Each strategy provides an overview of the technology, potential benefits, and an implementation strategy, with an appropriate low-tolerance risk management approach.

Artificial intelligence and machine learning, especially, can deliver benefits to the electricity sector, presenting an opportunity for Top Energy to improve its business operations. However, several barriers can hinder the successful adoption of AI, including:

- a lack of quality data
- insufficient technical infrastructure, and
- concerns about reliability, risks and transparency around AI.

We will explore the potential benefits of implementing AI in business operations by examining four Proof of Concept (PoC) solutions, each targeting different asset management and operations areas. These Proof of Concepts (PoCs) serve not only as practical demonstrations of AI's capabilities but also as crucial steps toward cultivating a culture of innovation within the organisation.

Our first PoC will be delivered in FY 2026.

- Asset Data Quality Reconciliation: Retroactively enhance inspection data quality by employing AI-driven image recognition to review and correctly classify mislabelled materials in inspection photographs.

With the remaining three delivered in subsequent years (see Section 2.12) .

Intelligent Automation (IA) is revolutionising business processes by combining the precision of Robotic Process Automation (RPA) with advanced technologies such as Artificial Intelligence (AI), machine learning, and natural language processing. IA goes beyond mere automation, it reimagines how processes are designed and executed, offering a comprehensive solution that:

- streamlines operations
- reduces errors, and
- enables scalability with minimal human intervention.

According to McKinsey & Co. (November 2021), organisations that embrace IA can significantly enhance efficiency and resilience, positioning themselves for sustained competitive advantage.

For Top Energy, adopting IA involves deploying 'digital workers' to automate routine tasks like data entry, invoice processing, and report generation. This not only frees up employees to focus on strategic, value-added activities but also ensures consistent accuracy and speed across processes. The integration of AI-driven technologies within IA can empower Top Energy to:

- handle complex decision-making processes
- improve customer service, and
- elevate overall operational quality, providing a secure, reliable, and scalable workforce capable of 24/7 operation (McKinsey & Co., July 2024).

We implemented our first digital worker in 2025 and automated two platform processes as a proof-of-concept, which proved successful. We will automate a further two appropriate processes each year in subsequent years.

Cybersecurity

Cybersecurity encompasses practices and technologies to protect systems, networks, and data from cyber threats like malware, ransomware, and phishing. It involves firewalls, encryption, intrusion detection, and continuous monitoring to prevent unauthorised access and data breaches. In today's technology-driven world, cybersecurity is crucial for safeguarding critical infrastructure, ensuring data integrity and privacy, and maintaining trust. Without it, businesses face financial losses, reputational damage, and legal issues, making robust cybersecurity a vital element of modern enterprise strategy.

Our five-year roadmap includes:

- regular reviews of our information systems security management systems
- regularly measuring and reviewing our cyber security maturity against industry best practice frameworks such as ISO 27001 and AESCSF
- preparing and delivering regular 1 or 2-year improvement plans based on the assessments above
- regularly reviewing and adding additional new cybersecurity systems or capability additions to existing systems to ensure we remain prepared to combat any emerging threats, and
- regularly reviewing our BCP and DR plans.

2.12.4 – QUALITY AND ACCURACY OF ASSET MANAGEMENT INFORMATION

The following processes are used to ensure the quality and accuracy of asset management data and information.

Data Collection at Source

Top Energy's approach is to assure the quality and accuracy of data at the time they are collected. In practice this is achieved through:

- Clear training and work instructions for field teams, in particular for tasks that require precision measurement.
- Field mobility solutions that make it easy for the user to input information accurately, including data validation at source.

Where repeated instances of incorrect data and information being returned are identified, a review of the work process is conducted to identify improvement opportunities.

DataFrame

The DataFrame tool provides a perspective on how data and information are consumed by critical asset management processes. For each process, information requirements are identified and linked to specific fields in information systems. Data quality checks are established and run overnight to provide feedback to Top Energy staff on emergent issues. This tool is also used to track improvements to data quality for specific projects where new data and information requirements have been raised.

2.12.5 – ASSET MANAGEMENT DATA AND INFORMATION TO ASSESS ASSET HEALTH

Top Energy's asset management strategy is increasingly underpinned by data-driven decision-making, ensuring that safety, reliability, and efficiency remain at the core of operational planning. Two key frameworks support this approach: the internal defect management process and Condition-Based Risk Management (CBRM) modelling.

The defect management process provides a structured pathway for identifying, assessing, and addressing asset issues. Defects are sourced through planned inspections, fault patrols, and reports from staff or the public. Each defect is assessed against asset management standards, including condition, repair-versus-renewal, and inspection cycles. Prioritisation is then determined based on safety, reliability (SAIDI/SAIFI), and likelihood of failure, with defects categorised into risk levels (X, A, B). This ensures that the most critical issues are addressed first, with feedback loops to reassess inspection quality, frequency, and clearance timing if reliability metrics trend unfavourably.

Complementing this, CBRM provides a broader, model-based view of asset risk by combining asset age, type, and historical fault data to estimate future performance and failure likelihood. While direct condition data is limited, CBRM enables prioritisation of renewal and maintenance activities based on risk exposure and consequence, rather than age alone.

The outputs from Top Energy's defect management process and Condition-Based Risk Management (CBRM) modelling play a pivotal role in shaping capital expenditure projections. By systematically identifying, categorising, and prioritising asset defects based on risk and condition, the defect management process ensures that the most critical issues are addressed first.

Together, these models enable Top Energy to target capital investments where they will have the greatest impact on safety, reliability, and overall network performance. This evidence-based approach ensures that capital expenditure projections are transparent, justifiable, and aligned with both immediate operational needs and long-term strategic objectives, details of which are outlined in Section 6.

Identification of the specific data requirements for the defect management process and CBRM modelling are determined using the process described in Section 2.12.2.

2.12.6 – ASSET MANAGEMENT DATA AND INFORMATION LIMITATIONS AND IMPROVEMENTS

Asset Information Governance

The Asset Information Governance Group was intended to be established to develop and implement the Asset Information Strategy in FY 2026, however this was delayed due to resourcing constraints.

Improving data and information outcomes requires:

1. An Asset Information Strategy informed by Top Energy's objectives and the current state of data
2. Feedback on the effectiveness of information improvements
3. Visibility of the business benefits realised through successfully implemented improvement strategies

Overseeing these improvements is the Asset Information Governance Group representing key information stakeholders who collectively own this strategy. The diagram below shows this relationship between the strategy, the governance group and continual improvement of information in ways that are aligned with Top Energy's objectives.

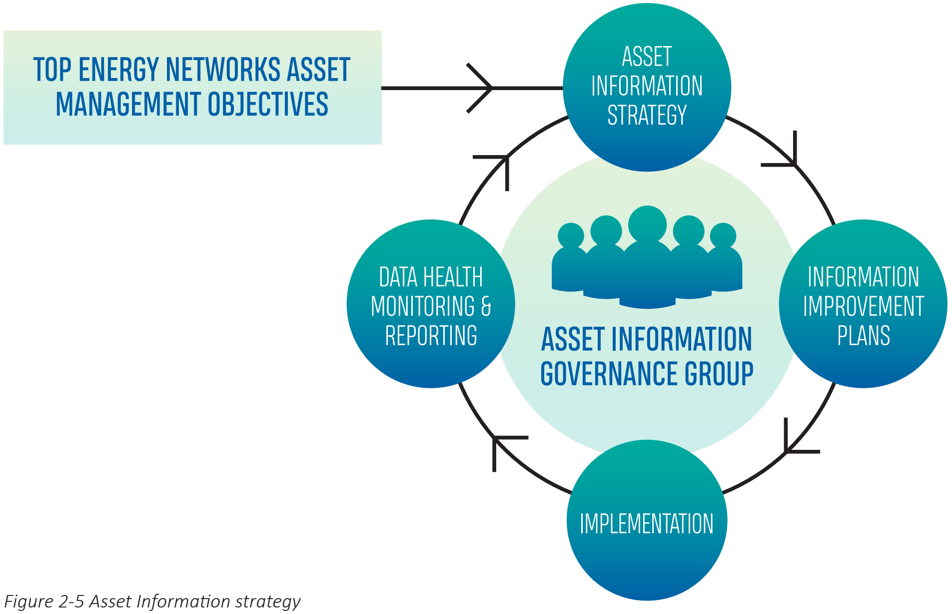

Figure 2-5 Asset Information strategy

In 2024 we started to assess our asset information maturity. Included in this work was:

- Completed Asset Information Maturity Assessment
- Developed an Asset Information Strategy
- Implementation of DataFrame
- Reviewed and updated asset information requirements during contractor agreement renewals
- Reinstated the Equipment Change Process
- Continuation of LV data collection

In 2026, this is being progressed further with the Asset Information Governance Group with the following activities identified

TIMEFRAME	SUBJECT	LEVEL	INITIATIVE
Short term	Systems	3	Link the 5-year information systems roadmap to the asset information strategy
	Systems	3	Standardise process for assessing and deploying information system changes
	Systems	4	Ensure alignment between asset registers
	Standards	4	Report on non-conformance
	Standards	4	Review data collection standards
	Data	4	Capture data quality metrics based on automated checks and inspections
	Data	4	Implement internal audit program for data collection
Long term	Strategy	5	Develop & implement framework for evaluating the value of new information types and sources
	Standards	5	Link data collection standards to asset management functions
	Standards	5	Ensure data collection standards are applied to KPIs for all contractors and sub-contractors
	Systems	5	Implement a register of information system priorities
	Data	5	Ensure defects which have been completed are closed out
	Data	5	Utilise system integration to reduce data collected by field staff to only that which is site specific

Table 2-5 Asset Information Governance Activities:

GIS Data Accuracy

GIS data is considered accurate in the following areas:
- 11 kV lines and associated equipment
- transformers (overhead and ground mount)
- line switchgear and equipment
- 33 kV zone substations
- 33 kV lines
- 33 kV switchgear
- transmission assets transferred from Transpower
- other technical equipment, including SCADA
- 11 kV cable and related equipment, including switchgear, and
- 33 kV cable and related equipment, including switchgear.

For these asset types, individual assets, down to the mother/child connectivity level, are identified, and attributes and capacity are recorded The quality of the dataset is improving over time as assets are progressively inspected and data input specifications are refined and improved. However, we do still find errors as we continue to enhance our reporting functions and data queries. As a result, this can cause some swings in asset quantities and condition. This financial year, we identified that 20 km of conductor was incorrectly identified as two 2-wire conductor, when it is Single Wire Earth Return (SWER), resulting in a large increase in the asset quantity of SWER in our reporting.

Data gaps and errors still exist with:
- low voltage systems, and
- consumer points of connection (i.e. three-phase, single-phase, underground or overhead).

These issues arose because the data on approximately 30% of the low voltage network was not collected during the data gathering exercise that was undertaken to initially populate the GIS database.

GIS LV Data Accuracy

Top Energy is currently undertaking an LV Data Capture and Visibility project to accurately capture, document, and quantify our LV data set, the project was initiated in FY 2023 and is scheduled to continue for most of the planning period. This data is:
- input into the GIS system, and
- used to extend the ADMS functionality to include management of the low voltage network.

We have developed two GIS-based maps.
- Map 1: Capture's locations of PV Installations to visually represent congestion or hot spots on the network that could potentially develop constraints. Further, we continue to monitor solar uptake on the network monthly.
- Map 2: Forms part of an investigation we are conducting on the Distribution System. This is a heat map that identifies potential constraints based on ADMD.

In 2025, we completed a trial of the Hiko Energy Insights system for LV visibility. This is now implemented in our business, allowing us to:
- monitor voltage quality, PV compliance, and network congestion, and
- provide real-time outage management capabilities.

Our ADMS is being further developed to provide greater visibility into the low voltage network. To take full advantage of this additional functionality, we:
- require more accurate field data on our low voltage assets, and
- included provision in our opex expenditure for a low voltage data capture project to address this.

A pilot project is planned for FY 2027 to use ADMS for LV switching. The success of this project will result in further areas being considered for LV switching on our network.

Asset Configuration Information

Processes for managing maintenance data in SAP have matured, and we have specified measurement points and asset condition criteria for the different asset types. The quality of the dataset is improving over time as assets are progressively inspected and data input specifications are refined and improved. However, we do still find errors as we continue to enhance our reporting functions and data queries.

[2.13] Asset Management Processes

2.13.1 – ASSET INSPECTIONS AND MAINTENANCE MANAGEMENT

Routine maintenance and inspection programmes are developed and reviewed based on:
- analysis of equipment failure modes and investigation of asset failures
- engineering knowledge in the management of electricity distribution equipment
- industry knowledge that is acquired in both structured and informal ways, and
- original equipment manufacturer recommendations

Top Energy has planned an initiative to consolidate structured Asset Class Strategies to formalise the management of this information Routine maintenance and inspection programmes are registered in our enterprise asset management system SAP, which generates individual tasks to be delivered. Our visual asset inspections are complemented by a structured, non-invasive condition assessment programme that targets:
- key assets (e.g., power transformers), and
- items that are prone to failure (e.g., cable terminations).

A more detailed description of the maintenance policies for specific asset types is provided in Section 6.

Defects are prioritised and packaged into work orders by TEN staff. These maintenance work packages, designed to ensure that all defects in a particular area requiring maintenance intervention are remedied simultaneously, are passed to TECS for implementation. Furthermore, defects will be referenced against the asset's criticality as outlined in the Condition-Based Risk Management (CBRM) framework. This support prioritisation, ensuring that maintenance efforts focus on the most critical assets first. The quality and efficiency of TECS's defect remediation are monitored through sample auditing and monthly reporting.

Regular reports from TECS on maintenance work completed are used as the basis for Board reporting on maintenance completion and expenditure against the maintenance budget. Analysis of network performance and equipment failures is used to determine the effectiveness of maintenance programmes and to identify where improvements may be required. A 24-hour emergency maintenance service is operated to promptly repair network faults and address defects that pose an immediate threat to public safety.

2.13.2 – NETWORK DEVELOPMENT PLANNING AND IMPLEMENTATION

Our network development plan is reviewed annually at both a strategic and detailed planning level to ensure alignment with the Board's mission, values, and consumer expectations in a dynamic operating environment. With full funding now secured for the current AMP, including major projects such as zone substation upgrades and the construction of the new 110 kV Wiroa–Kaitaia line, the primary constraint on delivery has shifted. The challenge is now less about financial availability and more about the efficient execution and resource coordination. This enables us to accelerate the implementation of critical initiatives that strengthen reliability, expand capacity, and support the integration and electrification of renewable energy.

At the strategic level, the plan continues to focus on long-term resilience and growth, ensuring that investments address both current demand and future requirements driven by decarbonisation and technology adoption. Detailed planning emphasises risk-based prioritisation, timely delivery, and optimisation of capital works to maximise consumer value and regulatory compliance DigSilent analysis is used to reassess the current plan against revised assumptions to ensure it efficiently and effectively addresses security, reliability, and capacity issues. Our network development plan, load forecasting and the development of the network capital investment strategies are discussed in greater detail in Section 5.

Our high level Network Development process is:

1. Develop demand forecast, using Digsilent, Historian and growth forecasts from Far North District Council (FNDC) outputs.
2. Determine risk of voltage, security, capacity, performance shortfall across the network through planning period. Datasets used for this are:
    - Demand forecast outputs, per above
    - Condition-based Risk Modelling
    - Hiko LV Management
3. Determine options to address risks, including non-network solutions such as demand management and use of flexible resources
4. Select best value option
5. Register option in AMP programme for consideration amongst other investment options and timing windows
    - All AMP projects are reviewed by a cross-functional team to ensure alignment with our objectives, prioritisation requirements and are co-ordinated for efficiency.
6. Develop formal business case (if required); business cases may be staged if seed funding is required for detailed design and scope, where projects are complex.
7. Develop detailed design report, including shutdown outage plan; health and safety plan; environmental plan; commissioning plan
8. Construct project
9. Commission project
10. Post-implementation review

2.13.3 – NETWORK PERFORMANCE MEASUREMENT

We use our ADMS to automatically calculate the SAIDI and SAIFI impact of supply interruptions caused by network faults occurring at 11 kV and above. An interruption starts when the system timestamps the operation of protection equipment. If the protection operation is not automatically timestamped, it is assumed to start when we are first advised of the outage.

The ADMS subsequently tracks and timestamps the operation of all switching/protection equipment until supply is restored to all affected consumers. It then traces sections of the network that are disconnected from supply, or reconnected by each switching operation, and counts the ICPs affected by each operation. This allows the system to calculate the customer interruption minutes for each step of each event. The ADMS uses this information to automatically determine total SAIDI and SAIFI for the interruption, based on the actual switching record created in response to the event. The Network Operations team performs daily checks of the system and reviews each event to ensure quality and accuracy of reporting is maintained.

Annual audits of interruption impacts are also conducted by an external auditor, as required by the Commerce Commission to support its regulatory compliance assessment. The Network Operations team are responsible for network performance measurement and tracking. Monthly fault statistics, together with SAIDI and SAIFI performance, are prepared for inclusion in the General Manager Network's monthly Board report.

[2.14] Distribution System Operator (DSO)

2.14.1 – OVERVIEW AND FUNCTION OF THE DSO

In 2024, we began efforts to establish a new department, Distribution System Operations (DSO). This department is specifically tasked with:

- the comprehensive management of the control centre
- overseeing operations management, and
- implementing the DSO function.

DSO aims to enhance the reliability and resilience of our networks by:

- facilitating bidirectional power flow to support demand response
- minimising outage durations, and
- enabling flexible services for our consumers.

A DSO Governance Committee was established to provide oversight and strategic direction to ensure effective governance of DSO-related initiatives. The current DSO vision is centred around a hybrid operational model designed to foster seamless collaboration among key stakeholders, including:

- Transpower
- electricity retailers
- embedded generation entities (such as solar and geothermal power plants)
- distributed energy resources, and
- behind-the-meter consumer energy resources.

The primary objective of the DSO is to leverage traditional DNO activities with smart technology (smart meters, IoT, etc.) and data-driven analytics to enable the Network team to gain visibility, control, and interoperability across our various systems with ADMS (Advanced Distribution Management System).

2.14.2 – DSO READINESS JOURNEY

Our DSO readiness is focused on a collaborative approach that integrates our Electricity Infrastructure with our Digital Infrastructure to enable effective data analysis and flows. This integration is crucial for operations management of embedded generators, distributed energy resources (DER), and consumer energy resources (CER).

Recently, we completed a pilot project on smart meter data and analytics, which yielded positive results and led to the procurement of this service. This new service will enable us to access smart meter data related to consumption and power quality, covering more than 70% of our network. Additionally, we have installed several transformer loggers and fault passage indicators on our low-voltage (LV) network as part of our initiative to enhance smart network capabilities. This initiative will continue in the upcoming years.

This year, we are continuing our LV data capture efforts, including collecting field data and updating our network Geographic Information System (GIS). A comprehensive plan is in place to gather all necessary field data on our network.

Our Advanced Distribution Management System (ADMS) serves as the primary tool for our Network Controllers to oversee network operations. Several developments are underway within the DSO framework, as follows:

- the integration of smart meter data into the ADMS through an API will enable near real-time monitoring and enhance the existing Outage Management System
- the Adaptive Network Management (ANM) and Distribution Power Flow (DPF) modules in ADMS have facilitated the automation of our Congestion Management Policy, and
- a pilot project in the Kerikeri area will test the LV management module in ADMS, which will support LV switching capabilities. This project will also integrate our smart network devices and smart meter data. Additionally, it will include testing a field tool (tablet device) designed to assist our field crew in performing LV switching and live update of the switching on ADMS.

Lastly, GE Grid OS has been identified as the preferred Distributed Energy Resource Management System (DERMS) platform for our DSO implementation plan. The DERMS rollout timeline is anticipated for FY 2030 or earlier, contingent on meeting regulatory and industry market requirements.

[2.15] Asset Management Documentation, Controls and Review

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

2.15.1 – ASSET MANAGEMENT POLICY

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

2.15.2 – ASSET MANAGEMENT PLAN

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

We have qualitative objectives derived from the corporate mission statement, which are discussed in detail in Section 2.5. However, we still need to develop a formal process to evaluate how well we are achieving these. This could mean developing quantified measures to track our progress towards the objectives that we consider most critical to achieving our corporate mission. The quantified supply reliability indicators outlined in Section 4 of this AMP are central to our overarching asset management strategy. 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 for the completion of planned asset inspections and for defect management backlogs.

2.15.3 – ANNUAL PLANS

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

2.15.4 – SERVICE LEVEL AGREEMENT

The service level agreement (SLA) between TEN and TECS is integral to implementing the action plans outlined in this AMP. The SLA, which was updated in July 2025:

- defines the relationship between the two business units, based on an asset manager–service provider model
- specifies the different responsibilities of the two parties
- defines key performance indicators that measure the extent to which each party fulfils its obligations
- specifies the information that TEN must provide to TECS and when it is to be provided, and
- details the TECS service response to cover the delivery of the annual work programme in accordance with agreed targets.

TEN undertakes all planning for capital works, asset inspections, and maintenance requirements. The resulting design and delivery documentation from TEN enables TECS to develop an annual work programme and to ensure that resources are available to undertake the required work.

2.15.5 – OUTSOURCING STRATEGY

Where resources are not available for delivery in-house, we use will engage specialist consultants or contractors to assist in parts of our asset management system.

We have several process in house to manage outsourced activities:

- Procurement frameworks embed asset management requirements into contractor evaluation and ongoing management processes
- There is a documented process to manage vendor performance, which sets out requirements for contractor selection, performance monitoring, and non-performance management. This include regular performance reviews and feedback mechanisms.
- Our service level agreement with TECS defines performance standards and monitoring arrangements for internal outsourcing

Top Energy manages the performance of contractors, including professional consultants, as follows:

- Expectations, outputs (milestones), service levels and, if necessary, Key Performance Indicators (KPI's) are specified in the relevant contract.
- Contractor workshops are provided on maintenance codes and asset management procedures.
- Contractor competency is assessed and managed in line with our authorisation holder's certificate (AHC) requirements, which requires formal assessments of current competency, and is further described in section 8.3.1.
- The Top Energy Relationship Manager monitors the performance of the Contractor.
- Top Energy and the Contractor meet on a regular basis to review performance against service levels and KPI's, as well as progress achieved against required outputs.
- Non-performances are addressed and, if necessary, Procurement are engaged to ensure agreed remedies are properly documented.
- Non-performances that cannot be resolved are escalated to the relevant executive/s.
- Contractors engaged on a fixed-term basis are reviewed at least annually.
- Contractors engaged for large projects may also be required to participate in a Project Close Out review.

All decision-making processes and capabilities are retained in-house, and data, information and knowledge generated through outsourced activities are recorded in Top Energy information systems and documents.

2.15.6 – DOCUMENTATION OF THE ASSET MANAGEMENT SYSTEM

Our quality management system was re-certified as compliant with ISO 9001 in FY 2025. This system documents many processes and procedures relevant to asset management, particularly the implementation of the AMP. Documents are created and saved into a controlled document library, following a review and approval process. Review periods are system generated based on the document type and last review date – which may be as frequently as annual up to 5 yearly.

Review prompts are automated and sent to the document owner to check, update where appropriate and go for review and publish. The document owner is responsible for communication of the updated document once published. In the case of Policies, amendments to policy content must be approved by the Executive Team.

2.15.7 – LEGAL COMPLIANCE DATABASE

The General Manager Finance is responsible for ensuring Top Energy meets its legal obligations and maintains relevant records through a database that automatically emails staff responsible for legal compliance. The database does not capture changes to technically focused regulations, such as the Safety Rules. The General Manager Network and staff monitor these changes through their membership and engagement with relevant industry bodies and respond as required. We are confident that any change to a law or regulation that impacts how we manage our network assets will be identified and addressed in a timely manner.

2.15.8 – AUDIT

Our NZS 7901 certified public safety management system and ISO 9001 certified quality system both require an independent external audit. These systems strengthen the internal auditing of our asset management activities and the field activities undertaken by TECS and our external contractors. In 2025 we engaged an independent consultancy to carry out a comprehensive asset management maturity assessment using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

2.15.9 – CONTINUAL IMPROVEMENT

There is a commitment to continual improvement within TEN and the wider Top Energy Group. The successful recertification of our public safety management system and the ISO certified quality management system is testimony to our continual improvement culture. Our Board and executive management team drive this. The preparation and ongoing improvement of this AMP are accorded a high priority, with input from the Board to provide strategic direction at an early stage of its development.

[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 managing our network, and all senior managers within TEN are involved in its preparation.

We actively encourage external stakeholders to review and comment on the AMP's content. We distribute the AMP widely across the organisation and publish it online on our website. A copy is kept in the reception area 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. We seek feedback on significant changes to our network development strategy. We have gained broad acceptance of the network development plan described in this AMP from those involved in the consultation.

External communication of our asset management plan has largely focused on vegetation management and the total cost of our network investment programme. Consumers easily understand vegetation management because it is visible, and its impact on improving reliability is well known. Communicating the cost of our network investment programme signals to stakeholders the level of service delivery that is to be expected over time.

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

2.16.3 – COMMUNICATION, PARTICIPATION AND CONSULTATION

Ongoing communication of asset management issues with external stakeholders, by the CEO and TEN's senior managers, continues to support our operational and organisational objectives. Top Energy has also included on its website to include a video on the future of energy in our supply area and real-time information on planned and unplanned supply interruptions. Communication with Top Energy employees occurs regularly through CEO presentations to staff at the 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. Further details on customer engagement can be found in Section 2.8 and 4.5.

[2.17] Capability to Deliver

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

The challenges in delivering the projects and programmes described in the AMP include:
- financing
- engineering, and
- construction.

Each is discussed in the following sections.

2.17.1 – FINANCING

As a 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 over $378 million on 31 March 2025.

With the help of external consultants, Top Energy maintains a financing plan to fund our ongoing investment programme. This includes:
- revenues from line charges, and
- bank borrowings.

There is a balance between the ability to increase line charges so that they remain affordable to our consumers and the level of debt that represents sustainable long-term borrowing.

2.17.2 – ENGINEERING

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

2.17.3 – CONSTRUCTION

Construction of the works described in this AMP is undertaken by TECS, which has the skills and resources available. In general, line construction and cable laying are undertaken internally, while the construction of new substations, subtransmission line maintenance and other specialist works are outsourced.

2.17.4 – MAJOR PROJECTS

Where individual projects are significantly large, project management teams are set up with specialist consultants and contractors to support planning, engineering, project management and project governance. This may include fixed term, or contracted resource to act as Project Director, Subject Matter Experts or externally resourced delivery teams. The Wiroa-Kaitaia 110 kV line build project (as described in section 6.19.5) is one such example, where a project director and Operational Delivery Manager have been engaged in order to provide sufficient time, expertise and governance to a project of its size.

[2.18] Public Safety Management Issues

The Health and Safety at Work Act 2015 has raised awareness of:
- the risk that the operation of an electricity network can hold to the 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 three significant issues.

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 distribution system in our area. Consequently, SWER lines were extensively used in the reticulation of our supply area, and many of these legacy lines remain. However, the load is now getting too high for the SWER lines in some areas.

SWER lines also pose a public safety risk because, unlike two- and three-wire lines, the earth system carries the full load current. If the earth resistance is too high, the earth potential can rise to hazardous levels. This creates a risk of shock and possibly death to persons and stock that come into contact with these assets. While SWER earthing systems are designed and installed to mitigate these risks, such precautions cannot be relied on to provide complete protection. 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. 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. We now also require any new consumer wanting to connect to our SWER network to install a two-wire line so that when we upgrade, we do not have to fund the cost of upgrading that consumer's private line.

2.18.2 – PRIVATE LINES

Many of the private lines in our area are in poor condition. These lines are not regularly inspected, and there are no systems in place to ensure they remain in a safe condition. The Commission's view is that this is not our role, and we are therefore unable to fund such inspections. It is the line owner's responsibility to ensure that they are maintained in a safe condition. Top Energy's preference is to assume ownership of newly installed 11 kV service lines to prevent this situation in the future. Existing service lines are fused and labelled when the opportunity arises.

2.18.3 – VANDALISM, THEFT AND RESULTING UNSECURED ASSETS

Over the past year, we have noticed a rise in vandalism and theft, leading to unsecured or unsafe assets. Earthing tails on switch handles and earth banks that can be sold for scrap value are cut, leaving switches and substation compounds in a dangerous state, since it affects protection schemes. We also experienced a few incidents in which our bulk fuel supplies for critical backup generation at a zone substation, supplied by a single 33 kV circuit, were stolen. To gain access, the zone substation perimeter fence was cut and rolled back, providing the public with unsecured access to live switchyards after the incident until it was discovered.

[2.19] Innovation Practices

Recent innovation practices which have been planned or undertaken in through FYE 2025 include:

- Risk Based Investment Modelling: Development of the condition based risk management model for asset renewal planning (refer 6.1.6). The desired outcome for this is to support cost-efficient investment decisions, directing expenditure to where value can be delivered, as well as improving long term reliability outcomes.
- LV Monitoring: Trial of an LV monitoring system, refer section 2.12.6. The desired outcome for this is to improve our ability to assess DER applications in an efficient manner, improving customer service levels, and allow us to monitor voltage quality pro-actively improving our customers experience, and assist in fault resolution timeframes.
- Vegetation Risk Modelling: For FYE 2026 we are looking at vegetation data models, such as LiDAR or Satellite risk modelling. The desired outcome for this is to support cost-efficient investment decisions, directing expenditure to where value can be delivered, as well as improving long term reliability outcomes.
- ADMS Developments: Ongoing development of additional ADMS modules to manage embedded generation (refer section 2.12.3 and 7.2.1), and integrate the outage management system. The desired outcome for this is to improve operational delivery and provide us the tools to monitor and react to our network congestion and act promptly, in order to minimise customer disruption, or network instability.
- Use of Artificial Intelligence: For further detail refer to 2.12.3. We have been investigating, and will continue to look into utilising AI and system automation to provide the desired outcome of improving our processes to increases efficiency, support cost-effective decision making and improve our customer experience.

When looking at new systems, or practices we determine our measures of success from the outset, and are related to our business and asset management objectives. If the innovation is new product, or system, then the success measures are presented as part of the business case to the executive team, these are measurable SMART outcomes which the products are assessed against. The outcomes of any trials are then fed back through the executive management team for assessment. Dependant on the value of the system, or practice, this may be at GM level, or alternatively through a governance committee, for example the LV Monitoring (Hiko) trial was presented and approved via our DSO Governance Committee.

Innovations in standards, asset types or technical products will follow the new equipment process, which will look at the benefits and is a cross functional group to assess and manage change on the network. This process is described in section 5.2.7. When assessing options, we actively seek feedback from our peers and will request references from other EDBs, as well as suppliers directly. We are engaged with the future network forum, EEA working groups and other industry working groups (such as North Island Network Operators (NINO) Forum) to get direct feedback about their experiences, learnings and outcomes from their innovation practices. This feedback plays a large role in our decision making process, as we look to be fast followers.

Types of information we look for to identify innovative solutions and assess against our requirements are:

- Regulatory , legal or customer service requirements to identify the need;
- Key benefits and dis-benefits
  - Return on investment
  - Reliability benefits
  - Efficiency benefits
  - Scaling opportunities
- Key learnings from any trials or case studies
- Operational or capital requirements
- System or integration requirements.

ASSET DESCRIPTION

SECTION 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 6,822 km2. The area is bounded by both the east and west coasts, and the territorial local authority boundary of the Far North District Council in the south.

Most of our supply area is rural. There is no single dominant urban area, and urban development is spread amongst several small towns with populations between 1,000-7,000 people and numerous smaller settlements. Coastal settlements, especially on the eastern and north-eastern coasts, are growing faster than the district average. Most inland towns, including Kawakawa, Moerewa and Kaikohe, have relatively static or, in some instances, declining populations.The Maungataniwha Range separates our supply area into two distinct geographic areas. The northern area, which includes Kaitaia, Taipa and the Cape Reinga peninsula, is supplied from our 110 kV Kaitaia substation located at Pamapuria, approximately 10 km 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 110 kV Kaikohe substation and grid exit point (GXP). A single circuit 110 kV line owned by Top Energy connects these two 110 kV substations. There is currently no other 110 kV or 33 kV interconnection between the two geographic areas.

Compared to the rest of New Zealand, our distribution area has a higher proportion of people who are unemployed or on low incomes. The average quantity of electricity supplied to each active connection point is one of the lowest in the country.

3.1.2 – NETWORK CHARACTERISTICS

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

A 33 kV subtransmission network delivers electricity from our Kaikohe and Kaitaia 110 kV substations to 15 zone substations – five in the northern area and 10 in the southern area. These zone substations supply 69 distribution feeders operating at 11 kV (except for a section of the Rangiahua feeder, which has been uprated to 22 kV). 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).

Distribution feeders supply distribution transformers that convert electricity to low voltage (LV) for supply to consumers. Our LV distribution is 400 V three-phase, 460/230 V two-phase, and 230 V single-phase. We have a total of 17.2 MW of diesel generation to increase our network resilience. This can supply all small use consumers in our northern area when the incoming 110 kV circuit from Kaikohe is out of service.

Our double-circuit 33 kV line between Kaikohe and Wiroa has been built to 110 kV construction standards. It is planned to eventually form part of a 110 kV ring. This will provide a high-capacity network backbone interconnecting the Kaikohe, Kaitaia, and Kerikeri load centres. A section of one circuit of this line has already been energised at 110 kV to provide a connection between the newly commissioned OEC4 generator at Ngāwhā and the Kaikohe 110 kV switchyard.

During FY 2026, we supplied an average of 34,634 active connections. The maximum demand on our network was 72.5 MW, and the total energy delivered to consumers was 328 GWh.

3.1.3 – GRID EXIT POINT

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

3.1.4 – 110 kV SYSTEM

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

The 110 kV circuit between Kaikohe and Kaitaia has a winter rating of 68 MVA, which is sufficient to supply the foreseeable Kaitaia consumer load. We also have utility-scale solar farms in the Kaitaia and Pukenui areas, connected to our network. However, the 55 MVA summer rating of this line limits the amount of electricity from these generators that can be exported south.

At Kaitaia, there is a three-phase transformer rated at 40/60 MVA. There is also an older transformer bank consisting of three single-phase units rated at 20 MVA, which, by itself, is insufficient to handle the total generation during peak output periods. However, this scenario is unlikely given the good condition of the larger transformer.

There are two 60/40 MVA 110/33 kV transformers at Ngāwhā 110/33 kV Substation. This substation connects the newest Ngāwhā plant to the subtransmission network at Kaikohe. The second of these transformers, installed in 2025, provides security of supply for the power station, which allows maintenance on either side of the substation.

3.1.5 – 33 kV SUBTRANSMISSION SYSTEM

We have two 33 kV subtransmission networks. One serves the northern area, and the other serves the south. They are both supplied by our Kaitaia and Kaikohe 110 kV substations. The outdoor 33 kV switchyard at Kaikohe was replaced in FY 2015 with a new indoor switchboard.

Our 33 kV subtransmission networks and the locations of the zone substations they supply are shown geographically in Figure 3-1 and Figure 3-2. Approximately 94% of our subtransmission system is overhead. Underground 33 kV 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

SUBSTATION	UNIT	NOMINAL RATING (MVA)	MAXIMUM CAPACITY (MVA)
SOUTHERN AREA			
Kaikohe	T11 T12	11.5/23 11.5/23	17[1] 17[1]
Kawakawa	T1 T2	5/6.25 5/6.25	6.25 6.25
Moerewa	T1 T2	3/5 3/5	5 5
Waipapa	T1 T2	11.5/23 11.5/23	23 23
Omanaia	T1	3/5	5
Haruru	T1 T2	11.5/23 11.5/23	23 23
Ngāwhā Transmission Station	T41 T42	40 40	40 40
Mt Pokaka	T1	3/5	5
Kerikeri	T1 T2	11.5/23 11.5/23	23 23
Kaeo	T1 T2	5/10 5/10	11.5 11.5
NORTHERN AREA			
Okahu Rd	T1 T2	11.5 11.5	11.5 11.5
Taipa	T1	5/6.25	6.25
Pukenui	T1	5	5
NPL	T1 T2	11.5/23 11.5/23	23 23

Table 3-1: Zone Substation Security

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 below shows the transformer capacity at each zone substation. The limiting factor determining transformer capacity is the transformer oil's temperature. Most transformers are fitted with radiators for air cooling. The transformer's capacity can be increased by adding fans to force air through the coolers (air forced, or AF) or pumps to pump oil through the radiators (oil forced, or OF), rather than relying on natural circulation. Most transformers, therefore, have two ratings: one for natural cooling and a higher one for forced cooling.

With the addition of diesel generation and existing feeder transfer capabilities, our subtransmission network is now robust enough to restore power after a single element failure. In most cases, supply can be maintained without interruption or restored within an hour, except for two large consumers who may experience a brief outage. The two consumers who do not fall under this do not accept a lower level of security. The security level we now provide at individual substations is discussed in detail in Section 5.1.3.

We also have a 33/11 kV, 7.5 MVA mobile substation that can be relocated within 12 hours in the event of a transformer failure at one of our single transformer substations. While diesel generation is available at all but one of these substations. The mobile substation avoids the need to run this generation for extended periods. The mobile substation is located at Taipa on a semi-permanent basis, providing backup for the permanent transformer.

A single line diagram of our network can be issued on request via our website, at https://topenergy.co.nz/i-want-to/get-in-touch/send-feedback.

3.1.6 – DIESEL GENERATION

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

LOCATION	NO. OF UNITS	RATED CAPACITY (MW)	COMMENTS
Pukenui substation	1	1	Provides support to the northern area when the Kaikohe Kaitaia 110 kV line is out of service. The substation also provides local substation support when the transformer or incoming line is out of service.
Bonnetts Rd	8	8	Bonnetts Rd is a standalone generator farm 2km west of Kaitaia. These generators provide support to the northern areas when the 110 kV line is out of service.
Kaitaia depot	3	3	Provides support to the northern area when the 110 kV line is out of service.
Taipa substation	2	3.2	These units were installed in FY 2014 to provide local support when the transformer or incoming line is out of service. They also provide support to the northern area when the 110 kV line is out of service.
Omanaia substation	2	2	These are the only diesel generators in our southern area. They provide local support when the incoming 33 kV line or transformer is out of service.
TOTAL	**16**	**17.2**	

Table 3-2: Diesel Generation Installed for Network Support

3.1.7 – DISTRIBUTION NETWORK

Our distribution system consists of 69 predominantly rural feeders, 93% of which are overhead. Underground cable is used in commercial areas and newer subdivisions. The system operates at 11 kV, except for 20 km of the Rangiahua feeder, which has been upgraded to 22 kV. Figure 3-3 to Figure 3-16 shows the extent of the distribution system supplied from each of our zone substations.

The distribution network supplies approximately 6,100 transformers. These fall into three types:

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

Despite extensive LV cabling, 85% of distribution transformers are pole-mounted. However, due to seismic constraints, pole mounting is now limited to transformers rated up to 100 kVA. Ground mounted transformers are generally enclosed in steel cabinets that may also house 11 kV switches, depending on the application. Only five distribution transformers that are not installed within consumer premises are located within purpose-built substation buildings.

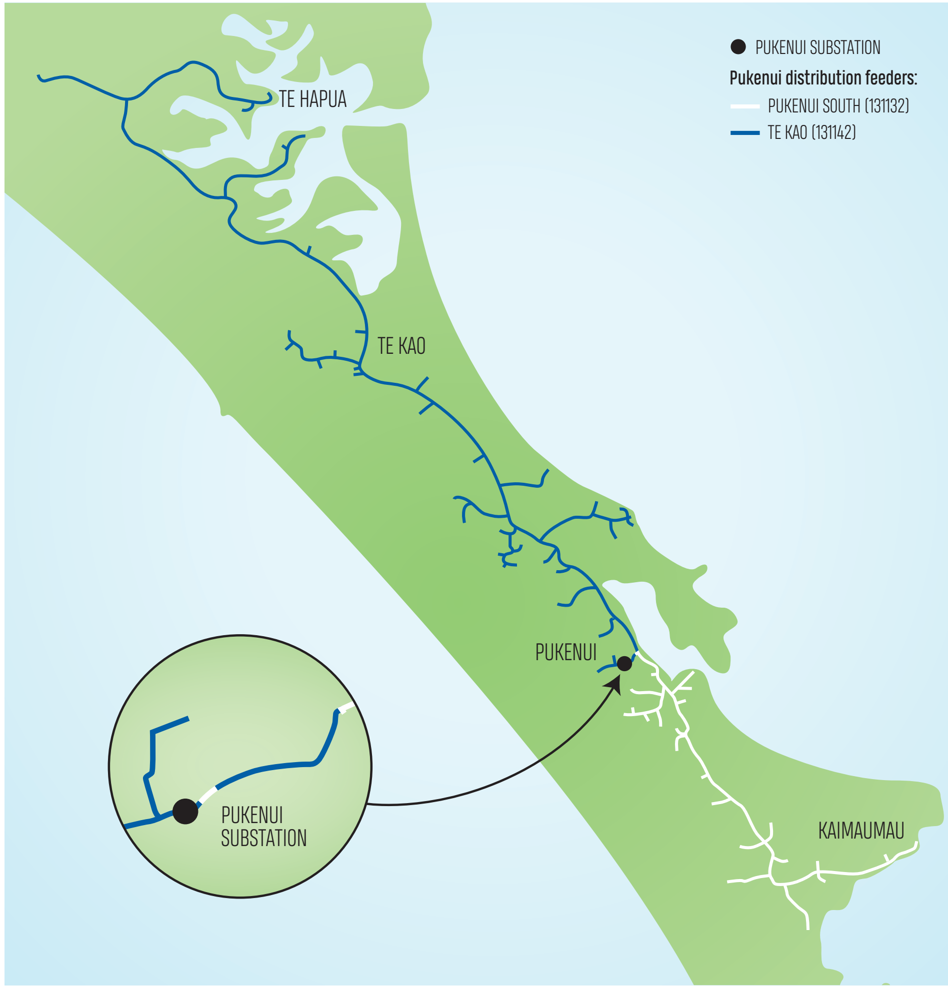

Figure 3-3: Geographic Diagram of the Pukenui Zone Substation

Figure 3-4: Geographic Diagram of the NPL Zone Substation

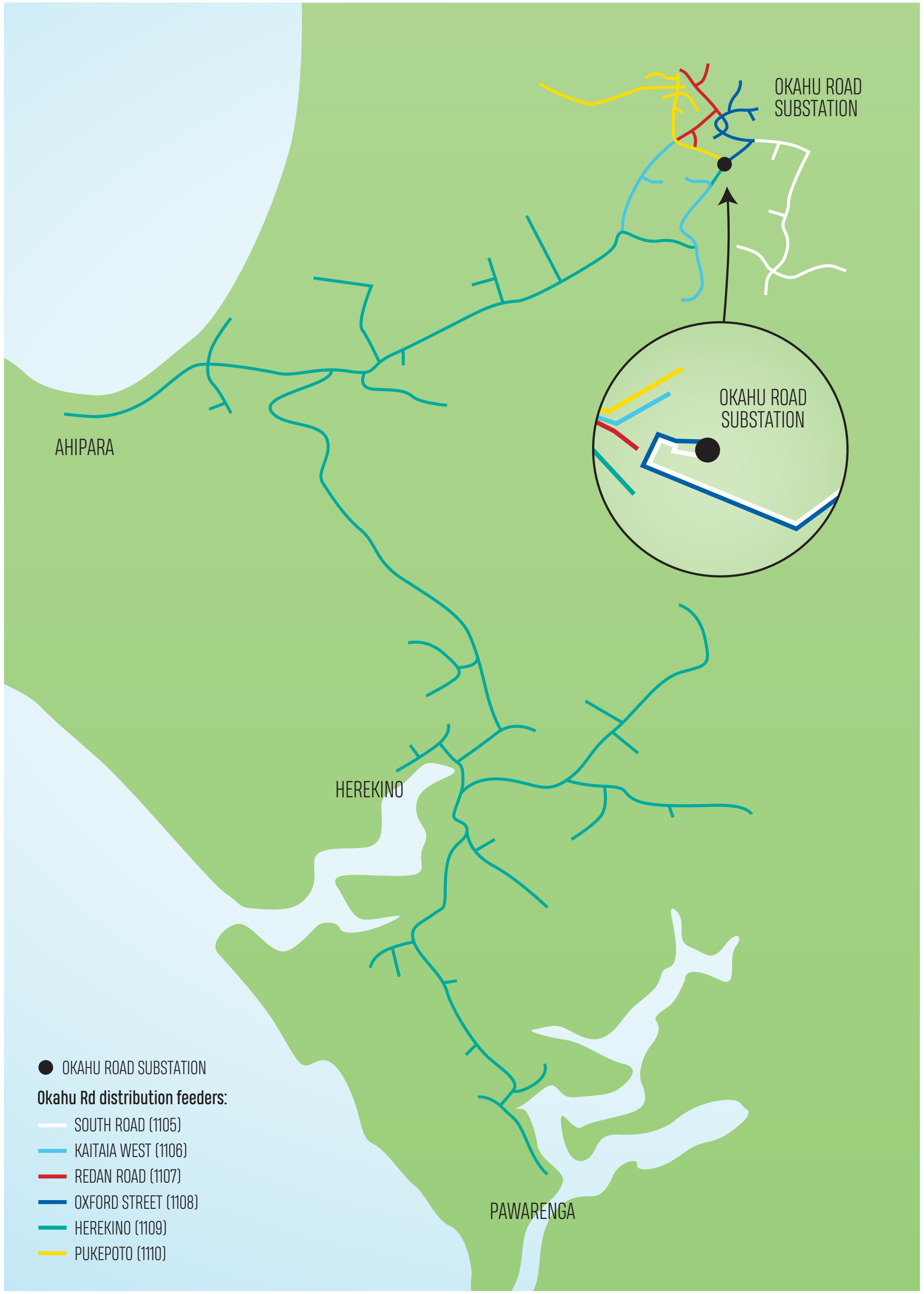

Figure 3-5: Geographic Diagram of the Okahu Road Zone Substation

Figure 3-6: Geographic Diagram of the Kaitaia Zone Substation

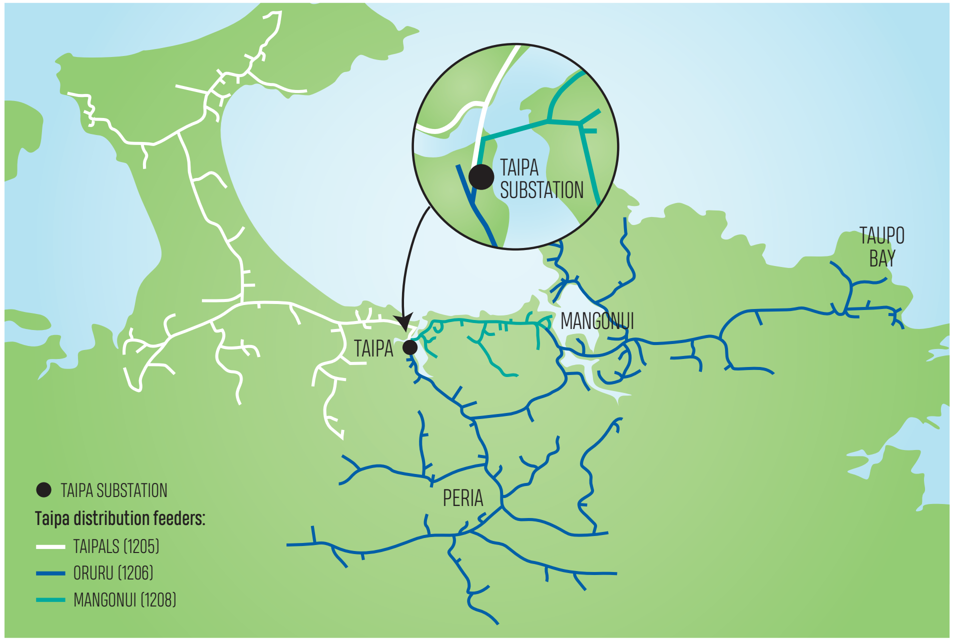

Figure 3-7: Geographic Diagram of the Taipa Zone Substation

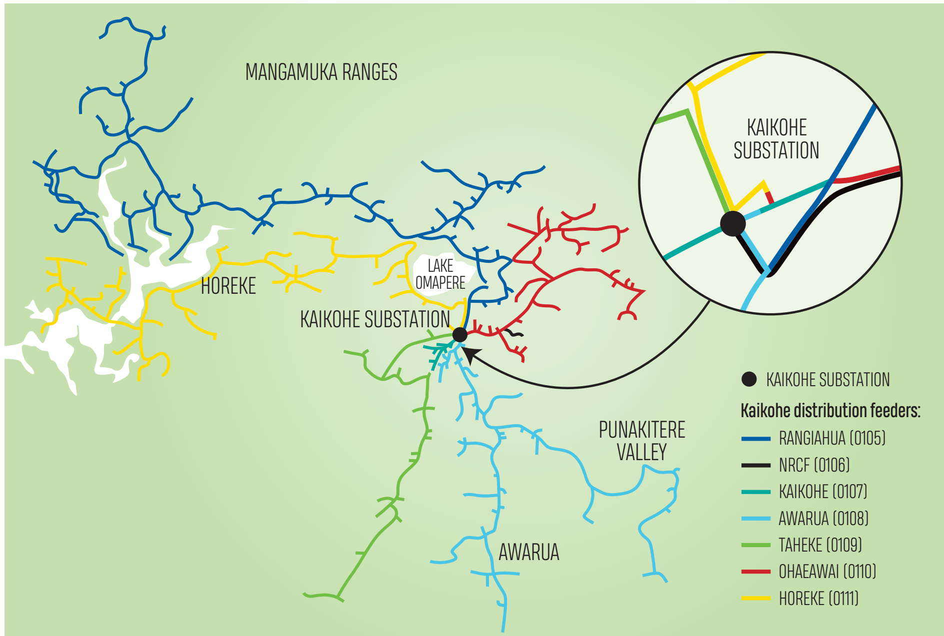

Figure 3-8: Geographic Diagram of the Kaikohe Zone Substation

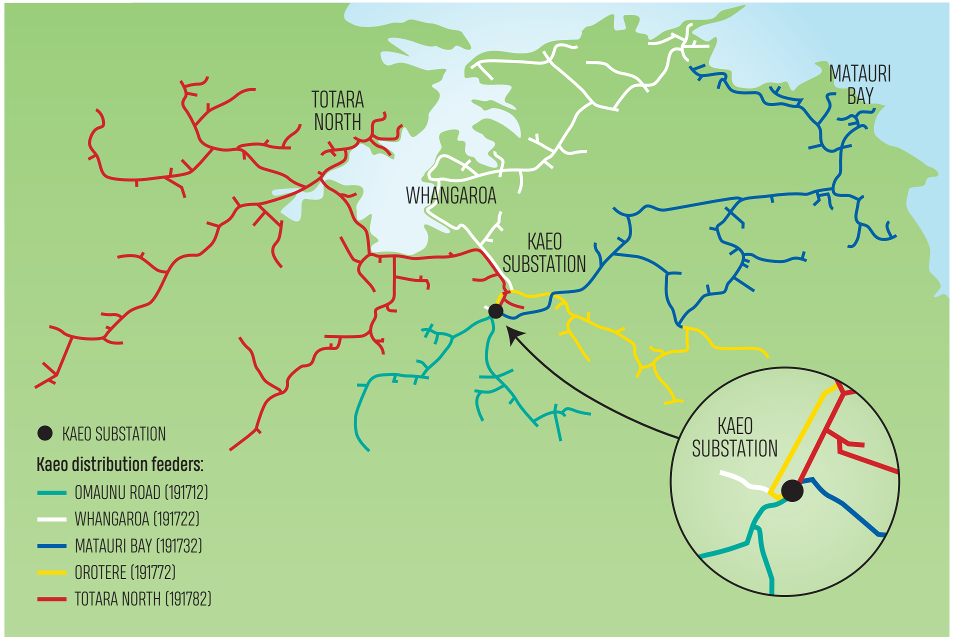

Figure 3-9: Geographic Diagram of the Kaeo Substation

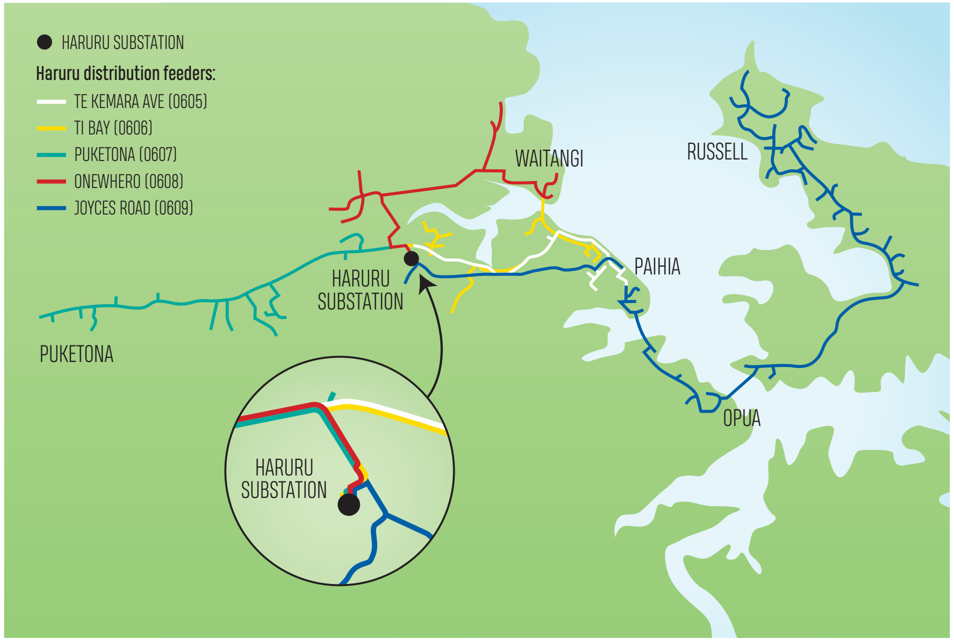

Figure 3-11: Geographic Diagram of the Haruru Zone Substation

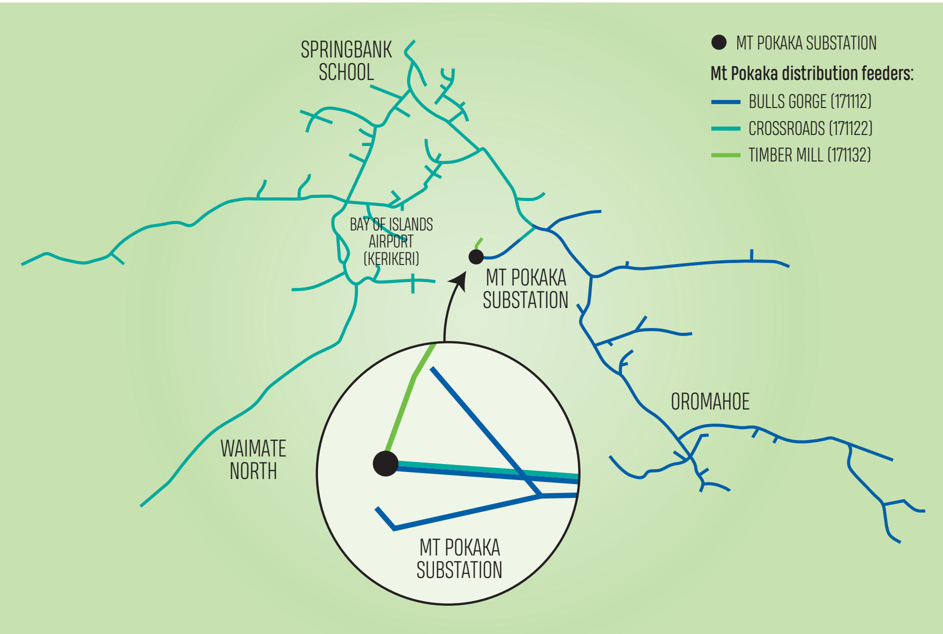

Figure 3-10: Geographic Diagram of the Mt Pokaka Zone Substation

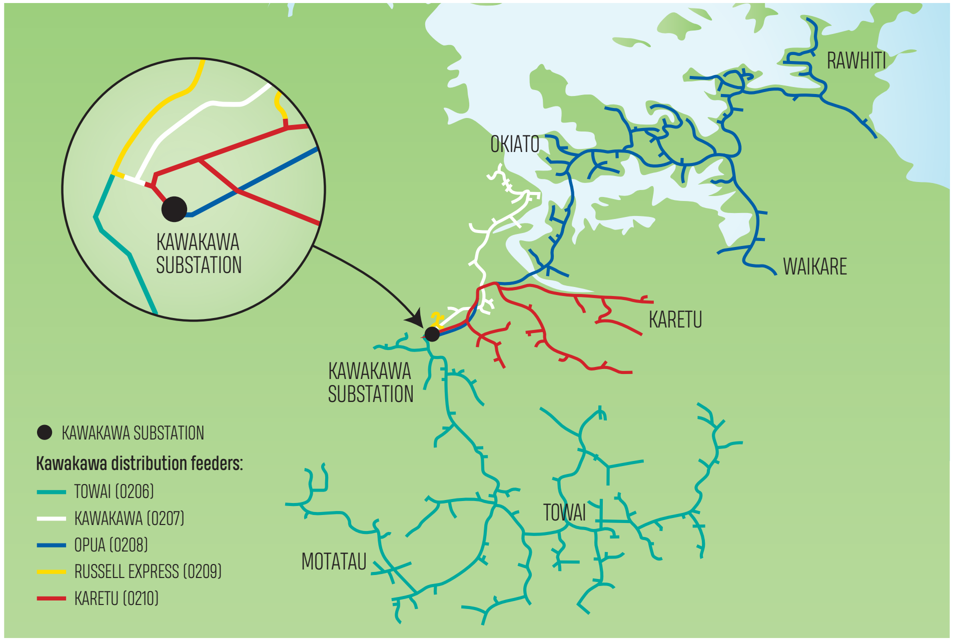

Figure 3-12: Geographic Diagram of the Kawakawa Zone Substation

Figure 3-13: Geographic Diagram of the Omanaia Zone Substation

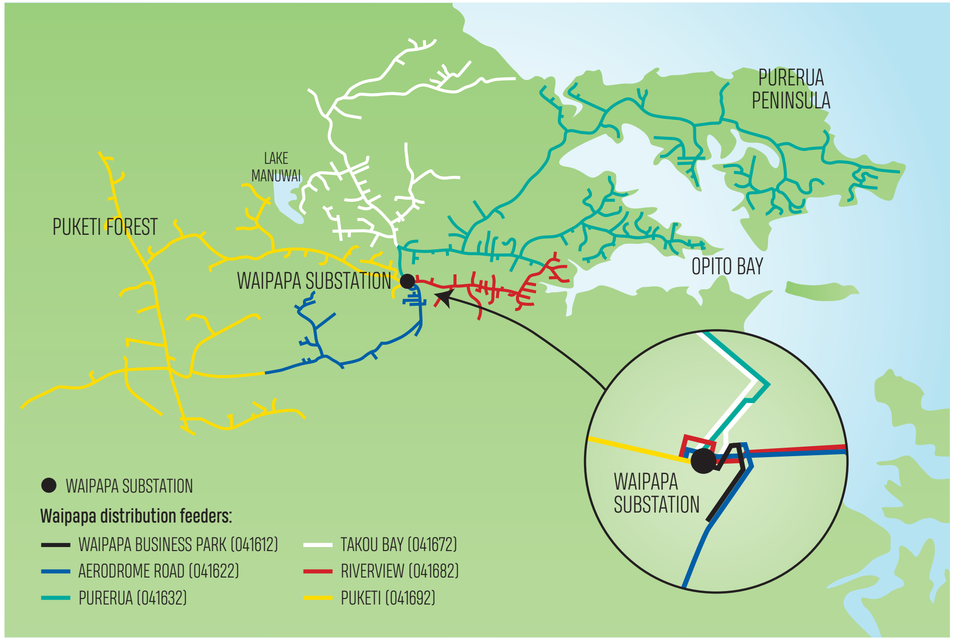

Figure 3-15: Geographic Diagram of the Waipapa Zone Substation

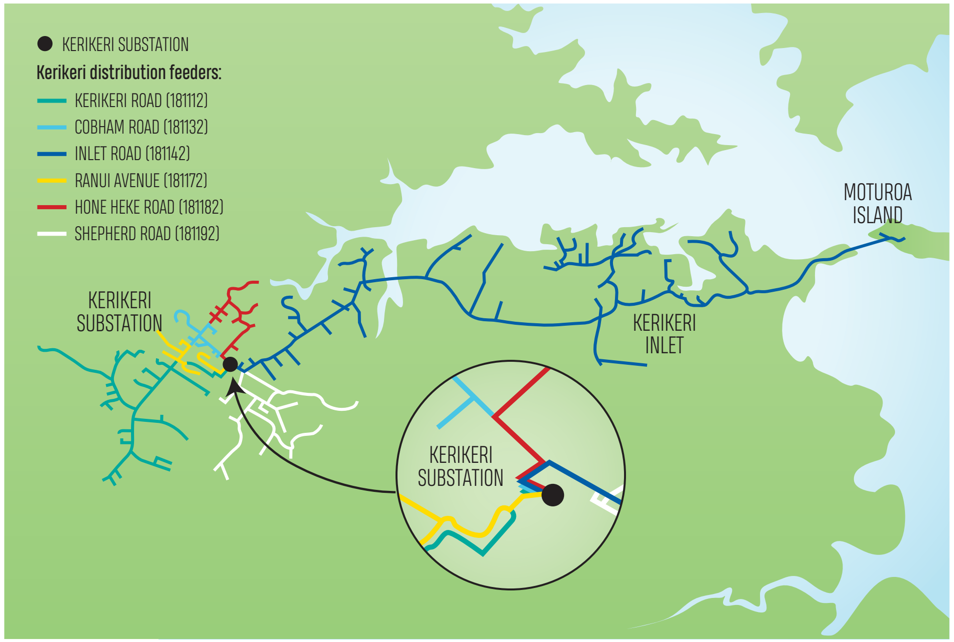

Figure 3-14: Geographic Diagram of the Kerikeri Zone Substation

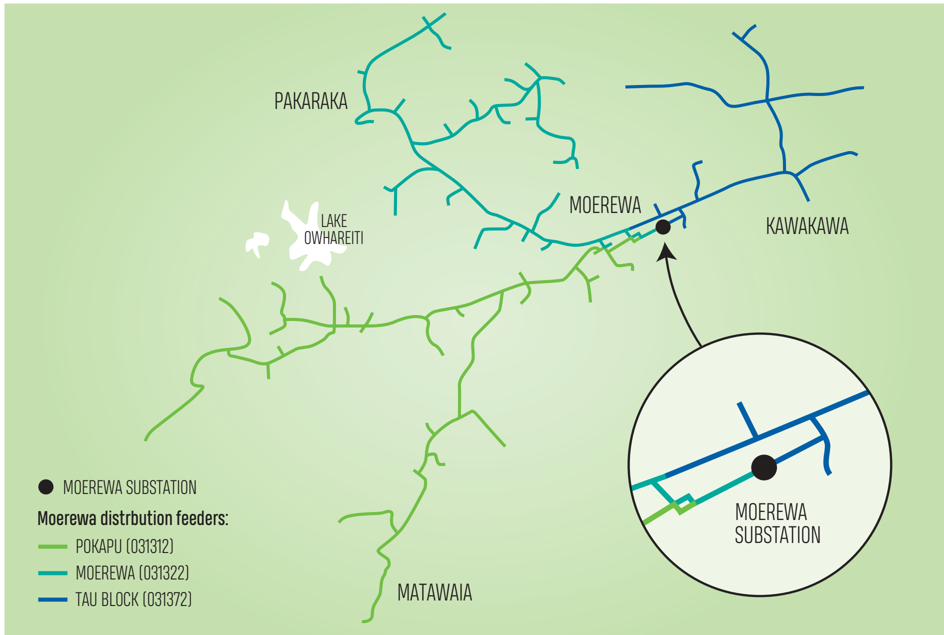

Figure 3-16: Geographic Diagram of the Moerewa Zone Substation

Submarine Cables

Our distribution network includes two 11 kV submarine cables that feed the Russell Peninsula. The first cable is laid across the Waikare Inlet and is a three-core, 70 mm2 copper cable around 1.5 km long and was livened in 1975. It has been through 47 years of its nominal 70-year economic life.

The second cable is across the Veronica Channel between Opua and Okiato Point and is a three-core, 150 mm2 copper cable, livened in 2007.

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

3.1.8 – LOW VOLTAGE

Low voltage can be supplied at 400 V three-phase, 460/230 V two-phase, or 230 V single-phase, although three-phase is not available to consumers supplied from a two-wire 11 kV spur line or a SWER line. For more than 40 years, we have required new developments and subdivisions to be underground. This has resulted in a high percentage of underground distribution at the 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 between transformers at the LV level, except in the Kaikohe, Kaitaia, Kerikeri, Russell, and Paihia urban areas.

3.1.9 – PROTECTION ASSETS

We use a mixture of protective devices, including:

- electromechanical and electronic relays
- numerical relays
- integrated protective devices such as fuses, pole top reclosers and sectionalisers, and
- indoor and outdoor circuit breakers with either local or remote-control functionality.

These devices are used to detect and isolate faults as quickly as possible, maintaining public safety and minimising damage. Protective devices that carry the full load current (including fuses, reclosers, and circuit breakers) are considered primary assets. In contrast, protection relays, which operate based on measured current and voltage values, 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 most electromechanical protection relays in our zone substations and installed fibre-optic cable on most 33 kV subtransmission lines. As a result, these lines now have differential protection, which continuously compares the current entering and leaving a circuit, and is more effective when the fault current is low. This allows subtransmission lines and transformers at a substation to operate in parallel, so that a single subtransmission fault will not result in a supply interruption.

3.1.10 – SCADA AND COMMUNICATIONS

We use a GE PowerOn Advanced Distribution Management System (ADMS) to monitor the state of our network in real time. We allow key network assets to be remotely controlled from our network Control Centre in Kerikeri, including:

- 110 kV, 33 kV and 11 kV substation circuit breakers
- the majority of the distribution network reclosers and sectionalisers, and
- a number of remote-controlled switches located in the field.

This also incorporates an outage management system that combines real-time system state inputs with connectivity data from our GIS to assist in predicting fault locations. The system automatically calculates the SAIDI and SAIFI impacts of supply interruptions. It also generates switching schedules to support Control Centre operators in managing network outages.

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

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

We have also installed a standby Control Centre at the Ngāwhā power station.

The existing analogue radio communications system functionality is fit for purpose. Although not committed, we are currently investigating a digital platform that would provide extra functionality.

3.1.11 – LOAD CONTROL SYSTEM

Our load control system operates by injecting a control signal into 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 into our 33 kV 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 Centre via our SCADA system. The Kaikohe plant was commissioned in 2007 and is rated at 80 kVA, while the Okahu Rd plant (commissioned in 1991) is rated at 30 kVA. The standby Waipapa plant was commissioned in 1981 and is also rated at 30 kVA.

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

3.1.12 – LOAD CHARACTERISTICS AND LARGE USERS

We have five large consumers:

- Juken New Zealand (JNL) Mill near Kaitaia (≈ 7MVA)
- AFFCo Meat Works near Moerewa (≈ 2MVA)
- Mt Pokaka Timber Products Ltd, south of Kerikeri (≈ 1MVA)
- Imerys Tableware near Matauri Bay (≈ 1MVA), and
- Northern Regional Corrections Facility (NRCF) at Ngāwhā (≈ 0.6MVA).

JNL, AFFCo and Mt Pokaka all have dedicated distribution feeders from zone substations located at, or close to, their sites. Imerys Tableware is supplied from its local distribution feeder, while NRCF has a dedicated 11 kV feeder from the Kaikohe zone substation. More than 15% of the energy delivered through our network is supplied to these five largest consumers.

Our other consumers are predominantly residential or rural, with dairy sheds accounting for a significant share of the rural load. There is no predominant urban centre in our supply area, and light commercial and industrial loads are generally concentrated in small towns and settlements dispersed throughout it. We currently supply 14 public electric vehicle fast-charging stations across our network, as shown in Figure 3-17. (Note that some locations shown have two chargers.)

Figure 3-17: Public Electric Vehicle Charging Station Locations

3.1.13 – ECONOMICS OF SUPPLY

Many of our distribution lines were built with subsidies from the Rural Electrical Reticulation Council (RERC). These were provided to assist with post-war growth in farming productivity in remote areas. They also provided an electricity supply to consumers in sparsely populated rural areas that would otherwise have been uneconomic to service. Many of these lines are now at a stage where extensive rebuilding and refurbishment are required. We are obligated under Section 105(2) of the Electricity Industry Act 2010 to continue to supply consumers currently supplied from existing lines, even if this supply is not 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 fewer than three connected low-consumption consumers per km. Low consumption was defined either by :

- the volume of energy delivered per year (less than 6,500 kWh per consumer), or
- the installed distribution transformer capacity (less than 20 kVA 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% of our 11 kV distribution network, by length, is uneconomic under the MBIE cost-of-supply criteria. These lines supply just 9% of our consumers. While this study was undertaken almost 15 years ago, its findings still apply today.

In 2018, we investigated this issue further by developing a cost-to-serve model that examined the costs we incur in supplying consumers across different parts of the network. Our modelling showed that revenue from consumers in the remote segments of our network is sufficient to cover the operating costs of the assets used to provide their supply, but makes only a marginal contribution to the capital costs of these assets. Consumers connected to the lower-cost parts of our network therefore subsidise the capital costs we incur in maintaining supply to them.

[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

TYPE	QUANTITY (NO.)	AVERAGE AGE (YR)	EXPECTED LIFE (YR)
Steel	158	18	60-80
Concrete	36,347	38	60-80
Wood	916	44	35-45
Fiberglass	44	7	15-20
TOTAL	**37,465**	**38**	**–**

Table 3-3: Network Pole and Structure Quantities

3.2.2 – OVERHEAD CONDUCTOR

TYPE	QUANTITY (CCT-KM)	AVERAGE AGE (YR)	EXPECTED LIFE (YR)
110 kV Kaikohe-Kaitaia line	56	43	50-60
110 kV Ngāwhā-Worsnops line	10	6	50-60
33 kV	315	35	50-60
Distribution (excluding SWER)	2,454	42	50-60
SWER	474	51	50-60
LV	272	43	50-60
Subtotal	**3,094**	**43**	**–**

Table 3-4: Network Overhead Conductor Quantities

3.2.3 – UNDERGROUND CABLE

TYPE	QUANTITY (CCT-KM)	AVERAGE AGE (YR)	EXPECTED LIFE (YR)
33 kV	27	9	55
Distribution	287	18	45-70
LV (excluding streetlight)	800	29	45-55
Streetlight	342	33	45-55
TOTAL	**1,456**	**27**	**–**

Table 3-5: Network Underground Cable Quantities

3.2.4 – OTHER ASSETS

TYPE	QUANTITY (CCT-KM)	AVERAGE AGE (YR)	EXPECTED LIFE (YR)
Pole-mounted distribution transformers	5,255	26	45
Ground-mounted distribution transformers	955	20	45
Voltage regulators	14	8	45-55
Zone substation buildings	25	32	50+
Power transformers	32	30	45
Outdoor 110 kV circuit breakers	9	21	40
Indoor 33 kV circuit breakers	59	10	60
Outdoor 33 kV circuit breakers	48	20	40
11 kV circuit breakers	107	30	45-60
33 kV switches – pole mount	175	23	35
33 kV switches – ground mount	3	1	45-60
Outdoor distribution switches/links	6,208	21	35

TYPE	QUANTITY (CCT-KM)	AVERAGE AGE (YR)	EXPECTED LIFE (YR)
Sectionalisers/reclosers	322	14	40
Ring main units	*228	12	40
Underground service fuse boxes	12,772	28	45
Protection relays	472	11	20-40
Capacitor Banks	21	38	40

Table 3 6: Other Network Asset Quantities

[3.3] Regulated Asset Value

In accordance with the Commerce Commission's information disclosure requirements, Top Energy disclosed that its regulated asset base was valued at $378 million as of 31 March 2025, an increase from $362 million in 31 March 2024. This total was derived as shown in Table 3-7 and reflects the value of assets commissioned in FY 2025 as part of our network development programme.

	$000
Asset Value at 31 March 2024	**362,368**
Add: – New assets commissioned – Indexed inflation adjustment – Asset allocation adjustment	 20,556 9,128 -19
Less: – Depreciation – Asset disposals	 13,359 30
Asset value at 31 March 2025	**378,644**

Table 3-7: Value of System Fixed Assets

The asset value shown in Table 3-7 is the value of our regulatory asset base, as measured 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 under IFRS. Secondly, the regulatory asset base includes assets, such as the land and buildings (e.g., substation control buildings), that form an integral part of the network, but are recorded under other asset categories in the financial accounts. Neither value includes works under construction that have not yet been commissioned.

Table 3-8 breaks down the value of system fixed assets shown in Table 3-7 into its main asset categories.

	$000
Transmission and subtransmission lines	74,662
Subtransmission cables	10,536
Zone substations	44,758
Distribution and low voltage lines	114,382
Distribution and low voltage cables	44,760
Distribution substations and transformers	39,125
Distribution switchgear	40,208
Other network assets	5,837
Non-network assets	4,377
Total	378,644

Table 3-8: Disaggregated Value of System Fixed Assets as of 31 March 2025


0800 TOP ENERGY
HINO

LEVEL OF SERVICE

SECTION 4
LEVEL OF SERVICE

At Top Energy, our approach to Levels of Service is grounded in a commitment to delivering a safe electricity supply across our network. We set clear targets for both unplanned and planned interruptions and track our network reliability and asset performance.

Our approach to customer connections is designed to be transparent and responsive, providing clear communication at every step and striving to meet agreed timeframes. **Our robust customer engagement practices** complement these levels of services.

- We regularly consult with consumers to understand their evolving needs and expectations.
- We monitor satisfaction through targeted surveys and direct feedback.
- We consistently review our complaints processes to ensure timely and effective resolution.

[4.1] Introduction

Our network reliability outcomes are, in part, a consequence of our fringe location at the end of the grid, where we remain reliant on a single dual 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. Another disadvantage has been our highly dispersed population, spread over a large supply area with no dominant urban centre. Other networks with electrically secure, highly populated areas and close to Transpower's grid exit points have the advantage of balancing their more vulnerable rural areas with a proportional percentage of their total customer count.

Furthermore, our grid connection at Kaikohe and the 110 kV subtransmission line route over the Maungataniwha range are no longer optimally located to serve our present load. They were constructed during an era when Kaikohe and Kaitaia were the hub of both economic and population growth within our supply area. Over the last 30 years, growth in both towns has declined, while significant growth has occurred in Kerikeri, the Bay of Islands, and the eastern coastal peninsulas. In recent years, Kerikeri and its surrounds have been among the fastest-growing population centres in the country and are now the dominant load centre in our supply area.

A major driver for the TE 2020 network development plan we have implemented since FY 2010 has been to augment our subtransmisison network to provide the capacity required to accommodate this demographic shift. This capacity augmentation will be completed with the commissioning of a new 110/33 kV substation at Wiroa. Construction of this substation, which will provide sufficient subtransmission capacity to supply the expected consumer demand in the Kerikeri area beyond 2050. Initial enabling works are scheduled to commence 2026, with the first zone transformer scheduled to be installed circa 2028 and full site completion scheduled for 2035.

At the same time, we have improved the reliability and resilience of our subtransmission network by:

- installing backup generation
- upgrading protection to allow the 33 kV subtransmission circuits to operate in parallel, and
- refurbishing those 33 kV subtransmission lines without parallel circuits.

These investments have reduced the unplanned SAIDI impact of our subtransmission system from a typical 150 minutes to around 25 minutes. Realistically, there is little scope for further improving the reliability of the subtransmission network and, going forward, investments targeting network reliability will focus on the 11 kV distribution network.

[4.2] Consumer-Oriented Service Levels

4.2.1 – UNPLANNED INTERRUPTIONS

The service level targets included in this AMP are limited to the normalised SAIDI and SAIFI measures used by the Commerce Commission to monitor the reliability of our network under its price-quality regime. These are:

- Unplanned System Average Interruption Duration Index (SAIDI): This is the accumulated total time that the average consumer is without supply on the network in any measurement year, due to faults originating within the network. The units are minutes.
- Unplanned System Average Interruption Frequency Index (SAIFI): This is the total number of supply interruptions that the average consumer connected to our network will experience in a measurement year, due to network faults. The units are outages per consumer per year. While an individual consumer can experience only a whole number of outages, the target is set to a real number to account for averaging.

The Commission uses internationally accepted measures because they are considered effective indicators of how well an EDB provides a reliable electricity supply to consumers. For internal management measurements and target setting, we use the normalising approach adopted by the Commerce Commission. This approach is used to assess the reliability of supply provided by all the EDBs it regulates under the default price-quality path regime. Normalisation of the raw performance measures is designed to limit the impact of events outside our reasonable control on the network reliability measure. We believe using normalised measures to set targets gives a better indication of the success of our asset management strategies.

In the normalisation process, any rolling 24-hour period in which the aggregate unplanned network SAIDI or SAIFI from all supply interruptions that commence during the period exceeds a predetermined boundary value is categorised as a SAIDI or SAIFI major event. The SAIDI or SAIFI impact of all interruptions during a major event is normalised back to 1/48 of the boundary value (unless the SAIDI or SAIFI impact of the individual interruption is lower than this).[2] The normalisation process is designed so that the aggregate normalised SAIDI or SAIFI over any rolling 24-hour period cannot exceed the boundary value. Furthermore, SAIDI and SAIFI are normalised independently so that you can have a SAIDI major event without a corresponding SAIFI event and vice versa.

Note 2: Periods are rolled forward in half hourly increments starting on the hour and half-hour. Interruptions that occur within the same half-hour period are aggregated and treated as a single interruption for normalisation purposes.

The normalisation process can significantly impact reported reliability in years with poor reliability due to the number of abnormally severe storms. For example, in FY 2023, our raw Unplanned SAIDI was 1,791 minutes, primarily due to the major weather event Cyclone Gabrielle. Normalisation reduced this to 514 minutes. Under its price-quality regime, the Commission sets a normalised SAIDI and SAIFI threshold for each regulated EDB. These reflect the historical average normalised SAIDI over the 10 years FY 2014 to 2024, but also include a margin to provide for volatility. Should we breach a threshold in any year, the Commission will investigate our management of the network and has the power to impose a civil penalty. Table 4-1 shows our normalised SAIDI and SAIFI thresholds and boundary values.

	THRESHOLD	BOUNDARY VALUES
SAIDI	399	26.78
SAIFI	4.82	0.1689

Table 4-1: Current Unplanned Interruption Reliability Limits and Boundary Values

The indicators measure only interruptions that originate within our network. Interruptions that originate outside the network, such as an automatic under-frequency load shedding event or loss of the grid connection from Transpower's Network, are not included. Interruptions lasting less than one minute are also excluded, irrespective of cause. These interruptions are generally caused by:

- a transient event, such as a lightning strike or debris brushing a line, and
- an automatic system reclosure restores supply without the need for operator intervention.

Our internal unplanned SAIDI and SAIFI targets for each year of the planning period are shown in Table 4 2 and graphically in Figure 4 1 and Figure 4 2. These graphs also compare the targets with the historical reliability[3] . The basis for setting these targets is described in Section 4.4.

FY	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Unplanned SAIDI Target	289	286	278	273	268	258	248	241	232	228
Unplanned SAIFI Target	4.08	4.08	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07

Table 4-2: Consumer Service Level Targets (normalised)

Note 3: The Commission's current normalisation methodology came into effect in DPP3. In Figure 5-1 and Figure 5-2 the normalised outcomes shown for the years prior to FY 2021 have been reverse engineered by applying the current normalisation methodology to the raw interruption data.

NORMALISED UNPLANNED SAIDI GLIDE PATH

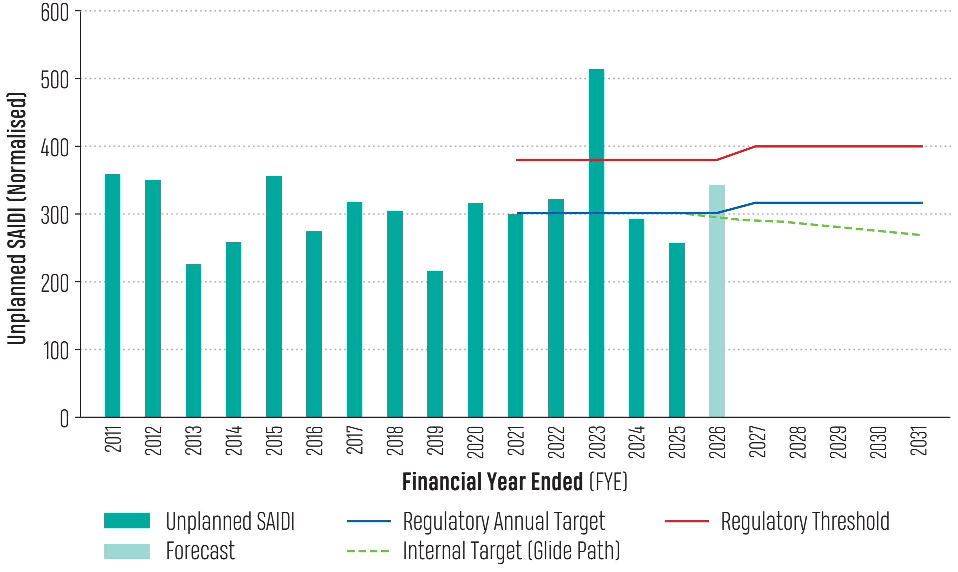

Figure 4-1: Historical and Target Normalised Unplanned SAIDI

NORMALISED UNPLANNED SAIFI

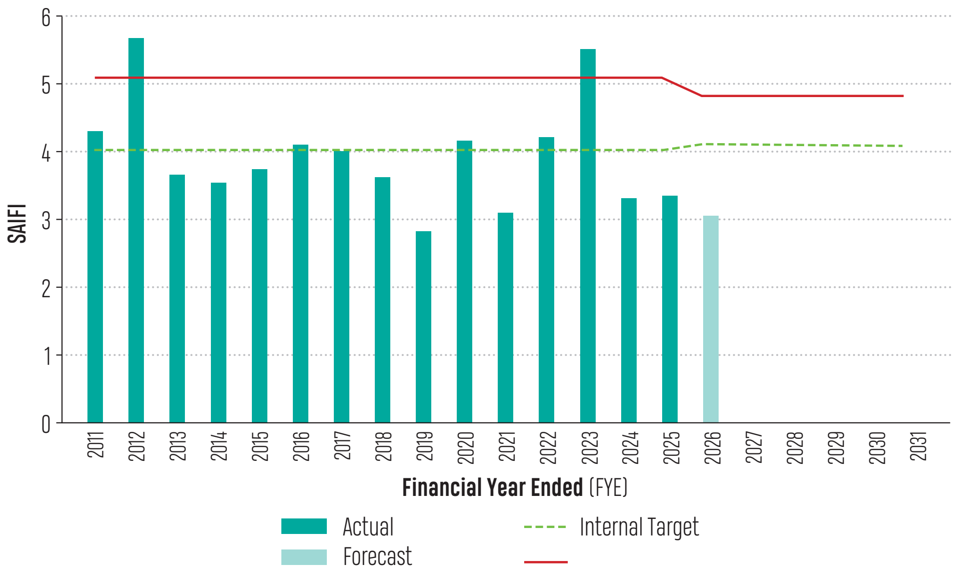

Figure 4-2 Historical and Target Normalised Unplanned SAIFI

We note the points below regarding these targets.

- Our internal targets are based on modelled SAIDI improvements, assuming corresponding network improvements are implemented as described in sections 5.6.2, reflecting our continued focus on the reliability of the 11 kV network
- There is no provision for the normalisation of planned SAIFI.

4.2.2 – PLANNED INTERRUPTIONS

While planned interruptions are disruptive to consumers, they are less disruptive than unplanned interruptions because consumers receive advance notice of the outage and can plan for it. They can also be resourced to deliver maximised return on work done while the lines are out of service. With generation installed at Kaitaia, Omanaia, Pukenui and Taipa, planned interruptions should now normally only be required for work on the 11 kV distribution network[4].

For DPP4, the Commission has not set an annual limit for the impact of planned interruptions but has set aggregated planned SAIDI and SAIFI limits for the whole regulatory period. As compliance will only be assessed at the end of the period, EDBs are free to use up this allowance at any time over the period. Our limit is 1727.59 SAIDI minutes and 8.5279 SAIFI interruptions, calculated by the Commerce Commission using its methodology and our annual planned SAIDI and SAIFI over the FY 2015-24 period.

For internal management purposes, we have set an annual planned SAIDI target equal to the Commerce Commission's SAIDI planned interruption target for the FY 2025-30 period[5]. In line with the target in the 2021 AMP and the 2022 AMP Update, we have doubled the internal planned SAIFI to 1.2 interruptions per year to better reflect our actual performance over the FY 2020-24 period. Given the buffer allowed by the Commission, this does not imply a material increase in the risk of breaching the threshold. Given that planned interruptions on our subtransmission network are now less likely, these targets will allow us to increase maintenance on the 11 kV. These targets are shown in Table 4-3. Assuming the SAIDI target is met exactly, the aggregate SAIDI impact of planned interruptions over the DPP4 regulatory period will be 863.8 minutes, half of the 1727.59 minutes set by the Commission. The aggregate SAIFI impact will be 6 interruptions over the regulatory period. Which is 70% of the regulatory threshold.

FY	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Planned SAIDI	172.76	172.76	172.76	172.76	172.76	172.76	172.76	172.76	172.76	172.76
Planned SAIFI	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2

Table 4-3: Targets for the Impact of Planned Interruptions

Note 4: The one exception to this is the Juken New Zealand mill. Generation was not installed at Kaitaia to supply the mill operations during an outage of the 110 kV Kaikohe-Kaitaia line. An arrangement is in place with the customer to ensure the mill operations are shut down during a planned interruption of this line.

Note 5: These are rounded values. The reliability incentive scheme has a planned SAIDI component with a target SAIDI of 172.76. This is the neutral level, for which no reward or payment will apply.

[4.3] Asset Performance and Efficiency Targets

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

The loss ratio and the ratio of operational expenditure to total regulatory income are based on performance indicators. They show how effectively we manage network assets for the benefit of electricity consumers in our supply area.

4.3.1 – LOSS RATIO

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

Energy losses are measured as the difference between the energy flowing into the network and the energy sold out. They include both:

- technical losses, due to the loss of energy flowing through the physical network, and
- non-technical losses, due to factors such as incorrect metering installations, meter errors and power theft.

In our case, the relatively poor loss ratio is primarily driven by technical losses. These arise from the high network loading and rural nature of the network. Large distances between connected customers mean multiple distribution transformers are required to supply individual or small groups of customers along an extended length of line. In urban areas, the ratio of customers to transformers is much higher, resulting in lower electrical losses and greater efficiency.

Over time, distribution losses should decrease incrementally as we continue our investment in network development, such as:

- creating new 11 kV feeders
- constructing new substations
- replacing zone transformers, and
- upgrading conductors.

Nevertheless, there is a limit to how much loss can be mitigated. A large proportion of losses occur on the low voltage network and cannot be easily reduced.

We can expect losses to reduce once the 110/33 kV Wiroa substation is commissioned, and to reduce further when the 110 kV Wiroa-Kaitaia line is constructed in approximately FY 2031. 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.

Network losses are recalculated after significant network changes, additions, or reconfigurations. With the Twin Rivers Solar Farm yet to be fully commissioned, we anticipate another fluctuation in the losses. It was recently identified that testing and commissioning by the Solar Farms significantly affect our Unaccounted for Energy (UFE) values. Generally, if our UFE value is at 1%, we do not recalculate the loss factor values. Therefore, we believe it would be premature to adjust our loss factor targets until we have a better understanding of the impact of this new generation.

In FY 2027 we will engage an external consultant to complete a study on our loss factors methodology, our current loss ratio results and recommendations for further improvement.

FY	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Loss Ratio	10.5%	10.5%	10.5%	10.2%	10.2%	10.2%	10.2%	10.2%	10.2%	10.2%

Table 4-4: Target Loss Ratios

LOSS RATIOS OF TOP ENERGY SINCE FINANCIAL YEAR 2011

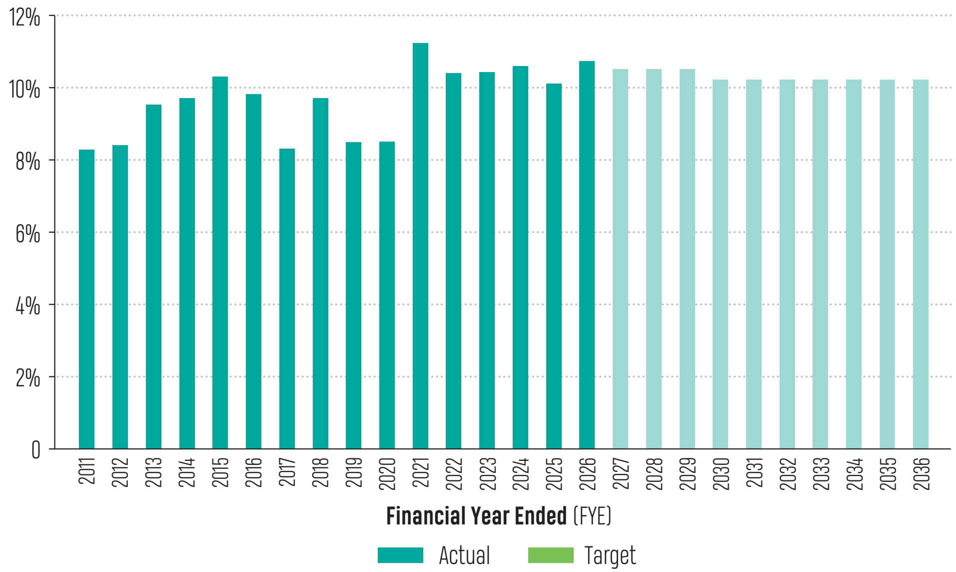

Figure 4-3: Loss Ratios of Top Energy since FY 2005

4.3.2 – COST PERFORMANCE

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 alternatives, such as the ratio of operational expenditure to circuit length, as 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. 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. This measure reflects the portion of revenue from the provision of distribution line services 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 capital expenditure metrics are not good indicators of asset management efficiency at a time when we are implementing an extensive network development programme, given the potential year-to-year variability of capital expenditure.

Table 4-5 shows our targets for the ratio of total operational expenditure to total regulatory income.

FY	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Ratio	56.1%	54.3%	53.1%	52.0%	51.3%	49.8%	49.2%	47.6%	47.1%	48.0%

Table 4-5: 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 FY 2011 is apparent as we implemented our vegetation management and reliability improvement programme. Operational expenditure has now reverted to more normal and sustainable levels, as reflected in the forward targets.

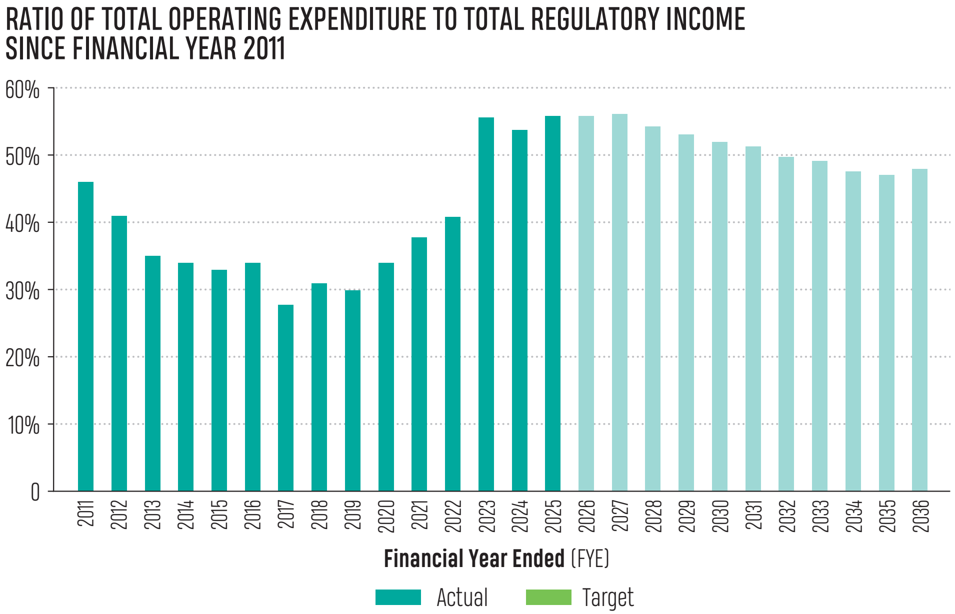

Figure 4-4: Ratio of Total Operating Expenditure to Total Regulatory Income Since FY 2008

[4.4] Justification for Service Level Targets

4.4.1 – SUPPLY RELIABILITY TARGETS

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

4.4.2 – UNPLANNED SAIDI AND SAIFI

The Commerce Commission sets standardized regulatory limits for Top Energy's SAIDI and SAIFI under DPP4 using a consistent methodology applied across all electricity distribution businesses (EDBs). These limits are based on 10 years of historical SAIDI data, calculated as the mean plus two standard deviations, with a 5% annual cap on increases for unplanned SAIDI targets. While this establishes the regulatory framework, Top Energy has adopted a more ambitious internal target—our SAIDI glide path—reflecting a commitment to enhanced reliability and service quality. The SAIDI and SAIFI targets over the planning period can be found in Figure 4-1 and Figure 4-2.

The SAIDI glide path was developed using historic feeder-level SAIDI data as a baseline, then applying modelled improvements from initiatives such as reclosers, sectionalisers, backfeeding, and group fusing, along with associated costs. Projects were ranked by cost-effectiveness (SAIDI minutes saved per dollar) and scheduled accordingly. To smooth annual variability, improvements were projected over a ten-year period, creating a progressive glide path that averages year-to-year fluctuations while delivering cumulative reliability gains.

The forecasted raw unplanned SAIDI and SAIFI figures published in our Information Disclosure S12D show slight variation to last year's projections. This change is primarily due to incorporating an additional year of historical data and applying an updated modelling approach that reflects anticipated reliability improvements from planned network projects.

For Unplanned SAIDI, we calculated the five-year average of raw data, excluding 2023 (an outlier due to Cyclone Gabrielle) and removing Major Events. For Unplanned SAIFI, we applied a similar approach, using the five-year average excluding outliers and Major Events, with the current year based on internal reporting. These refinements ensure our forecasts are more accurate and aligned with current investment strategies and reliability initiatives.

4.4.3 – PLANNED INTERRUPTIONS

We have set our targets for planned interruptions based on our average historic performance. As we no longer work on live assets, we rely on planned interruptions to maintain our 11 kV network assets. Therefore, we do not think targets that severely limit our ability to arrange planned interruptions are in the long-term interest of our consumers. This has been recognised by the Commission and reflected in their planned outage SAIDI settings.

There is no provision for de-weighting in the assessment of planned SAIFI, and we have therefore increased the planned SAIFI target from 1.0 to 1.2 to better reflect our planned SAIFI outcomes in the DPP4 assessment period.

4.4.4 – LOSS RATIO

Our loss ratio targets reflect the network's performance and include losses on the 110 kV subtransmission system. The commissioning of the 110 kV line to Kaitaia and construction of the 110 kV Substation at Wiroa is expected to result in a material improvement in the loss ratio. Construction of the new 110 kV line is programmed to commence in FY 2029 and continue through FY 2031, while the Wiroa substation project is already underway.

4.4.5 – RATIO OF TOTAL OPERATIONAL EXPENDITURE TO TOTAL REGULATORY INCOME

The ratio of total operational expenditure to total regulatory income in FYE 2025 was 55.9% compared to a target of 59.3%, with operational expenditure being 3.8% lower.

Over the past five years, three have been at or below target levels and the two that were higher were primarily driven by higher network maintenance (one including the Gabrielle year). Over this period, the actual ratio has increased from 39.0% to 55.9%. with a 46.4% growth in operational expenditure. Significant inflationary pressures occurred over this time driving a 39.4% increase in Network opex.

The ratio increase has been further impacted by revenue only increasing by 2.1% as there has been a focused effort on minimising the price impact on consumers.

The AMP target is expected to increase as we continue to minimise price impacts on consumers over the next regulatory period. A target ratio of 60% is reasonable at this stage, but we expect that this will require further adjustment as we refine our pricing strategies.

[4.5] Customer Service Management

We operate a centralised customer service line via our 0800 number. Our call centre team facilitates a seamless handover to the appropriate contact within Top Energy to ensure the timely and effective resolution of customer enquiries. We maintain an internal Key Performance Indicator (KPI) requiring that 80% of calls be responded to within two working days – a target consistently met.

In alignment with the Utilities Disputes Limited (UDL) definition of a complaint, where a customer expresses dissatisfaction, complaints are escalated to our dedicated Complaints Resolution Specialist. All complaints are actively monitored and managed through our Customer Relationship Management (CRM) system to ensure accountability and resolution.

Customers can also provide feedback or submit an enquiry via the online feedback form on our website.

4.5.1 – CUSTOMER COMPLAINTS

When a customer expresses dissatisfaction or concern about the services or goods provided by Top Energy, this is treated as a complaint.

If at any time a customer has a complaint, we must advise the Executive Assistant (EA) of the complaint immediately with as much information as possible, including:

- date of complaint
- ICP number (if possible)
- street address
- contact number/s
- customer/invoice number (if relevant)
- details of the complaint, and
- desired outcome if requested.

We advise the customer that, if for any reason we can't agree on a solution, they can contact Utilities Disputes on 0800 22 33 40, a free service that resolves complaints about utilities providers. The EA then acknowledges the complaint with the customer by phone or email (depending on their initial contact) and ensures a complaint case is raised in Salesforce.

The EA then investigates the complaint and attempts to resolve it with the customer within 20 working days (in accordance with UDL guidelines).

If no resolution is reached within 20 working days and further investigation is required, we advise the customer that an extension of 20 working days is needed.

If no resolution can be reached, the customer is reminded of their right to contact Utilities Disputes. All correspondence, including call records, is recorded in the Salesforce case.

4.5.2 – OUTAGE NOTIFICATION

Planned Outages

Planned outages on the LV, HV or Subtransmission Networks are scheduled in advance and are created in the Advanced Distribution Management System (ADMS) by our network controllers. These outages are published:

- to Top Energy's outage centre server, which displays outages on a map on our website: https://outages.topenergy.co.nz, and
- the Top Energy Outage App, which can be downloaded from the Google Play or Apple App Store if customers elect to do so.

Where we already hold sufficient consumer contact information, we push outage information directly via email or SMS, with an opt-out option for consumers who wish.

This map draws polygons around the affected outage, and users can click on these for additional information. From the Outage Centre website, customers can also elect to receive outage updates via text and/or email by subscribing using their address or ICP number.

Our outage centre also sends planned outage information via email using the EIEP5A protocol directly to customers' electricity retailers.

We use multiple communication channels to ensure customers are informed of planned outages in advance. For all planned outages, we:

- send an email to each account holder detailing the outage date and time, along with a link to our online outage map. Customers may also opt in to receive SMS notifications, and
- publish outage information on our outage map at least 10 days prior to the scheduled interruption.

For planned outages affecting a large number of customers, we additionally:

- place notices in local newspapers and advertise across digital platforms and radio stations, and
- may install electronic signage in affected areas to provide visual reminders of upcoming outages.

In cases where planned outages are scheduled at short notice or affect only a small number of customers in defined areas, we may also distribute notification cards directly to the letterboxes of impacted households.

We aim to complete 80% of our shutdowns within the advertised timeframes.

Unplanned Outages

Top Energy's network controllers manage all unplanned outages in our control centre via ADMS. Once a fault is confirmed, it is raised in ADMS. The outage is raised and published on Top Energy's outage centre website, under the active outages tab at https://outages.topenergy.co.nz.

In the event of an unplanned outage, we send an SMS to the account holder to notify them of the fault. This message includes a link to our outage map and details about the fault's cause. A follow-up SMS is sent once the fault has been resolved.

If a user has subscribed with their address or ICP, they will be notified of outages affecting their registered location. Top Energy is constantly looking for ways to improve its communication with customers, and any upgrades to web services and Apps are automatically pushed across the different platforms.

4.5.3 – CONNECTIONS

Processes

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

- standard and complex residential connections
- commercial and Industrial connections
- subdivisions
- changes and upgrades, and
- distributed generation.

Top Energy's website provides customers with clear guidance and access to the necessary application forms for requesting new electricity connections or alterations. These requests are managed by our dedicated Customer Initiated Works team, which comprises administrators and network estimators who maintain direct contact with customers to support and progress their applications.

All customer interactions, including applications, call centre enquiries, and online submissions, are systematically captured and managed within our Customer Relationship Management (CRM) system. This ensures a consistent service delivery and effective follow-up.

New Connections

Top Energy has comprehensive processes for connecting new offtake and injection customers to its network. Below is an outline of the process.

- The customer completes the application and pays the application fee. A quote, or proposal for complex connections, will be provided within 10 working days upon receipt of the fee.
- For a simple connection, once the quote is accepted and paid, an ICP number will be provided. Once the service is ready to connect to the Top Energy Network, we will connect the service within 10 working days.
- For complex connections where a design is required, timeframes will be provided to the customer for both the design and construction start date estimates.
- Once installation is complete, the customer calls an Electricity Retailer to request a new connection. This retailer will send a request to Top Energy to install a meter.

Refer to the Top Energy website for customer information that supports this process: Top Energy- Residential connection- New Connection Guide

Salesforce is used as a software tool for managing the connection from application to completion.

Top Energy identifies issues through bimonthly feedback and annual surveys, which feed into a programme of work on customer experience. This programme builds our three-year plan and work initiatives to ensure those issues are addressed.

Standard connections are priced on a fixed fee schedule. Where a customer connects to an existing asset that needs upgrading, the customer pays a capacity charge towards the cost of the work based on the capacity requested. Any capital contribution extension, upgrade or alteration to the network not covered by the capacity charge fees is priced to the customer at cost.

If a customer pays a capital contribution to extend, upgrade or alter the network, they may be eligible for a pro rata. This applies when another customer connects to that customer-funded work. We use standardised equipment and look for the most cost-effective designs for complex connections.

Standardisation helps keep the costs lower and consistent across consumers.

All communication to and from a customer is recorded in Salesforce, which is monitored to ensure timely responses. Further enhancements to Salesforce and customer communication protocols are ongoing.

Alterations of Existing Connections

The alterations process aligns with the new connection process, where the customer must complete the same application and fee.

Salesforce is used as a software tool to manage the connection from application through to completion, including any alterations to the connection.

Common Issues Encountered with Customer Connections Work

Global shipping delays for materials, adverse weather, and availability of contracting resources all contribute to delays in connection projects.

4.5.4 – INFORMATION ON CURRENT AND FORECAST CONSTRAINTS

Top Energy advertises its known network congestions/constraints on its website. This document is reviewed annually. Top Energy also publishes a Generation Congestion Management Policy, available on its website. This policy aligns with the Electricity Authority’s statutory objective, which is to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

Information about constraints is shared and discussed with connecting customers on request, as appropriate to the connection request.

NETWORK DEVELOPMENT PLANNING

SECTION 5

NETWORK DEVELOPMENT PLANNING

This section of the AMP considers the processes used by Top Energy to develop the network to ensure that levels of service will be delivered cost-effectively into the future. It covers:

- The criteria and other factors we consider when making decisions
- Demand forecasts and associated assumptions and uncertainties
- Network-level development options and decisions
- The network development programme and associated financial projections
- A summary of our policies on embedded generation and non-network solutions
- We consistently review our complaints processes to ensure timely and effective resolution.

[5.1] Planning Criteria

Planning criteria are the factors considered when identifying and assessing network constraints and making decisions about required actions to resolve constraints.

5.1.1 – RELIABILITY CRITERIA

Our network reliability philosophy is to provide an electrical distribution network that supports the Far North's potential for sustainability, growth, and development. We aim to achieve this within a safe, efficient, affordable, and cost-effective framework that meets or exceeds the community's aspirations. The strategy to achieve this is based on:

- effective planning
- continuously refining management and reporting systems, and
- delivery processes to validate network reliability investment decisions. These decisions aim to maximise the performance of asset renewals, inspections, remediations and investment in technologies and equipment designed to maximise distribution network performance and reliability.

In the AMP, we set internal targets for both planned and unplanned interruptions for each year of the planning period. These targets reflected an expected improvement in our reliability of supply due to our investment over the last decade in improvements in the resilience of our subtransmission network. We have met our reliability improvement goals for the subtransmission network. The reliability of the 11 kV distribution network had deteriorated over the several years, in part due to climate change. We have done work to analyse the modes of failure on our 11 kV assets, and the parts of the network most affected by supply disruptions, which has provided a platform for identifying initiatives to improve the reliability of the 11 kV network, especially in areas with higher rates of supply interruptions.

The initiatives include;

- Targeted asset replacement programmes to renew aged or poor-condition equipment in areas of the network with fault-prone assets.
- An increase in vegetation control spending, coupled with a revised vegetation management strategy, that aims to improve our effectiveness in targeting high-consequence tree risk.
- Trailing and installation of fault detection equipment stationed at key points along problem lines help pinpoint the locations of line faults during unplanned outages.
- The installation of more line protection equipment that automatically isolates sections of faulted lines from other parts of the network reduces the number of customers experiencing outages from localised fault events.
- We have also invested heavily in interconnection work on vulnerable parts of the network to provide alternative supply options to areas of lines that previously had only a single point of supply. This means that in these areas, damaged sections of the line can be isolated to allow access for repairs. In contrast, downstream areas can be restored using alternative lines, minimising outage time for many customers. Three interconnection projects were completed in FY 2025, with two further projects due for completion in FY 2026.
- In support of the objective of continuous performance improvement, we are currently implementing an updated vegetation management strategy. The objective of this strategy is to ensure continuous improvement in the safety, reliability, and efficiency of the electricity distribution network by effectively managing vegetation growth and associated risks, and by effectively using budgets and resources.

Progress against these initiative can be found in further detail in section 9.1.1.

The strategy applies to all assets operated within the Top Energy electricity distribution network, including overhead lines, substations, and other infrastructure. It identifies key areas where we can further enhance our vegetation management efforts and associated spending. These areas include improved data capture and reporting to classify likelihoods and the potential consequences of specific sites exposed to vegetation. This information will help us create a priority matrix for the annual vegetation management work plans.

The strategy will focus on managing vegetation growth in areas where it poses a significant risk to the public, employees, contractors and the network. Priority will be given to locations with high exposure, such as near densely populated areas, areas susceptible to fire, lower socio-economic areas, schools, childcare centres, and play areas. Vegetation in these areas can:

- present a threat to allow the unintended release of energy into the public domain, or
- be used as a climbing aid to live parts and assets, or
- threaten damage or disruption to the electricity network.

Fundamental to implementing the strategy is improving vegetation management reporting systems to enhance data inputs for the annual remediation and cutting plans.

Figure 4-1 shows a consistency in network performance, except for in FY 2023, when a series of weather events hit the Far North throughout the year, including three named ex-tropical cyclones, the most notable being Cyclone Gabrielle. There has also been a drop in the average customer count since 2023. Investment in fault isolation equipment is a factor in this trend. Our SAIDI results demonstrate a steady trend since 2023, however, the full effect of targeted reliability efforts and pending trends will develop over a longer period. The forecast for FY 2026 indicates a possible increase in SAIDI as a result of vulnerable parts of the network being affected by consistent wind and rain events through the year. During the winter months, we expect that the combined effect of the initiatives outlined above, along with proposed investments in process improvements and field asset investments, will drive improvement trends in network performance. These improvements should continue as we progress through the current regulatory period.

We have also adjusted our AMP reliability targets to better reflect the expected reliability of our network under average weather conditions over the course of a year. The new unplanned SAIDI/SAIFI targets are based on the average annual performance of our network over the 10-year historical reference period used by the Commission to set the thresholds for the current Default Price-Quality Path (DPP4). This is consistent with the Commission's approach, which sets the thresholds on the basis that there should be no material deterioration over time in the reliability of the supply we provide our consumers.

5.1.2 – VOLTAGE CRITERIA

We use the following design voltage limits:

- 33 kV subtransmission +3% to-12% of nominal voltage. (zone sub transformer tap changer limits of +4.5% to-16.5%)
- 11 kV distribution: +2% to-5% of nominal voltage, and
- LV network: +5% to-5% of nominal voltage up to the legal point of supply.

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

The following benefits from improved voltage levels or voltage control justify our voltage compliance-related projects:

- 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 capacity issue in the network. It is therefore the most common driver for augmentation projects on our 11 kV and LV networks.

Recent amendments to the Electricity (Safety) Regulations 2010 have expanded the voltage range at the point of supply on low voltage networks from ±6% to ±10%. This change, which occurred in the third quarter of 2025, will, in theory, increase the hosting capacity of distribution networks for Distributed Energy Resources (DER). Increased voltage limits will allow better management of voltage fluctuations, particularly rises caused by solar export during peak generation times.

Voltage Quality and Constraints

We monitor the voltage quality of our low voltage network through the use of the Hiko LV monitoring system, which uses smart meter data to identify voltage fluctuations and compliance to the allowable voltage limits. Identified quality issues are then issued for investigation and rectification through our corrective maintenance teams.

We may also receive quality complaints directly from customers which are managed through our customer initiated works workstream, which is monitored through Salesforce, including our customer communications. These quality complaints are then investigated, the appropriate corrective actions are then taken to address this. If an outage is required to rectify, affected customers will be contacted directly to advise them of any work being undertaken as described in section 4.5.2.

As Hiko is a new system, we are continuing to work through and refine our processes, work practices, and improve our adoption of the system.

Historically, we have not been able to monitor voltage quality, as we did not have access to Smart Meter data, however this has changed with our adoption of the Hiko Platform which utilises the SmartCo meters. We are working with Hiko to expand this further with the adoption and ingestion of smart meter data from other Metering Equipment Providers (MEP) into the system to ensure we are able to monitor as many of our network ICPs as possible through one platform. Portable power quality loggers are available to be used ad hoc when the need arises.

As discussed in 2.12.4, we are aware that there are inaccuracies in our LV asset information, and are proactively correcting this through a designated asset information correction project, with dedicated LV technicians and GIS operators. Improving this data is key to improving our ability to monitor our low voltage network and any potential areas where constraints may exist,

We plan to use the LV data we gather, and Hiko system to analyse or model the following:

- **LV Fault Detection and Restoration Validation**: To quickly identify outages, confirm restoration after switching or fault repair, and improve accuracy of Outage Management System (OMS).
- **LV Load Profile**: To access customer-level load data for accurate demand analysis and improved planning for new connections.
- **LV Congestion Identification & mapping**: To detect and respond to constrained transformers or overloaded LV feeders before customer impact occurs.

5.1.3 – SECURITY OF SUPPLY CRITERIA

Security of supply considers the time it would take for supply to be restored to customers in the event of a single element failure on different parts of the network. Security of supply is a function of the network architecture and the capacity of equipment.

Subtransmission

Our objective is to restore supply to all affected consumers within one hour following a failure on the 33 kV network unless otherwise agreed with consumers. A fault on the 110 kV line between Kaikohe and Kaitaia may have a longer restoration time.

An overview of security of supply for the subtransmission networks are set out in Table 5-1.

SUBSTATION	TARGET RESTORATION TIME	COMMENT
Kaitaia 110/33 kV Substation	24 hours	Staged restoration of the Northern network area following a confirmed permanent 110 kV line fault would use diesel generators installed at Kaitaia depot, the Northern Generator Farm, Taipa and Pukenui. Supply to the JNL timber mill would be restored to allow an orderly plant shutdown and then disconnected until the fault is repaired. Note: A black start of the Northern network area without a grid connection has never been undertaken, and restoration time is speculative. The Top Energy Control Centre has prepared a switching plan for this eventuality.
Kaikohe **Kawakawa** **Kerikeri** **Moerewa** **NPL** **Okahu Rd** **Waipapa**	–	No interruption. All these substations have two transformers and two incoming lines.
Omanaia **Pukenui** **Taipa**	1 hour	These substations have a single transformer and a single incoming line. Supply would be restored using diesel generators located at the substation. There is insufficient generation capacity at Taipa to supply the full substation load during peak demand, but supply to most consumers can be restored by transferring some load to adjacent substations.
Kaeo	1 hour	This substation has two transformers, but only one incoming line. In the event of an incoming line fault, most of the load can be transferred to adjacent substations using voltage regulators on the 11 kV distribution system. However, during peak demand, it might not be possible to fully restore supply to all consumers before the fault is repaired.
Mt Pokaka	1 hour	This substation has one incoming line and one transformer. In the event of a transformer or line fault, supply can be restored to all small-use consumers by transferring their load to adjacent feeders. We have an agreement with the Mt Pokaka mill that supply will not be fully restored until the mobile transformer is put into service. This could take up to 12 hours.

Table 5-1: Subtransmission System Security

We own a 7.5 MVA 33/11 kV mobile substation, which limits the maximum total outage duration should all transformer and generation capacity be lost at any substation. This will be used in the event of a transformer failure at any of our four single-transformer zone substations to:

- avoid the need to run generators continuously for extended periods of time, and
- restore system security to normal levels until the fault is repaired.

Relocating this unit from its current location to provide backup at another substation can take up to 12 hours. This includes the time required for packing, travelling between zone substations, and assembling, connecting, and testing/commissioning the unit at its new location. Transformer failures are rare, but if one occurs, repair time could take up to a week, and replacement could take up to 24 months, given the lead time for new Power Transformers.

Distribution

The 11 kV distribution network has a radial configuration, meaning a supply interruption will occur whenever a fault occurs. The number of consumers affected will depend on the fault location. Adjacent feeders often have interconnections which give us limited capability to reroute supply around a faulted switching zone to restore supply to downstream consumers before the fault is repaired. The availability of such an alternative supply depends on the fault location, but, in general, the likelihood reduces as the distance of the fault from a zone substation increases. Supply cannot be restored to consumers in remote locations or on the edge of the network until a fault is repaired.

Low Voltage

The LV network has a radial configuration, meaning a supply interruption will occur whenever a fault occurs, with restoration achieved after repairs are complete.

5.1.4 – PRIORITISING NETWORK DEVELOPMENT PROJECTS

Network development projects are prioritised using the multi-stage process outlined below. The implementation of this process to specific constraints and projects is discussed in Section 5.5.

- Network constraints are identified through load forecasting, network analysis, and discussions with customers who may wish to connect load or generation.
- A risk assessment of each constraint is undertaken which considers the impact and likelihood of the constraint impacting levels of service at any time during the planning period.
- Options to address the constraint are identified, which includes consideration of non-network solutions.
- The preferred solution is selected based upon a consideration of all factors, including cost, degree to which the solution would mitigate the risk associated with the constraint, and other network performance considerations.
- A portfolio of preferred solutions addressing multiple constraints is brought together and ability to fund the projects is evaluated. Where not all work can be funded those projects with the lowest benefit to cost ratio are deferred.

This approach is aligned to Top Energy's corporate goals and vision through alignment with the risk management framework.

[5.2] Standardised Assets and Designs

To maximise cost efficiency and reduce the number of spares required, we have adopted equipment supply standards for the capacity and rating of stock-issued equipment.

5.2.1 – DISTRIBUTION TRANSFORMERS

Distribution transformers are sized according to the ISO standard. Pole mounting of new transformers is now limited to those rated 100kVA and below for seismic reasons. Transformers may be single, two, or three-phase, depending on 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.

5.2.2 – CABLES

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

5.2.3 – POLES

Wooden 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 110 kV subtransmission lines and will also be used for new subtransmission lines in locations where our standard concrete poles do not meet the design requirements.

The Kaikohe-Haruru section of the 110 kV Kaikohe-Wiroa line uses concrete poles. This section was constructed before the decision was made to standardise on steel poles for 110 kV circuits.

5.2.4 – OVERHEAD CONDUCTORS

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

5.2.5 – ZONE SUBSTATION TRANSFORMERS

Zone substation transformers have been standardised as 11.5/23 MVA units, except for small sites where this capacity is not warranted, and 5/10 MVA and 3/5 MVA transformers are used. 110/33 kV transformers with a 110 kV primary winding are standardised at 40/60 MVA.

In our view, given the small number of power transformers in the fleet, this relatively small number of standard power transformer ratings is justified as it ensures that assets are interchangeable between sites.

5.2.6 – ASSET CAPACITY CRITERIA

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 a reasonable planning period serves as the basis for design. In situations where the appropriate asset size is unclear, or demand forecasts are highly uncertain, we prefer to install a higher-capacity asset. This assumes that the incremental cost of the additional capacity is much lower than the cost of installing a new asset if the smaller asset becomes fully loaded.

For design purposes, we consider different capacity-constraint levels for primary assets during normal and contingent operations and apply the more restrictive of the two. The nominal values cater for the increase in domestic DG Export limits as well as the expanded voltage range at the point of supply on low voltage networks from ±6% to ±10%. These are shown in Table 5-2.

ASSET TYPE	CONDITION	PERCENTAGE OF NOMINAL CURRENT RATING	
		NORMAL OPERATION	CONTINGENT OPERATION
Transformers	Nominal	100	125 for one hour
Overhead Conductors	Still air 30 degrees	75	100
Underground Cables	In duct	75	100
Circuit Breakers	Nominal	75	100

Table 5-2: Design Capacity Limits

5.2.7 – MANAGEMENT OF CHANGE

When making changes to standardised assets and designs we use a structured equipment change process that considers the cost, risk, and performance implications of the change, as well as communication to stakeholders, procurement strategies and impact to network and equipment standardisation.

[5.3] Energy Efficiency

While we are not responsible for the cost of losses on our network, we recognise that the energy-efficient operation of our network is in the long-term interest of all stakeholders. Many of the investments set out in this AMP that are motivated for other reasons will have the effect of improving energy efficiency through lower losses. This includes:

- Completion of the Wiroa substation that will result in subtransmission at 110 kV instead of 33 kV, bringing the step-down point closer to the Kerikeri/Waipapa load centres.
- Creating new 11 kV feeders using the tertiary winding of the existing 110/33/11 kV transformer at the Kaitaia 110/33 kV substation.
- Installation of larger conductors to cater to future load growth when asset renewals are required.

We actively control consumers' hot water heating and other loads during peak demand to ensure more efficient use of available network capacity. Load control is estimated to reduce our network's maximum demand by more than 10 MW. This action reduces losses on our network, given the high proportion of losses that occur during peak demand.

Our standard specification for power and distribution transformers includes industry-standard clauses relating to minimising transformer losses, and the cost of losses is considered during tender evaluation.

In addition to these network considerations, the Ngāwhā Geothermal Power Station provides more than 95% of the energy requirements of our consumers. The power station displaces generation located south of Auckland, eliminating most of the losses that would be incurred in transmitting this power.

[5.4] Demand Forecasting

5.4.1 – OVERVIEW

Load forecasting provides an estimate of future demand, which is essential for prudent planning. Long-term electricity demand is largely dependent on:

- nature and number of customers connected
- population change and movement
- economic conditions, and
- technology adoption (e.g., photovoltaic cells, heat pumps, EVs, etc.).

5.4.2 – DEMAND FORECASTING METHODOLOGY

Top Energy's demand forecasting methodology provides a structured, repeatable process for assessing future load, generation, and storage requirements across the 110 kV, 33 kV, 11 kV and LV networks. The approach integrates system data, scenario based uncertainty analysis, and spatial modelling to ensure that both traditional load growth and emerging technologies (DER, EV charging, BESS, flexible demand) are appropriately incorporated into network planning.

Measuring the scale and impact of new demand, generation, or storage capacity

Top Energy assesses the scale and impact of new loads, DER, and storage through a combination of:

- **SCADA-based measurements of actual network behaviour:**
  - Half-hourly real/reactive power and current measurements are extracted from SCADA historian for each feeder and substation.
  - Abnormal operating conditions (e.g., outages, transfers, backfeeds) are identified and normalised before trend analysis.
  - This provides the baseline from which incremental impacts of new demand or generation are quantified and based on.
- **Quantifying demand and export impacts using Digsilent Power Factory:**
  - The ADMS Distribution Power Flow model is continuously updated with connectivity and asset data from GIS and both connectivity and load half hourly data is fed into DigSilent powerfactory.
  - New load or DER applications are modelled to identify voltage, thermal, and security impacts under peak, off-peak, and contingency conditions.
  - For generation, we have developed within ADMS an Automatic Network Management function (ANM) that evaluates export hosting capacity and power-flow constraints, including impacts on the Kaikohe–Kaitaia and Kaikohe–Maungatapere 110 kV circuits. The ANM function does real time measuring and execution of controls based on the constraints table embedded in the ADMS.
- **Application-specific technical assessments required to quantify the scale and impact on the network**.
  Each new connection ≥1 MW or any generation/storage installation requires a detailed study, including:
  - power quality studies (e.g., harmonics, voltage excursions)
  - Fault level assessments & protection studies, including WAPS
  - Thermal loading impact assessments
  - LV hosting capacity checks using Hiko smart meter voltage data
  - DER control/interface requirements, including potential curtailment needs
- **DER and storage impact analysis.**
  - Proposed generation profile from the connecting customer, and actual generation profiles from existing DER customers
  - Rooftop PV injection patterns from smart meter LV monitoring
  - Battery charging/discharging profiles (where data is available)
  - Modelled generation forecasts for DER across the network and future large scale generation

This enables quantification of both load reductions (PV offset) and increases (EV and battery charging), including diversity effects and alignment/misalignment with network peaks.

Accounting for timing and uncertainty of new demand, generation, or storage

Top Energy incorporates timing and uncertainty using a structured multi-scenario methodology:

- **Scenario-based demand/DER forecasts**
  Three planning scenarios are used:
  - **Low growth** (slow population growth, lower DER uptake)
  - **Central growth** (reference case aligned with FNDC projections and observed DER trends)
  - **High growth** (accelerated EV charging, DER, subdivision activity, and industrial developments)
- **Uncertainty weighting for block loads and industrial development**
  For large industrial customers or subdivision developments: Each proposed load is assigned a certainty category (High / Medium / Low). Medium and low categories are included in planning models with probabilistic weightings, influencing timing windows rather than fixed commissioning dates.
- **Uncertainties on DER and storage uptake**
  Future rooftop PV and residential battery uptake is modelled using logistic adoption curves developed from past years of observed data. Top Energy has observed strong growth in rooftop solar, but the future pace is inherently uncertain.

  We note elsewhere in the AMP that 62% of distributed generation installations in the last five years include batteries, as recorded in our 'Salesforce' CMS; 7.9 MW of behind-the-meter battery-enabled generation and 15.5 MW of total DER capacity to date. This is expected to plateau but the timing is uncertain; our predictive modelling suggests a levelling out in about 10 to 15 years from now.
- **Timing flexibility in investment triggers**
  Network constraints are measured and monitored by systems and assessed biannually or when large step loads or generation are applied for. Investments are triggered annually when combinations of the deterministic thresholds are reached e.g. thermal, voltage and security and load peaks are exceeded.

This approach ensures that uncertainty does not result in premature over-investment or deferred risk exposure.

Accounting for location-specific factors (network location of new demand, generation, or storage)

Top Energy's methodology explicitly incorporates spatial location as a core driver of forecasting accuracy and investment prioritisation:

- **Location-based modelling using GIS + ADMS**
  - All new connection applications (load, generation, or storage) are geospatially mapped in GE Smallworld.
  - DPF and LV modelling assess constraints at the actual point of connection, including phase imbalance, transformer loading, and localised voltage headroom.
- **Sub network architecture**
  Location affects constraints differently:
  - Northern area: constraints driven by export limits on the Kaikohe–Kaitaia 110 kV line, Pukenui 33 kV circuit capacities, and limited diesel support.
  - Southern/Kerikeri–Waipapa area: voltage sensitivity due to long 33 kV circuits and growing residential density.
  - LV networks: capacity and voltage issues influenced by exact feeder topology, cable types, conductor sizes, and local PV clustering.
- **Spatial risk evaluation for new developments**
  For each proposal, the following location-specific factors are assessed:
  - Proximity to existing firm capacity and transfer paths
  - Whether the site is on a constrained or unconstrained feeder
  - Ability to utilise existing interconnection and back feed routes
  - Presence of SWER networks (where new demand may trigger conversion)
  - Vegetation, terrain, and weather exposure (for asset resilience considerations)
  - Reverse power flow risks emerge

5.4.3 – DEMAND FORECASTS

Using the methodology described above, the Winter peak demand forecasts for each substation and the network are shown in Table 5-3. The peak demands shown in the table do not include the load that can be shed using our load management systems (Ripple Control).

At present, apart from household solar installations with batteries, embedded generation within our network does not reduce peak network demand. Apart from Pukenui, all our zone substations have winter peaks. With the adoption of 10kW domestic PV systems it is likely that small-scale photovoltaics with batteries would have a material impact on our peak demand. In the last 5 years, 62% of distributed generation installations have contained battery storage. This equates to roughly 7.9MW of distributed generation capacity with batteries installed, capable of offsetting network peaks. We currently have a total combined residential and commercial DER value of 15.5 MW.

FY	2025 (ACTUAL)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NORTHERN AREA											
Pukenui	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.1
NPL	10.6	11.4	13.9	16.4	16.4	16.5	16.5	16.6	16.6	16.7	16.7
Okahu Rd	8.7	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.6	7.6
Taipa	5.8	5.9	5.9	6.0	6.0	6.0	6.1	6.1	6.2	6.3	6.4
Kaitaia		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9
SOUTHERN AREA											
Kaeo	3.6	3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.7	3.7	3.7
Waipapa	9.1	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10.0
Kerikeri	7.7	7.9	8.1	8.3	8.5	8.7	8.9	9.1	9.3	9.5	9.7
Mt Pokaka	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Haruru	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.8
Kawakawa	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.3
Moerewa	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8
Kaikohe	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Omanaia	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9

Table 5-3: Zone Substation Demand Forecast (MVA)

FY	2025 (ACTUAL)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Kaitaia	24.8	25.9	28.2	30.7	30.8	31	31.1	31.3	31.4	31.7	31.9
Wiroa					23.7	24.1	24.4	24.7	25.1	25.4	25.7
Kaikohe	47.6	48	48.4	48.8	25.4	25.6	25.7	25.9	26.1	26.2	26.4
Network	**71**	**72.5**	**75.1**	**77.9**	**78.4**	**79.1**	**79.6**	**80.3**	**80.9**	**81.7**	**82.3**

Table 5-4: 110/33 kV Substation and Network Peak Demand Forecast

Note: Estimated from SCADA data. May not correspond to disclosed demand in annual information disclosure, which is derived from metered data. Data does not add to the zone substation data above due to peak diversity.

5.4.4 – UNCERTAINTIES IN THE DEMAND FORECAST

Listed below are the assumptions for the forecast.

- Slowing population growth across the Far North District, as shown in Statistics New Zealand population projections.
- Relative load growth by substation continues as it has over the last ten years. This has been verified by cross-referencing with Statistics New Zealand population projections for the areas that each substation serves.
- A load transfer of 1.8 MVA from the Okahu Rd Substation to the Kaitaia 110/33 kV Substation when the 11 kV winding of the existing 110/33/11 kV transformer is brought into service, and the newly built 11 kV switchboard and feeders are connected. This 11 kV winding has a rating of 10 MVA and is due to be commissioned by the end of FY 2025.
- A load transfer of 22.4 MVA from the Kaikohe Substation to the Wiroa Substation is expected when this new 110/33 kV Substation is commissioned, expected in FY 2029.
- Step-load increases at NPL Substation as the ResWax kauri gun extraction and processing facility is brought online over FY 2026 - FY 2028, ultimately totalling 6.0 MVA of load. No other step-loads are confirmed at this time.

The load forecasts in Table 5-4 and Table 5-5 relate only to consumer loads and ignore the 67 MVA of new utility-scale solar generation. As discussed elsewhere in this AMP, this will significantly load the 110 kV Kaikohe-Kaitaia line and will also increase the load on the Kaitaia 110/33 kV transformers.

There remains reasonable demand growth from new housing around Kerikeri and the Bay of Islands, and in the Doubtless Bay area, but not the acceleration we have seen in the past (Cable Bay, Coopers Beach and Mangonui). Subdivisions are treated as incremental demand growth rather than new block loads, as the load on new subdivisions develops gradually as houses are built and occupied. We have similarly treated new EV fast-charging stations as incremental demand rather than as new block loads.

While some new charging stations are rated at up to 300 kW, the probability that they will be fully utilised during peak network demand is low. The charging rate of most EVs is controlled to limit battery temperature and reduces as the battery state of charge increases. We therefore think the increase in demand from new EV charging stations will be incremental.

Step loads associated with the ResWax kauri gum extraction and processing facility have been included in this forecast, as this project has a high certainty of progressing.

LOAD	MW	COMMENT
Imerys Tableware	3	Imerys Tableware is investigating the electrification of the kiln fleet at its Matauri Bay Rd site. This would require significant upgrades to the existing 11 kV feeder.
Te Tai Tokerau	1	This would require upgrades and extensions to the existing 11 kV feeder from the NPL substation to the general vicinity.

Table 5-5: Potential Block Loads

The Northland Iwi have yet to negotiate a treaty settlement with the Government that, when finalised, could inject well over $200 million into the Northland economy. As negotiations have yet to conclude and be signed into law, no firm development plans are available, our forecast makes no provision for the economic stimulus that an eventual treaty settlement could provide to Top Energy's supply area.

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

5.4.5 – EMBEDDED UTILITY SCALE SOLAR GENERATION

Top Energy now has three large-scale solar farms connected to its subtransmission network, totalling 65 MW of generation capacity. The existing 110 kV Kaitaia to Kaikohe line is fully committed and unable to accommodate any further large-scale generation.

- **Far North Solar Farm:** This 17.2 MW solar farm is located adjacent to our Pukenui zone substation. It is connected to the substation via an underground 33 kV cable.
- **Twin Rivers Solar Farm:** A 24 MW solar farm located approximately 2.6 km southeast of our Kaitaia 110/33 kV Substation. It is connected to the substation's 33 kV bus via a single-circuit 33 kV underground cable running alongside SH1. This is under commissioning at the time of writing, expected completion by the end of FY 2026.
- **Kōhira Solar Farm:** This 23.7 MW solar farm, owned by Lodestone Energy, is located approximately 3.6 km north-west of our NPL substation. It is connected to the substation via a single 33 kV circuit comprised of 2.8 km of overhead line and 0.9 km of cable.

Currently, both the Kaitaia and Far North solar farms are operational, while Twin Rivers Solar Farm is not yet commissioned. The corresponding generation profiles are shown in Figure 5-1 below. The Kaitaia Solar Farm (NPL_CB3392) and Far North Solar Farm (PKN_CB3792) are shown in teal and lime line graphs, respectively.

KŌHIRA SOLAR FARM & FAR NORTH SOLAR FARM GENERATION PROFILE

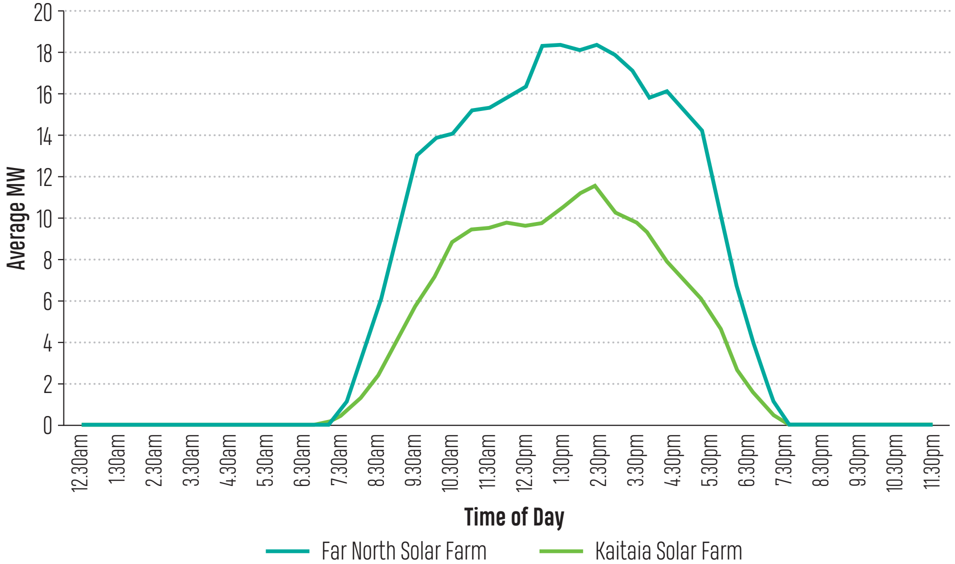

Figure 5-1: Load Profile of Utility Scale Solar Farms

5.4.6 – EMBEDDED UTILITY SCALE GEOTHERMAL GENERATION

Top Energy has base load geothermal generation plants connected to its 33 kV and 110 kV network. The Ngāwhā Power Station consists of Ngāwhā A (OEC 1&2&3) and Ngāwhā B (OEC 4). When Ngāwhā A is operational, its output feeds directly into the Kaikohe 33 kV network, bypassing the Kaikohe 110 kV transformers. On the other hand, Ngāwhā B connects to the 110 kV busbar at Kaikohe. The corresponding generation profiles are shown in Figure 5-2. The Ngāwhā A is indicated by the light lime and lime areas (KOE_CB3702 & KOE_CB3592), while the Ngāwhā B is indicated by the teal area (KOE_CB0172).

TOP ENERGY 'NGĀWHĀ A' & 'NGĀWHĀ B' GENERATION PROFILE

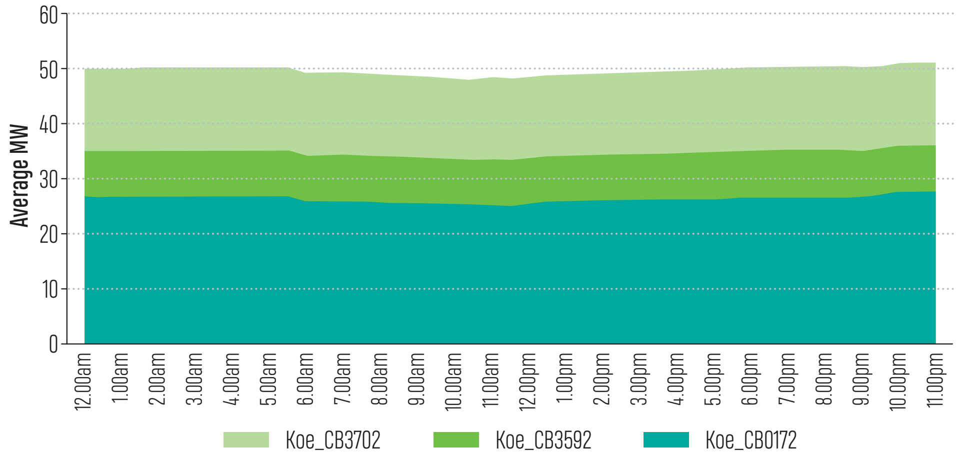

Figure 5-2: Load Profile of Ngāwhā Power Plants

5.4.7 – DISTRIBUTED SOLAR GENERATION

Currently, a total of 2,512 customers on the Top Energy Network have DER connections. Of these, 2233 are residential connections of less than 10 kW capacity, and 279 are larger units, inclusive of commercial units that are equal to or larger than 10 kW capacity. This represents 7% of ICPs on our network, totalling 15.5 MW, which is presented in Figure 5-3 below.

DISTRIBUTED GENERATION IN MW

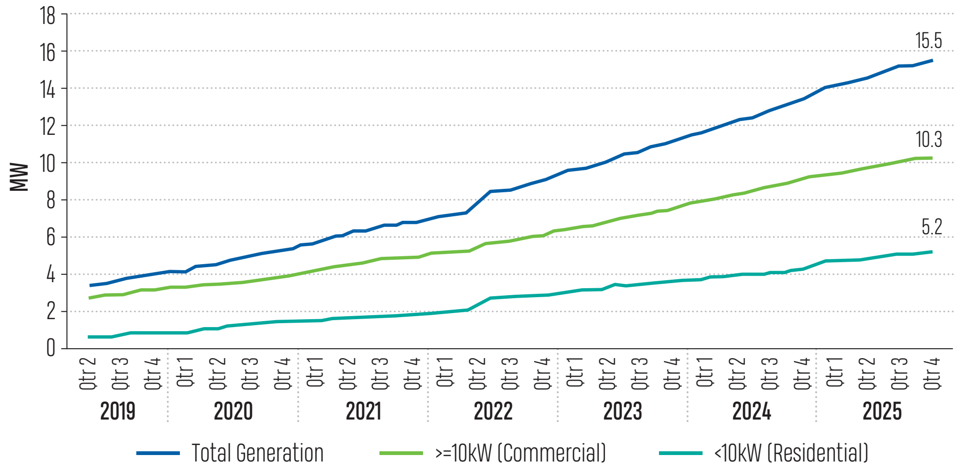

Figure 5-3: Rooftop Solar Generation Capacity

A predictive model for distributed solar generation connections was created using historical data from 2013–2025. The model accounts for slowing population growth and assumes logistic growth, as seen in Australia. After generating over 54,000 logistic curves and validating predictions against observed data, the model estimates we will have 6,161 distributed solar generation connections on our network by 2034. While predictions appear accurate for most feeders, they will be dependent on future policy changes, such as rooftop solar injection limits. The solar ICP projection can be seen in Figure 5-4.

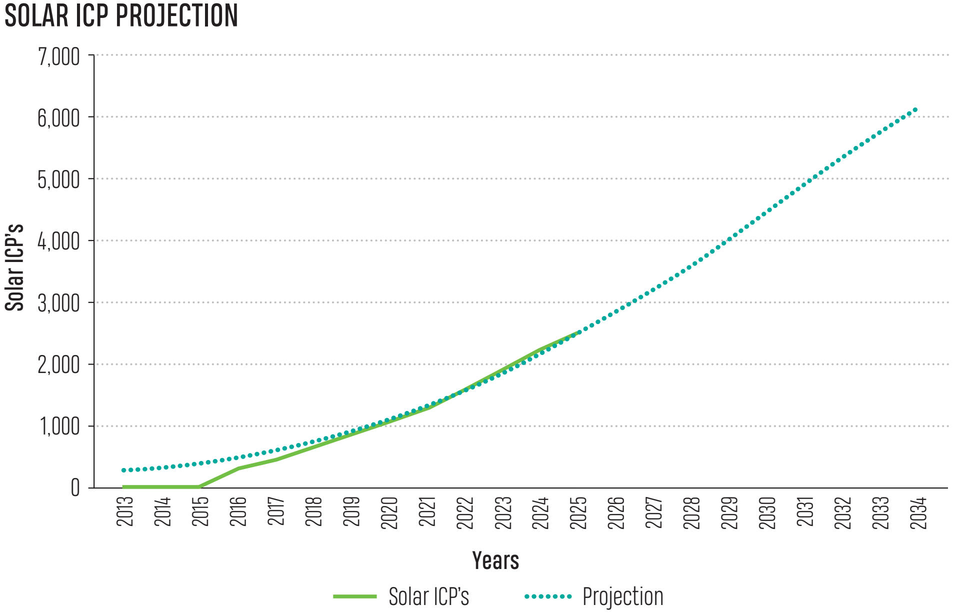

Figure 5-4: Distributed Solar ICP Projection

Over the past five years, 62% of distributed solar installations have included battery storage. This represents approximately 7.9 MW of distributed generation capacity paired with batteries. This additional capacity is available to support generation during network load peaks, reducing overall demand. Currently, the combined residential and commercial distributed solar generation capacity totals 15.5 MW.

As is shown in Figure 5-5, our 2025 network peak loads during most of Winter have been lower than usual. This is likely due to the Winter being warmer than usual, which reduced heating demand and overall power consumption. Additionally, the growing number of distributed solar generation systems, particularly those paired with battery storage, may have contributed by enabling customers to generate and store their own electricity for use during peak periods, further reducing demand on the network.

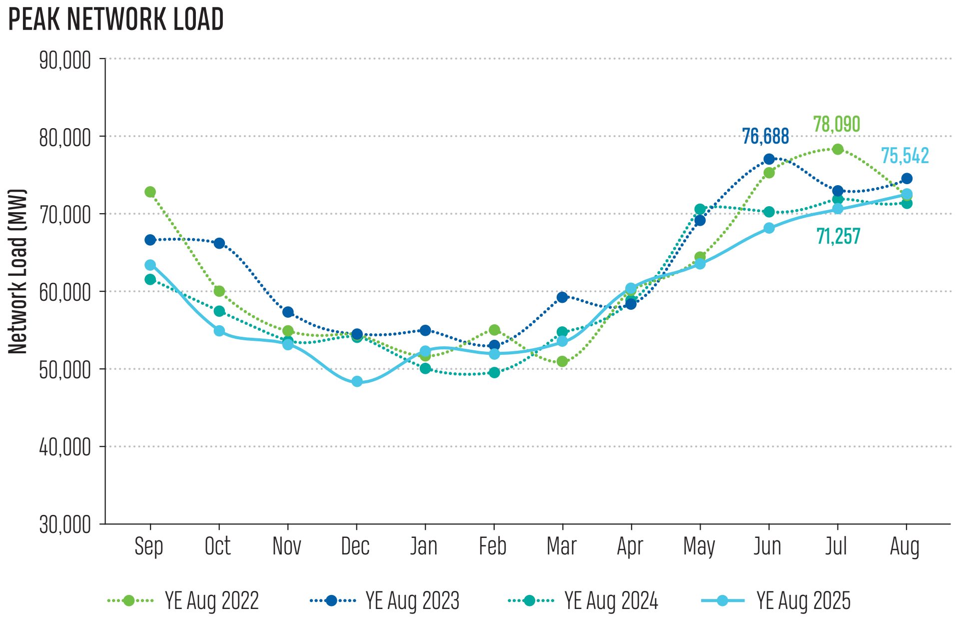

Figure 5-5: Peak Network Load

[5.5] Network Constraints and Development Options

5.5.1 – TYPES OF CONSTRAINTS

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

- voltage
- thermal capacity, and
- security.

Voltage

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

To reduce these constraints on 33 kV and 11 kV systems, voltages are regulated at key points of the network using:

- transformer tap changers at zone substations, or
- voltage-regulating transformers strategically located across the network.

Voltage constraints can appear on the LV network due to the limited ability to dynamically adjust the voltage at this level. In Australia, managing voltages on LV networks with a high number of consumers and rooftop photovoltaic generation has become a significant issue. In New Zealand, this is less of a problem due to the lower penetration of distributed generation connected to the LV network. However, we have one of the highest penetration of small-scale photovoltaic generation in the country. We have already received some complaints of power injection into the LV network, which is affecting the quality of supply experienced by adjacent consumers. To date, the problems that have arisen have been minor and easily resolved, but we expect the issue to become more serious over time. On 1 April 2021, we introduced an energy injection charge of 0.5c per kWh exported into the LV network to recover the incremental network costs of investigating and mitigating the impact of uncontrolled intermittent generator connections.

Equipment Rating

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

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

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

Security

A security constraint relates to an alternative source of supply in the event of a fault on the primary supply. It may be a full constraint, where no alternative exists, or a partial constraint that limits supply due to capacity or voltage-regulation limitations on the alternate supply. Security constraints are most concerning in the subtransmission network because faults on these networks can affect large numbers of consumers.

5.5.2 – KNOWN CONSTRAINTS

Known constraints are summarised in Table 5-6. Each constraint, the options considered to resolve it, and the selected option are discussed in the following sections.

LOAD	MW	COMMENT
Maungatapere-Kaikohe 110 kV Line (Transpower asset)	Capacity	2030 Upon commissioning of Ngāwhā OEC5
Kaitaia-Kaikohe 110 kV Line	Capacity	2026 Upon commissioning of Twin Rivers Solar Farm
Pukenui 33 kV	Capacity	2026
Kaitaia 110/33 kV Transformers	Security	2026
Kaikohe Transformers	Security	2026
Voltage Constraint at Waipapa and Kaeo Substations	Security	2026
Taipa Generation Constraint	Security	2026
Taipa Transformer Constraint	Capacity & Condition	2026
Doubtless Bay Constraint	Capacity & Security	2035-2040
Potential Feeder Capacity Constraints	Capacity & Security	2034
Substation Transfer Capacity Constraints	Security	2026
Sub-Optimal Conductors Along Feeders	Capacity	2026

Table 5-6: Known Constraints

5.5.3 – MAUNGATAPERE-KAIKOHE 110 kV LINE

The double circuit 110 kV line between Kaikohe and Maungatapere is owned by Transpower and is the only connection between our network and the national transmission grid. The line is used to export electricity generated within our supply area when this generation exceeds consumer demand on our network.

When all the generation we have signed connection agreements for is commissioned, the total utility-scale generation connected to our network will be 156 MW (89 MW geothermal and 67 MW solar). This is well above the generation required to meet local demand in our supply area. When both Kaikohe-Maungatapere circuits are in service, there is sufficient line capacity to export this excess generation south. However, over the summer, there will be times when both circuits' capacity will be fully utilised. If one circuit is out of service, generation will need to be constrained off at certain times over the summer. This is shown in Table 5-7, where it is assumed that the anytime minimum demand occurs in the middle of the night when the solar farms are not generating.

PERIOD	LINE CAPACITY (MVA)	TE MINIMUM DEMAND	MAXIMUM UNCONSTRAINED GENERATION	TOTAL GENERATION CAPACITY OEC1-5 AND SOLAR	MAXIMUM GENERATION CONSTRAINED OFF
Summer Night	63/651[1]	21	84	89	5
Winter Night	77/801[1]	24	101	89	–
Summer Day	63/651[1]	29	92	156	64

Table 5 7: Transmission Constraints Kaikohe-Maungatapere (MVA, with one circuit out of service)

Note 1: The two ratings are because the two lines have slightly different configurations.

Note 2: The summer anytime minimum demand occurs at night when the solar farms will not be generating.

Note 3: The winter anytime demand occurs in the late evening after dark, so the solar farms will not be generating.

Implications

- Assuming all planned new generation projects proceed, if one circuit is out of service, generation may need to be constrained off during the day when the solar farms are generating. The size of this constraint will peak over the summer, when up to 64 MW of local generation may need to be constrained off.
- There could also be a relatively small constraint on dispatching Ngāwhā generation overnight during the summer.
- OEC5 at Ngāwhā will fully utilise the capacity of the Kaikohe-Maungatapere line. Currently, this is unused during the summer when the solar farms are generating at full capacity (as the 64 MVA of constrained-off generation equals the full capacity of the second circuit). This means that we are unable to accept any more applications for the connection of a new generation anywhere on the network, unless the proponent is willing to accept the constraints discussed.

Likelihood

- The likelihood of a single circuit constraint is low, as the loss of a single circuit is a rare event. Transpower aims for one unplanned interruption every five years.
- This is comparable to the risk of a complete loss of the grid connection, most likely caused by a grid event south of Maungatapere. Ngāwhā cannot operate without a grid connection, and connected photovoltaic generation would also need to be shut down.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network solution	Construct second Kaikohe-Maungatapere Line	>$100m
Option 3	Non-network solution	Ensure that embedded generation contracts provide Top Energy with the ability to constrain generators off. Coordinate the timing of line maintenance outages with Transpower. These need to occur during the winter, when solar generation output is low. Implement a 'Runback' SPS / COPS, so that unplanned loss of a single KOE-MPE circuit that results in an overload of the remaining circuit, automatically disconnects excess generation.	Internal opex only

Table 5-8: Maungatapere-Kaikohe 110 kV Line – Options Considered

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 3	Non-network solution	Given the very low likelihood of the loss of one circuit and the high cost of a second line (more than $100 million), a second Kaikohe-Maungatapere Line cannot be justified. Transpower is investigating a thermal upgrade of the existing circuits. This is likely to involve increasing the conductor tension on the sections of the line with the lowest ground clearance. This allows the conductor to be run at a higher temperature, without the increased sag breaching ground clearance requirements. A thermal upgrade could increase the summer capacity of both circuits to 170 MVA. In the meantime, in association with Transpower, a Circuit Overload Protection Scheme (COPS) has been installed to remove excess generation should the KOE-MPE Line rating be breached.

Table 5-9: Maungatapere-Kaikohe 110 kV Line – Option Selected and Rationale

5.5.4 – KAITAIA-KAIKOHE 110 kV LINE

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

- the line is out of service, in which case the amount of solar generation would theoretically be limited to the northern area demand. However, in this situation, the solar farms would need to be constrained off, as solar generation is non-dispatchable and our diesel generation is too slow to respond to variations in solar farm output, or
- the line is in service, but the amount of solar generation exceeds the sum of the line capacity and local load. This is shown in Table 5-10.

PERIOD	LINE CAPACITY (MVA)	NORTHERN AREA DEMAND MINIMUM (MVA)	MAXIMUM UNCONSTRAINED GENERATION (MVA)
Winter Day	68	11.4	79
Summer Day	55	9.2	64

Table 5-10: Subtransmission Constraints KOE – KTA

Implications

- The major impact of this constraint is our inability to permit the connection of more generation in our northern area while the constraint persists. There is an ongoing demand to connect additional solar generation, but we are unable to accommodate it.

Likelihood

- While it is theoretically possible for the line capacity to be exceeded if all three solar farms were generating at full capacity and the local load at Kaitaia was minimum, the likelihood of this happening simultaneously is low. In any case, the extent to which the line capacity was exceeded would be small, so the amount of generation that would need to be constrained off would be small.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network solution	Build Wiroa-Kaitaia 110 kV line and renew Kaitaia-Kaikohe 110 kV line	$121m
Option 3	Network solution	Build Wiroa-Kaitaia 110 kV line and decommission Kaitaia-Kaikohe 110 kV line	$71m
Option 4	Non-network solution	Ensure that embedded generation contracts provide Top Energy with the ability to constrain generators off. Limit the connected capacity or triggering a network upgrade at the generators' cost.	Internal opex only

Table 5-11: Kaitaia-Kaikohe Line – Options Considered

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 3	Network solution	To fully mitigate this constraint, we will need a second line, but the level of additional maintenance and operational costs required to service two lines in the Far North would be cost-prohibitive for our customers. We have now approved and included the Wiroa-Kaitaia 110 kV line build into our capital expenditure forecast as a replacement project for the Kaitaia-Kaikohe line. This will provide an additional 10 MVA capacity. We then intend to decommission the existing circuit after the 10-year planning period. We will also implement the identified non-network solution.
Option 4	Non-network solution	

Table 5 12: Kaitaia-Kaikohe Line – Option Selected and Rationale

5.5.5 – PUKENUI 33 kV

The Far North solar farm has a connection agreement for a capacity of 20 MVA and is located adjacent to the Pukenui substation. It is currently commissioned at 17.16 MW/19.47 MVA, is connected to the substation via a new 33 kV line, and exports generation south via the 33 kV Church Rd-Pukenui single-circuit line, which has a capacity of 20 MVA. The local Pukenui demand peaks at 1.9 MVA, so there is no capacity to connect additional solar generation to the Pukenui substation. This would be the case even if the Kaikohe-Kaitaia and Kaikohe-Maungatapere line constraints were removed.

Implications

- No capacity to connection additional solar generation to the Pukenui substation.

Likelihood

- High, given the strong demand for the connection of solar generation in our northern area.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period.	$0
Option 2	Network Solution	New generation applications could trigger rebuild/reconductor of the CHT-PKN Line (and further into KTA) at the existing operating voltage to achieve the desired capacity	$9m
Option 3	Network Solution	New generation applications could trigger rebuild of the CHT-PKN Line and transformer assets at each end, at an upgraded voltage (eg 66 kV) to achieve the desired capacity	$20m (Line) + $10m (transformers, associated switchgear & protection)
Option 4	Non-network solution	Require that new DG installations are fitted with the ability to control the output	$20k Base + $5k per site (or less), dependent on the selected communications technology

Table 5-13: Pukenui 33 kV – Options Considered

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 4	Non-network	Apart from the back-end communications infrastructure, the individual DG connections will pay the incremental costs of deploying the equipment for each site.

Table 5-14: Pukenui 33 kV – Option Selected and Rationale

5.5.6 – KAITAIA 110/33 kV TRANSFORMER

There are two 110/33 kV transformers at the Kaitaia substation: a relatively new 40/60 MVA transformer (T1) and an older 20 MVA single-phase transformer bank (T5) nearing the end of its economic life.

In the event of a T1 transformer failure, the T5 bank has sufficient capacity to meet consumer demand, with support from our diesel generation during peak demand. However, its rating is insufficient to accommodate the 67 MW of solar generation that will soon be connected in the Kaitaia area.

Implications

- Should the T1 transformer fail, most of the new solar farm generation would need to be constrained off until a replacement transformer of sufficient capacity could be installed. If a suitable transformer could not be found as a temporary replacement, this could be up to a year.

Likelihood

- Low, as power transformer failures are rare events. The T1 transformer has been in service for only eight years of its expected 50-year life and is in good condition.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network solution	Replace T5 with a new 'T2' transformer with rating to match T1, providing a firm capacity of 40/60(/80) MVA, matching the available capacity of the connecting 110 kV line(s) servicing KTA Substation.	$5m

Table 5-15: Kaitaia 110/33 kV Transformers – Options Considered

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network Solution	In the absence of a viable non-network solution, the conventional solution of installing a second transformer of equivalent rating to form a firm capacity that can accommodate the current and projected loads seems reasonable.

Table 5-16: Option Selected and Rationale

5.5.7 – KAIKOHE TRANSFORMERS

There are two 110/33 kV transformers at Kaikohe: T3, rated at 50 MVA, and T2, rated at 30 MVA. Ngāwhā generators OEC1, 2 & 3 inject power directly into the 33 kV network. If all of these generators and one of the 110/33 kV transformers are out of service at the same time, there is a capacity shortfall, as all the southern area demand would need to be supplied through the remaining in-service transformer. This is more severe when the larger unit is out of service, as shown in Table 5-17.

PERIOD	TRANSFORMER T3 CAPACITY (MVA)	TRANSFORMER T2 CAPACITY (MVA)	MAX SOUTHERN DEMAND (MVA)	% HALF HOURS DEMAND EXCEEDS T2 CAPACITY
Winter	50	30	47	40%
Summer	50	30	36	15%

Table 5-17: 110 kV Transformer Capacity Constraint – Kaikohe

Implications

- With only one 2 MW Backup diesel generator installation available in the Southern Area (serviced by Kaikohe 110/33 kV substation), Ripple control of discretional loads and possible rolling feeder outages (both with customer impact) are the short-term solution
- For longer term application, rental of temporary generation installed at locations around the network could be used to offset shortfalls.

Likelihood

The likelihood of this constraint materialising is very low, provided prudent asset management practices are applied to both the network and generators. It is an N-2 contingency, as it requires simultaneous outages of more than one critical plant item during peak demand. The network is not usually designed to cater for N-2 contingencies.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network Solution	Installation of generator connection points at Zone Substations	Capital: $100k Opex: $600k
Option 3	Network Solution	Creation of an additional 110/33 kV Supply point at Wiroa	$10m
Option 4	Non-network solution	Connection of a BESS or similar device of suitable capacity at 33 kV	Estimated at $300k per MWh; require 15 MW for 4 hours; $300k x 4h = $1.2m

Table 5-18: Kaikohe Transformers – Options Considered

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Options 2 & 3	Network	For a minimal capital outlay, connection points can be established at locations that can provide the required security & facilities. There is a low likelihood of such a double contingency requiring the generators to be installed and used, but the preparation of the connection points will save time in setting them up and restoring the level of service expected. Building the Wiroa 110/33 kV Substation will allow some of the load to be relieved from KOE 110/33 kV Substation via the interconnecting 33 kV circuits.

Table 5-19: Kaikohe Transformers – Option Selected and Rationale

5.5.8 – VOLTAGE CONSTRAINT AT WAIPAPA AND KAEO SUBSTATIONS

The Wiroa 33 kV switching station is supplied by two incoming 33 kV lines – the double circuit 110 kV line from Kaikohe, which is currently configured as a single circuit and operated at 33 kV, and the older 33 kV Kaikohe-Mt Pokaka-Wiroa circuit. This second line is longer and has smaller conductors. If the 110 kV line is out of service during peak network demand, then:

- the load on the Kerikeri, Waipapa, and Kaeo substations will all be supplied via Mt Pokaka, and
- the 33 kV voltage at Kaeo and potentially Waipapa may fall below acceptable levels.

Consumers north and west of Kerikeri will experience low voltage unless load is shed.

Implications

- This is only a partial constraint. The load at risk will not be the full Kerikeri/Whangaroa area demand, but the difference between this demand and the load that the Mt Pokaka circuit can supply. Initially, this would be low but would progressively increase as the load in the area grew. The timing of the Wiroa build is therefore a risk management decision based on the probability of the event (low) occurring and its consequences (initially small but increasing over time). Probabilistic planning of this nature is now accepted industry practice.

Likelihood

- Low, since the Kaikohe-Wiroa line is still in very good condition, and the load would only need to be shed if the event occurred during peak demand.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network Solution	110/33 kV supply at Wiroa Substation (closer to Kaeo & Waipapa 33/11 kV Substations); 2nd 33 kV supply line to Kaeo Substation (reduce load at Waipapa Substation)	$10m (Wiroa 110/33 kV Substation build) $31m (Kaeo 2nd 33 kV Line)

Table 5-20: Voltage Constraint at Waipapa and Kaeo Substations – Options Considered

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network	The construction of the Wiroa 110/33 kV Substation resolves predicted issues at multiple locations, including providing capacity to partially offload KOE 110/33 kV transformers

Table 5-21: Voltage Constraint at Waipapa and Kaeo Substations – Option Selected and Rationale

5.5.9 – TAIPA GENERATION CONSTRAINT

The Taipa substation has a single 5/6.25 MVA transformer, a single incoming 33 kV line and two diesel generators with a combined capacity of 3.6 MVA. Hence, in the event of a loss of the incoming line or the transformer, there is a supply shortfall of up to 2.65 MVA.

Implications

- Shortfalls cannot be fully accommodated by connections from adjacent substations. Subsequently, a portion of the customers normally supplied via Taipa Substation, will be off supply. This may require rolling outages across the Taipa feeders that could be supplied from the backup diesel gensets

Likelihood

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

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network solution	The generators are mainly used for emergency situations that could arise from a Taipa Transformer fault or KTA-TPA 33 kV Line fault. While the generators do not meet the size of the transformer, we do have our Mobile sub located at this site to compensate for the constraint formed by transformer capacity. This constraint is triggered by a larger network resilience programme of works to relocate this Sub away from the current site as it is located in a flood plain. This is not presently in the 10 year planning apart from the land acquisition for the installation of the new transformer.	N/A

Table 5-22: Taipa Generation Constraint – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network Solution	The substation site is in an area identified as a flood risk and we plan to relocate this substation as part of the Coopers Beach development programme. This is currently not in this planning period.

Table 5-23: Taipa Generation Constraint Option Selected and Rationale

5.5.10 – TAIPA TRANSFORMER CONSTRAINT

The peak demand at the Taipa substation, as measured by our SCADA system, is 6.3 MVA, slightly above the transformer's rated capacity of 5/6.25 MVA. This measured peak demand has occurred for only short periods (minutes) on any given day. To date, it has not exceeded the transformer's continuous rating and is within its short-term contingency rating. Nevertheless, there is a potential for the transformer rating to be exceeded in the short to medium term.

Implications

- This would result in a shortfall of capacity for the transformer and a potential overload situation. Shortfalls cannot be fully accommodated by connections from adjacent substations. Subsequently, a portion of the customers normally supplied via Taipa Substation, will be off supply. This may require rolling outages across the Taipa feeders that could be supplied from the backup diesel gensets

Likelihood

- Low – Our mobile substation has now been relocated to Taipa on a semi-permanent basis and will only be moved in the unlikely event it is required elsewhere on the network. The subtransmission network upgrades completed under the TE 2020 programme have reduced the probability that the mobile substation will be needed elsewhere.
- The condition of the Taipa transformer is of increasing concern, although a failure remains unlikely. Should a failure occur, the mobile substation's capacity is sufficient to supply all the Taipa substation load.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network solution	Replace the aging transformer bringing it up to spec and ratings. This transformer will be relocated to the new Taipa substation location as and when we proceed with the Eastern Seaboard development plan.	$2,921m

Table 5-24: Taipa Transformer Constraint – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network Solution	Replace the aging transformer bringing it up to spec and ratings. The transformer is at its end of life and is running close to its max rating.

Table 5-25: Taipa Transformer Constraint – Option Selected and Rationale

5.5.11 – DOUBTLESS BAY CAPACITY AND SECURITY CONSTRAINT

The Doubtless Bay development has been deferred beyond the 10-year planning period due to changing network priorities and a reduced forecast in load uptake. The Doubtless Bay Development involves the relocation of the Taipa Substation to high ground behind Mangonui Village or Coopers Beach, and a second substation on the Karikari Peninsula. FNDC currently predicts a negative population growth and our model indicates a flat load trend.

Implications

- Socially-driven change to the projected load growth could require a response sooner than currently anticipated. Current transformer constraints that service this area has been addressed in the constraint listed above.

Likelihood

- Low – Currently the likelihood of sudden load growth is perceived as being low in the current planning period.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action during the planning period	$0
Option 2	Network solution	Develop the proposed substation and 33 kV lines in a staged manner, described below in the write up described within section 5.6.1	$14M

Table 5-26: Taipa Transformer Constraint – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network Solution	Construct this development in a staged manner to allow for the use of each component as soon as it is ready, regardless of the progress of the other facilities, eg: – The construction of the 33 kV line from Awanui toward Taipa can provide an express 11 kV feeder, improving load sharing capability on the 11 kV system from either end. – The installation of 11 kV switchboards at Mangonui and/or Tokerau substations can operate as dedicated switching sites, supporting improved configuration of the existing 11 kV network and reducing the SAIDI impact associated with fault events.

Table 5-27: Taipa Transformer Constraint – Option Selected and Rationale

5.5.12 – POTENTIAL FEEDER CAPACITY CONSTRAINTS

While our 11 kV feeders have sufficient capacity to accommodate incremental demand growth and increased small-scale solar penetration, they may not have the capacity to supply localised new block loads. Loads with the potential to cause capacity shortfall are shown in Table 5-28.

DEVELOPMENT	FEEDER	DEMAND	MITIGATION	CONSTRAINT	DEVELOPMENT PROBABILITY
Kaikohe Irrigation	Ohaeawai	2-4 MW	Feeder upgrade	Capacity Voltage	Medium
Kaitaia Irrigation	Awanui	2-4 MW	New feeder	Capacity	Medium
Tokerau Resort	Tokerau	5 MW	New substation and 33 kV line	Capacity Voltage	Low
Hokianga Wind	Herekino	5 MW	Feeder upgrade	Capacity	Low
Energy Park	Ohaeawai	5 MW	New 11 kV feeder or 33/11 kV substation	Capacity	Some low-load development confirmed. Low probability of a new substation or feeder being required.

Table 5-28: Potential Feeder Capacity Constraints

Implications

- In the event that we do not have the capacity to supply new block loads, our standard customer funding model would apply. The developer applying for the new connections would be required to pay for any associated upgrade required to accommodate their load requirement. An increasing number of DER connections now include batteries, this together with the upcoming changes in the code allowing a 10 kW photovoltaic DER residential connection would have an impact network wide offsetting both capacity and consumption on these and other feeders. Refer to Figure 5-4: Distributed Solar ICP Projection for growth in Solar PV.

Likelihood

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

Mitigation

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

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Take no action	$0
Option 2	Network Solution	These developments would be funded by the applicant should they wish to proceed and the timing for these are not confirmed as yet.	N/A[1]
Option 3	Non-network solution	This would be investigated closer to the time. There would be aspects or components of the installation that could have a non network solution but would be dependant on the design and customers ultimate load requirement.	N/A[1]

Note 1: This cost would be dependent on the design and option chosen by the customer available.

Table 5-29: Potential Feeder Capacity Constraints – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 1	Do nothing	The uncertainty of the developments means that it is not prudent to plan investments in capacity upgrades at this time.

Table 5-30: Potential Feeder Capacity Constraints – Option Selected and Rationale

Substation Transfer Capacity Constraints

Zone substations have been upgraded so that supply can be restored to all consumers within 1 hour in the event of a foreseeable N-1 contingency (refer to Section 5.1.3). However, in the event of an unforeseeable high-impact-low probability (HILP) event that disables the entire substation, the amount of load that can be supplied from alternative substations varies, as shown in Table 5-31. The network is not designed to withstand such an event, and if one did occur, the Emergency Preparedness Plan described in Section 3.1.4 would be activated.

Table 5-31 shows the proportion of each substation's current peak demand that can be supplied from neighbouring substations.

SUBSTATION	PEAK DEMAND (MVA)	SUMMER PEAK (MVA)	SHOULDER PEAK (MVA)	TRANSFER CAPACITY (MVA)	% PEAK DEMAND
Kaikohe	9.3	6.2	8.1	1.0	10%
Kawakawa	6.0	5.5	5.4	2.5	37%
Moerewa	3.4	3.5	3.9	3.3	100%
Waipapa	9.7	5.1	6.9	7.6	78%
Omanaia	2.8	2.0	1.9	2.31	85%
Haruru	7.0	4.5	4.8	1.5	20%
Mt Pokaka	2.5	2.1	2.2	1.5	60%
Kerikeri	7.7	5.0	6.0	6.0	78%
Kaeo	3.7	3.0	3.4	4.0	100%
Okahu Rd	9.5	5.9	6.7	3.7	44%
Taipa	6.3	4.9	4.6	3.0	48%
NPL	11.1	10.9	10.7	4.3	39%
Pukenui	1.9	1.9	1.9	1.8	95%

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

Table 5-31: Substation Transfer Capacity

Implications

- The substations are designed and built to be resilient and has the ability to restore supply to the local distribution network, however the implications would largely be associated to the type High Impact Low Probability (HILP) event. Further implications would result in large scale outages and the activation of our rolling outage plan. Extended outages of the furthest ends of our distribution network would result as the network is restored.

Likelihood

- The probability of an event that disables an entire substation is very low.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing		$0
Option 2	Network Solution	Zone Transformer Replacement programme during the Planning period	>$33.923m
Option 3	Non-network solution	Standardisation of transformer specification. Should a HILP incident occur we can easily relocate transformers across substations.	N/A

Table 5-32: Substation Transfer Capacity Constraints – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
2	Network Solution	The 33 kV zone transformers are approaching the end of their life and needs to be replaced. Wiroa transformers are being installed for both capacity and security.

Table 5-33: Substation Transfer Capacity Constraints – Option Selected and Rationale

5.5.13 – FEEDER TRANSFER CAPACITY CONSTRAINTS

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

- Some feeders, particularly in urban locations, can be fully supported by adjacent feeders.
- Some feeders, particularly those along main roads in rural areas, can be back fed from an adjacent feeder, but capacity is limited and insufficient to provide full back feed during peak demand.
- For geographic reasons, much of the network cannot be back fed. While faults on these parts of the network cannot be back fed, in some situations, it may be possible to restore supply after a fault elsewhere on the feeder, depending on the feeder backbone supplying the network.

This situation is common in rural networks. However, it is exacerbated in our network by legacy factors discussed elsewhere in this AMP, which have resulted in limited injection points into the 11 kV network and many long radial feeders with a high number of connected consumers.

Implications

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

Likelihood

- The likelihood is dependent upon the location and nature of the fault. Given the tropical nature of the region's weather patterns, fault locations vary significantly. The likelihood of a fault closer to the start of a rural feeder being back fed and picked up is higher as opposed to a fault closer to the end of the feeder.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing	Do no upgrades	$0
Option 2	Network Solution	11 kV feeder interconnection programmes to provide back feed capability	$9.79M

Table 5 34: Feeder Transfer Capacity Constraints – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network solution	Implementing normally open feeder interconnections will support improvement of network performance at the 11 kV level. DPF capability will enable the Control Centre to make optimal decisions about 11 kV back feeding in real-time to minimise outage durations and risk of overloading equipment.

Table 5-35: Feeder Transfer Capacity Constraints – Option Selected and Rationale

5.5.14 – SUB-OPTIMAL CONDUCTORS ALONG FEEDERS

Standards have been established for conductor sizes along a feeder to optimise losses, manage voltage limits and provide appropriate network capacity. Generally, the front end of feeder backbones from the substation to about one-third along its length uses the largest standard conductor, the next third and spur lines use a medium-sized conductor, and the end of lines, as well as SWER lines and short spurs use the smallest size.

Since the early days of the network, the sizes of standard conductors have increased as loads increased and the network extended. Consequently, the older undersized conductor have been replaced with the new standard size of the day.

Unfortunately, not all spans of substandard conductor were changed to the new size during the upgrade work, and so there are now many short lengths of small conductor throughout the network. For example, there were 12 spans of $35mm^2$ copper conductor through the middle of Moerewa. This conductor has recently been replaced with a $157mm^2$ aluminium conductor.

By way of example, Figure 5-6 shows locations within a portion of the network around Kaikohe, Moerewa and Kawakawa where the conductor is undersized. In some instances, these sections are of considerable length and close to the substation source.

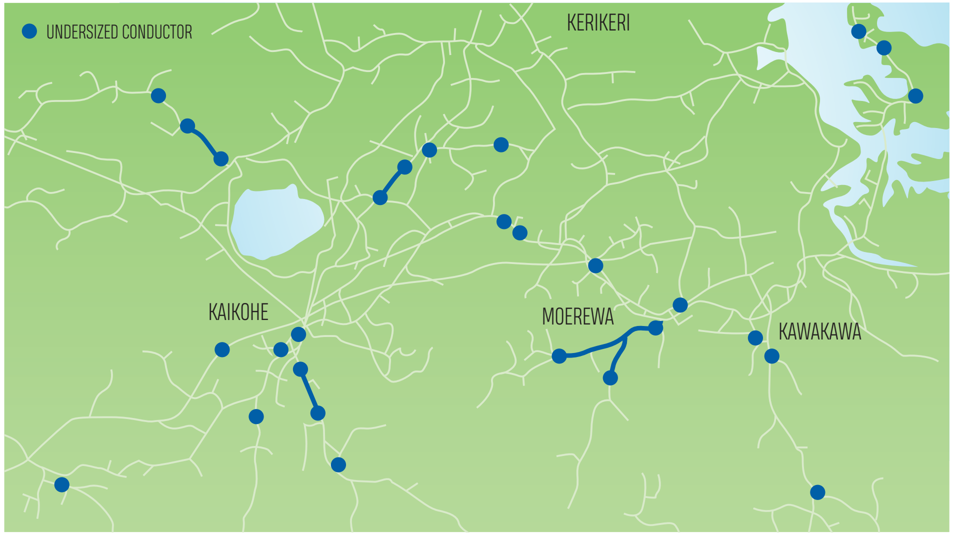

Figure 5-6 A Typical Area of the Network Showing Locations of Sub-optimal Conductor

Implications

- There is a risk of overheating and excessive sagging under high load conditions. This can cause heat cycling stresses, hot joints, and other potential failure modes.

Likelihood

- Short sections of undersized conductor has only a small impact on feeder capacity or voltage limits and therefore do not create a significant network constraint. Nevertheless, the progressive replacement of sub-optimal feeder conductors is underway. This is predominantly to remove the network of old galvanised steel and copper conductors due to rust and age-related embrittlement, and the consequent high risk of failure.

Options Considered to Address Constraint

OPTION	TYPE OF OPTION	DESCRIPTION	ESTIMATED COST
Option 1	Do nothing		$0
Option 2	Network Solution	Conductor replacement programmes split over the 10-year period to bring the network up to standard	$8.69M

Table 5-36: Sub-Optimal Conductors Along Feeders – Options Considered to Address Constraint

Option Selected and Rationale

OPTION	TYPE OF OPTION	RATIONALE
Option 2	Network solution	There is a requirement to upgrade undersized conductor to ensure voltage, capacity, and security requirements can be met. The phasing of this work will be prioritised based upon the condition of the conductor. Our capital expenditure forecast totals $7.3 million for conductor replacement over the 10-year AMP planning period, sufficient to replace 50 km of conductor. In addition, we have allocated $11.3 million to the reconstruction of the two- and three-wire 11 kV network and $7.3 million to SWER rebuilds.

Table 5-37: Sub-Optimal Conductors Along Feeders – Option Selected and Rationale

[5.6] Network Development Programme

This section 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 development categories in line with the Information Disclosures:

- Network Development;
- Reliability, Safety and Environment; and
- Customer Connections.

Over the first five years of the planning period, our network development focus will be on asset renewal and reliability projects. The network has sufficient capacity to accommodate our forecast short-term growth in consumer demand. The need to stabilise the reliability of the 11 kV network and subtransmission power transformers is more urgent. The Renewal and Replacement programme can be found in the Asset Lifecycle chapter, section 6.1

The exception to this is increased demand for new customer connections and Solar DER connections, including the connection of the three new solar farms, all of which will be connected directly to our 33 kV subtransmission network. Much of this work will be funded by customer capital contributions.

In the latter half of the planning period, we expect the penetration of DERs, EVs, and other decarbonisation technologies to continue to increase. As a result, localised electricity demand in some communities may increase to the point where it exceeds the capacity of the 11 kV network that currently supplying them. It is premature to forecast when and where this growth will occur, we are agile enough to adapt as these trends are identified. The change in the code allowing residential export of up to 10kW per connection could be a leading contributor to this capacity growth and would be funded as part of customer capex. Our capex forecast has pushed capacity expansion projects beyond the 10-year planning period. The expected increase in demand in the Kerikeri area will be addressed by the current Wiroa project, which will also improve overall supply quality and resilience.

5.6.1 – SYSTEM GROWTH & CUSTOMER CONNECTION CAPITAL EXPENDITURE

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

Over the first half of the AMP planning period, all of our capacity expansion work involves:

- the expansion of the Wiroa Substation
- a provision for new customer connections, and
- the connection of Twin Rivers, the last of the three new solar farms in our northern area. At the time of this AMP, this was still pending.
- The doubtless bay development begins with land acquisition in financial year 36.

Wiroa 110/33 kV Substation

The Kerikeri/Whangaroa area faces a potential future voltage constraint at Kaeo and Waipapa due to continued demand growth. Historically, the network planning approach required **N 1 security at all demand levels**, which triggered the expectation that a new 110/33 kV injection point at Wiroa would be urgently required. This project corresponds to the constraint detailed in section 5.5.8.

However, detailed risk assessment identified that **the actual operational risk in the medium term is low**, because:

- A breach of the voltage constraint could only occur if a **fault on the Kaikohe–Wiroa double circuit line** coincided with **peak deman**d periods — a rare scenario given the line is only ~10 years old and in very good condition.
- Periods where demand would exceed the alternative Kaikohe–Mt Pokaka–Wiroa circuit capacity occur for only a **small percentage of total annual hours**.
- Even if a fault did occur at peak demand, **loss of supply would not be total**.
  - Most of the load could still be supported via Mt Pokaka.
  - Only **managed load shedding** would be required, initially minor and gradually increasing over time as demand grows.
  - The shortfall in energy supplied would be **comparable to an 11 kV feeder outage** for the first few years.

This assessment showed that the immediate need for full N 1 security was lower than previously assumed and that renewal of the **deteriorating 11 kV network** represented a more urgent reliability priority.

The chosen solution is to **progress with the new 110/33 kV Wiroa Substation**, but to **stage the development** to align expenditure with actual risk and system need:

Stage 1 – Initial Build (FY 2026–2029)

- Construct the new 110/33 kV injection point at Wiroa.
- Install **one transformer** initially.
- Deliver the capacity required to address future constraints while prioritising capital for ongoing 11 kV reliability improvements.

Stage 2 – Full N 1 Capability (FY 2034–2035)

- Procure and install the **second transformer** later in the decade.
- Move to full security and long term capacity provision once demand growth justifies it.

This incremental approach ensures:

- Capital is **optimised**, allowing investment to be redirected to higher priority reliability risks.
- The network continues to meet performance expectations without overbuilding ahead of need.
- The region is prepared for long term growth while maintaining affordability.

Project Description:

The Wiroa 110/33 kV Substation project involves constructing a new subtransmission level injection point at the existing Wiroa 33 kV switching station. Initially planned for FY 2023 to support projected demand growth, the project was deferred following a formal risk review that showed the voltage and security constraints could be managed safely in the short to medium term.

The project will now be delivered in two stages:

- **FY 2026–29**: Construct the site and install the first transformer. This reduces immediate voltage and load transfer exposure while maintaining cost efficiency.
- **FY 2034–35**: Install the second transformer, completing the substation and delivering full N 1 capacity as future demand requires.

Throughout the staged build period, the existing Kaikohe–Wiroa infrastructure, supported by Mt Pokaka, provides adequate interim capacity. Managed load shedding during a rare coincident fault peak scenario remains technically feasible, with impact comparable to a typical 11 kV feeder event.

This project is a key strategic enabler for long term network resilience and growth in the Kerikeri/Whangaroa region, while ensuring prudent and risk aligned capital allocation.

Doubtless Bay Development

The Doubtless Bay development has been deferred beyond the 10-year planning period due to changing network priorities and a need to keep abreast of the deteriorating condition of the 11 kV network. In our 2023 AMP, we reported on the recent growth in demand, however, we have not yet seen the anticipated acceleration.

There is a need to eventually relocate the Taipa zone substation, given its proximity to the Taipa estuary and the risk of flooding from sea-level rise driven by climate change. This is discussed in Section 8.6, there is also a potential tsunami risk. Our plans to address this and best serve Doubtless Bay would be to replace Taipa with two new substations: one on the Karikari Peninsula, in the vicinity of Tokerau Beach, and the second at either Coopers Beach or Mangonui.

The two substations would be served by the existing 33 kV line feeding Taipa, and possibly by a new 33 kV line between a tee point on the Church Rd-Pukenui line at Awanui and Tokerau. An additional 33 kV line would connect these substations, eventually forming an Awanui-Tokerau-Coopers Beach-Kaitaia ring. An alternative would be to supply the second 33 kV line to the Doubtless Bay area from our Kaeo zone substation, through the construction of a new Kaeo-Mangonui/Coopers Beach line. This would provide a 33 kV connection between our northern and southern areas.

This project corresponds to the constraint detailed in section 5.5.11.

Decarbonisation Load Growth

Beyond the 10-year planning period, we expect demand growth to accelerate, driven in part by the increased penetration of EVs. Some of this growth will be due to the installation of high-capacity fast chargers, which are spot loads where the developer will pay for any network reinforcement. However, the majority will be incremental as most EV charging will continue to be done at home.

While the existing subtransmission network generally has sufficient capacity to meet this expected increase in demand, the 11 kV network does not. This network will need to be reinforced if it is supplying localised demand growth in locations not close to our zone substations. Often, this is most effectively achieved by increasing the injection points, which involves constructing new subtransmission lines and zone substations. In many cases, this development can be incremental, as suggested in our plans for the Doubtless Bay region, through the initial operation of new 33 kV lines at 11 kV to defer the construction of new substations.

We have identified several locations in our supply area where we think reinforcement of this nature might be required, but at this point, it is difficult to forecast when it might be needed at each location. We therefore plan to include this in our capex forecast, which provides for such reinforcement beyond this planning period.

Network Capacity Expansion Expenditure Forecast

Our capital expenditure forecast for the network capacity augmentation project is shown in Table 5-38.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Wiroa Substation	4,584	1,575	1,829	0	0	0	**7,988**
Tokerau Substation	0	0	0	0	0	504	**504**
Total – System Growth	**4,584**	**1,575**	**1,829**	**0**	**0**	**504**	**8,492**

Table 5-38: Network Capacity Augmentation Forecast

Note: Totals may not add due to rounding.

Customer Connections

This relates to new assets required to connect new customers to the network. Capital contributions largely fund it. Our total forecast expenditure on customer connections and forecast recovery in capital contributions are shown in Table 5-39.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Customer-driven, funded by capital contribution	2,018	2,018	2,018	2,018	2,018	10,254	**20,344**
Customer-driven, funded by Top Energy	1,123	1,126	1,126	1,126	1,126	5,635	**11,262**
Total – Customer Connections	**3,141**	**3,144**	**3,144**	**3,144**	**3,144**	**15,889**	**31,606**

Table 5-39: Consumer Connection Expenditure Forecast

Note: Totals may not add due to rounding.

5.6.2 RELIABILITY, SAFETY AND ENVIRONMENT

Our network development programme for the last two regulatory periods has focused on:

- rehabilitating our subtransmission network
- adding new zone substations
- the installation of upgraded protection systems to improve the security of the 33 kV system
- most recently, the installation of diesel generation to secure those parts of the subtransmission system that are vulnerable through a lack of redundancy, and
- at the end of the last DPP period, the reliability and resilience of the 11 kV network.

This allowed us to develop a programme of works.

11 kV Reliability Improvements

Recent analysis, including the independent SAIDI review by Ergo Consulting and internal reliability assessments, confirms that the 11 kV network remains the dominant contributor to unplanned outages, accounting for over 90% of total SAIDI. Performance deterioration has resulted in breaches of the Commerce Commission's price-quality-path threshold, underscoring the need for accelerated intervention.

The updated reliability improvement strategy shifts from incremental upgrades to a risk-based, data-driven approach that prioritises feeders with the highest fault exposure and consumer impact. Key elements are listed below.

- **Strategic Asset Renewal:** Replace high-risk poles, conductors, and hardware identified through condition-based assessments and failure trend analysis, rather than age alone. We plan to allocate 73% of our budget to asset renewal.
- **Protection Enhancements:** Deploy advanced reclosers and sectionalising schemes on critical rural spurs to minimise outage duration and improve restoration speed across the 11 kV network.
- **Resilience Through Interconnection:** Construct feeder ties and alternative supply paths to reduce vulnerability to single-point failures and weather-related events highlighted in recent reviews. Two strategic interconnection projects we are currently completing are the South Road and Rangiahua feeders, as well as the Matauri Bay and Whangaroa Feeders.
- **Capacity Reinforcement:** Utilise the 11 kV tertiary winding on the Kaitaia 110/33 kV transformer to strengthen supply security for South Road and Oxford St feeders (FY 2024–FY 2025). This project is nearing its completion and is set to be commissioned by March 2026.
- **Performance Monitoring:** Implement real-time reliability metrics and fault analytics to validate improvements and guide future investment decisions.

This programme reflects a shift toward proactive reliability management, integrating lessons from recent SAIDI performance reviews and aligning with the Board's directive to stabilise service quality while maintaining cost efficiency. Table 5-41 and Table 5-42 below show the planned expenditure forecast for reliability, safety and environment.

Communications Upgrades

The communications upgrade programme consists of:

- **Backbone** – installation of Microwave and optical fibre backbone to bring back aggregated data to our systems (i.e. ADMS).
- **VHF** - This is our current communications network, which we will be retaining for voice. Repeaters will be installed in Russell and Kawakawa (FY 2028), and upgrade to the VHF digital radio network in FY 2030
- **UHF** - UHF has a smaller range than VHF, but increased capacity, for data throughput. We will be utilising the lower end of the frequency range to maximise the range where possible. We will be installing UHF telemetry base stations, and field telemetry remote devices from FY 2027-2030 alongside our existing VHF repeaters, as well as creation of new base station sites where required to fill the gaps in network coverage.

Kaeo Security of Supply

Table 5-40 below represents the 33 kV line build from Wiroa to Kaeo substation which is planned to be constructed in tandem with the 110 kV line build from Wiroa to Kaitaia. This approach allows for a double circuit build, with both lines sharing the same structures up to Omaunu Road. At this point, the 33 kV line will branch off and continue down to the Kaeo substation, ensuring efficient use of infrastructure and minimising environmental and construction impacts along the shared route and resources to construct the line, as well as benefitting from efficiencies gained in resourcing, procurement and planning with the Wiroa to Kaitaia build. This project also corresponds to the constraint detailed in section 5.5.8.

Costs for the double circuit shared with the Wiroa-Kaitaia 110 kV line build, to replace the existing Kaitaia-Kaikohe 110 kV line, is shared evenly between the projects.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Wiroa - Kaeo Security 33 kV line	**-**	**-**	**9,000**	**15,700**	**-**	**-**	**24,700**

Table 5-40 Wiroa-Kaeo 33 kV Spur Expenditure Forecast

Reliability, Safety and Environment Expenditure Forecast

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
WIROA - KAEO SECURITY 33 kV LINE							
Wiroa – Kaeo Access and Vegetation	0	0	6,900	0	0	0	**6,900**
Wiroa – Kaeo Dual Circuit	0	0	2,100	4,200	0	0	**6,300**
Wiroa – Kaeo Spur Build	0	0	0	11,500	0	0	**11,500**
Total – WRR-KAO Spur Build	**0**	**0**	**9,000**	**15,700**	**0**	**0**	**24,700**
SUBTRANSMISSION							
33 kV Circuit Interconnections	0	0	0	0	0	4,238	**4,238**
Total – Subtransmission	**0**	**0**	**0**	**0**	**0**	**4,238**	**4,238**
SUBSTATIONS							
Kaitaia Substation	0	0	0	0	0	889	**889**
Kaikohe Substation	22	0	0	0	0	451	**473**
Wiroa Substation	0	0	0	0	0	6,214	**6,214**
Waipapa Substation	0	0	0	0	0	4,062	**4,062**
Minor Substation Upgrades & Operational Improvements	65	54	54	54	54	0	**281**
Total – Substations	**87**	**54**	**54**	**54**	**54**	**11,616**	**11,919**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
DISTRIBUTION LINES							
11 kV Feeder Interconnections	644	0	1,289	2,951	590	4,293	**9,767**
Power Quality Upgrades	228	228	283	228	228	693	**1,888**
Minor Network Upgrades	0	65	65	65	66	198	**459**
Small Network Capital Additions	73	73	73	73	73	299	**664**
Miscellaneous Network Modifications	0	214	0	0	0	0	**214**
Total – Distribution Lines	**945**	**580**	**1,710**	**3,317**	**957**	**5,483**	**12,992**
DISTRIBUTION CABLE							
Russell 11 kV Reinforcement	0	0	0	0	0	1,936	**1,936**
Total – Distribution Cable	**0**	**0**	**0**	**0**	**0**	**1,936**	**1,936**
DISTRIBUTION SWITCHGEAR							
Install New Autoreclosers & Sectionalisers	765	765	809	679	671	2,075	**5,764**
Group Fusing	106	284	138	284	81	699	**1,592**
Remote Control Switches	102	102	102	102	102	0	**510**
Total – Distribution Switchgear	**973**	**1,151**	**1,049**	**1,065**	**854**	**2,774**	**7,866**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
OTHER NETWORK ASSETS							
Communications Upgrades	363	748	676	103	167	1,065	**3,122**
Protection Upgrades	0	0	0	477	444	0	**921**
Fault Passage Indicators	73	73	73	73	0	0	**292**
Total – Other Network Assets	**436**	**821**	**749**	**653**	**611**	**1,065**	**4,335**
Total – Reliability, Safety & Environmental	**2,441**	**2,606**	**12,562**	**20,789**	**2,476**	**27,112**	**67,986**

Table 5-41: Reliability, Safety and Environment Capital Expenditure Forecast

Note: Totals may not add due to rounding.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Subtransmission	0	0	9,000	15,700	0	4,238	**28,938**
Substations	87	54	54	54	54	11,616	**11,919**
Distribution Lines	945	580	1,710	3,317	957	5,483	**12,992**
Distribution Cable	0	0	0	0	0	1,936	**1,936**
Distribution Switchgear	973	1,151	1,049	1,065	854	2,774	**7,866**
Other Network Assets	436	821	749	653	611	1065	**4,335**
Total – Reliability, Safety & Environmental	**2,441**	**2,606**	**12,562**	**20,789**	**2,476**	**27,112**	**67,986**

Table 5-42: Consolidated Reliability, Safety and Environment Capital Expenditure Forecast

[5.7] Embedded Generation Policies

Our approach to the connection of embedded generation by external parties is based on the principles listed below.

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

To enable the expansion and adoption of renewable energy, Top Energy has recently doubled the export limit for residential connections from 5 kW to 10 kW. Our policy and requirements for connecting embedded and distributed generation are available on our website. Nevertheless, proponents seeking to connect generators larger than 10 kW to our network should contact us to discuss their specific requirements.

Connection agreements have now been signed for 89 MW of geothermal generation and 67 MW of utility-scale solar generation. This exceeds our peak network demand. On a summer day when solar generation is at full capacity, and our internal network demand is relatively low, it is expected to fully utilise the capacity of the Kaikohe-Maungatapere connection to the Transpower grid.

Any new generation connected to our network is therefore likely to be frequently constrained over the summer. That said, spare capacity would be available when the solar generation output is low, and we are open to the connection of generators that can work around this constraint. This particularly applies to the generation that can provide network support, as discussed in Section 5.8.5.

[5.8] Non-Network Solution Policies

5.8.1 – INTRODUCTION

EDBs have traditionally relied on poles and wires to distribute electrical energy and assumed power flow would be in one direction – from the generator to the customer. However, as generation becomes more widely distributed across and within the network, these assumptions no longer necessarily hold true.

Consequently, we are closely monitoring and assessing the application of non-network alternatives to supply customers with power. Equally, the impacts of these technologies on the network are also being monitored.

5.8.2 – DEMAND SIDE MANAGEMENT

Demand side management (DSM) is the management of a consumer's demand to avoid overloading the network. It typically involves shifting a consumer's peak away from the network's peak to reduce the magnitude of the network's peak demand. This can defer the need for capital investment to increase network capacity, and potentially also reduce the transmission charges we pass through to our consumers.

DSM can also reduce the need to install diesel generation for network support. Our consideration of the need for a network augmentation incorporates an assessment of any identified DSM opportunities that could defer or reduce the cost of an augmentation.

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

- **Direct Load Management:** We routinely control water-heating load through our ripple-frequency-controlled load management system. Daily peak load shedding is based on the GXP peak load. Under emergency conditions, where network components are out of service, we also use the system to reduce load and maintain supply for as many consumers as possible. Load control relays also delay the restoration of hot water load for a short period after a total loss of supply, reducing switching spikes and avoiding equipment overload. We estimate that direct load management can reduce network peak demand by up to 11 MW.
- **Automatic Under-Frequency Load Shedding:** To prevent a total power system collapse following a major grid disturbance, Transpower System Operator, in accordance with the Code, requires automatic tripping of a percentage of each EDB's network load if a significant under-frequency event occurs. Top Energy has selected feeders at its substations to disconnect to meet the four load blocks stipulated by the System Operator. Under-frequency protection has been set up to meet the System Operator's North Island standard requirements.

Work is ongoing across the industry to develop market-based solutions for demand-side management through initiatives such as FlexTalk. Top Energy remains committed to closely following developments in this area and acting in concert with other EDBs to ensure a consistent approach, improved network performance and an overall improved service for our customers.

5.8.3 – REMOTE AREA POWER SUPPLIES

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

These studies have applied various criteria to determine a project's viability, including:

- customer location (end of a line)
- line length potentially to be removed
- condition of the line to be removed
- line route environmental factors
- number of connected consumers
- reliability and/or where a single supply circuit is prone to interruption
- location-specific risks (e.g., vegetation and/or forestry), and
- access.

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

We have found that this last factor, where a line has already undergone a degree of replacement and refurbishment as a reactive measure, continues to tip the balance against adopting RAPS as an economic alternative to lines. To date, no potential site has been identified that meets this level of scrutiny. This is before the customer consultation has commenced. Apart from a small number of enthusiastic adopters of new technologies, consumer acceptance of non-line alternatives is unlikely to be positively received unless suitable inducements are offered. This will further reduce RAPS's viability.

We estimate the standard residential installation cost of a RAPS to be close to $100,000, and its ongoing maintenance costs are not insignificant. The economic lives of RAPS assets are also much shorter than that of an upgraded distribution line, further reducing the economic potential of RAPS when assessed on a lifecycle cost analysis.

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

5.8.4 – BATTERIES

Battery storage, particularly when coupled with photovoltaics, is not entirely new, as small DC systems have been commonly used for many years. However, the use of battery storage in the world of AC power is relatively new, driven largely by:

- reductions in battery costs and solar panel costs, and
- improvements in battery efficiency and inverter technology.

Battery storage transforms how solar (or wind) power generation can be used, enabling it to be made available when it is needed, rather than when it is generated (depending on the capacity of the installed batteries). Batteries behind the meter, to store energy generated during the day for use in the evening when demand is higher, have become more prevalent in domestic photovoltaic installations.

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

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

We currently have a few network constraints where batteries could provide a potential solution. However, there is potential to use batteries to manage transients when utility-scale photovoltaic generation is connected to our network. None of the three utility-scale solar farms to be connected to our northern network incorporates a battery. The proponents have stated that these solar farms can meet the required dynamic response without one, and our own consultant has confirmed this.

While the cost of battery storage is reducing rapidly, cost remains a barrier to widespread, large-scale adoption of battery installations.

5.8.5 – NETWORK SUPPORT

If privately owned generation or other equipment, such as battery storage, seeks to connect to the network and has a network benefit, we will negotiate on a case-by-case basis to find a commercial solution that recognises the connection’s network benefit. We are open to negotiating with investors to:

- secure such a generation that would improve supply reliability, or
- defer the need for network augmentation to meet localised incremental load growth.

This could be an opportunity for a business considering installing generation as a backup in the event of a network supply interruption. Areas where such generation or utility-scale battery storage could potentially provide distribution network support include:

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

5.8.6 – OTHER FUELS

Two further technical developments that may affect electricity networks are the manufacture and use of methanol and hydrogen for the transport industry, as the production of both fuels is electricity-intensive. Methanol is likely to be only an interim fuel while electric and hydrogen-powered vehicle technology matures.

Hydrogen-powered vehicles are like battery EVs because the electric motor provides the motive power. However, whereas in a battery EV the energy is stored in a battery, in a hydrogen-powered vehicle, it is stored in a pressurised hydrogen tank. The hydrogen is then converted to electricity by a fuel cell within the vehicle. Hydrogen vehicles can be refuelled in minutes and travel longer distances than battery EVs, making hydrogen an attractive option for powering the heavy transport fleet. Its main disadvantage is the need to use electricity to produce hydrogen, which is then converted back to electricity, reducing the end-to-end efficiency of the process. Hydrogen is also only attractive as a fuel if it is manufactured using electricity generated by renewable resources.

A network of hydrogen refuelling stations is currently being built in New Zealand by a private developer. Four are currently under construction, and 24 are planned by 2026, one of which is likely to be in Whangarei. The developer plans to expand this network to 100 by 2030, which could include one or more refuelling stations in our supply area.

5.8.7 – SMART METERING

Smart metering measures consumption on a half-hourly basis, enabling the introduction of tariff structures that discourage electricity consumption during peak demand. Meter readings are downloaded over a communication link, avoiding the cost of monthly meter reading visits. Approximately 75% of our consumers have smart meters installed.

Smart meters can be programmed to automatically notify our Control Centre when the supply is lost. Our opex forecast includes a data-gathering exercise to enable us to extend our ADMS functionality to include active, real-time management of the LV network. This will be done by having ADMS ingest AMI data from SmartCo smart meters using an API. Planning for this initiative has begun. The disaggregated demand data available using such meters would also enable more effective management and planning of our network.

Top Energy has recently acquired access to smart meter data through the Hiko platform. This provides LV visibility into the current state of the LV network, including information on power quality, planning, design, and reliability. The package integrates the LV connectivity model in the GIS, developed using data from the data capture project, with smart meter data, to identify potential power quality issues on the LV network.

The tool uses voltage and loading data from smart meters to provide a detailed analysis of network performance, offering a thorough evaluation of network capacity and potential congestion points.

The reports available include:

- Voltage Compliance – Voltage quality, Tx over voltage, Tx under voltage, and
- PV compliance – Over limit export, over voltage export, unapproved export, among others.

LIFECYCLE ASSET MANAGEMENT

SECTION 6
LIFECYCLE ASSET MANAGEMENT

This section of the AMP outlines the policies, strategies, and practices that we use to ensure that assets:

- deliver acceptable performance, and
- can be operated safely over their full economic service life.

[6.1] Maintenance and Renewal Planning Criteria and Assumptions

Our lifecycle asset management practices are planned to deliver the required level of service for the lowest possible lifecycle 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 efforts on high-risk assets, where criticality reflects both the likelihood of failure and the potential consequences associated with that 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, or
- if necessary, the replacement of assets where immediate, unplanned intervention is required to address critical safety issues or to maintain supply to consumers.

This work is driven by unexpected asset failures, which can result from third-party interference, such as a car hitting a pole, foreign interference from birds or animals, damage from lightning or storms, or asset component failures. The forecast, which is based on costs incurred in previous years, has two elements:

- an opex element that covers the repair or replacement of components, and
- a capex element that covers the replacement of complete assets.

Our Kerikeri Control Centre is always staffed. Field staff are on standby outside normal working hours to attend to service interruptions and emergencies. The cost of operating our Control Centre is included in the system operations and network support forecast and is not considered an asset lifecycle management cost.

6.1.2 – ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTION

Our routine and corrective maintenance, and inspection programme is designed to ensure that assets continue in service for their expected economic life. It includes:

- periodic asset inspections and condition assessments, and
- 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. The programme focuses on assets where:

- end-of-life drivers are most likely to be present, and
- an unexpected failure would result in widespread supply interruptions or a high safety risk.

Asset Health Indicators

Table 6-1 lists the categories we use as our asset health indicators.

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'. This is the point at which an asset starts to deteriorate, and closer monitoring of its condition is justified.

6.1.3 – RISK-BASED INSPECTION AND MAINTENANCE

Top Energy applies a risk based lifecycle approach to inspection, testing, servicing and renewal across all major asset classes. Our objective is to deliver required safety, service quality and reliability at least cost over the asset life. We combine time based intervals with condition based triggers where observed asset health or performance warrants intervention earlier or later than calendar schedules. During inspections, defects are recorded and the inspector assesses whether each asset is likely to remain in service until its next programmed inspection. Where survival is uncertain, the asset is routed into our defect management process; assets rated H1–H3 under the EEA asset health indicator system are prioritised accordingly.

We already use health/condition assessments from PM inspections—including oil sampling, thermography, ultrasound, relay validations and defect severity—to decide whether assets are maintained, replaced, or managed on a run to failure basis with appropriate controls. Time based tasks are detailed in each fleet section, and condition based triggers will override calendar schedules where diagnostics indicate elevated risk.

We will continue to enhance how decisions are captured and reviewed. This includes review of fault data and use it as a direct feedback loop into replacement priorities, inspection frequencies, and the definition or refinement of failure modes. A simple Plan–Do–Review–Refine cadence will guide updates: plan and document criteria and thresholds; do by applying them in standards and work instructions and scheduling work; review performance and failure insights on a periodic cycle; and refine intervals, thresholds and renewal triggers, reflecting updates in both our standards and this AMP. This approach keeps the programme clear, consistent and evidence based, and aligns our lifecycle planning with regulatory expectations.

6.1.4 – DEFECT MANAGEMENT

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

- assets exhibiting end-of-life drivers are re-inspected at appropriate intervals
- intrusive maintenance activities are performed when they represent a cost-effective and operationally sound approach to extending asset life, and
- assets are replaced at the appropriate time. This will depend on the asset's criticality, which is primarily determined by the consequences of an in-service failure. Critical assets are replaced earlier to minimise the risk of failure, while non-critical assets may be allowed to run to failure. Consequence is assessed in terms of both safety and the impact of an asset failure on the level of service we provide.

Figure 6-1 shows our defect management process.

When an asset enters the defect management system, it is assigned a defect priority. Listed below are the assigned defect priorities we apply.

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

These defect priorities are broadly equivalent to the risk categories R1-R3 in the EEA's Asset Criticality Guide. Risk categories in the criticality guide are two-dimensional, considering not only the condition of an asset but also the consequences if the asset fails in service.

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

Additional measures are also taken to ensure that defect management is both effective and efficient. These additional measures are listed below.

- 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 planned asset renewal capex programme, so we don't repair defects shortly before an asset is to be renewed. Situations may also arise in which several small defects on a single asset lead to earlier asset renewal.
- Asset components may be separated and managed separately if we find, through fault analysis, that their failure rates are increasing. We have identified an increasing trend in crossarm failures. A separate provision has been included in our asset renewal capex forecast for a proactive crossarm replacement programme.

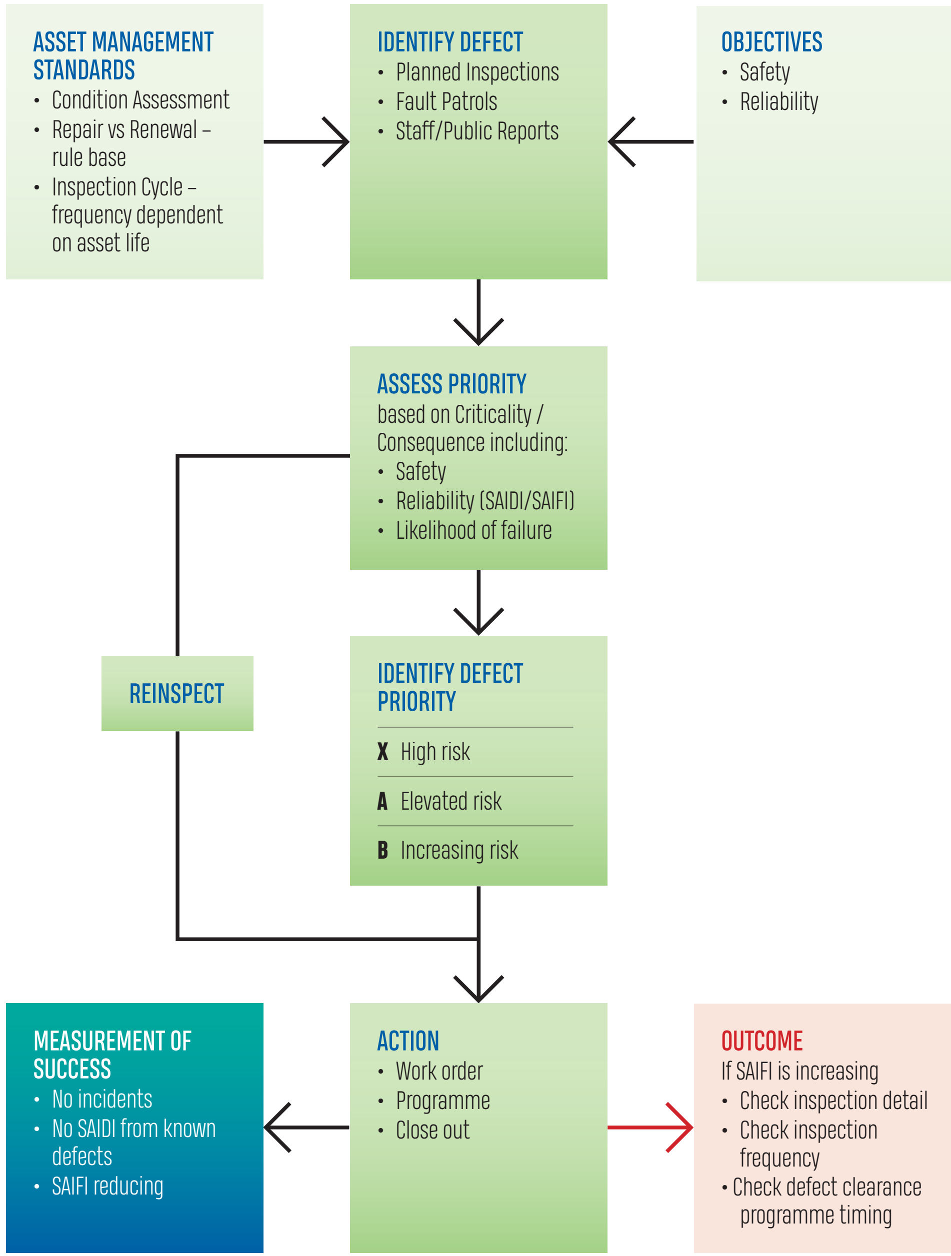

Figure 6-1: Defect Management Process

6.1.5 – REPLACEMENT AND RENEWAL MAINTENANCE

Replacement and renewal maintenance is proactive condition-based maintenance triggered by the findings of the inspection, condition assessment and defect management programmes described in Section 6.1.2.

The objective of the renewal maintenance programme is to prevent unexpected in-service failures with unacceptable safety or network performance consequences.

6.1.6 – CAPITAL REPLACEMENT

We continue to develop our condition-based asset risk management models (CBRM) and have now reached the point where most of our high volume field asset classes have been modelled.

The classes we model for risk are:
- Poles
- Crossarms
- Conductor
- Switchgear

The model ranks the asset risk of each individual as a factor of asset health which is the probability of the asset failing in service weighted by criticality, or the potential consequence, of such a failure.

The individual asset scores can then be aggregated to give a broader picture of the overall health of each asset class and how this would change over time if different interventions were applied. Inputs to the model include a wide range of parameters that can be expected to affect asset health – such as age, condition, and environmental factors likely to impact the rate of deterioration. As well as parameters related to criticality – such as the impact of the asset failure on the operation of the network and the likelihood of the failure causing a public safety hazard.

The model forecasts asset condition over ten years and uses data such as:
- Inspection Data;
  - Asset Health
  - Defects
- Asset Characteristics;
  - Age
  - Type
  - Configuration
- Geospatial Data;
  - Pollution
  - Coastal

High risk assets are validated for data accuracy and outputs are balanced with the defect remediation requirements, customer feedback, regulatory or compliance impacts and fault/performance inputs to create replacement requirements and prioritisation.

The output of these models are now used as part of our replacement decision making. This process is currently in its infancy and being refined. Asset replacements are currently a mix of age and condition based using the CBRM models. Our detailed asset replacement strategies for each asset category are described in Sections 6.2 to 6.17.

Our capital forecast for the replacement of existing assets (as distinct from the creation of new assets) is described in Section 6.19. The list below shows the four components covered in this section.

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

Our top-down analysis of the various asset fleet categories is presented in Sections 6.2 to 6.17.

6.1.7 – VEGETATION MANAGEMENT

Vegetation management is a cornerstone of our asset management strategy, underpinning both public safety and the reliability of our electricity network. High vegetation growth rates and diverse land use characterise the unique environmental conditions in our supply area. These conditions demand a proactive, systematic approach to controlling the risks posed by trees and other vegetation near our assets.

Our philosophy is prevention-first. We aim to identify and mitigate vegetation-related risks before they affect network performance or public safety. This is achieved through:
- a comprehensive programme of regular inspections, targeted cutting, trimming and spraying, and
- the establishment of vegetation clear zones around critical infrastructure.

By maintaining these clearances, we significantly reduce the likelihood of vegetation-related faults, outages, and safety incidents.

We recognise that effective vegetation management is not solely a technical or operational challenge, but also a collaborative process involving landowners, regulatory authorities, and the wider community. Our strategies are developed in accordance with the Electricity (Hazards from Trees) Regulations 2003 and the Health and Safety at Work Act 2015. These place clear obligations on both network operators and Persons Controlling a Business or Undertaking (PCBU) to manage vegetation risks.

We work closely with landowners to reach agreements on tree removal, trimming, and ongoing maintenance. We actively engage in public awareness campaigns to ensure all stakeholders understand their responsibilities.

Where possible, our preferred approach is to reduce vegetation hazards by establishing and maintaining clear zones where planting is restricted. In cases where this is not feasible, such as on land not owned by the network or where trees have high amenity value, we negotiate management agreements with tree owners. For new plantings, we emphasise the importance of minimising foreseeable hazards and complying with regulatory requirements from the outset.

Active management is an ongoing necessity. Our inspection regime includes annual and biennial surveys of vegetation proximity and risk, with a focus on high-voltage lines and areas of rapid growth. When vegetation is found to be encroaching or presenting a future risk, we intervene promptly, either by direct action or by working with the responsible landowner. In situations where vegetation has already caused a fault, we ensure only qualified personnel undertake remediation, reflecting the heightened safety risks.

While our protection systems provide a critical backup, detecting faults and interrupting supply in the event of vegetation contact, these are considered the last line of defence. Our operational focus remains firmly on prevention, as this is the most effective way to safeguard both the public and the network. This proactive approach not only supports regulatory compliance but also aligns with our commitment to delivering a safe, reliable, and resilient electricity supply to our community.

In summary, our vegetation management programme is built on the principles of risk reduction, stakeholder engagement, and continuous improvement. By prioritising early intervention and fostering strong partnerships with landowners and regulatory bodies, we ensure that vegetation risks are managed efficiently and effectively, protecting people, property, and the integrity of our network.

[6.2] Poles

6.2.1 – FAILURE MODES

Interference	• Excavations. • Third-party attachments (drilling into poles). • Accidental contact (vehicles).
Typical degradation	• Spalling, rotting, and rusting of poles. • Foundation movement due to ground subsidence.
Accelerated degradation	• Material degradation in coastal and geothermal environments. • Vehicular impact. • Tree falling. • Ground subsidence. • Substandard manufacturing quality.

Known equipment issues	• Wood poles are organic and are susceptible to rot and cellular breakdown. The breakdown rate is variable and depends on:
	  • the tree type
	  • growing environment
	  • pole processing
	  • wood treatments, and
	  • the environmental conditions in which the pole is installed.
	• These variables make the rate of deterioration of wood poles unpredictable. Larch poles pose a heightened risk as they can look good on the outside but be hollow and weak inside.
	• L-and T-shape concrete poles have a known construction flaw. Short reinforcing pieces were welded together to make full-length pieces when the required length was unavailable. Affected units have failed, and their whereabouts are unknown.

Table 6-2: Failure Modes

6.2.2 – 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. • A defect is raised, which will be addressed through a corrective maintenance work order.
Wood pole loses strength due to rot	• All wood poles are treated as unsafe and given a below-ground inspection to determine whether they are safe before they are climbed. • We have ultrasonically checked all wood poles on the network for residual strength, and all high-risk poles identified by this process have now been replaced. The results of this assessment are now being used to prioritise poles for scheduled replacement.
L/T shape pole failure	• L- and T-shape poles are not climbed without being supported. These are not tagged, as field staff are made aware of this requirement during competency training.
Poles can be climbed unassisted	• New structures are designed to be difficult to climb unassisted. Securing signage and other attachments to our poles is prohibited. The Far North District Council is aware of the risk and this restriction. • When a climbable pole is discovered, we undertake a risk assessment and prioritise remediation as appropriate to manage the risk. This may include removing the climbing aid, installing a climbing barrier, or replacing the pole.

Table 6-3: Risk Management

6.2.3 – PREVENTIVE MAINTENANCE

Visual	• A visual condition assessment every five years with defects recorded in our ERP where appropriate
Test	• A wood pole ultrasonic serviceability assessment has been completed and documented.

Table 6-4: Preventive Maintenance

6.2.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Minor unplanned and reactive remediation	• Foundation repair and stay installations. • Hardware replacements. • Reactive patrols post-fault as required

Table 6-5: Preventive Maintenance

6.2.5 – STEEL AND CONCRETE POLES

Steel Towers

There are 14 steel tower structures on the 110 kV Kaikohe-Kaitaia line. These were installed about 1966 to support the now dismantled 50 kV line that originally supplied Kaitaia. They have been well-maintained and are still in serviceable condition.

Steel Poles

There are 176 steel pole structures on our network. Most of these are on the 110 kV system, including:

- the Kaikohe-Wiroa line (currently operating at 33 kV), and
- the recently constructed 110 kV line that delivers electricity generated by the OEC4 unit at Ngāwhā to the 110 kV bus at Kaikohe.

A small number are replacement structures on the 110 kV Kaikohe-Kaitaia line, installed as part of our ongoing structure maintenance programme on this asset.

Steel is now our preferred pole type for the 110 kV network.

Concrete Poles

Over 96.6% of the poles on our network are concrete, which remains our preferred pole type for all voltages, except 110 kV.

AGE PROFILE – CONCRETE AND STEEL POLES

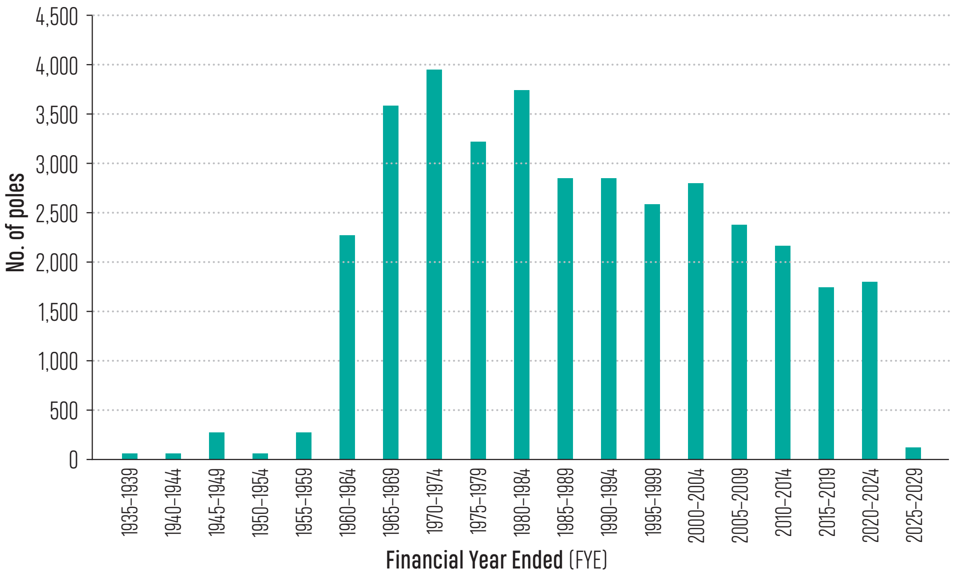

Figure 6-2: Age Profile – Concrete Poles

6.2.6 – WOOD POLES

There are 917 wood poles or pole structures on our network, of which almost 50% are hardwood. While some of the original wood pole structures on the 110 kV Kaikohe-Kaitaia line remain, more than half of our wood poles are on the low-criticality SWER and low-voltage lines. A small number of wood poles remain on the 33 kV subtransmission network, and the balance are dispersed across the 11 kV two- and three-wire distribution network.

AGE PROFILE – WOOD POLES

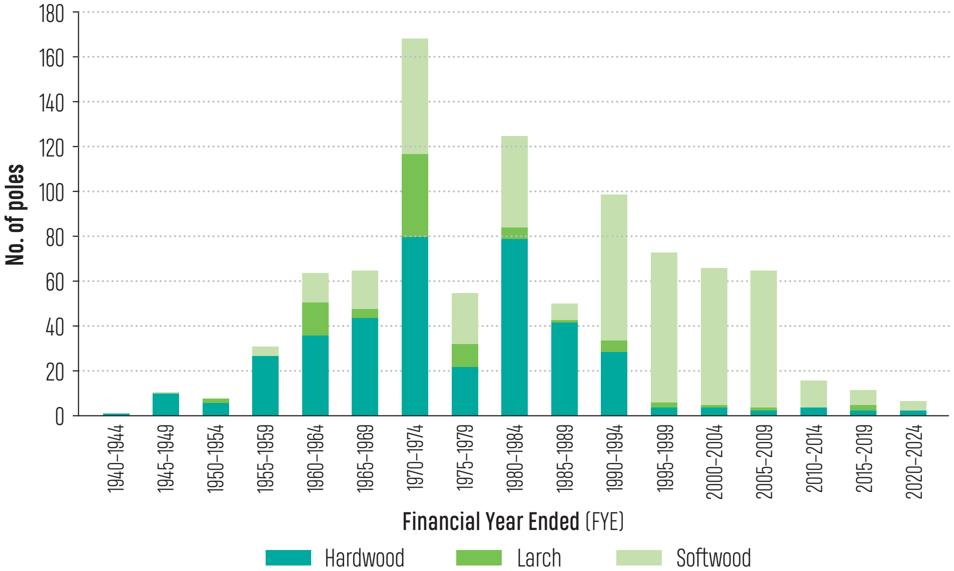

Figure 6-3: Age Profile – Wood Poles

6.2.7 – FIBERGLASS POLES

There are 44 fibreglass poles on our low voltage network. These have all been installed in the last 10 years and are in new or serviceable condition.

6.2.8 – POLE HEALTH SUMMARY

	UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
Steel and concrete	2,401	20	133	1,605	31,509	863	**36,531**
Wood	37	7	47	474	338	13	**916**
Fiberglass	–	0	0	0	12	32	**44**

Table 6-6: Health Summary – Poles

6.2.9 – REPLACEMENT PROGRAMME

110 kV structures	• The Kaikohe–Kaitaia 110 kV line remains a critical part of our subtransmission network. Recent condition assessments have highlighted the need to strengthen our approach to structure and hardware replacement. In addition to replacing approximately four pole structures per year based on condition and outage planning, we are placing increased focus on replacing ageing hardware components. These include insulators, crossarms, and fittings, which are renewed during scheduled shutdowns.
	• While full-line inspection remains important, the most effective method for assessing conductor condition is:
	  • physical sampling, and
	  • laboratory testing, which can be conducted only with conductor segments removed during scheduled annual outages. This testing will inform prioritisation but will not delay necessary conductor replacements where deterioration is already evident. Where conductor replacement is required, strain structures will be installed to support sectional upgrades. This integrated strategy supports:
	  • long-term asset resilience
	  • improves safety, and
	  • maintains reliable service delivery across the northern network.

Concrete poles	• Top Energy's replacement programme focuses on addressing higher-priority defects, particularly those classified as Priority X and A. They are identified through our inspection and asset health monitoring processes.
	While dedicated capital allocation supports the programme, the volume and nature of high-priority defects will require, and hence will be supported through, the annual capex works programme. This ensures that critical remediation of issues raised through the defect process can proceed without compromising broader network objectives.
	To further enhance prioritisation and planning, Condition-Based Risk Management (CBRM) models are being applied to pole and crossarm fleets. These models provide a data-driven view of asset health and risk, supporting both the:
	  • validation of replacement needs, and the
	  • identification of assets for inclusion in future renewal programmes.
	• This integrated approach ensures that the replacement programme remains responsive, efficient, and aligned with long-term asset management strategies.

Table 6-7: Replacement Programme

[6.3] Crossarm Assemblies

6.3.1 – 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).

Table 6-8: Failure Modes

6.3.2 – RISK MANAGEMENT

2-piece insulator failure during in-service handling	• Pre-work assessment of the two-piece insulator condition to augment the work method, mitigate risk, and replace if appropriate.

Table 6-9: Risk Management

6.3.3 – PREVENTIVE MAINTENANCE

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

Table 6-10: Preventive Maintenance

6.3.4 – CORRECTIVE AND REACTIVE MAINTENANCE

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

Table 6-11: Corrective and Reactive Maintenance

6.3.5 – REPLACEMENT PROGRAMME

Crossarm assemblies continue to be a significant contributor to equipment-related interruptions, historically accounting for a substantial portion of SAIDI. With the implementation of our updated ERP system, SAP S4HANA, crossarms are now treated as discrete assets, enabling improved tracking and planning of their condition and performance.

Recent trends have shown a notable increase in Priority A defects, with crossarms representing a significant share of this growth. In the last financial year, crossarm-related failures contributed approximately 10% of total unplanned SAIDI. While reliability remains a key driver, crossarm condition is also recognised as a public safety consideration. As such, prioritisation is now informed not only by historical interruption data but also by consequence modelling using CBRM and GIS tools. This ensures that assets in higher-risk environments are addressed appropriately. Although hardware-related failures have generally trended downward since 2022, recent data indicate a return to earlier levels. Crossarms, suspension insulators, and binders are the primary contributors.

These trends are closely monitored to inform future planning. To support this, we are continuing with our programme of crossarm and insulator replacements, targeting critical distribution line sections. These sections are selected based on a combination of historical performance, asset health indicators, and network criticality. Proactive replacements over defined line sections are treated as capital projects. In parallel, we remain committed to our public safety management obligations, including managing the volume of Priority A and B defects. Current levels exceed our internal KPI threshold of open defects, highlighting the importance of sustained investment across both corrective and planned renewal programmes.

[6.4] Overhead Conductor

6.4.1 – 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 (high demand, underrated conductors). • Vibration.
Known equipment issues	• Steel conductor (rusting and weakening). • Copper conductor (ageing and weakening). • Bimetal 'pencil' connector (grease leaching). • Two-piece ceramic insulator (prone to the top shearing off).

Table 6-12: Failure Modes

6.4.2 – RISK MANAGEMENT

Conductor failure during in-service handling	• All live line work is currently suspended due to updated occupational safety and health requirements.
Close approach service	• A close approach service is provided to enable contractors to better manage risk where conductors are present.

Table 6-13: Risk Management

6.4.3 – PREVENTIVE MAINTENANCE

Visual inspection	• Post fault reactive patrols. • Two-yearly vegetation survey for conductors <33 kV. • Annual vegetation survey for conductors ≥33 kV.
Conductor Testing	• Funds have been allocated for testing conductors, which may be permanently removed from the network—particularly those made of copper and steel—during scheduled maintenance activities.

Table 6-14: Preventive Maintenance

6.4.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Conductor	• Join broken conductors (no conductor replacement). • Cut out and replace damaged sections (partial span replacement). • Whole span replacement (one or more span replacements).

Table 6-15: Corrective and Reactive Maintenance

6.4.5 – SUBTRANSMISSION-110 kV CONDUCTOR

The Kaikohe-Kaitaia 110 kV line comprises approximately 56km of coyote ACSR conductor, installed several decades ago. While earlier assessments noted only minor signs of wear, more recent inspections have identified localised surface deterioration across multiple spans. These findings, along with the conductor's age and evolving network demands, suggest that replacement may be required sometime during this AMP planning period.

To support future planning, conductor samples will be collected during annual outages and analysed to assess line condition, including local factors. These insights, together with a one-off drone inspection, will guide targeted conductor replacement where required and complement mitigation measures such as installing vibration dampers during structure replacements.

6.4.6 – SUBTRANSMISSION-33 kV CONDUCTOR

Most of our 315km of overhead 33 kV subtransmission conductor is AAC, although ACSR has been used over about 33km where extra strength is required. Approximately 36km of recently installed conductor is AAAC. An age profile of our 33 kV subtransmission conductor is shown below. This conductor includes the Kaikohe-Wiroa subtransmission line, as it is currently energised at 33 kV.

AGE PROFILE – 33 kV OVERHEAD CONDUCTOR

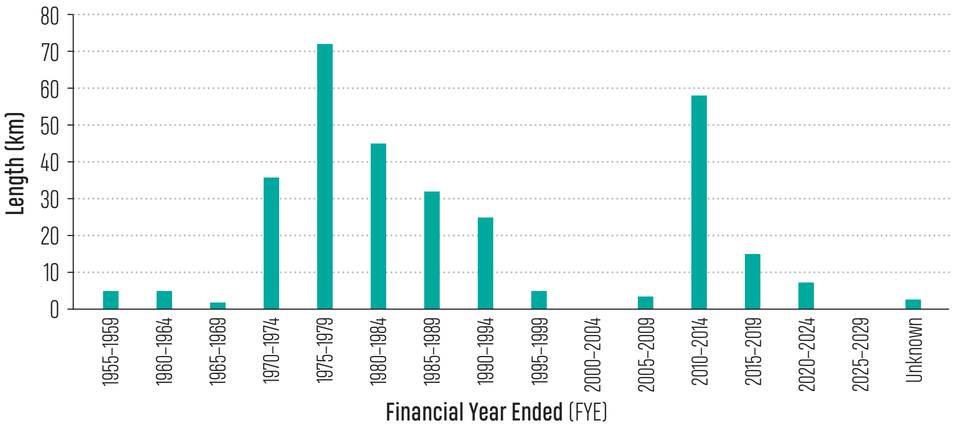

Figure 6-4: Age Profile – 33 kV Conductor

6.4.7 – DISTRIBUTION CONDUCTOR – TWO AND THREE WIRE LINE

Most of the 2,131 km of conductor on our 11 kV two- and three-wire network is aluminium or ACSR, although 85 km of older copper conductor remains.

AGE PROFILE – DISTRIBUTION CONDUCTOR (2 & 3 WIRE)

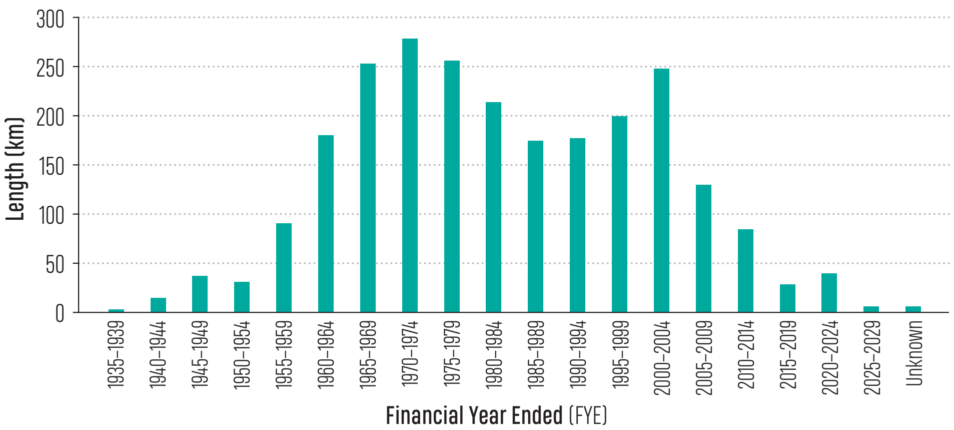

Figure 6-5: Age Profile – Two and Three-Wire Distribution Conductor

6.4.8 – DISTRIBUTION CONDUCTOR – SINGLE WIRE EARTH RETURN LINES

We have 452 km of SWER conductor on the network. Around 20 km of galvanised steel and 55 km of copper conductor remain on this part of the network. The balance is aluminium or ACSR.

AGE PROFILE – SWER CONDUCTOR

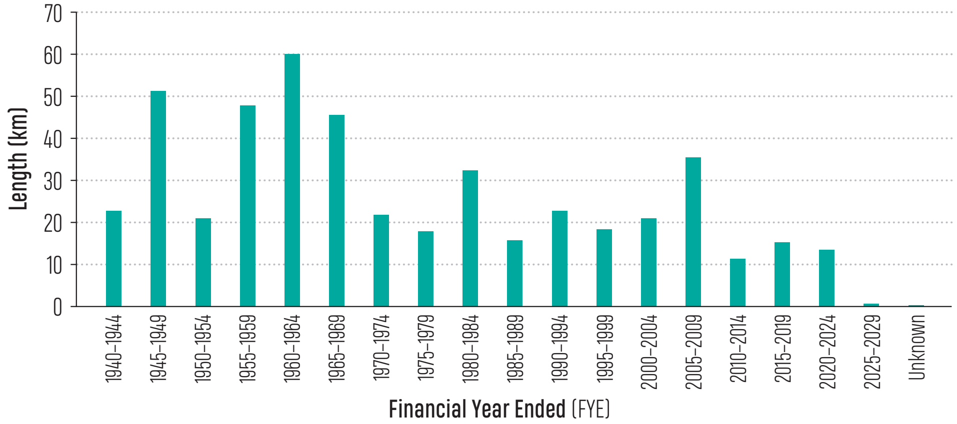

Figure 6-6: Age Profile – SWER Conductor

6.4.9 – LOW VOLTAGE

We have 272 km of low voltage overhead conductor on the network, of which about 150 km of mostly older conductor is copper. The balance is aluminium, with a small amount of ACSR.

AGE PROFILE – LV CONDUCTOR

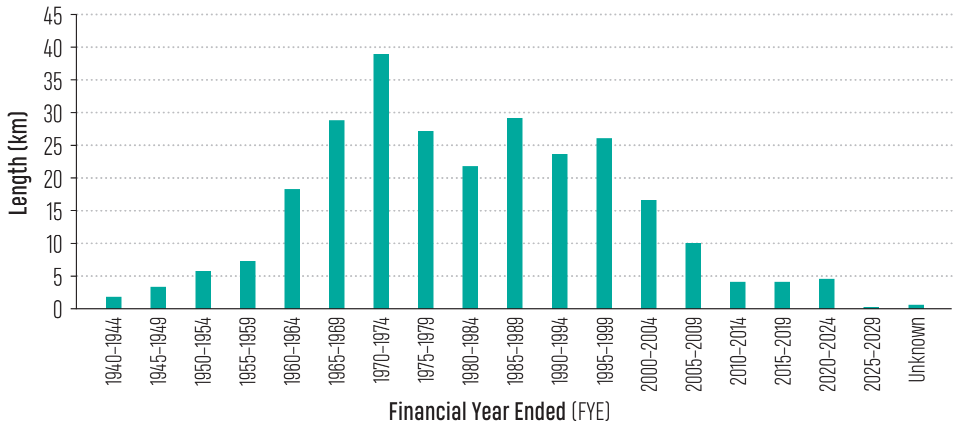

Figure 6-7: Age Profile – Low Voltage Overhead Conductor

6.4.10 – OVERHEAD CONDUCTOR HEALTH SUMMARY

CIRCUIT-KM	UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
110 kV	12	–	–	58	–-	–	**70**
33 kV	3	–	48	148	32	84	**315**
11 kV 2 and 3 wire	6	93	597	842	681	235	**2,454**
11 kV SWER	–	64	106	57	49	41	**317**
LV	1	13	76	94	68	19	**272**

Table 6-16: Overhead Conductor Health Summary

6.4.11 – REPLACEMENT PROGRAMME

We are planning to replace up to 10 circuit-km of conductor per year. The priority to complete this replacement is listed below.

- **Steel conductor:** Steel conductors, while offering high tensile strength and cost efficiency for long spans in remote areas such as SWER lines, have poor electrical conductivity. All steel conductors in the network have now deteriorated and reached end-of-life.
- **Copper conductor:** The copper conductor that remains in service is prone to failure due to its small size and deteriorating condition.
- **Mink conductor:** We have 85 km of mink ACSR conductor on our network, much of which is now well over 65 years old. It is a small conductor that is prone to breakage and can be difficult to repair.

Replacing these ageing assets will reduce outage risk, improve network resilience, and support long-term performance.

6.5 Cables

6.5.1 – 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 allow water ingress. • Poor bedding or installation techniques can reduce sheath life.

Table 6-17: Failure Modes

6.5.2 – RISK MANAGEMENT

Cable strike by third-party excavation or drilling	• A cable location service is provided to help contractors better manage risk when working near cables.
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.

Table 6-18: Risk Management

6.5.3 – 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.

Table 6-19: Preventive Maintenance

6.5.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Cable faults	• Repair sheath damage. • Cut away the damaged cable to a good section of the existing cable and join it to a new piece. • Overlay larger, damaged sections.
Termination fault	• Strip back old or damaged termination and repair. • Cut away the damaged termination from the good cable, join with a new piece, and terminate.

Table 6-20: Corrective and Reactive Maintenance

6.5.5 – SUBTRANSMISSION-33 kV (XLPE)

We have a total of 27 km of 33 kV underground cable, all of which is in serviceable or as-new condition.

AGE PROFILE – 33 kV CABLE

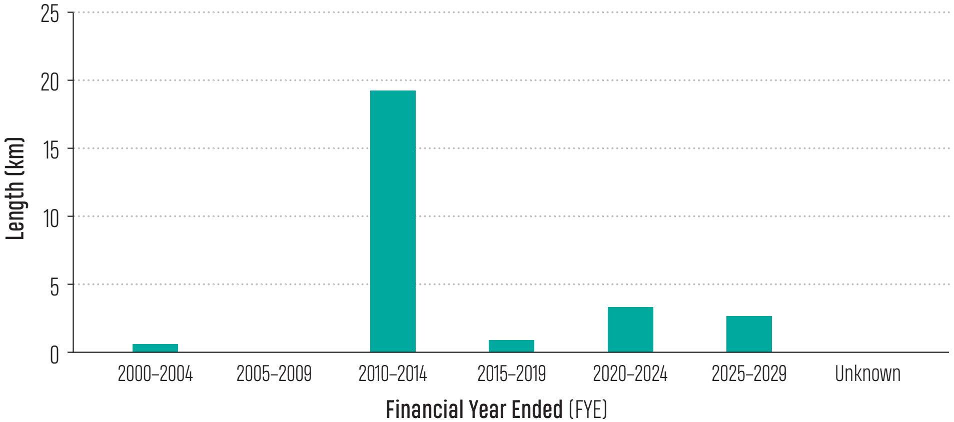

Figure 6-8 : Age Profile – 33 kV Underground Cable

6.5.6 – DISTRIBUTION

We have a total of 335 km of 11 kV underground cable on the network. Approximately 48 km of mostly older cable is paper-insulated, lead-covered (PILC). The rest is crosslinked polyethylene (XLPE).

AGE PROFILE – 11 kV CABLE

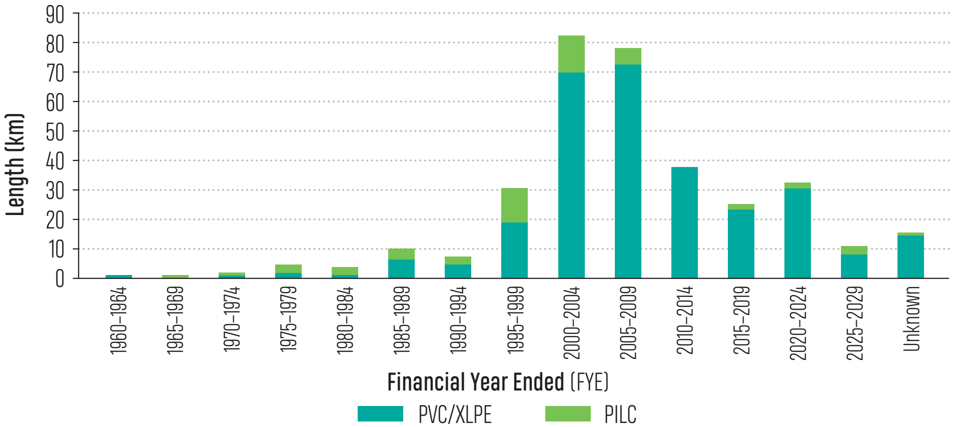

Figure 6-9: Age Profile – Underground Distribution Cable

6.5.7 – LOW VOLTAGE

All our low voltage cable, including streetlight cable, is PVC-insulated.

AGE PROFILE – LV CABLE

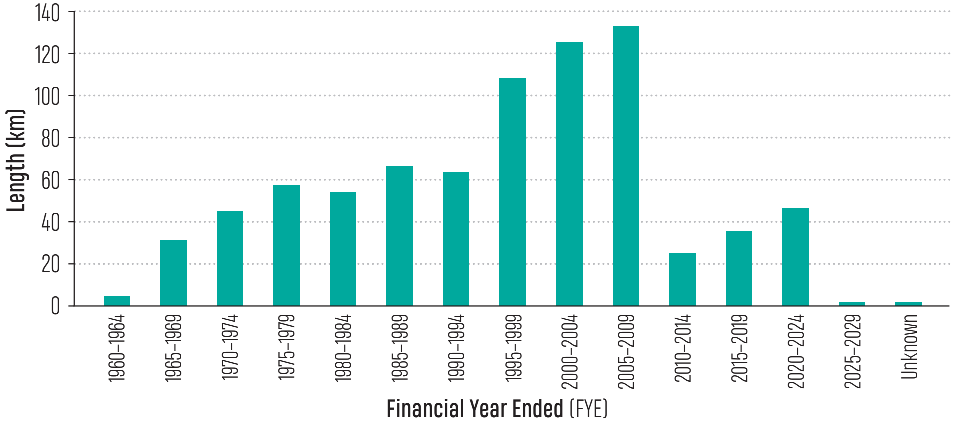

Figure 6-10: Age Profile – Underground Low Voltage Cable

Note: Excludes streetlight cable.

6.5.8 – STREETLIGHT CABLE

AGE PROFILE – STREETLIGHT CABLE

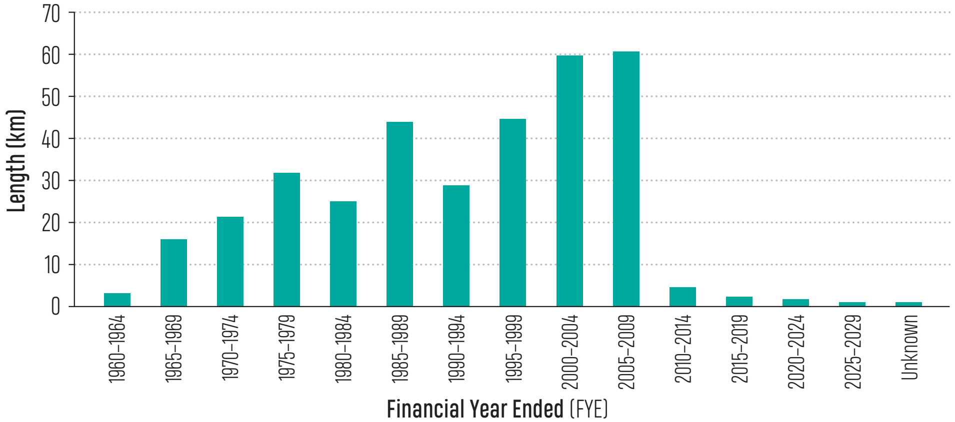

Figure 6 11: Age Profile – Streetlight Circuits

6.5.9 – CABLE HEALTH SUMMARY

CIRCUIT-KM	UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
33 kV	–	–	–	–	1	26	**27**
Distribution-PILC	1	–	5	10	27	5	**48**
Distribution-XLPE/PVC	14	–	3	13	162	95	**287**
LV	5	51	120	167	301	156	**800**
Streetlight	–	14	71	93	156	8	**342**

Table 6-21: Health Summary – Underground Cable

6.5.10 – REPLACEMENT STRATEGY

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

[6.6] Distribution Transformers

6.6.1 - 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.

Table 6-22: Failure Modes

6.6.2 – RISK MANAGEMENT

Exposure to live internal parts	• Ground mounted transformer enclosures are fitted with locks and bolts to prevent access. • Warning notices are attached to the equipment advising of the extreme risk within the enclosure. The emergency response number is also attached, so people can 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 that present a high risk	• All distribution transformers are inspected in accordance with our time-based inspection strategy, and any identified safety issues are recorded and programmed for remediation. • An emergency response number is available to the public to report problems.

Table 6-23: Risk Management

6.6.3 – PREVENTIVE MAINTENANCE

Visual	• Pole-mounted transformers are inspected every two years; ground-mounted units are checked yearly for defects like rust, oil leaks, damaged tanks etc.
Test	• Both pole mounted and ground mounted transformers have their earths tested every ten years.

Table 6-24: Preventive Maintenance

6.6.4 – 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 the earth bank to improve its resistance and functionality.
Protection system malfunction	• Check and test that the protection system meets the design standard. • Correct, repair, or replace protection to meet design standard.
Mounting and foundation malfunction	• Repair or replace the hanger arm, platform, pad, or components. • Re-secure equipment to the 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 an 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 its safety and operability, as appropriate.

Table 6-23: Risk Management

6.6.5 – POLE MOUNTED DISTRIBUTION TRANSFORMERS

AGE PROFILE – POLE MOUNTED DISTRIBUTION TRANSFORMERS

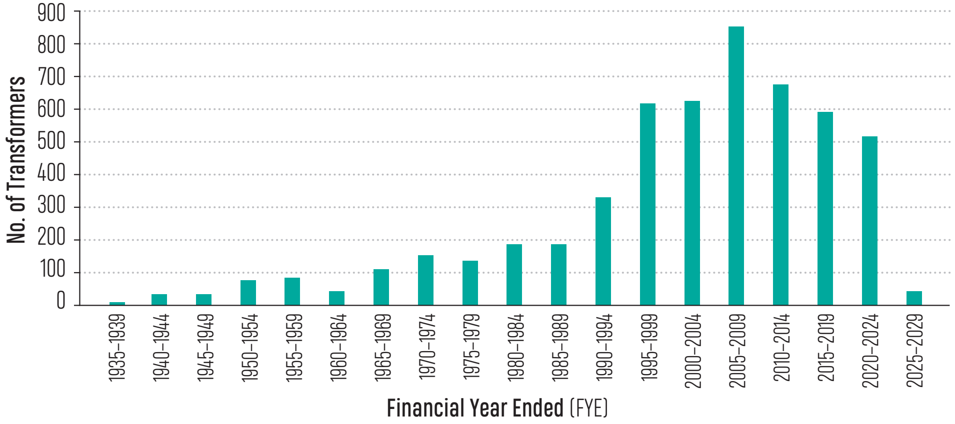

Figure 6-12: Age Profile – Pole Mounted Distribution Transformers

6.6.6 – GROUND MOUNTED DISTRIBUTION TRANSFORMERS

AGE PROFILE – POLE MOUNTED DISTRIBUTION TRANSFORMERS

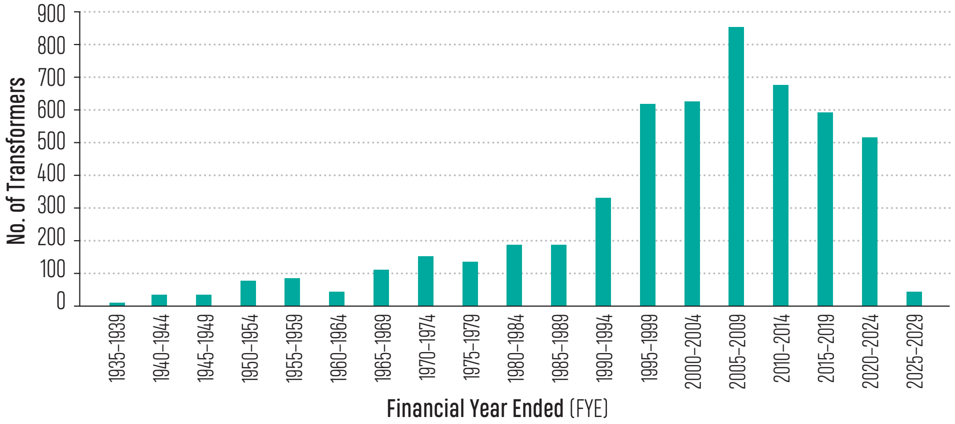

Figure 6-13: Age Profile – Ground Mounted Distribution Transformers

6.6.7 – GROUND MOUNTED SUBSTATION HOUSINGS

Top Energy currently manages sixteen distribution substations located within dedicated buildings. These assets vary in age, with construction dates ranging from 1960 to 2004. Of the sixteen sites, five are owned by Top Energy, while the remaining 11 are situated within buildings owned by third parties, predominantly within multifunctional commercial or industrial premises.

These substations have been identified as part of an ongoing Asset Access and Site Security Programme. This programme aims to establish a prioritised remediation schedule, focusing on sites assessed as high risk due to factors such as building condition, accessibility, and ownership complexity. Remediation works for the highest-priority sites are scheduled for completion by the end of FY 2027.

6.6.8 – DISTRIBUTION TRANSFORMER HEALTH SUMMARY

	UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
Pole mounted	328	4	26	142	4,662	93	**5,255**
Ground mounted	118	0	0	10	816	11	**955**

Table 6-25: Health Summary – Distribution Transformers

6.6.9 – REPLACEMENT STRATEGY

Our distribution transformer fleet is generally in good condition, with only four (0.2%) considered unreliable or end-of-life. Units are replaced:

- if actual or potential overloading is detected, or
- if oil leaks or excessive levels of rust are found during asset inspections.

Many older pole-mounted transformers are not fitted with surge arresters, and a small number of transformers fail each year after being struck by lightning. An external repair workshop assesses the condition of distribution transformers removed from service and, if economically viable, refurbishes them prior to returning them to service.

[6.7] Voltage Regulators

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, the unit is removed, sent for testing, and reconditioned if economical.

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

6.7.1 – 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.

Table 6-26: Voltage Regulator Failure Modes

6.7.2 – 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.

Oil leaking into environment	• The risk of 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 are designed to minimise the risk of exposure to faults.
Public awareness of risks and reporting problems	• Warning notices are attached to enclosures that advise of the risks contained within. • Contact numbers are included in the enclosures, enabling people to call for help if any problem is identified.

Table 6-27: Risk Management

6.7.3 – PREVENTIVE MAINTENANCE

Inspection	• An annual Inspect of tank and general fittings for corrosion and oil leaks
Test	• Oil tests – undertaken as part of the annual inspection programme. • Operational tests are undertaken six-yearly. • 10-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.

Table 6-28: Preventive Maintenance

6.7.4 – 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 the earth bank to improve its resistance and functionality.
Mounting and foundation malfunction	• Replace damaged platform or components. • Re-secure the equipment to the 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 an 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 its safety and operability, as appropriate.

Table 6-29: Corrective and Reactive Maintenance

6.7.5 – AGE PROFILE

AGE PROFILE – VOLTAGE REGULATORS

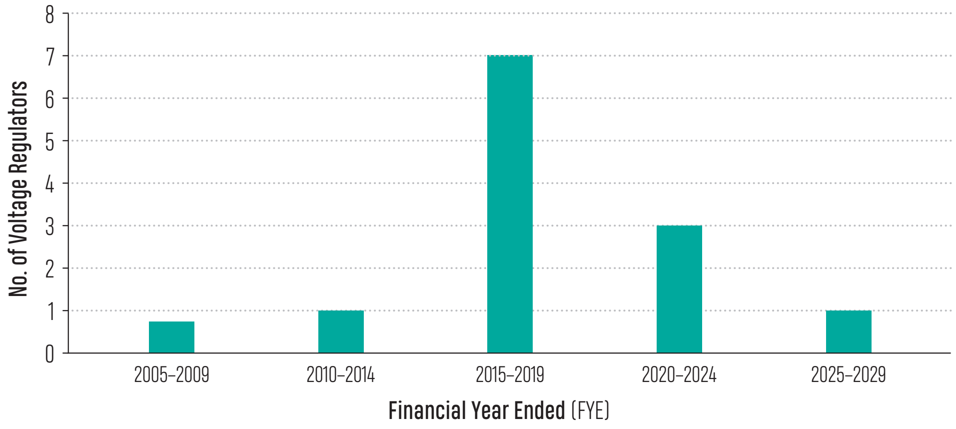

Figure 6-14: Age Profile – Voltage Regulators

6.7.6 – VOLTAGE REGULATOR HEALTH SUMMARY

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
3	–	–	1	6	4	**14**

Table 6-30: Health Summary – Voltage Regulators

6.7.7 – REPLACEMENT STRATEGY

Regular maintenance is required due to the frequency of regulator operation during service, and we maintain a spares inventory so units can be rotated in and out of service.

We are planning to replace two units in FY 2026, one in Towai and one at Pukenui, due to age and condition. The Pukenui generator is an old two-tank unit and will be replaced with a new three-tank unit. This is expected to improve the network's operational performance in the region.

As we work to build resilience across the network and install additional interconnections, the network's topography results in longer circuit lengths, which in turn require regulators to boost voltage. We are currently investigating additional regulator points across the network, which will form part of the capital works. These future works will then be included in our network development sections of the AMP.

[6.8] Zone Substations

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

Asbestos is present at some substations. Regular surveys are carried out in our older buildings. A recent site survey has identified asbestos in a limited-access roof space, which will be removed in FY 2027 to eliminate the risk of exposure. The remaining asbestos is non-friable and low risk. It will be regularly monitored and removed when any building is refurbished.

A shipping container has been used to house control equipment at Mt Pokaka substation. Containers are also used to house our generator sets. These containers require ongoing maintenance and periodic replacement to maintain equipment integrity. The Taipa generators are the first to be re-housed.

6.8.1 – 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, and 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.

Table 6-31: Failure Modes

6.8.2 – RISK MANAGEMENT

Access to energised or operable equipment by unauthorised persons	• Switchyards are enclosed with security fencing. Buildings and enclosures are secured 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 are installed at zone substations. • Substations are checked monthly to confirm security measures remain intact and functioning as intended.
Water or pest ingress affecting equipment operation	• Substations are inspected monthly. 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 building materials is necessary, 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 must assess and manage hazards. • A site-specific hazard board is also installed to enable workers to notify others of hazards. • A defect reporting process enables issues to be registered, prioritised, and scheduled for remediation.

Table 6-32: Risk Management

6.8.3 – PREVENTIVE MAINTENANCE

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

Table 6-33: Preventive Maintenance

6.8.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Security malfunction	• Replace missing or damaged locks. • Repair or replace doors, windows, and gates, as necessary. • Engage a 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 a service provider to assess the extent of the subsidence. • Undertake action to mitigate any risks associated with the subsidence. • Reinstate the subsidence to its original state if practicable. • Undertake any repairs to the building or equipment affected by the subsidence if possible. • Significant subsidence, such as that caused by an earthquake, sinkhole, landslide, or tsunami, may result in irreparable damage to the site.

Table 6-34: Corrective and Reactive Maintenance

6.8.5 – AGE PROFILE

We have two older 110 kV substation buildings: one constructed in 1939 and the other in 1945. Both remain in a serviceable condition. The third 110 kV building is the switch room at the Ngāwhā transmission 110 kV switchyard, commissioned in 2020. Other substation buildings include zone substation control and switchgear rooms, and a small number of distribution substation buildings. Refurbishment works have recently been completed at Wiroa Road switching station. This included installing an industrial HVAC system to support optimal operating conditions for the assets housed within. Many of our buildings require short-term refurbishment. The Kaikohe 33 kV switch room will be the next site to be refurbished.

AGE PROFILE – SUBSTATION BUILDINGS

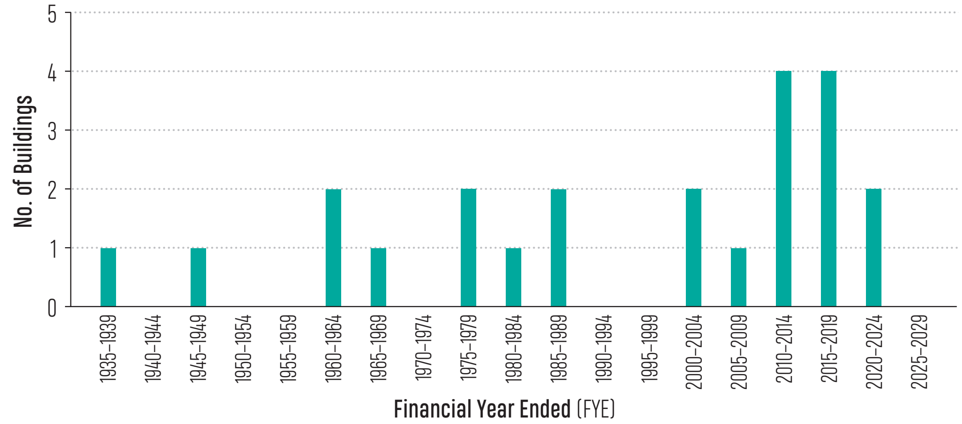

Figure 6-15: Age Profile – Substation Buildings

6.8.6 – SUBSTATION BUILDING HEALTH SUMMARY

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
–	–	–	1	22	2	**25**

Table 6-35: Substation Building Health Summary

6.8.7 – REPLACEMENT STRATEGY

Building maintenance on all substation buildings will be undertaken as required to ensure all remain fit for purpose. Several of our older locations have deteriorated fencing, which requires replacement to ensure ongoing site security.

[6.9] Power Transformers

6.9.1 - FAILURE MODES

Insulation & active part (core/ windings)	• Thermal ageing of cellulose/oil leading to reduced dielectric and eventually mechanical strength. • Moisture ingress and hotspots causing accelerated degradation. • Inter-turn faults from mechanical displacement or through-fault stress.
OLTC & controls	• Diverter/selector contact wear/erosion causing heating and mis-operation. • Drive mechanism faults (motor/gearbox/linkages) leading to irregular timing or stalled taps. • AVR/position feedback errors causing hunting or incorrect voltage regulation. • OLTC oil contamination or leaks reducing dielectric performance.
Oil system & tank/seals	• Oil oxidation/sludging and acidity rise impairing cooling and dielectric strength. • Gasket/seal failure and corrosion causing leaks and water ingress.
Bushings	• Dielectric breakdown/partial discharge. • Leakage and gasket failure. • Mechanical damage (impact, contamination).
Cooling system	• Fan/pump failure or control faults reducing heat removal. • Blocked/contaminated radiators leading to elevated oil/winding temperatures.

Table 6-36: Failure Modes

6.9.2 – RISK MANAGEMENT

Exposure to live internal parts / high-energy faults	• Controlled substation access (locks, permits), clear signage and barriers. • Remote switching where practical; arc-flash studies and PPE/ clearance controls. • Routine technical inspections and defects raised for identified hazards.
Oil leaking into environment	• Bunds/containment, spill kits and immediate containment/ cleanup procedures. • Proactive seal/gasket maintenance; corrosion remediation; annual oil quality checks. • Environmental reporting and certified disposal for contaminated materials.
OLTC malfunction (irregular timing, mis-position, control faults)	• Scheduled OLTC inspection/service and OLTC oil condition checks. • Targeted corrective actions and renewal programme for ageing tap-changer types.
Thermal overload / cooling system failure	• SCADA alarms; thermography of tank/radiators. • Operational load management and protection settings review.
Bushing failure / flashover	• Visual inspections and partial discharge checks. • Planned replacement of degraded units.

Table 6-37: Risk Management

6.9.3 – PREVENTIVE MAINTENANCE

Visual	• General visual inspection of insulating systems, cooling, bushing and insulators, tapchanger compartment, foundations, and other ancillaries- monthly.
Test	• Oil Tests & DGA on an annual basis.
Service	• Tap changer servicing Condition-based (no fixed interval)[1]

Table 6-38: Preventive Maintenance

Note 1: Condition-based services e.g., regulator services) are undertaken on a condition basis with no fixed calendar interval. These are triggered by diagnostic indicators (oil analysis, thermal anomalies, characteristic test deviations), defect severity thresholds, or reliability risk signals. This approach aligns lifecycle renewal timing with asset health and consequence-of-failure considerations.

6.9.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Security malfunction	• Replace or repair missing/damaged locks, doors and perimeter fencing; secure OLTC and tank access panels. • Install/refresh safety signage and temporary barriers; verify interlocks where fitted. • Log in defect system and schedule follow-up inspection after restoration.
Earthing system malfunction/damage	• Repair damaged earth conductors and bonding (tank, OLTC, neutral). • Test earth resistance; extend/upgrade earth mat/bank to meet design/resistance targets.
Protection system malfunction	• Function-test protection devices/alarms and replace failed components. • Validate/update relay settings and record results. • Investigate root cause (e.g., sensor failure, settings drift) and implement corrective actions.
OLTC malfunction (irregular timing, mis-position, drive/ control faults, OLTC oil issues)	• Inspect/service diverter contacts; rectify motor/gearbox/ linkage faults and calibrate position feedback. • Test AVR control loop; trend alarms; replace worn parts; plan renewal where end-of-life types are identified. • Sample/replace OLTC oil; repair seals/gaskets; leak-test before return to service.
Mounting and foundation malfunction (plinth, hold-downs, alignment)	• Repair or replace plinths/anchor bolts/hold-downs; re-level and re-secure equipment. • Remediate subsidence and treat corrosion; verify clearances and movement indicators.
Equipment leaks (tank, bushings, OLTC valves)	• Identify leak source; isolate and contain spill; deploy spill kits and bunding. • Repair/replace seals and gaskets; patch/weld per standard; vacuum treat/refill oil and perform DGA if required.
Environmental contamination	• Contain leaks, clean up contamination and dispose of contaminated soil/material responsibly per procedure. • Notify per environmental incident protocol and restore bunding/containment capacity
Damage affecting equipment safety or operability (impact, flashover)	• Isolate and make safe; inspect for structural/electrical damage; initiate temporary protection as needed. • Repair, recondition or replace damaged components; update inspections/standards; record root-cause findings.

Table 6-39: Corrective and Reactive Maintenance

6.9.5 – MAINTENANCE STRATEGY

Our zone substation power transformers are visually inspected every three months as part of our technical substation inspection programme. There is also a monthly non-technical walk-through as part of the grounds and buildings inspection strategy, during which any obvious issues may be identified and reported.

The transformers are also subject to a four-yearly servicing strategy. This is an overall condition assessment, clean and protection scheme testing and service.

We undertake oil sampling and testing of our power transformers every year. The results of these tests are analysed for any immediate potential issues and feed into longer-term lifecycle strategies.

6.9.6 – AGE PROFILE

AGE PROFILE – POWER TRANSFORMERS

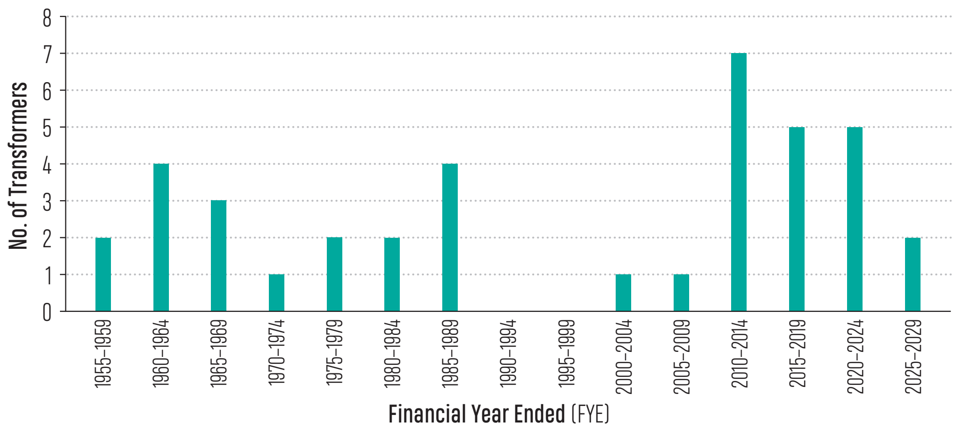

Figure 6 16: Age Profile – Power Transformers

6.9.7 – POWER TRANSFORMER HEALTH SUMMARY

An external consultant has reported on the condition of our power transformer fleet. The report indicated five transformers in an unreliable condition: Pukenui, Taipa, Kawakawa T1, and Kaikohe T11 and T12. A further 11 transformers were considered fatigued. The report considered the holistic condition of the transformer and therefore found that many older transformers were at greater risk than indicated by our regular oil-testing regime in isolation.

Our ongoing programme of tap-changer maintenance is finding decreasing reliability in our Fuller and Ferranti tap-changer fleet, which is now all over 38 years old. This deterioration of their condition increases the need for their replacement.

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
–	–	1	1	18	12	**32**

Table 6-40: Age Profile – Power Transformers

6.9.8 – POWER TRANSFORMER REPLACEMENT STRATEGY

The Pukenui and Taipa transformers are both 60 years old and continue to show signs of decline in condition. Oil processing has been undertaken to help slow the rate of deterioration and extend operational life. The report shows that of the five transformers categorised as unreliable, only Pukenui and Taipa are at single-transformer substations.

Taipa is the first of these to be replaced during the AMP period, releasing the mobile substation for use elsewhere, including during the Pukenui transformer replacement, which is also scheduled to be commissioned in FY 2029.

Pukenui has backup generation at the substation to support some, but not all the load, while the mobile substation is stationed at Taipa on a permanent basis, unless required for an emergency elsewhere on the network. Should the Pukenui transformer fail before replacement, we would replace it with one of the Moerewa transformers. If the Taipa transformer failed, we would replace it with one from a substation with newer transformers. Both replacement transformers are located at two-transformer substations and are in new condition. The other three transformers are in two-transformer substations, and should one fail, the second transformer would pick up the load. We note that:

- the Kaikohe transformers are not fully loaded (approx. 25% utilised capacity at N-1 Security), and
- more than 20% of the load on the Kawakawa substation has been transferred to the Haruru substation, reducing the proportion of load at risk.

[6.10] Circuit Breakers

6.10.1 – FAILURE MODES

Interrupter & contacts (vacuum/SF6)	• Contact wear/erosion leading to elevated contact resistance or failure to interrupt. • Vacuum loss or SF6/gas degradation causing reduced dielectric strength and arc quenching capability. • Deposits/contamination in arc chamber increasing restrike risk.
Operating mechanism & control	• Spring/motor charging failure; latch/gear wear causing slow or failed operations. • Trip/close coil failure; auxiliary contact malfunction; mechanism misalignment. • Timing deviations (slow pole, out-of-synchronism) and failure to operate on first trip.
Insulation/ enclosure & gas system	• SF6 leaks or low gas density; moisture ingress; gasket/seal failure. • Surface tracking/partial discharge on insulators and busbar compartments. • Corrosion or contamination affecting dielectric clearances.
Bushings	• Loose/overheated terminals; incorrect torque; degraded joints. • Bushing cracks or leakage leading to flashover.

Table 6-41: Failure Modes

6.10.2 – RISK MANAGEMENT

Arc-flash / incorrect operation under fault	• Remote switching where practicable; arc-flash studies and PPE/ clearance controls. • Periodic timing/first-trip tests, coil current/min trip voltage, and functional interlock checks. • Apply manufacturer & standard test procedures; record and trend results.
SF6 gas leak / environmental and dielectric risk	• Leak detection and repair per gas-handling standards. • Environmental reporting and certified handling/disposal; restore enclosure integrity.
Failure to trip/ close on demand	• Test trip circuit supervision; verify control power; perform mechanism service and timing tests. • Update relay settings and perform end-to-end protection checks where applicable.
Thermal hotspots / loose connections	• Thermography of terminals/busbar; torque checks and cleaning; replace degraded joints.
Partial discharge / insulation tracking	• TEV/ultrasound/PD assessments; clean/restore creepage; replace affected components if readings persist.

Table 6-42: Risk and Mitigation

6.10.3 – PREVENTIVE MAINTENANCE

Visual	• General visual inspection of circuit breakers, cabinets and panels, and partial discharge (PD) scans- monthly.
Test	• Relay Operational assessment and servicing of the breaker – every four years

Table 6-43: Preventive Maintenance

6.10.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Security malfunction	• Replace or repair missing/damaged locks, doors and perimeter fencing; secure control and tank access panels. • Install/refresh safety signage and temporary barriers; verify interlocks where fitted. • Log in defect system and schedule follow-up inspection after restoration.
Earthing system malfunction/damage	• Repair damaged earth conductors and bonding (tank). • Test earth resistance; extend/upgrade earth mat/bank to meet design/resistance targets.
Protection system malfunction	• Function-test protection devices/alarms and replace failed components. • Validate/update relay settings and record results. • Investigate root cause (e.g., sensor failure, settings drift) and implement corrective actions.
Circuit breaker malfunction (irregular timing, mis-position, drive/control faults)	• Inspect/service contacts; rectify motor/gearbox/linkage faults and calibrate position feedback. • Sample/replace insulating fluid; repair seals/gaskets; leak-test before return to service.
Mounting and foundation malfunction (plinth, hold-downs, alignment)	• Repair or replace plinths/anchor bolts/hold-downs; re-level and re-secure equipment. • Remediate subsidence and treat corrosion; verify clearances and movement indicators.
Equipment leaks (tank, bushings)	• Identify leak source; isolate and contain spill; deploy spill kits and bunding. • Repair/replace seals and gaskets; patch/weld per standard; vacuum treat/refill oil and perform DGA if required.
Environmental contamination	• Contain leaks, clean up contamination and dispose of contaminated soil/material responsibly per procedure. • Notify per environmental incident protocol and restore bunding/containment capacity.
Damage affecting equipment safety or operability (impact, flashover)	• Isolate and make safe; inspect for structural/electrical damage; initiate temporary protection as needed. • Repair, recondition or replace damaged components; update inspections/standards; record root-cause findings.

Table 6-44: Corrective and Reactive Maintenance

6.10.5 – MAINTENANCE STRATEGY

Oil-filled substation circuit breakers are serviced every four years. This includes an operational check and may include an oil change and contact replacement, depending on the condition and the number of operations.

6.10.6 – OUTDOOR 110 kV CIRCUIT BREAKERS

We have nine outdoor 110 kV circuit breakers, five at Kaikohe, three at Kaitaia and one at Ngāwhā. The two unreliable units are older oil-filled units at Kaitaia. One of these is scheduled to be replaced in FY 2027, and the second is not in service but is an identical circuit breaker kept as a spare. All other 110 kV breakers are SF6 insulated.

AGE PROFILE – 110 kV CIRCUIT BREAKERS

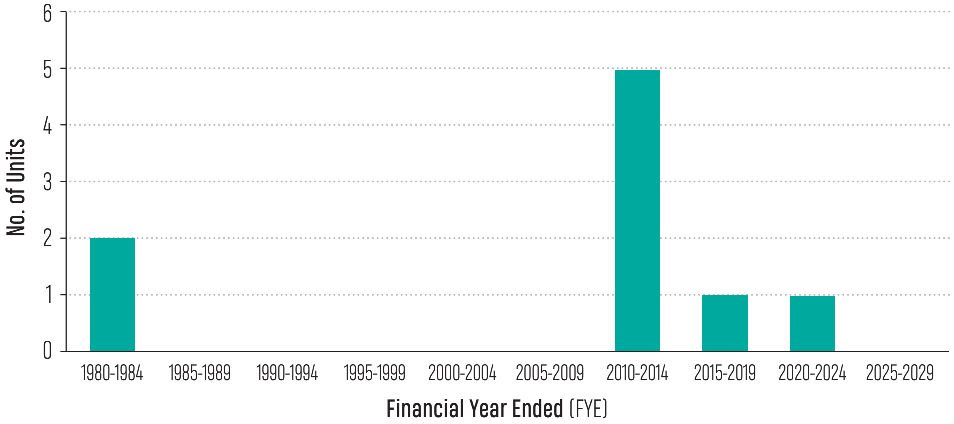

Figure 6-17: Age Profile – 110 kV Circuit Breakers

6.10.7 – INDOOR 33 kV CIRCUIT BREAKERS

We have 52 indoor 33 kV circuit breakers on the network at Kaikohe, Wiroa, Moerewa, Kerikeri and Kaeo zone substations, and Ngāwhā 110/33 kV Substation. They were installed between FY 2014 and FY 2020, and all are in as-new or serviceable condition.

6.10.8 – OUTDOOR 33 kV CIRCUIT BREAKERS

The outdoor 33 kV circuit breakers at Kaitaia and a limited number of other outdoor units scattered across the network are oil-filled. The remainder are either vacuum or SF_6 units.

AGE PROFILE – OUTDOOR 33 kV CIRCUIT BREAKERS

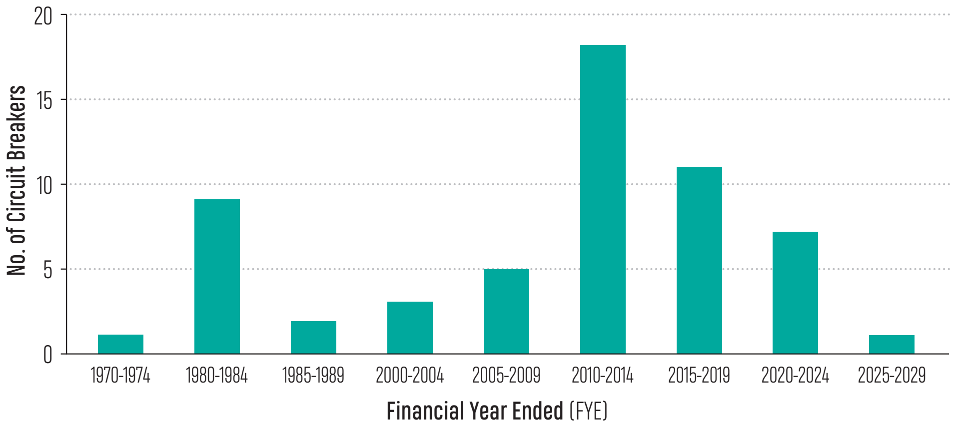

Figure 6-18: Age Profile – 33 kV Outdoor Circuit Breakers

6.10.9 – 11 kV CIRCUIT BREAKERS

We have 107 11 kV circuit breakers in our zone substations, most of which are ground mounted. While most ground mounted units are part of an indoor switchboard, a number are enclosed, individual ground mounted outdoor units. The indoor circuit breakers at Kaikohe, Okahu Rd, and Taipa substations are oil-filled, but all other 11 kV circuit breakers are either vacuum or SF_6.

AGE PROFILE – 11 kV SUBSTATION CIRCUIT BREAKERS

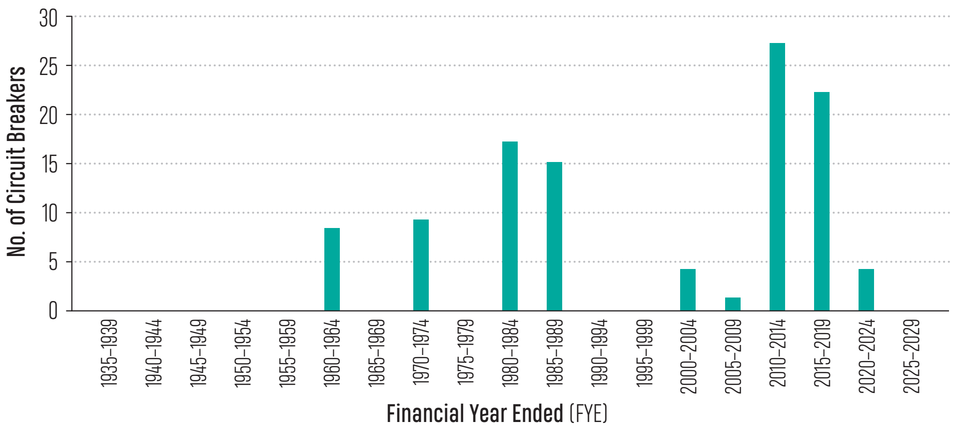

Figure 6-19: Age Profile – 11 kV Circuit Breakers

6.10.10 – CIRCUIT BREAKER HEALTH SUMMARY

	UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
110 kV Outdoor	1	–	2	–	1	5	**9**
33 kV Indoor	7	–	–	–	12	33	**52**
33 kV Outdoor	9	–	–	2	37	0	**48**
11 kV	1	–	5	–	86	15	**107**

Table 6-45: Health Summary – Circuit Breakers

6.10.11 – CIRCUIT BREAKER REPLACEMENT STRATEGY

As noted in Section 6.11.2, we plan to replace the in-service, unreliable 110 kV circuit breaker at Kaitaia in FY 2027.

[6.11] Switchgear

6.11.1 – INTRODUCTION

A variety of switchgear types have been used historically. Switchgear manufacturers have used several mediums for insulation and arc quenching. Some, such as oil, have now been superseded. Other equipment no longer meets safety or operational requirements, including arc flash management and remote-control operation.

Design requirements for new switchgear include, as appropriate:
- remote control and SCADA visibility
- non-withdrawable gear
- arc flash management capability, and
- plug in cable connections.

6.11.2 – AIR-BREAK SWITCHGEAR

We no longer buy air-break switches. Existing air-break switchgear is replaced at end-of-life with switchgear fitted with vacuum or SF6 interrupters.

6.11.3 – OIL FILLED SWITCHGEAR

Oil-filled switchgear is being phased out when changed due to its:
- high maintenance requirement
- 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 SF6 interrupters and air, resin, or SF6 insulation, as appropriate for the application. Remote operation will be provided when a unit is replaced.

6.11.4 – INDOOR SF6 SWITCHGEAR

As substations have been upgraded in the last 10 years, older switching technology, typically oil-insulated circuit breakers, has been replaced with SF6 gas-insulated equipment. This equipment provides:
- increased reliability through indoor housings
- reduced maintenance requirements, and
- highly engineered arc-flash management to minimise the safety risk to staff working in substations.

6.11.5 – 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 parts or structural weakening.
Accelerated degradation	• Corrosion in coastal and geothermal environs. • Termination failure from poor installation. • Lightning strike.

Table 6-46: Failure Modes

6.11.6 – 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, and
	  • 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 are 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. • Switches are defected, and appropriate replacements 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 being reduced as equipment condition or operational requirements drive replacement.
Public awareness of risks and reporting problems	• Warning notices are attached to all substations advising of the risks contained within. • Contact numbers are included in the enclosures, enabling people to call for help if any problem is identified.

Table 6-47: Risk Management

6.11.7 – PREVENTIVE MAINTENANCE

Inspection	• Field-mounted overhead and underground switchgear are visually inspected every two years. • Substation switchgear is included in our quarterly zone substation inspections.
Service	• Batteries on remote-controlled switchgear are replaced every 6 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.

Table 6-48: Preventive Maintenance

6.11.8 – 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 the earth bank to improve its resistance and functionality.
Protection system malfunction	• Check and test that the protection system meets the design standard. • Correct, repair, or replace protection to meet design standard
Mounting and foundation malfunction	• Repair or replace the hanger arm, platform, pad, or components. • Re-secure equipment to the 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 an 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 its safety and operability, as appropriate.

Table 6-49: Corrective and Reactive Maintenance

AGE PROFILE – POLE MOUNT 33 kV SWITCHES

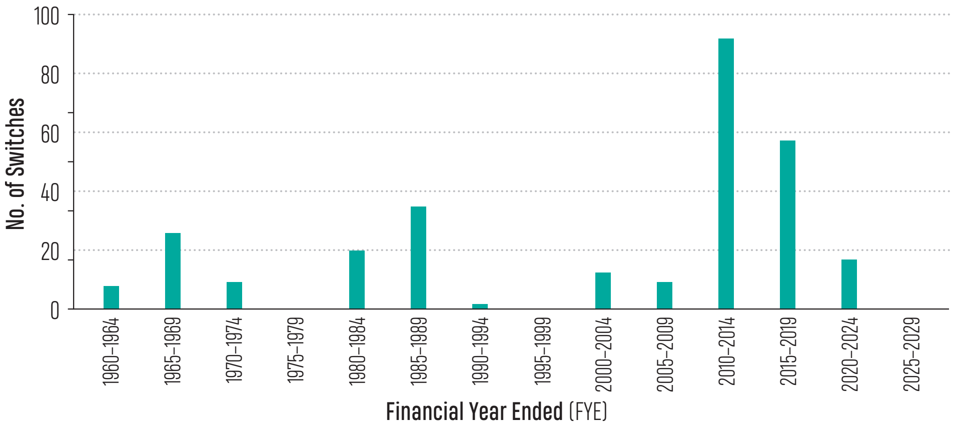

Figure 6 20: Age Profile – 33 kV Switches

6.11.10 DISTRIBUTION VOLTAGE (11 kV AND 22 kV) SWITCHGEAR

Introduction

A variety of switchgear types have been used historically. Switchgear manufacturers have used several mediums for insulation and arc quenching. Some, such as oil, have now been superseded. Other equipment no longer meets safety or operational requirements, including arc flash management and remote-control operation.

Design requirements for new switchgear include, as appropriate:

- remote control and SCADA visibility
- elevated switch handles
- non-withdrawable gear
- arc flash management
- plug in cable connections, and
- stainless steel for coastal installations.

Air-Break Switchgear

Air-break switchgear forms an important part of our overhead distribution network. Where practical, existing air-break switchgear is replaced at end-of-life with switchgear fitted with vacuum or SF6 interrupters. Pole mounted switches currently operated from a ground-level position are preferentially replaced with stick-operated units. This minimises the risks associated with having a handle within reach of the ground and the need for an associated earth system.

Oil Filled Switchgear

Oil-filled switchgear is being phased out due to its:

- high maintenance requirement
- flammability in certain failure conditions, and
- environmental impact as a contaminant.

We no longer purchase oil-filled switchgear. New switching equipment uses vacuum or SF6 interrupters and air, resin, or SF6 insulation, as appropriate for the application. Remote operation may also be provided when a unit is replaced.

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 parts or structural weakening.
Accelerated degradation	• Corrosion in coastal and geothermal environs. • Termination failure from poor installation. • Lightning strike.

Table 6-50: Failure Modes

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 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 are 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 included in the enclosures, enabling people to call for help if any problem is identified.

Table 6-51: Risk Management

Preventive Maintenance

Inspection	• 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. • Switchgear is inspected reactively following a fault that may have caused equipment damage.
Service	• Batteries on remote-controlled switchgear are replaced every 6 years.
Test (field)	• Six-yearly remote management system test. • Four-yearly oil test for oil-filled switchgear. • Ten-yearly earth test.
Test (substation)	• Two-yearly earth bond test. • Two-yearly remote management system test.

Table 6-48: Preventive Maintenance

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 the earth bank to improve its resistance and functionality.
Protection system malfunction	• Check and test that the protection system meets the design standard. • Correct, repair, or replace protection to meet design standard.
Mounting and foundation malfunction	• Repair or replace the hanger arm, platform, pad, or components. • Re-secure equipment to the 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 an 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 its safety and operability, as appropriate.

Table 6-53: Corrective and Reactive Maintenance

Overhead Distribution Switches and Links

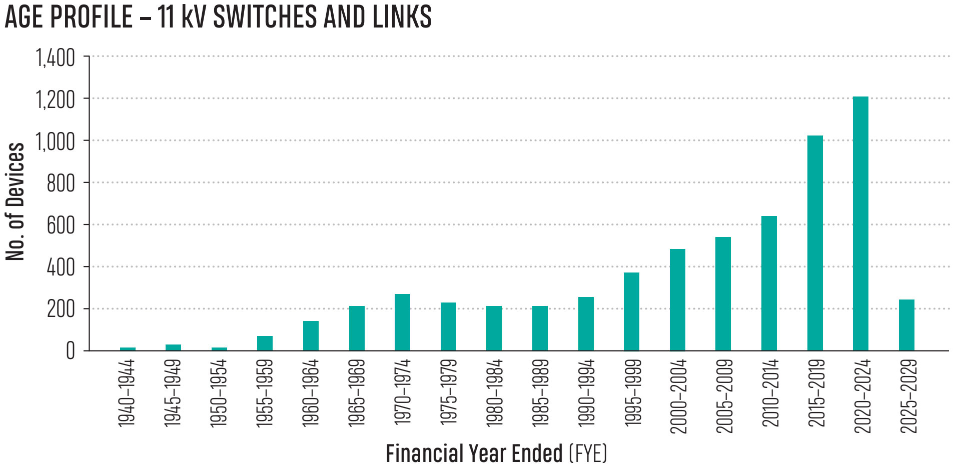

Figure 6-21: Overhead Distribution Switches and Links

Sectionalisers and Reclosers

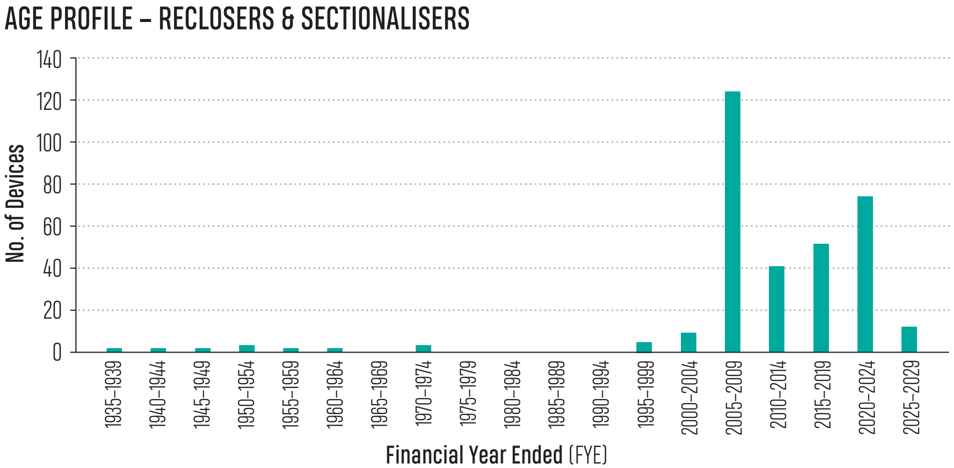

Figure 6-22: Age Profile – Sectionalisers

Ring Main Units

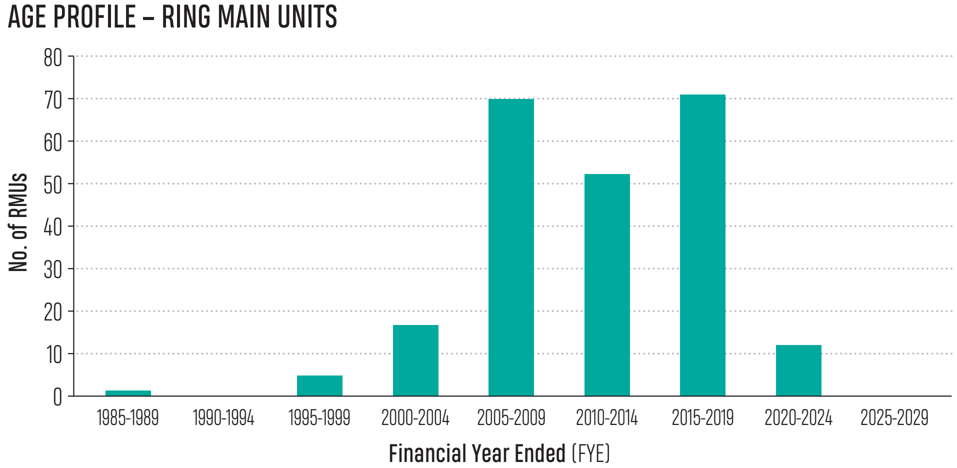

Figure 6-23: Age Profile – Ring Main Units

6.11.11 – HEALTH SUMMARY – SWITCHGEAR

	UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
33 kV Switches – Pole Mount	8	0	0	0	93	74	**175**
11 kV Switches/ Links	1,901	460	655	800	1,462	1,289	**6,567**
Reclosers / Sectionalisers	88	2	–	10	210	12	**322**
Ring Main Units	20	–	–	5	162	41	**228**

Table 6-54: Health Summary – Switchgear

6.11.12 – GROUND MOUNTED SWITCHGEAR REPLACEMENT STRATEGY

Ring Main Units (RMUs) are compact, ground-mounted switchgear assemblies used for medium-voltage distribution, typically in urban and industrial environments. While RMUs are essential for sectionalising and fault isolation, a significant portion of Top Energy's RMU fleet, ABB SDAF oil-filled units, has been identified as a critical operational and safety concern.

6.11.13 – FLEET PROFILE AND RISK ASSESSMENT

Top Energy currently operates 228 RMUs, of which a third are oil-filled ABB SD series units. These units have demonstrated multiple failure modes and pose elevated safety risks. Listed below are the key issues associated with these units.

- Mechanical failure of the fuse switch mechanism leading to catastrophic failures in New Zealand and Australia.
- Corrosion at the base of enclosures, compromising structural integrity and exposing the public to live cable components within.
- Corrosion of the main tanks leading to environmental impact in the form of oil leaks.
- Restricted live operation protocols, especially in high-foot-traffic areas. All switching operations require a remote actuation tool to be used.
- Partial discharge-related failures in band joints
- Operational Restrictions and Safety Notices due to the risks associated with live switching. Top Energy (2009 and 2012) and other networks in New Zealand and Australia have issued multiple safety notices. These notices include:
  - a ban on accessing RMU fuse units while the RMU is energised (outlined in 2015, reaffirmed in 2019), and
  - restrictions on operating ABB SD units without approved remote actuators (outlined in 20172, updated in 2020). Top Energy has approved options to allow remote control of SDAF RMUs. These measures help maintain the safety of switching operators and ensure public safety.
- Despite mitigation efforts, such as replacing taped band joints with Guroflex, corrosion and enclosure degradation continue to compromise unit integrity. This can lead to safety, environmental, and/or operational risks.

6.11.14 – ENTEC HALO RMUs

The Halo RMU has been used since 2017. The Halo RMU has a stainless-steel tank, which provides resilience to the environment in many of our coastal locations. In recent years, several pieces of equipment have failed. As a result, the supplier has issued a do not operate (DNOL) live restrictions on this switch type. Consequently, no new Halos are being installed on the network. The DNOL being in place results in operational constraints.

6.11.15 – RINGMASTER RMUs

It is recognised that the Ringmaster RN2c SF6 insulated ring mains installed in our total pad transformers are now obsolete, with spare units no longer available as replacements. Contingencies for installing these units at sites are required to account for future failures.

6.11.16 – T-BLADE SWITCHES

T-blade switches are an obsolete design of switch housed within the HV cubicle of a ground mounted transformer. This switch design is an operational constraint on the network as it cannot be operated live. As a result, T-blades are being phased out as transformers are required to be replaced.

6.11.17 – REPLACEMENT STRATEGY

Top Energy's strategy is to fully retire all oil-filled RMUs due to their compromised condition and elevated risk profile. The replacement programme prioritises:

- units with severe corrosion, oil leakage, or taped band joint failures located in high-density or high-foot-traffic areas
- units with restricted operational access or lacking remote switching capability, and
- eighteen Halo RMUs are scheduled for replacement due to known failure risks across the network and manufacturer-imposed operational constraints, which prevent live operation and increase outage impact.

Replacement RMUs will be modern SF6 or vacuum switchgear, which:

- includes Arc flash containment systems, and
- are non-oil-based insulation systems.

[6.12] Underground Service Fuse Pillars

6.12.1 – FAILURE MODES

Interference	• Vandalism. • Accidental contact (e.g., vehicle, mower).
Mounting and foundation malfunction	• Flooding. • Foundation subsidence. • Poor design or installation.

Table 6-55: Failure Modes

6.12.2 – RISK MANAGEMENT

Exposure to live or operable parts	• Equipment is designed to prevent unauthorised access to live or operable parts and to minimise the risk of harm by being self-enclosed and secured with 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 during box replacement, reducing the likelihood of exposing live parts if security is compromised.
Poor connections overheat and damage box	• Connections that come loose over time or due to poor installation practices will overheat. This often burns out the fuse base and mountings. Occasionally, the location of the fuse and the heat intensity are enough to melt the enclosure. New fuse bases utilise shear-off bolted connections, ensuring the connection is tightened correctly.

Box is regularly damaged	• Any pillar that suffers repeated breakdown due to exposure to events (e.g., a location that makes it prone to vehicular impact, vandalism, flooding, erosion, or vegetation) will be:
	  • considered for relocation, or
	  • redesign to manage associated risks.

Table 6-56: Risk Management

6.12.3 – PREVENTIVE MAINTENANCE

Inspect	• Detailed inspection of LV boxes located near parks, public amenities, schools, and business districts every three years; every ten years for the others. • Post-fault reactive inspection.

Table 6-57: Preventive Maintenance

6.12.4 – CORRECTIVE AND REACTIVE MAINTENANCE

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

Table 6-58: Corrective and Reactive Maintenance

6.12.5 – AGE PROFILE

AGE PROFILE – LV PILLARS

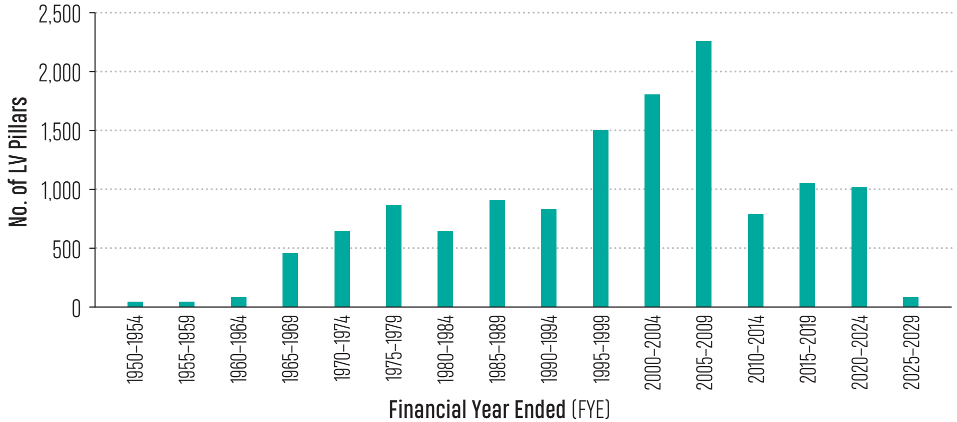

Figure 6-24: Age Profile – Underground Service Pillars

6.12.6 – UNDERGROUND SERVICE FUSE PILLAR HEALTH SUMMARY

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
1,431	5	38	1,124	9,735	439	**12,772**

Table 6-59: Health Summary – Underground Service Pillars

6.12.7 – REPLACEMENT STRATEGY

Fibreglass boxes can become brittle, while metal boxes require earth systems for safety. We now use plastic boxes to avoid these issues. There are very few fibreglass or metal boxes remaining on the network. These are being targeted for replacement when identified.

Assets identified as safety hazards, whether on inspection or following public reports, are also replaced. We anticipate replacing around 15 boxes per year.

[6.13] SCADA and Communications

While we have replaced our SCADA master station with an ADMS, the hardware outside our Control Centre is being retained and incorporated into the new system.

6.13.1 – FAILURE MODES

Interference	• Foreign object blocks signal (e.g., vegetation, structures, aerial damage). • Vandalism (e.g., damage, theft of assets).
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.

Table 6-60: Failure Modes

6.13.2 – RISK MANAGEMENT

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 is located at Ngāwhā and can be used in the event of a server failure.
Telecommunications 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 multiple pathways fail, remote control equipment can be manually operated and locally monitored.

Table 6-61: Risk Management

6.13.3 – PREVENTIVE MAINTENANCE

Inspection (Distribution)	• Post-fault reactive inspection.
Inspection (Substation)	• Six-monthly battery and charger inspection.
Test	• Six-yearly remote-controlled communications and SCADA functional test.
Service	• Six-yearly remote-controlled communications and SCADA battery replacement.

Table 6-62: Preventive Maintenance

6.13.4 – CORRECTIVE AND REACTIVE MAINTENANCE

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

Table 6-63: Corrective and Reactive Maintenance

6.13.5 – RTU REPLACEMENT

Remote terminal units (RTUs) are installed in our zone substations and in the field. While we have not prepared an RTU age profile or a fleet condition assessment, approximately 10 substation RTUs and 30 field units are now obsolete. The manufacturer no longer supports them. We respond to failures of these units using spare parts from:

- our inventory, and
- units that have been removed from service for various reasons, even if they are still operational.

We anticipate being able to keep these obsolete units serviceable using this approach for a further 10 years for substations and 5 years for field units. After this, any obsolete RTUs that fail in service will need to be replaced with new units.

[6.14] Protection Equipment

6.14.1 – FAILURE MODES

Interference	• Foreign object tangled in protection device (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into the protection device, component theft).
Typical degradation	• Normal environmental exposure causing corrosion or component seizing. • 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.

Table 6-64: Failure Modes

6.14.2 – RISK MANAGEMENT

Exposure to live or operable parts	• Equipment is designed to prevent access to live or operable parts by unauthorised persons and 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, and
	  ◦ mounted on a pole and out of easy reach.
	• Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.

Protection system power supply or communications failure	• Systems requiring power supplies or communication systems are routinely checked and tested. Equipment with these systems is often self-monitoring and provides warnings before failure when conditions indicate a problem.

Table 6-65: Risk Management

6.14.3 – PREVENTIVE MAINTENANCE

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

Table 6-66: Preventive Maintenance

6.14.4 – PREVENTIVE MAINTENANCE

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

Table 6-67: Corrective and Reactive Maintenance

6.14.5 – PROTECTION RELAY AGE PROFILES

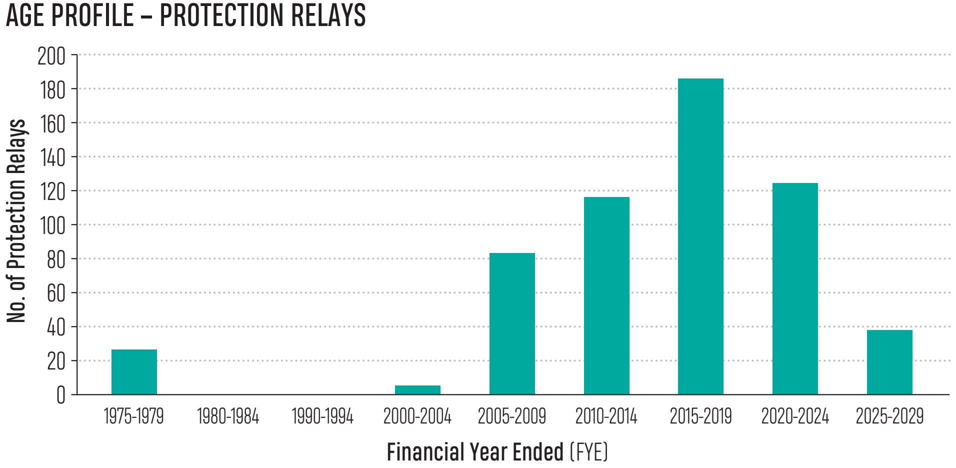

Figure 6-25: Age Profile – Protection Relays

6.14.6 – PROTECTION RELAY HEALTH SUMMARY

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
–	35	–	7	137	291	**471**

Table 6-68: Protection Relay Health Summary

6.14.7 – REPLACEMENT STRATEGY

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

[6.15] Capacitor Banks

Capacitors are used to improve the power factor16F across the network, maintain compliant voltage, and reduce losses. Our capacitors are pole mounted on the 11 kV distribution network and protected by a small vacuum circuit breaker.

6.15.1 – 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.

Table 6-69: Failure Modes

6.15.2 – PREVENTIVE MAINTENANCE

Visual	• Detailed visual inspection, checking for corrosion, damage, and leaks every two years.
Inspection	• Post-fault reactive inspection.
Test	• Ten-yearly earth test.

Table 6-70: Preventive Maintenance

6.15.3 – CORRECTIVE AND REACTIVE MAINTENANCE

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

Table 6-71: Corrective and Reactive Maintenance

6.15.4 – CAPACITOR BANKS AGE PROFILE

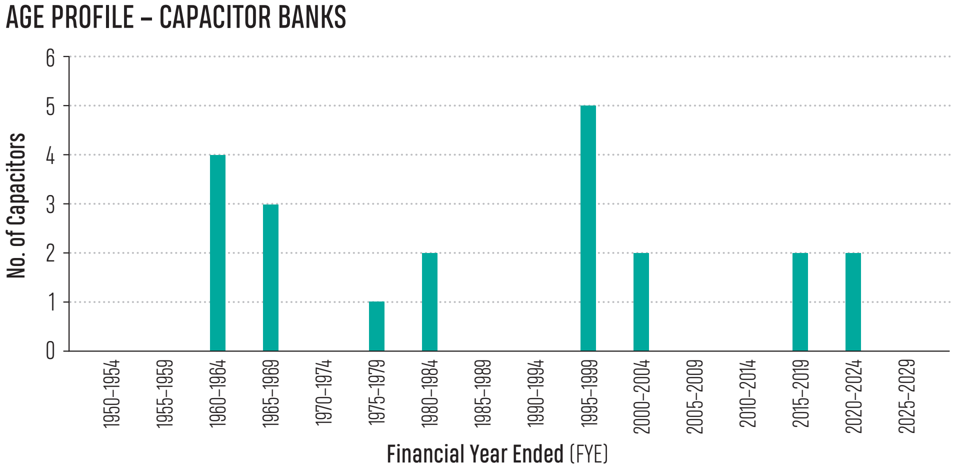

Figure 6-26: Age Profile – Capacitor Banks

6.15.5 – HEALTH SUMMARY

H0 UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
–	–	–	8	12	1	**21**

Table 6-72: Health Summary

6.15.6 – REPLACEMENT STRATEGY

Capacitors were installed to manage power factor and have not been considered operationally critical or requiring proactive renewal or replacement.

As a result, some units have now reached end-of-life. We have planned to replace one unit per year.

[6.16] Load Control Equipment

6.16.1 – 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).

Table 6-73: Failure Modes

6.16.2 – 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, 24-hour support and an emergency backup plant.
Server failure	• A disaster recovery site exists at Ngāwhā that can be used in the event of a server failure. A software support agreement is in place with the software provider.

Table 6-74: Risk Management

6.16.3 – 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.

Table 6-75: Preventive Maintenance

6.16.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Equipment malfunction	• Activate the service agreement with the service provider. • Diagnose the malfunction and repair or replace the faulty component.
Damaged or faulted equipment	• Activate the service agreement with the service provider. • Clean up any debris and contamination in the plant room. • Replace damaged equipment

Table 6-76: Corrective and Reactive Maintenance

6.16.5 – LOAD CONTROL AGE PROFILES

AGE PROFILE – LOAD CONTROL

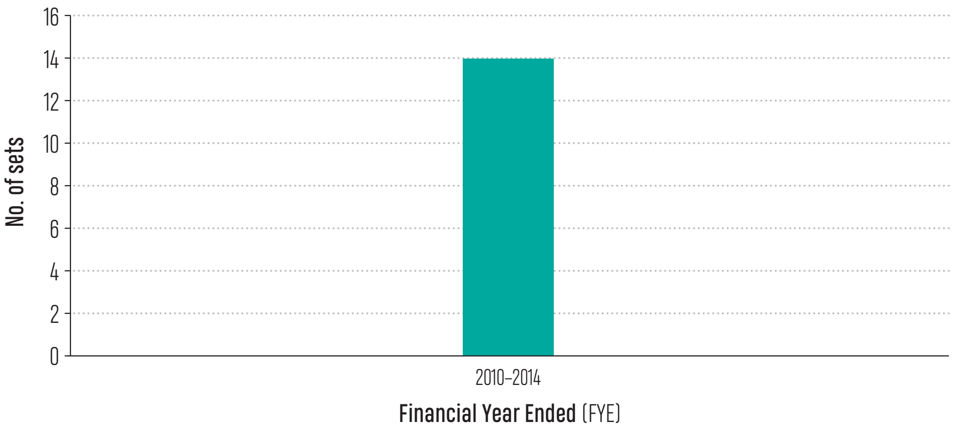

Figure 6-27: Age Profile – Protection Relays

6.16.6 – PROTECTION RELAY HEALTH SUMMARY

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
–	–	–	–	13	1	**14**

Table 6-77: Protection Relay Health Summary

6.16.7 – REPLACEMENT STRATEGY

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

[6.17] Generators

6.17.1 – FAILURE MODES

Typical degradation	• Environmental exposure causing corrosion of enclosures, terminals, or fuel tanks • Wear and tear of drive belts, bearings, engine mounts • Battery degradation (loss of charge, sulphation) • Coolant system leaks or low coolant • Oil leaks or low oil • Control unit/component failure • Governor drift or sticking • Sensor or alarm failure.
Accelerated degradation	• High usage leading to early wear of engine or alternator • Repeated short cycling • Coolant contamination or overheating • Fuel contamination • Multiple defects or complex issues arising simultaneously

Table 6-78: Failure Modes

6.17.2 – RISK MANAGEMENT

Equipment failure during operation	• Routine monthly, quarterly, and annual testing to identify issues early; immediate remediation of defects found during inspections.
Fluid leaks or low levels	• Regular checks of fluid levels and leaks; prompt reporting and remediation.
Electrical or mechanical faults	• In-depth annual testing (including valve lash, load test, electrical/mechanical checks); defects fixed at time of service.
Governor or control system malfunction	• Regular testing of governor and control response; calibration and repair as needed.
Battery failure	• Quarterly inspection and testing; replacement as required.
Cooling system failure	• Quarterly inspection of coolant, hoses, and pumps; annual fluid change and pressure test.
Extended downtime due to complex defects	• Additional diagnostic and repair time scheduled as needed, especially after high usage or multiple issues.

Table 6-79: Risk Management

6.17.3 – PREVENTIVE MAINTENANCE

Test	• Monthly In-house test run (20 minutes), check for leaks, fluid levels, drive belts, alarms, running hours
Inspection - Quarterly (every 3 months)	• Contractor inspection of wiring, battery, oil, fluids, heaters, fans, water pumps, governor; minor repairs, oil/coolant sampling
Annual check	• Specialised service: change filters/fluids, check bearings/engine mounts, detailed electrical/mechanical tests, valve lash, load test, backup control configs, governor calibration

Table 6-80: Preventive Maintenance

6.17.4 – CORRECTIVE AND REACTIVE MAINTENANCE

Issue found during routine/ annual check	• Report for remediation; fix defects immediately if possible; schedule additional diagnostic/repair time as needed.
High usage (≥250 hours/year)	• Schedule annual maintenance after 250 hours run time
Multiple or complex defects	• Allocate additional time (from less than half a day to several days) for diagnosis and repair
Governor, battery, or coolant system failure	• Diagnose and repair or replace faulty component; recalibrate as required

Table 6-81: Corrective and Reactive Maintenance

6.17.5 – GENERATORS AGE PROFILES

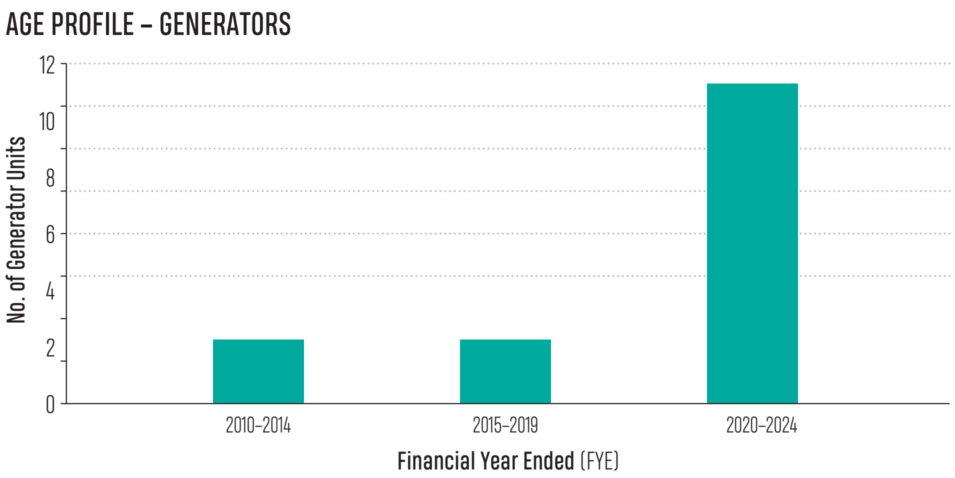

Figure 6-28: Age Profile – Generators

6.17.6 – GENERATORS HEALTH SUMMARY

UNKNOWN	H1 END OF LIFE	H2 UNRELIABLE	H3 FATIGUED	H4 SERVICEABLE	H5 NEW	TOTAL
–	–	–	6	11		

Table 6-82: Load Control Health Summary

6.17.7 – REPLACEMENT STRATEGY

Generators do not require replacement currently. Instead, we will continue to inspect these assets according to our established inspection schedule and will remedy issues or replace assets as necessary, based on condition-driven triggers identified during inspections or fault events.

[6.18] Replacement Strategies Summary

The replacement strategies for all assets can be summarised as follows:

ASSET CLASS	REPLACEMENT METHODOLOGY	REASONING FOR METHODOLOGY
Poles	Defect process, CBRM, condition-based assessment	Wood poles deteriorate unpredictably; concrete/ steel/fiberglass are more predictable. Risk-based prioritisation ensures reliability and safety.
Crossarm Assemblies	Defect process, CBRM, consequence modelling	Crossarms contribute significantly to interruptions and safety risks; CBRM and GIS tools prioritise high-risk areas.
Overhead Conductor	Defect process, condition-based, age profile, CBRM	Steel and copper conductors prioritized for replacement due to end-of-life risk; CBRM and inspection data guide decisions.
Cables	Run-to-failure for LV, condition-based for HV, defect process	LV cables are low criticality and can run to failure; HV cables replaced based on condition and risk to minimize outages.
Distribution Transformers	Condition-based, defect process, replacement on overload or oil leaks	Generally, in good condition, replaced if overloaded, leaking, or rusted. Older units without surge arresters are higher risk.
Voltage Regulators	Condition-based, oil testing, defect process	Frequent operation leads to wear; oil testing and condition assessment guide replacements. Spares inventory supports rotation.

ASSET CLASS	REPLACEMENT METHODOLOGY	REASONING FOR METHODOLOGY
Zone Substations	Condition-based, defect process, scheduled refurbishment	Older sites prioritized for refurbishment based on risk factors such as asbestos, security, and structural integrity.
Power Transformers	Condition-based, oil testing, external consultant assessment, CBRM	Critical assets: oil testing and external assessments identify unreliable units. Replacement prioritized for single-transformer sites.
Circuit Breakers	Condition-based, defect process, scheduled servicing	Oil-filled and older units prioritized for replacement; SF6/vacuum units preferred for reliability and safety.
Switchgear	Condition-based, defect process, risk-based prioritization	Oil-filled and obsolete switchgear phased out due to safety/environmental risks; modern SF6/vacuum units installed.
Underground Service Fuse Pillars	Condition-based, defect process	Fiberglass/metal boxes replaced when identified; plastic preferred. Safety hazards or repeated damage trigger replacement.
SCADA and Communications	Condition-based, defect process, planned replacement of obsolete RTUs	Obsolete units replaced as needed, critical for network control and reliability. Multiple communication pathways maintained.
Protection Equipment	Condition-based, defect process, scheduled testing	Mechanical relays replaced if unreliable; annual and six-yearly testing ensures reliability and compliance.
Capacitor Banks	Run-to-failure, planned replacement of end-of-life units	Not operationally critical; replaced at end-of-life, typically one per year.
Load Control Equipment	Condition-based, defect process	Obsolete mechanical relays replaced if testing indicates unreliability; otherwise maintained as serviceable.
Generators	Condition-based, defect process, routine testing	Inspected and maintained per schedule; replaced or repaired based on condition and operational hours.

Figure 6-29: Replacement Strategy Summary

[6.19] Asset Lifecycle Expenditure

6.19.1 – OPERATIONAL EXPENDITURE

The tables below disaggregate the network maintenance forecasts further than shown in the regulatory schedule s11b (see Appendix A). The disaggregation of the service interruption and emergencies forecast is based on:

- a breakdown of our current reactive repair costs, and
- the disaggregation of our asset replacement and renewal forecasts is based on an analysis of our defects schedule.

We use these breakdowns to signal our likely resource and skill requirements to our contractors.

The forecasts below show opex only. Therefore, they do not capture our full maintenance costs. The replacement of complete assets, along with targeted line refurbishments packaged as separate projects, is all capitalised. A breakdown of the defect and fault-driven maintenance capex forecast is shown in Table 6 86 and Table 6 87.

6.19.2 – SERVICE INTERRUPTIONS AND EMERGENCIES

($,000 in constant FY 2026 prices)	FY									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Lines and poles	66	104	101	104	100	88	84	86	72	84
Cables and pillars	20	22	37	33	31	28	27	25	14	17
Transformers	4	2	3	3	4	2	6	5	3	3
Buildings and grounds	2	1	0	0	0	0	2	1	1	2
Switchgear and protection	16	14	14	31	33	22	15	28	21	17
Secondary systems	28	32	32	36	28	29	22	29	19	23
Total	**1,381**	**1,387**	**1,394**	**1,401**	**1,408**	**1,415**	**1,423**	**1,430**	**1,437**	**1,444**

Table 6-83: Service Interruptions and Emergency Maintenance Opex by Asset Category

Note: Totals may not add due to rounding.

6.19.3 – ROUTINE AND CORRECTIVE MAINTENANCE

($,000 in constant FY 2024 prices)	FY									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Routine maintenance & inspection	**2,197**	**2,208**	**2,219**	**2,230**	**2,241**	**2,253**	**2,264**	**2,275**	**2,287**	**2,298**
Vegetation	**2,238**	**2,290**	**2,301**	**2,313**	**2,324**	**2,336**	**2,347**	**2,359**	**2,371**	**2,383**
ASSET REPLACEMENT & RENEWAL										
Lines and poles	736	740	743	747	751	755	759	762	766	770
Cables and pillars	94	94	95	95	96	96	96	97	97	98
Transformers	354	355	357	359	361	362	364	366	368	370
Buildings and grounds	139	140	140	141	142	142	143	144	145	145
Switchgear and protection	170	170	171	172	173	174	175	176	176	177
Secondary systems	155	156	157	157	158	159	160	160	161	162
Subtotal – replacement & renewal	**1,647**	**1,655**	**1,663**	**1,671**	**1,680**	**1,688**	**1,697**	**1,705**	**1,714**	**1,722**
Total	**6,122**	**6,153**	**6,183**	**6,214**	**6,245**	**6,277**	**6,308**	**6,339**	**6,372**	**6,403**

Table 6-84: Breakdown of Routine and Corrective Maintenance

Note: Totals may not add due to rounding.

6.19.4 – SUMMARY OF MAINTENANCE OPEX FORECAST

($,000 in constant FY 2026 prices)	FY									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Service interruptions & emergencies	2,244	2,289	2,335	2,381	2,429	2,478	2,527	2,578	2,629	2,682
Vegetation	3,002	3,062	3,123	3,186	3,249	3,314	3,381	3,448	3,517	3,588
Routine maintenance and inspection	3,023	3,083	3,145	3,208	3,272	3,338	3,404	3,472	3,542	3,613
Replacement & renewal	2,303	2,349	2,418	2,515	2,642	2,806	3,019	3,292	3,646	4,110
Total	**10,572**	**10,783**	**11,021**	**11,290**	**11,592**	**11,936**	**12,331**	**12,790**	**13,334**	**13,993**

Table 6-85: Breakdown of Maintenance Opex Forecast

Note: Totals may not add due to rounding.

6.19.5 – ASSET LIFECYCLE CAPITAL EXPENDITURE

We manage two types of asset replacement projects: first, targeted refurbishment of subtransmission and distribution lines in poor condition, handled as capital projects; second, a proactive replacement programme that annually renews specified numbers of assets across the network to maintain overall asset health, managed within a set budget, with the replacement strategies as described in Section 6.18.

These category of projects address assets that are still needed but must be replaced to maintain service delivery. If replacement rates are too low, asset condition and supply quality will decline, leading to more outages and higher repair costs. The Asset Health Indicator (AHI) process helps assess asset condition and set replacement priorities, considering factors like asset criticality and how quickly different asset types become unreliable at end-of-life (e.g., wood poles require faster replacement than concrete poles).

Asset renewal expenditure is given a high priority to reassure stakeholders that:

- our asset base is being sustained in a fit-for-purpose state, and
- the number of unplanned interruptions caused by equipment failure does not increase over time.

Over the 10-year planning period of this AMP15F, we have forecast a total of $136.794 million in renewal and replacement capital expenditure. This excludes the 110 kV line replacement. If we include the costs associated with replacing this line, we reach $196.794 million.

At the time of writing this AMP, we had budgeted for replacing the 110 kV line. The plan is to begin construction of the line in FY 2029. The budget and programme of works are pending a detailed externally assessed construction programme and a review of the design.

Fault Capex

Most faults are caused by the failure of an asset component, such as a crossarm, in which case the repair cost is accounted for as operational expenditure. However, some faults require replacing an entire asset (e.g., a pole, transformer, or pillar), in which case the repair cost is capitalised. We have forecast expenditure of just over $1.34 million per year based on our historic capital expenditure on fault response, as shown in Table 6-86.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Subtransmission	68	68	68	68	68	338	**679**
Zone substations	–	–	–	–	–	–	**–**
Distribution and LV lines	805	805	805	805	805	4,023	**8,047**
Distribution and LV cables	67	67	67	67	67	332	**666**
Distribution substations and transformers	202	202	202	202	202	1,009	**2,019**
Distribution switchgear	201	201	201	201	201	1,002	**2,005**
Other network assets	–	–	–	–	–	–	**–**
Total	**2,441**	**2,606**	**12,562**	**20,789**	**2,476**	**27,112**	**67,986**

Table 6-86: Fault Driven Asset Renewal and Replacement Capital Expenditure Forecast

Defect Capex

As outlined in Section 6.1.2 we run a structured asset inspection programme to identify and manage defects, which are then scheduled for repair or replacement. While most issues are addressed through our asset health-driven replacement programme, some defects require immediate replacement for safety or other reasons. We have a dedicated budget for these cases, and our defect remediation capital expenditure forecast is shown in Table 6-87.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Subtransmission	196	196	196	196	196	981	**1,962**
Zone substations	98	98	98	98	98	490	**978**
Distribution and LV lines	1,038	1,038	1,038	1,038	1,038	5,192	**10,383**
Distribution and LV cables	98	98	98	98	98	490	**978**
Distribution substations and transformers	196	196	196	196	196	981	**1,962**
Distribution switchgear	294	294	294	294	294	1,471	**2,940**
Other network assets	38	38	38	38	38	194	**386**
Total	**1,961**	**1,961**	**1,961**	**1,961**	**1,961**	**9,805**	**19,610**

Table 6-87: Defect Driven Asset Renewal and Replacement Capital Expenditure Forecast

Note: Totals may not add due to rounding.

[6.20] Significant Network Replacement Projects

The two significant programmes of works are discussed in detail, below, before going into the remained of the asset replacement and renewals projects.

Kaitaia–Wiroa 110 kV Line: Securing the Far North

The Kaitaia–Wiroa 110 kV line is a cornerstone of Top Energy's long-term network resilience strategy. The existing Kaikohe–Kaitaia 110 kV line, built in the early 1970s, is approaching its end-of-life and is exhibiting widespread defects, including corrosion, conductor vibration, structural movement, and other issues. With the commissioning of two solar farms (and a third by late 2025), the line's loading will reach 94.5% of its 55 MVA rating, further stressing this critical asset.

To this end, we have scheduled construction of the new 110 kV line from Kaitaia to Wiroa within this regulatory period. In FY 2027 and FY 2028, we will put together a comprehensive construction plan, review the design, and complete resource-consenting processes. Year one of the build stage starts in FY 2029. We have an optimistic three-year build plan, but this could change as we work through the programme of works.

This project was initiated in 2012, following Top Energy's acquisition of the Kaikohe-Kaitaia 110 kV line from Transpower. The main objective was to eliminate the need for the regular nine-hour supply interruptions that affected 12,500 consumers in the north of our supply area, including large industrial customers and solar farms. It was also considered prudent to build the line on a new route closer to the East Coast, as it would better serve the part of our supply area where the highest long-term population and economic growth were expected.

Prior to committing to the construction of the new line, a range of options were evaluated to address the ageing existing 110 kV line. These are listed below.

- Targeted remediation and monitoring would have cost between $30 and $35 million over 10 years, with the benefit of addressing only high-risk defects. However, it still carries the risk of a deteriorating line and high outage costs in the event of an HILP situation.
- Segment-based renewal was also considered. This involved reconducting the existing line in segments over 6–9 years at a cost of $70 million, plus $15 million for diesel generation during outages. This would have resulted in a prolonged customer impact and operational risks.

With this line, we have just N-1 security, which leaves us with very few options to reconductor it. Furthermore, the resilience to faults on the existing Kaikohe-Kaitaia line remains limited, as diesel generation is offline when the 110 kV circuit is in service. Hence, an unplanned interruption of the 110 kV circuit supplying Kaitaia will still result in a loss of supply to all our northern consumers. It will then take some time to restore supply to many consumers, as the generators need to be loaded gradually for technical reasons. Fortunately, unplanned 110 kV interruptions are relatively infrequent.

Relieving the constraints that prevent additional renewable generation from being connected to our northern network is, therefore, not something we can do alone. It is not economically viable, nor considered fair to our far north consumers to fund this only through network expenditure as it is for the benefit of utility scale generation. Funding will be required from elsewhere, either as a customer contribution or through another funding mechanism, in order to invest in both lines.

The preferred option is to build Kaitaia to Wiroa as a new line, then disestablish the existing line in order to minimise customer impact. The cost of the section towards Kaeo is shared with the additional line to Kaeo substation, which is programmed as a security of supply project, as it is proposed that this is a dual circuit with share structures.

FY ($,000)	2027	2028	2029	2030	2031	2032	TOTAL
110 kV Wiroa - Kaitaia Line Build	750	300	8,100	13,000	25,600	19,000	**66,750**

Figure 6-30 Kaitaia-Wiroa 110 kV Line Expenditure

Substation Power Transformer Upgrade

Maintaining a resilient and future-ready network requires a proactive, risk-based approach to substation transformer renewal. The AMP 2026 plan reflects updated priorities, timing, and investment to address asset health, capacity, and security of supply across our key substations.

Programme Overview

Options available for a zone transformer that is designed to supply sustained energy to a large 11 kV distribution network and that has reached its end of life are very limited if non-existent.

Table 6-88 summarises the planned timing for major transformer replacements and upgrades.

SUBSTATION/TRANSFORMER	AMP 2026 PLAN (FY)
Taipa	27–29
Wiroa T1	27–29
Pukenui T1	28–29
Kawakawa T1	30–32
Kaikohe T2	31–34
Kaitaia T5	33–35
Kaikohe T3	34–35

Table 6-88: Major Transformer Replacement Schedule

Key Projects and Rationale

The solution below provides the rational for the transformer replacements. These are key assets that would cause a significant SAIDI event if we had to lose one of them.

- **Taipa**: The existing transformer is fast approaching the end of its life, so we have brought forward the replacement of the 5 MVA transformer with a new, larger unit, which would be our standard spec for zone-level power transformers. The unit is scheduled for FY 2027–29. This upgrade addresses end-of-life risk and supports security of supply for the Doubtless Bay area, especially given the site's exposure to flooding and contamination.
- **Wiroa T1 & T2:** The first transformer at Wiroa is scheduled for FY 2027–29 to support ongoing growth in Kerikeri and the Eastern Bays. The second transformer is planned for FY 2034–35 to provide redundancy as the region develops.
- **Pukenui T1:** The single transformer at Pukenui will be replaced in FY 2028–29, addressing asset health risks and supporting feeder segmentation for improved reliability.
- **Kawakawa T1:** Replacement is planned for FY 2030–32, with design, procurement, and installation staged to minimise operational risk and ensure compliance with modern standards.
- **Kaikohe T2 & T3:** Kaikohe's two main transformers are scheduled for sequential replacement—T2 in FY 2031–34 and T3 in FY 2034–35. This approach ensures N-1 security is maintained throughout the process and aligns with projected load growth and the integration of embedded generation.
- **Kaitaia T5:** T1 is a 40/60 MVA transformer we installed about eight years ago, while T5 is a 22 MVA bank of single-phase units that are in relatively poor condition and nearing the end of their economic lives. The single-phase T4 bank, identical to T5, is still in place, and its three single-phase units are available as spares should one of the T5 units fail. T5 will be replaced in FY 2033-35, including associated civil works and commissioning. This is critical for maintaining supply security to the Far North and supporting future network reconfiguration.

Other Significant Work Programmes

There are some significant works programmes which are continued annually to address asset condition and health. These include:

- **Subtransmission - 110 kV Substation and Line Remediation Work:** There is an annual allowance to replace assets in critical condition on the Kaitaia-Kaikohe line. Due to the significant customer impact of outages, this is scheduled for an annual shutdown, supported by diesel generation over two days. Vegetation, access tracks and generation costs are a large contributor to the cost of maintaining this line. We are prioritising high criticality and high priority defects on this line whilst we complete the construction of the new line as described in this section.
- **Line Reconstruction – Pole Top Replacements:** Our pole top replacement programme comprises of crossarm and associated hardware replacement – these have been prioritised based on age, condition, known defects and safety. Increasingly we are using the condition-based asset risk management models (CBRM) as described in section 2.12.5 and 6.1.6. Where the pole, transformer and conductor are also requiring replacement, these are also included for efficiency of delivery. This is established during detailed design, but where possible identified through our desktop assessments in the planning phase.
- **Conductor Replacements:** Our overhead conductor fleet is ageing, particularly the smaller steel and copper types, with mechanical fatigue being the primary failure mode. Safety is the main concern, especially the risk of lines failing in public areas. There is a prioritised conductor replacement programme based on these specific type failure modes, due to repeated failures and associated performance issues. Historically these have been prioritised by age and public safety risk, however we are increasingly moving towards prioritising using the condition-based risk management models (CBRM) as described in section 2.12.5 and 6.1.6. The asset types included in these replacement programmes are:
  - Steel Conductor: Galvanised Steel and No 8 wire;
  - 16mm Copper; and
  - Single Wire Earth Return (SWER).
- **Switchgear - RMU Refurbishment:** We are undertaking a targeted replacement strategy for oil-filled Ring Main Units (RMUs), which have been identified as a critical operational and safety risk, leading to a phased retirement of these legacy assets. This includes prioritising units with known structural degradation, elevated public exposure, and restricted operational access.

Detailed expenditure profiles of these programmes are detailed in Table 6-90.

Asset Lifecycle Expenditure Forecast

Table 6-89 breaks down our forecast expenditure over the AMP planning period for the replacement and renewal of all our network assets by asset type. While the larger and more significant capital projects are individually identified, the forecast covers all proactive condition-driven replacements, regardless of whether they occur through a capital project or a programme.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
110 kV LINE BUILD							
Feasibility Study	80	0	0	0	0	0	**80**
Design, legal and preliminary works	670	200	0	0	0	0	**750**
Programme and Project Management	0	100	0	0	0	0	**100**
Line Bay Construction	0	0	6,000	0	0	0	**6,000**
Access and Vegetation	0	0	0	8,800	6,100	0	**14,900**
Line construction	0	0	2,100	4,200	19,500	19,000	**44,800**
Total – 110 kV Line Build	**750**	**300**	**8,100**	**13,000**	**25,600**	**19,000**	**66,750**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
SUBTRANSMISSION							
Kaikohoe – Kaitaia 110 kV line Tower Painting	187	241	264	268	268	0	**1,228**
110 kV Substation and Line Remediation Work	1,134	1,136	1,134	1,134	1,129	5,678	**11,345**
Omanaia 33 kV Structure refurbishment (Stage-8)	489	0	0	0	0	0	**489**
Replace Kaikohe Transformer replacement T3	0	0	0	0	385	4,720	**5,105**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
SUBTRANSMISSION – continued							
Replace Kaikohe Transformer replacement T5	0	0	0	0	0	4,015	**4,015**
Replace Taipa Transformer replacement T1	771	1,805	345	0	0	0	**2,921**
Haruru Insulator and Crossarm Replacement	470	0	0	0	0	0	**470**
Moerewa to Kawakawa Refurbishment	477	543	0	0	0	0	**1,020**
Waipapa to Waimate North Road Refurbishment	0	0	0	509	0	0	**509**
Warsnops to Mt Pokaka Reconstruction	603	714	0	0	0	0	**1,317**
Future 33 kV Reconstruction	0	0	0	0	509	2,277	**2,786**
Okahu/NPL Rebuild	0	0	625	0	0	0	**625**
Old Bay Road Crossarm Replacements	447	0	0	0	0	0	**447**
Pamapuria/ Okahu Rebuild	0	0	392	0	0	0	**392**
Targeted 33 kV subtransmission Insulator Replacements	75	75	75	75	0	0	**300**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
SUBTRANSMISSION (continued)							
Kawakawa Transformer replacement T1	0	0	0	375	2,999	214	**3,588**
Kawakawa 11 kV Switchboard	0	0	0	0	0	359	**359**
Pukenui Transformer replacement T1	0	621	1,442	0	0	0	**2,063**
Kaitaia Transformer replacement T5	0	0	0	0	0	4,802	**4,802**
Replace Kaikohe 11 kV Switchboard	0	0	0	0	0	1,438	**1,438**
TOTAL – Subtransmission	**4,653**	**5,135**	**4,277**	**2,361**	**5,290**	**23,503**	**45,219**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
DISTRIBUTION AND LV LINES							
LINE RECONSTRUCTION							
Replacement of Poles and Wires	0	0	0	0	660	1,660	**2,320**
Fault and Defect CAPEX	3,302	3,302	3,302	3,302	3,302	16,508	**33,018**
Replacement of Crossarms	0	0	260	260	260	1,068	**1,848**
Te Kao Pole Top Asset Replacement	0	0	0	0	0	464	**464**
Tokerau Pole Top Asset Replacement	0	0	0	0	0	464	**464**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
LINE RECONSTRUCTION – continued							
Taheke-Rakauwahia Road Pole Top Asset Replacement	0	1,122	0	0	0	0	**1,122**
South Road Pole Top Asset Replacement	530	0	0	0	0	464	**994**
Horeke Pole Top Asset Replacement	0	652	470	0	0	0	**1,122**
Oruru Pole Top Asset Replacement	0	0	0	0	0	528	**528**
Oruru Replacement of Wire and Crossarms	523	0	0	0	0	0	**523**
Oxford Street Pole Top Asset Replacement	0	0	525	0	0	0	**525**
Karetu Reconstruction	540	0	0	0	0	0	**540**
South Road/ Takahue Saddle Reconstruction	0	0	0	602	0	0	**602**
Distribution Refurbishment	0	318	0	351	0	0	**669**
Future 11 kV Reconstruction	0	0	0	0	0	1,207	**1,207**
Motukaraka Rebuild	0	0	514	0	0	0	**514**
Subtotal – Line Reconstruction	**4,895**	**5,394**	**5,071**	**4,515**	**4,222**	**22,363**	**46,460**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
CONDUCTOR							
Conductor replacement-16mm Cu	452	427	427	382	484	1,586	**3,758**
Conductor replacement-Galv St and No 8	0	0	329	0	0	0	**329**
Ohaeawai Feeder Reconductoring	664	0	0	0	0	0	**664**
Pokapu Feeder Reconductoring	0	0	0	642	0	0	**642**
Purerua Feeder Reconductoring	0	0	0	598	0	0	**598**
Future Reconductoring	0	0	0	0	0	2,702	**2,702**
Subtotal - Conductor	**1,116**	**427**	**756**	**1,622**	**484**	**4,288**	**8,693**

FY ($000)	2027	2028	2029	2030	2031	2032-36	TOTAL
SINGLE WIRE EARTH RETURN (SWER)							
Mangamuka SWER replacement	0	0	0	0	0	493	**493**
Matawaia Maromaku SWER replacement	0	302	0	0	0	0	**302**
Kohukohu SWER replacement	547	519	0	0	0	0	**1,066**
Rangiahua SWER replacement	0	0	0	524	0	0	**524**
Edmonds Road SWER replacement	426	0	0	0	0	0	**426**

FY ($000)	2027	2028	2029	2030	2031	2032-36	TOTAL
SINGLE WIRE EARTH RETURN (SWER) – continued							
Makene Road, Mangamuka Church Road, Otene Drive SWER replacement	0	0	0	743	0	0	**743**
Motukiore to Duddy's Road SWER replacement	0	0	462	0	0	0	**462**
Parapara SWER replacement	0	0	647	0	0	0	**647**
Tapuhi SWER replacement	426	0	0	0	0	0	**426**
Other SWER replacement	0	463	427	841	0	448	**2,179**
Subtotal – SWER	**1,399**	**1,284**	**1,536**	**2,108**	**0**	**941**	**7,268**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
POLES							
Concrete Pole Replacements	897	889	891	891	886	5,594	**10,048**
Wood Pole Replacements	572	572	572	572	572	2,819	**5,679**
Te Kao Pole Replacement	0	540	0	0	0	0	**540**
Te Paki Pole Replacement	0	470	0	0	0	0	470
Subtotal – Poles	**1,469**	**2,471**	**1,463**	**1,463**	**1,458**	**8,413**	**16,737**
TOTAL – Distribution and LV Lines	**8,879**	**9,576**	**8,826**	**9,708**	**6,164**	**36,005**	**79,158**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
DISTRIBUTION SUBSTATIONS AND TRANSFORMERS							
Pole Tx & Associated Pole Top Targeted Replacement	122	95	128	139	144	709	**1,337**
Replacement of Voltage Regulators	0	0	424	424	0	0	**848**
Transformer Earth Remediation	120	120	120	120	120	0	**600**
TOTAL – Distribution Substations and Transformers	**242**	**215**	**672**	**683**	**264**	**709**	**2,785**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
DISTRIBUTION SWITCHGEAR							
RMU Refurbishment	618	738	738	738	738	3,690	**7,260**
Replacing Switches with Entecs	233	153	153	153	191	0	**8,83**
TOTAL – Distribution Switchgear	**851**	**891**	**891**	**891**	**929**	**3,690**	**8,143**

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
OTHER NETWORK ASSETS							
11 kV Capacitor Replacements	0	35	36	36	0	0	**107**
Protection	116	0	0	0	0	0	**116**
OTHER NETWORK ASSETS – continued							
SCADA	94	84	84	84	0	0	**346**
Comms	0	0	0	0	0	917	**917**
Total – Other Network Assets	**210**	**119**	**120**	**120**	**0**	**917**	**1,486**
TOTAL ASSET REPLACEMENT & RENEWALS	**15,585**	**16,236**	**22,886**	**26,763**	**38,247**	**83,824**	**203,541**

Table 6-89: Capital Expenditure Forecast for the Proactive Replacement of Network Assets

Note: Totals may not add due to rounding.

Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

Table 6-90 consolidates forecast asset renewal and replacement capital expenditure into the asset categories used by the Commerce Commission for information disclosure.

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Subtransmission	5,403	5,435	12,377	15,361	30,890	42,503	**111,969**
Distribution Lines	8,879	9,576	8,826	9,708	6,164	36,005	**79,158**
Distribution Substations and Transformers	242	215	672	683	264	709	**2,785**
Distribution Switchgear	851	891	891	891	929	3,690	**8,143**
Other Network Assets	210	119	120	120	0	917	**1,486**
Total – Asset Replacement & Renewals	**15,585**	**16,236**	**22,886**	**26,763**	**38,247**	**83,824**	**203,541**

Table 6-90: Consolidated Asset Renewal and Replacement Capital Expenditure Forecast


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NON-NETWORK ASSETS

SECTION 7
NON-NETWORK ASSETS

[7.1] Non-Network Assets Overview

7.1.1 – FLEET

Top Energy has a fully maintained fleet of vehicles, either owned or leased for a 90-month term.

All non-network vehicles are owned and maintained with the support of a fleet management company.

Replacement criteria: Vehicles are considered for replacement:
- once they exceed 170,000 km
- if they are an outdated model that is no longer fit for purpose, or
- if business requirements change.

Key considerations when selecting a new or replacement vehicle:
- vehicle safety
- vehicle emissions and economy (newer technologies are adopted where feasible, e.g., hybrid vehicles), and
- alignment with the existing fleet.

7.1.2 – PROPERTY

Top Energy leases its main office and two depots. The properties are maintained and reviewed to ensure they are fit for purpose, with adequate space and equipped to support a functional, fit-for-purpose, efficient working environment.

Office equipment includes desktop and laptop hardware, video conferencing equipment, peripherals and suitable work areas for staff.

In FY 2025, the main office underwent full replacement of desks in the open plan areas to:
- make more efficient use of the space
- support the growing team, and
- provide ergonomic solutions to all office staff.

7.1.3 – DIGITAL SYSTEMS

Top Energy uses a five-year digital roadmap to improve asset data accuracy and maximise value through advanced digital systems supporting all core business functions. While there is uncertainty about specific digital solutions and timelines for transitioning from Distribution Network Operator to System Operator amid rising distributed energy resources, the focus remains on:
- optimising core system use
- enhancing network planning and operations, and
- improving asset data quality.

The roadmap also includes proof of concept (PoC) projects to assess new digital technologies and datasets for future application.

There is ongoing spend in non-network fleet, property areas and digital parts of the business, including:

- computer hardware and software
- motor vehicles assigned to TEN staff
- office equipment, and
- miscellaneous equipment.

To save costs in design and specification for systems and system development, we engage and collaborate with other EDBs to replicate, where possible, system design, setup, and configuration.

An overview of our Asset Management Digital Systems is available in Section 2.12.3.

[7.2] Non-Network Capital Expenditure

This section covers the significant projects being undertaken in non-network capex.

7.2.1 – NETWORK MANAGEMENT SYSTEM

The ADMS is a key tool for developing an open network that supports new technologies and for facilitating our transition from a distributor of electricity to a manager of a distributed energy system. The system has been future-proofed, and our ADMS vendor is developing modules to support Distributed Energy Resource Management (DERM) and Demand Response Management (DRM). These will be added as required.

DMS components planned to be implemented over the next five years 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.

Network Model Simulation

Network Model Simulation leverages DPF to provide a digital twin of the network, enabling operators to run simulations of various types of network events. This, in turn, supports network operations planning and, most importantly, operator training.

Automated Power Restoration System (APRS)

The APRS leverages the DPF module to help minimise the number of customers affected by unplanned outages. APRS automatically:

- determines the location of a high-voltage network fault
- completes a power-flow study, and
- depending on the mode of operation, it can either:
  - advise an operator on switching operations, or
  - automatically undertake the required switching to restore supply to as many customers as possible.

APRS performs best in highly meshed networks, which Top Energy currently has only to a limited extent. However, we believe it will still provide benefits to some feeders.

Smart Voltage Optimisation

The Smart Voltage Optimisation, otherwise known as Integrated Volt-Var Control (IVVC), recommends optimal capacitor bank control and power transformer tap-changer positions to ensure we stay within the System Operator (SO) defined limits.

PowerOn Mobile

PowerOn Mobile is a comprehensive suite of mobile modules. They enable collaboration between controllers, dispatchers, and field crews on real-time electrical network operations. Access and permitting are also managed from PowerOn.

While PowerOn Mobile could be used to manage access and permitting at any voltage level on the network, we intend to use this product only for LV network management in the meantime. Hence, it will be rolled out in parallel with LV Management.

LV Management

We are actively progressing the adoption of a new LV Management (LVM) system, which will introduce formalised access and permitting requirements for LV switching activities, aligning LV processes with the permitting and control standards currently applied at higher voltages. Delivering this safely and effectively requires accurate LV connectivity data and correct circuit labelling, meaning the full rollout will occur progressively over several years as LV data capture is completed across the network.

The programme will begin with the definition of the new end to end LVM process—work that is already underway—and a proof of concept in the Kerikeri area in FY 2026, where LV data capture is largely complete. Following this, LV Management will be deployed region by region in step with the wider LV data capture project. Refer to 2.12.6 for details on the LV Data Capture Project.

A key component of LV Management is the planned implementation of PowerOn Mobile, which will provide field crews with integrated switching workflows, real time visibility, and structured LV permitting.

In parallel, we intend to leverage real time SmartCo meter data for active LV fault management by co developing an API with Hiko to feed directly into our ADMS. This integration will enable:

- A live LV outage map, continuously updated using meter “last breath” and “first gasp” signals
- Faster, more accurate LV fault identification and localisation
- Enhanced monitoring of LV performance and improved customer restoration times

Collectively, these initiatives form the foundation of a modernised LV operating environment that supports safer switching, clearer visibility, and more efficient fault response.

Distributed Energy Resource Management (DERMS)

DERM is potentially the most complex digital system that we will implement and is a fundamental component of the evolution of our Distribution System Operator (DSO) capability. It is also currently surrounded by the most uncertainty. There are three or four possible alternatives, but the DERM product we are more interested in. We believe GE's GridOS DERMs offer the most potential for Top Energy.

Historical Network Viewer

Historical Network Viewer provides comprehensive post-incident analysis of network events, including recreating the network's status prior to, during, and after the event.

7.2.2 – GIS SYSTEM

GIS components planned to be implemented over the next five years will be added progressively as:

- the software is customised to our network, and
- our operators are trained in each new function as it is brought online.

SAP Enterprise Integration

Build automated bidirectional data updates between EO and SAP Cloud Datasphere to maintain data consistency across platforms.

Design Manager Development

Design Manager is a component of EO that accelerates the engineering planning and design process with:

- comprehensive workflow support and process control
- design tools, and
- cost estimation tuned for the needs of electricity network operators.

This includes:

- staging network asset Moves, Adds and Changes (MACs)
- the proposed state layout and cost estimating of the new network build within EO, and
- configuring Design Layout Tools (DLTs) that simplify adding assets to the GIS.

Data Warehouse and Integration Improvements

General improvements to the design, integration and workflows for GSA Warehouse. GeoSpatial Analysis (GSA) software provides advanced analysis and reporting of telecommunications network infrastructure.

GSA Warehouse is the spatial database where we store all our GIS data for integration into other systems, such as DataFrame for data quality checks, Power BI for reporting, and SAP.

Fibre and Wireless Network

We currently record fibre cable location and asset attributes in EO. However, we have no fit-for-purpose digital system for storing fibre connectivity information, such as fibre patching in fibre termination trays. We currently use Excel, but are considering several potential solutions.

HV, MV and LV SLDs Mastered in GIS

Single Line Diagrams (SLDs) are the electrical connectivity schematic diagrams for our HV (>=33 kV), MV (11 kV-22 kV) and LV networks. HV and MV are currently mastered in PowerOn. LV is currently mastered in CAD. Having these critical diagrams mastered in different systems and not integrated with EO increases the risk of errors and inconsistencies between as-designed and as-built. The intention is to master all SLDs in EO so they are automatically updated whenever asset connectivity is changed.

Asset GPS Coordinate Data Refresh and Corrections

A review of the veracity of the GPS coordinates of all our network electrical assets. This may or may not be necessary. As we have not conducted this exercise for many years, there may be value in correcting the location of our assets using relatively high-accuracy GPS equipment.

7.2.3 – INTELLIGENT AUTOMATION AND ARTIFICIAL INTELLIGENCE

Deliver the remaining three AI Machine Learning proof of concept projects.

- **Transparency of Alarms for Alarm Management:** Classify the likely causes and resolutions of alarms, addressing the critical issue of alarm overload through machine learning algorithms.
- **Incident Prediction for Storm Planning:** Estimate the number of field staff needed before severe weather events by analysing historical weather and outage data, enabling proactive resource planning.
- **Asset Defect Inspections:** To address ageing and defective infrastructure, image recognition algorithms efficiently identify defective poles, cross-arms, and conductors.

7.2.4 – MISCELLANEOUS HARDWARE

- Containerised data centre.
- Hardware infrastructure monitoring system.
- General infrastructure and workstation upgrades, and replacement of end-of-life non-network assets.

7.2.5 – NON-NETWORK CAPEX FORECAST

Table 7-1 shows the forecast costs of providing these services at 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.

FY ($,000)	2027	2028	2029	2030	2031
General	380	188	179	172	1,233
Software	1,530	817	645	277	978
Hardware	382	269	273	277	1,277
Total	**2,293**	**1,274**	**1,098**	**727**	**3,489**

Table 7-1: Non-Network 5-year Capex

[7.3] Non-Network Operational Expenditure

Non-network OPEX consists of Business Support and System Operations/network support. This section details the significant digital system operational expenditure projects, which make up a significant proportion of these budgets.

7.3.1 – GIS SYSTEM

Asset Information Maturity

A continuation of our asset information maturity plan. The asset information maturity project kicked off in Q4 2022 with an external assessment of our asset information maturity measured against the EEA's asset information maturity framework. The framework measures maturity across four domains: Strategy, Standards, Asset Information Systems and Data and Information Management. Unsurprisingly, we scored 1 to 2 in each domain out of 5. We subsequently created and are implementing a plan to reach level 4 in each domain.

7.3.2 – ENTERPRISE RESOURCE PLANNING AND ASSET MANAGEMENT

Enterprise Integration

Build an integration between SAP Cloud and all other relevant digital systems, including Salesforce, GIS and Enterprise Field Mobility systems. The aim is to ensure a cohesive data architecture that delivers fit-for-purpose business intelligence and value.

Resource Scheduling

One of the weakest areas in the business is:

- scheduling work, the necessary resources to deliver the work, and
- providing long-term visibility of the schedule to the various stakeholders.

Solving the problem will require a review of our scheduling responsibility structure (centralised or decentralised), process, and digital system capability. SAP Cloud and Salesforce have excellent resource scheduling capabilities for the digital system component. At this stage, we think building resource scheduling in SAP Cloud makes the most sense.

SAP Analytics Cloud

SAP Analytics Cloud (SAC) is a comprehensive solution designed for analytics and planning. It aims to unlock the full potential of investments in:

- mission-critical business applications, and
- valuable data sources.

It integrates with various systems to deliver cohesive business intelligence and value, enhancing modelling capabilities through evolving SAP AI technology. SAC will serve as the foundation for our future ERP and EAM analytics and modelling capabilities.

Bar Code Scanning

Enable booking out of materials to jobs using bar code scanning to improve stock management, job cost, and asset change data accuracy. We intended to implement barcode scanning last year, but decided to wait until we had completed the migration to SAP Cloud.

Datasphere Development

SAP Datasphere is a comprehensive data management solution that unifies data from various sources, enabling seamless access and integration. It provides robust data modelling, governance, and analytics tools, enhancing an organisation's ability to derive actionable insights from its data assets. Datasphere is fundamental for integrating with our other digital systems and delivering improved business information.

Develop AI Modelling

Carrying on implementing modelling and analytics function outlined in the AI strategy and leveraging SAC to deliver comprehensive, effective and valuable business intelligence.

7.3.3 – CUSTOMER RELATIONSHIP AND SERVICE MANAGEMENT

Replace Carding Proof of Concept (PoC)

Where practicable, and for shutdowns of 100 or fewer ICPs, we traditionally drop shutdown notification cards in the affected consumer mailboxes, which, while effective, is also a relatively inefficient exercise. We recently went live emailing customers planned outage notifications from our outage centre for consumers with an associated email address with their retailer. This carding PoC tested whether we still need to card customers for whom we have an email address, and, for those we do not, whether we should continue with manual carding or mail the shutdown notice instead.

Public Safety and Compliance

The digital system we currently use is no longer fit for purpose. We have used this system to record, track progress and report on performance when members of the public:

- fail to comply with various legal requirements, or
- are involved in an incident on our network that requires notification and/or communication with authorities.

We intend to build this workflow in Salesforce to resolve this issue.

Faults Work Management

The process and supporting digital system for recording and tracking individual consumer no power calls are convoluted and can be improved. The intention is to build a fault workflow that will be similar in many respects to the capital and maintenance workflows recently implemented in Salesforce. This will provide us with greater visibility of individual consumer reliability experience. It will:

- enable shutdown planning to consider this reliability performance when determining when to schedule shutdowns, and
- ensure we follow up on no-power calls to confirm the fault has been successfully rectified.

BeforeUDig Cable Locate

We are in the process of going live with the BeforeUdig plan Cloud service. This integration will add a tick box to the beforeUdig subscriber plan request form, allowing a cable locate request to be automatically created in our Salesforce system. This removes the need to visit our website and complete a separate form.

Customer Comms

Review our current customer communications and identify other areas where Salesforce could improve.

ICP Outage History

A follow-on to loading consumer no-power calls into Salesforce faults works management. This will provide further individual planned and unplanned outage history to:

- improve shutdown planning, and
- ensure consumers are not experiencing multiple power interruptions within a relatively short time frame.

DER Auto-approves Based on Capacity

The next evolution of our web-based DER application form is for our system to record and automatically approve requests that meet predefined criteria. This will speed up the application process and improve efficiency.

An effective functioning network capacity model operating in the background will be a prerequisite. This may also be a requirement of the standardised DER application request process that the regulator is currently consulting on.

Vegetation Management Integration

We are further developing our vegetation management system integration, which relies on multiple components in our EO GIS, SAP Cloud ERP and EAM, and Salesforce service management digital systems.

7.3.4 – ENTERPRISE FIELD MOBILITY

Timesheets

We will build electronic timesheets to replace our current paper-based ones. This will enable structured time sheet data capture and automated checks of job numbers, etc., to ensure time is booked.

Asset Change Form Design

Univerus recently improved the core architecture on which dynamic forms are built. This will substantially improve the dynamic nature of our current asset change forms, making them more intuitive and user-friendly.

Job Risk Management

We recently had a discussion and demonstration with Risk Mentor regarding the job safety risk assessment and control management mobile-enabled system. We have already completed much of this scope in Unity. However, we noted some good ideas to consider adding to our current Unity Job Safety Assessment forms and structure. If they are willing, we may engage Risk Mentor to help with these improvements, as the design is their IP.

7.3.5 – INTELLIGENT AUTOMATION AND ARTIFICIAL INTELLIGENCE

Automate two repetitive, rules-based tasks and processes per year on our Blue Prism intelligent automation platform.

7.3.6 – NON-NETWORK OPEX FORECAST

Table 7-2 shows the forecast costs of providing these services at constant prices. These forecasts are based on the current costs of providing these support services.

FY ($,000)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
System Operations and Network Support	11,419	11,546	11,542	11,598	11,742	11,368	11,533	11,049	11,191	11,297
Business Support	10,819	10,369	10,369	10,369	10,369	10,369	10,369	10,369	10,369	10,369
Total	**22,238**	**21,915**	**21,911**	**21,967**	**22,111**	**21,737**	**21,902**	**21,418**	**21,560**	**21,666**

Table 7-2: Non-Network 10-year Opex

RISK MANAGEMENT

SECTION 8
RISK MANAGEMENT

[8.1] Risk Management Policy

The Top Energy Group's risk management policy recognises risk as a core business responsibility and commits the Group to providing all necessary available resources to support those accountable for managing risk. The following activities are undertaken to ensure that this 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 using the risk management processes in line with their delegated risk authority
- maintaining a balance of risks, benefits, and costs to ensure that risks with the potential to impact negatively on the business are kept as low as reasonably 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 changes
- 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.

[8.2] 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, consistent process for risk identification, assessment, acceptance, and treatment is carried out company wide. Emphasis is placed on exposure to business and safety risks that may arise 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.

8.2.1 – 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.

8.2.2 – NETWORK RISK MANAGEMENT COMMITTEE

Top Energy Network has its own specialised network risk committee consisting of:

- General Manager Network
- Technical Safety Engineer
- Network Planning Manager
- Network Maintenance Manager
- Network Performance Manager
- Distribution System Operations Manager
- Network Programme Delivery Manager
- Estimating Manager
- Contracting Services Field Operations Manager
- Contracting Services Field Construction Manager, and
- Contracting Services HSQR Manager.

Our Technical Safety Engineer manages the committee through organising and chairing risk review meetings, second other internal expertise as required and are responsible for updating the risk register.

The network risk management committee reviews and maintains the network risk register. The review includes checks to ensure that:

- all existing risks remain valid
- new risks are identified
- all risks are appropriately controlled
- existing risk control plans are actioned, and
- the company's risk management policy is being followed.

Our network risk register is presented to the corporate risk management committee annually. 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 the network risk register	Network Risk Management Committee	Monthly
Risk register/control plan to the corporate risk management committee	General Manager Network	Annually
Approve the risk register and control plans	Corporate Risk Management Committee	Annually

Table 6-88: Major Transformer Replacement Schedule

8.2.3 – 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 as probabilities, they are used in the risk analysis.

This approach accommodates high-consequence risk events 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.

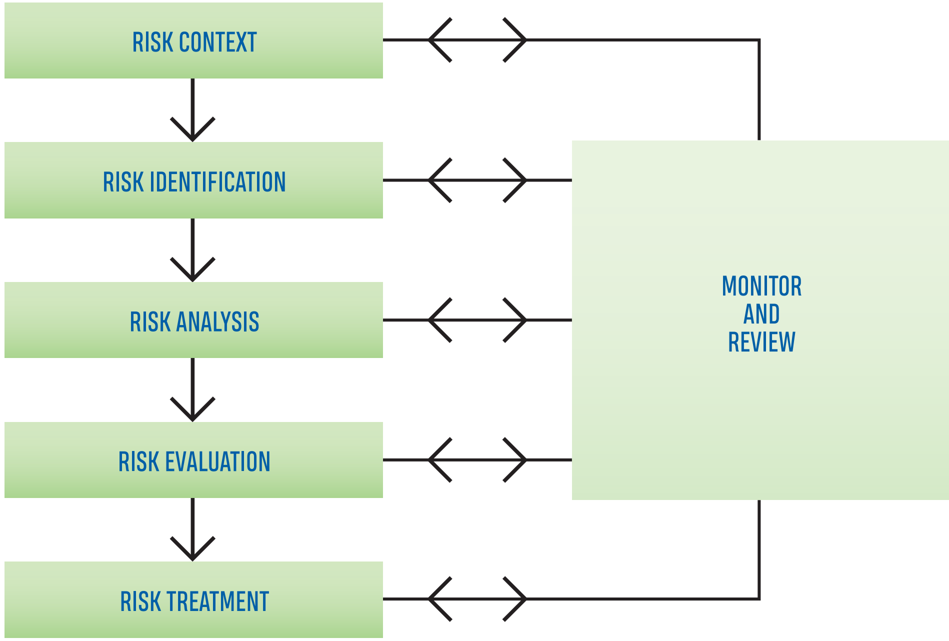

Figure 8-1: Network Risk Management Process

Our network risk process is consistent with AS/NZS ISO 31000:2009 and incorporates the steps shown in Figure 8-1. 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 for the entire risk management process.

Network risks are classified in the following areas (domains) and typical sub-areas:

RISK DOMAINS	CONSEQUENCES ARISING FROM POOR MANAGEMENT PRACTICES
Public/Employees	• Harm to the 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 8-2: Risk Process Main Elements

- **Risk identification:** Identifying all elements relevant to the risk context. After establishing this, the next step is to identify potential risks. A culture of risk awareness at all levels is encouraged within Top Energy to recognise, assess, and manage risks before they have a possible adverse impact on the public, personnel, or the company. There are also formal processes based on focus groups that actively identify new risks and review known ones.

  The network risk management committee and the person responsible for the risk domain consider identified risks. Once approved, it is added to the risk register and controlled. Risks considered are not limited to current risks but also include those that may arise over the asset's predicted life. 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 based on consequence and likelihood (or probability for high consequence events characterised by uncertainty or surprise rather than historical occurrence). This assessment produces a 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 consequences and likelihood levels. For example, in the case of network outages, consumers' costs of non-supply calculations often involve the analysis of historical asset failure rates.

  The Group's risk analysis and evaluation framework (Appendix G) is used to assess risks recorded in the network risk register.

- **Risk treatment:** Defining the controls to remove, mitigate or prepare for the risk. This involves developing contingency plans where appropriate.

[8.3] Network Risk Management

8.3.1 – HEALTH AND SAFETY

The safety of our employees, contractors and the public is of utmost importance in the operation, maintenance, and expansion of the network. The Group employs a Health, Safety and Risk Manager who is responsible for:
- promoting Health and Safety across all divisions of the organisation, and
- actively investigating all health and safety incidents.

A Contracting Health, Safety, Quality and Risk (HSQR) Manager reporting directly to the General Manager Contracting, leads and manages the division's health, safety, quality, and risk functions. The role also promotes a learning organisation culture in alignment with the Group strategy. In addition, a Technical Safety Engineer within TEN, reporting directly to the General Manager Networks, ensures that Top Energy complies with industry regulations, minimising safety risks to Top Energy staff, contractors, and the public.

We operate under the EEA Safety Rules, which meet the requirements of the Acts, Regulations, Codes of Practice, and Guidelines that govern the electricity industry.

We are committed to reducing both the frequency and severity of injuries to staff, contractors, and the public. The ongoing results from initiatives implemented under this system demonstrate staff's commitment to effectively managing 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 maintained in the timeframes and process for the reporting and investigation of incidents. Similarly, employee commitment is being maintained through the continued development of 'safe teams', which involve employees at all levels in managing health and safety. Employees participate 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 our employees' training and development. Our staff 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.

We maintain and continually improve our authorisation holder's certificate (AHC) system, which requires formal assessments of current competency before staff are permitted to work on or around the network. This assessment process ensures employee safety by ensuring they only work within their proven competency.

The current AHC system has been updated to integrate the EWRB's competency-based refresher classes. We are working to align with the Common Competency Framework (CCF), as are most EDBs. We maintain a proactive role in:
- staff competency
- monitoring industry safety issues, and
- implementing training and guidance where required.

ADMS is used to reduce the likelihood of a health and safety incident arising through operator error. The ADMS, which includes a network model and is used to produce switching schedules for all network outages. It will generate an alarm if a planned switching schedule results in a network condition that makes it unsafe to issue a clearance.

8.3.2 – SUBTRANSMISSION RISKS

Our subtransmission system comprises a single 110 kV circuit between Kaikohe and Kaitaia, and the 110 kV subtransmission line that delivers electricity generated by the Ngāwhā OEC4 generating unit to Kaikohe. It also includes the 110 kV transformers and switchgear at the Kaikohe and Kaitaia substations and the Ngāwhā 110 kV switchyard. These are critical assets, not least because of failure of the Kaikohe-Kaitaia circuit means that the 10,000 consumers in our northern area will be islanded from the grid. While we acquired most of our subtransmission assets from Transpower in April 2012, the TECS staff's experience in maintaining 110 kV subtransmission assets is limited.

To minimise and mitigate our subtransmission risk, we have:
- undertaken a comprehensive condition assessment of our subtransmission assets and developed a replacement plan that will ensure that the assets are replaced before they reach the end of their expected economic life. Provision for these asset replacements is included in the capital expenditure forecasts in this AMP
- contracted the maintenance of all our 110 kV line and 110 kV substation assets to an experienced external service provider. The contract requires that these assets be inspected to a level at least equivalent to that of similar Transpower assets. We also prioritise the repair of defects identified in subtransmission asset inspections.
- facilitated regular site inspections, and, in the process, engage with owners of property over which our 110 kV assets are situated.

We have installed diesel generation in the northern area to:
- avoid the need for maintenance shutdowns, and
- provide resilience in the event of an unplanned line outage.

This is discussed further in Section 8.3.7.

8.3.3 – NETWORK SPARES

We maintain an inventory of critical and specialised spares where there is potential for long delivery times in the event of network equipment failure. In most cases, the equipment we use is standardised and of modular design, allowing it to be replaced relatively easily using our inventory of equipment held to maintain and expand the network. We regularly review our inventory of critical and specialised spares and have joined a cooperative group of other EDBs to provide mutual support and risk mitigation when needed.

For the 110 kV subtransmission assets, critical spares have been procured for standard hardware, crossarms, insulators, and poles. An arrangement with Transpower is in place to obtain a 110/33 kV transformer bank at short notice if required. Our mobile substation is also a network critical spare.

A review of our critical spares strategy and holdings for our subtransmission assets is scheduled for FY 2027, with distribution assets to follow in FY 2028.

8.3.4 – DEFECT MANAGEMENT

Defects identified during our asset inspection programme are included in our defect management programme, where they are risk-assessed and categorised. This programme requires assets identified as defective to be inspected more frequently with the objective of allowing them to remain in service until they reach the end of their economic life. At the same time, ensuring that critical assets are replaced before they fail in service.

We monitor the implementation of our defect management programme using indicators related to outstanding defects and the SAIDI impact of defective equipment faults. We also report monthly to the Board any backlog in the repair or remediation of defects.

Our defect management programme is described in detail in Section 6.1.4.

8.3.5 – VEGETATION MANAGEMENT

Our ongoing vegetation management programme is described in Section 6.1.7. While the primary focus of this programme is the management of supply reliability, trees growing into our lines are a public safety and property hazard and addressing this problem is prioritised when the fire risk is high. We are also working with commercial forestry owners to develop vegetation management agreements and are actively campaigning to remove bamboo growing near our lines.

8.3.6 – ASSET MANAGEMENT

We have developed lifecycle asset management plans, including a risk management plan, for all our main asset groups. These are summarised in Section 6.

8.3.7 – NETWORK RESILIENCE

Network resilience is the ability of a network to withstand high-impact, low-probability events. The network development plan we have implemented over the last 10 years has focused on building a subtransmission network that is resilient to high-impact events. We are now at the point where we can restore supply with a target restoration time of 1 hour following a single element failure anywhere in our subtransmission network. This is explained in Table 5-1.

Our mobile substation is also available to support the subtransmission network as required. Now that we have increased the resilience of the subtransmission networks through our investment in diesel generation, the mobile substation is most likely to be used. Its use will save on the cost of running diesel generation for an extended period following the loss of a transformer or switchgear asset at one of our smaller zone substations.

Notwithstanding this significant improvement in network resilience, our 110 kV Kaitaia-Kaikohe line remains vulnerable to severe storms that can trigger landslides. Such an event occurred in FY 2015 when a tropical storm remained stationary over our supply area for three days. This resulted in the failure of one of the transmission tower foundations in the Maungataniwha Range. Fortunately, on that occasion, there was no supply interruption as the tower was supported by its conductors and did not fall over.

Nevertheless, there is evidence that the line route across the range is becoming increasingly geotechnically unstable, creating an increasing risk of a structure failure. If this occurs, we will first seek materials from our contractor, use our own if available, and, if needed, request a temporary structure from Transpower.

We have discussed this increasing risk with Transpower and the Department of Conservation, which manages the land, and are working with them to develop a detailed response plan should a structure fail. This will increase our preparedness for such an event. We have identified the most vulnerable structures along the line route and conduct geotechnical surveys on each site to secure the most suitable position for their replacement as part of our 110 kV structure replacement programme. Where the site is suitable, deeper and more resilient foundations mitigate the risk of land movement, where this is impractical or cannot be achieved, or major landslips are anticipated, re-locations are sought.

The diesel generation at Kaitaia has mitigated the consequences of such an event. However, this generation is not designed to run continuously for extended periods. Supplying our northern area with diesel generation for the time required to erect a temporary replacement structure would place a substantial financial burden on Top Energy.

A network constraint at the Kaitaia substation will occur once the full complement of 67 MVA of utility-scale solar generation comes online. The Kaitaia substation has two 110/33 kV transformers:
- a large 40/60 MVA (T1), which is relatively new and in good condition, and
- an older 22 MVA single-phase transformer bank (T5) is nearing the end of its economic life.

Should the 40/60 MVA transformer be taken out of service, planned or unplanned, the smaller 20 MVA transformer will not have the required capacity to accommodate all the connected solar generation.

Similarly, the Kaikohe substation has two 110/33/11 kV transformers:
- a large 50 MVA single-phase transformer bank (T3) which is 57 years old, and
- a 30 MVA single-phase transformer bank (T2) which is 65 years old.

Should the 50 MVA transformer bank be taken out of service, planned or unplanned, the smaller 30 MVA transformer do not have the required capacity to service the connected load. This specific scenario was unfortunately proven during the significant network outage experienced in November 2025. To bolster the network resilience for the southern network, the intention is to install connection points for diesel generators at each of our zone substations over the next 12 to 18 months.

Vulnerabilities remain in the distribution network primarily due to the number of long rural radial feeders serving sparsely populated rural parts of the network, remote from the major population centres. The length of these feeders exposes them to a high fault rate. Their remoteness extends the time required to repair a fault, and, together with the high number of connected consumers on each feeder, this can result in a high SAIDI impact. The risk is heightened during adverse weather events, when several faults can occur across different parts of the network. This is one reason why the reliability of the supply we provide consumers is volatile and sensitive to weather conditions. The 11 kV improvements described in Section 5 are designed to reduce these distribution network vulnerabilities.

8.3.8 – EMERGENCY PREPAREDNESS AND RESPONSE PLAN

Events can arise that are outside our network design envelope or exceed the response capacity of our field resources. The most likely scenario is a major storm event, but other events, such as the loss of both transformers at a large substation, are possible.

We have an Emergency Preparedness and Response Plan to deal with such situations. This is designed to ensure that our network capabilities are sustained as far as practicable during emergency circumstances and events through the adoption of effective network management and associated practices. They ensure we have the capability and resources to meet our community obligations, including fulfilling civil defence emergency management requirements, while also enhancing stakeholder and public confidence.

The plan addresses how we respond to major emergencies affecting the electricity supply by focusing on the four ‘R’s:

- **Reduction** (mitigation) of potential and actual threats or impacts arising from a diversity of natural and man-made hazards or risks that surround Top Energy and its assets. This does not extend to the management of network asset-related risks, which are separately addressed during network planning and included in the risk register.
- **Readiness** (preparedness) to anticipate and prepare for potential and actual risks or threats beyond those alleviated by other means.
- **Response** to a potential and actual emergency, to stabilise the situation and prevent further danger and unnecessary outage.
- **Recovery** following response, to restore full normal services and functions.

Listed below are the objectives of this plan.

- To provide general guidelines that can be combined with sound judgment, initiative, and common sense to address any emergency, irrespective of whether that set of circumstances has been previously considered and planned for. These guidelines define the roles, duties and obligations of Top Energy and other personnel in preparing for and managing an emergency, prioritised on:
  - protection of life (staff and public)
  - safety and health of staff, service providers, consumers, and the public
  - protection of property and network assets
  - protection of the environment
  - ongoing integrity of the electricity network, 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 the management and operation of the electricity network during an emergency.

The plan covers:
- emergency event classification
- emergency response team roles and responsibilities
- communications and reporting processes
- emergency response prioritisation
- detailed emergency response actions, and
- business continuity programme maintenance procedures.

Our Emergency Preparedness Plan was activated during Cyclone Gabrielle in February 2023, and most recently, it was activated during ex-Cyclone Tam in April 2025. After each activation, we review our plan to capture the lessons learned from our management of that specific event.

We have updated our formal emergency response plan and split it into two documents: one covering preparedness and the other covering response. The revised plan will:

- formalise the regular testing of our preparedness and response capability, and
- specify the frequency with which infrequently used systems, such as communications systems, that are in place to facilitate our response to high-impact low probability (HILP) events, are reviewed and tested.

8.3.9 – 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 stormwater, electricity, gas, telecommunications, and transportation networks including roads, rail, airports, and ports). Top Energy is an active member of the Northland Lifelines Group, coordinated by the Northland Regional Council. This group 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 to protect and preserve the region's lifelines.

As part of the Lifelines group's coordination activities, we have committed to working with the Northland Civil Defence Emergency Management Group to use our ripple control network to activate 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
- activation of alarms
- process for notifications, and the logging of events and activations, and
- protocols for testing and reporting of system failures.

We also participate in formal civil defence exercises organised by the Northland Lifelines Group.

8.3.10 – LOAD SHEDDING

We maintain a load-shedding system to meet our regulatory requirements, ensuring that an automatic under-frequency load-shedding system is installed at each grid exit point connected to a local network (in our case, Kaikohe). The system enables automatic disconnection of two demand blocks, as explained in Section 5.8.2.

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, specifying shedding priorities (manual and automatic) by under-frequency zone and substation for the 11 kV 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.

8.3.11 – CONTINGENCY PLANS

We have standardised operating procedures and switching instructions that are managed and updated regularly by our Control Centre staff. These switching instructions outline methods for rearranging the electrical network to supply consumers during network contingencies (e.g., equipment outages). We have also commissioned a separate and completely independent emergency control centre at the Ngāwhā Power Station. Our training programmes provide for regular operator familiarisation and testing activities.

8.3.12 – MOBILE SUBSTATION

Many of our risk scenarios involve consumer non-supply due to equipment failure in zone substations, particularly in substations with only one transformer. In FY 2003, we mitigated this risk by purchasing a mobile substation and modifying single-transformer substations to allow the unit to be installed quickly, in accordance with formalised procedures.

[8.4] Safety Management

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, and ensure that we:

- meet all legal compliance requirements, and
- interface with our contractors, 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 to which our staff comply with the system's requirements. We have integrated our PSMS into our asset management safety practices and use it to manage the safety risks in operating our network. Ensuring that our compliance with our PSMS is externally audited provides a level of governance that ensures that our safety practices take due account of the requirements of the Health and Safety at Work Act 2015 and other relevant legal requirements.

The coverage of our PSMS extends beyond our own network assets into consumer-owned assets. This is because, while we do not own consumer assets and therefore are not responsible for their compliance, we do operate them, and we must ensure the safety of our staff. We also have responsibilities regarding the equipment we allow to connect to our network and be energised.

[8.5] Corporate Risk Register

Table 8-3 below lists the risks in Top Energy's Corporate Risk Register assigned to TEN, along with the controls we have in place to mitigate them.

NO.	RISK	PROBABILITY	CONSEQUENCE	MITIGATION
Risks from the Top Energy Group Risk Register that are Assigned to TEN				
15.	Third-party loss or damage.	Medium, mitigated to medium.	Exposure to compensation or fines.	• Compliance with Electricity (Safety) Regulations and associated Codes of Practice. • Public Safety Management System, certified to NZS 7901, is in place.
2.	Serious harm to members of the public relating to interaction with the Group's facilities.	High, mitigated to medium	Exposure to compensation or fines.	• Compliance with Electricity (Safety) Regulations and associated Codes of Practice. • Public Safety Management System, certified to NZS 7901, is in place.
5.	Failure of network equipment or systems, owing to incorrect or inadequate design, specification, installation, operation, or maintenance.	Medium, mitigated to medium.	Regulatory investigation.	• Adoption of ISO 55000/PAS 55 as a best practice asset management standard. • Assessment of asset management capability and maturity, and continuous improvement as per the standard. • The use of external consultancy when in-house capability is insufficient.
16.	Inadequate execution of network projects.	Medium, mitigated to medium.	Impact on pricing control – loss of incentives and/or penalty	• Dedicated in-house project delivery manager to support a competent planning team.
20.	Significant (more than 10,000 customers affected for a period of 12 hours or more) unplanned network outage or damage to assets resulting from accident, vandalism or technical failure, but excluding those caused by natural disasters.	Medium, mitigated to low.	Breach of regulatory quality targets.	• Provision of network resilience with diesel generation. • Contingency plans, including disaster recovery and emergency preparedness.
19.	Loss of subtransmission power for more than 24 hours.	Medium, mitigated to medium.	Loss of grid supply to all consumers.	• The network currently has 17.2MW of diesel generation available to deploy to critical load locations in the event of a sustained loss of grid supply. Supply would need to be rationed in the event of an extended interruption. • Our Emergency Response Plan includes the contact details of hire generator suppliers who would be used to augment the generation capacity in the southern area.
21.	Environmental damage – Network.	Medium, 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 identifying environmental vulnerabilities and updating mitigation provisions.

Table 8-3: Corporate Risk Register

8.5.1 – NETWORK PUBLIC SAFETY MANAGEMENT SYSTEM HAZARD REGISTER

In implementing its Public Safety Management System, TEN maintains a formal Risk Register for which a 5x5 Risk Assessment Matrix is applied. This is actively managed by the Technical Safety Engineer and reviewed monthly by the Network Risk Management Committee as discussed in Section 8.2.2. For each risk, the register identifies the inherent risk and the risk control strategies throughout its lifecycle, including relevant external safety regulations and guidelines, as well as internal processes and controls in place to manage the risk. Each risk is assigned a residual risk score that is based on:

- **Consequence** – the likely worst potential harm to persons or damage to property if an event occurs from exposure to the risk.
- **Likelihood** – how likely the consequences would be incurred on each exposure.

We currently have no residual risk with an 'Extreme' rating on the current risk register. Risks with a 'High' residual risk rating are listed below.

RISK CATEGORY	RISK DESCRIPTION
Process/ Workmanship	Transposed conductors upon supply connection/reconnection (Residential, Commercial, Streetlights, etc.)
Working too close (ECP34)	If there are attachments to a pole or nearby objects that allow a member of the public to intentionally climb a pole and contact live parts, or fall.
Vehicle vs Asset	Ground mounted equipment (including poles) is hit more than once by a vehicle.
Vehicle vs Asset	Vehicle strikes live overhead lines while transporting an over-dimensional load.
Vehicle vs Asset	Aircraft strikes aerial conductors.
Vegetation	Vegetation at risk of being in contact with live network assets, e.g., the vegetation grows/wind, etc., including fire risk.
Working too close (ECP34)	Non-compliant ground clearances of lines.
Working too close (ECP34)	Construction/placement of structures/items near network assets (e.g., buildings, containers, piles of dirt/woodchips, etc).
Intentional third-party interference	Breaching security to ground-mounted field equipment – allowing access to live internals.

RISK CATEGORY	RISK DESCRIPTION
Protection insufficient/ failure	Long-duration fault currents- Protection fails to operate (HV and LV).
Intentional third-party interference	Theft of conductor.
Intentional third-party interference	Breaching security to zone substations.
Intentional third-party interference	Theft of earths.
Process/ Workmanship	Harm to person or property from connection/reconnection of non-compliant installations (Residential, Commercial, Streetlights, condition, vegetation, safety clearances, etc.).
Equipment failure	Catastrophic failure of equipment.
Working too close (ECP34)	Harm to persons from leisure activities around overhead lines, e.g., kites, drones, fishing, and boating.
Protection insufficient/failure	Low fault current leading to slow protection operation.
Other	Fittings or pieces falling from height.
Working too close (ECP34)	Third-party interference with underground cables and terminations.
Process/ Workmanship	Volume of protection event notifications during system events leading to indecisive or poor decisions or switching errors.
Process/ Workmanship	Information returned from asset inspections is potentially inaccurate, leading to poor asset management.
Working too close (ECP34)	Structures enable unassisted climbing and access to live-exposed parts.
Process/ Workmanship	Privately owned lines are not being maintained to industry and regulatory standards, posing a risk to persons and property.
Vegetation	Member of the public decides to clear vegetation around live power lines and receives an electric shock.

RISK CATEGORY	RISK DESCRIPTION
Vegetation	Person interacting with vegetation planted for non-commercial purposes under or too close to power lines.
Other	Contact between a live wire and a stay wire, causing a shock to the public due to the absence of a stay insulator. This includes broken stay wires and public interference with stay wires.
Other	Contact between overhead power lines of dissimilar voltages resulting in overvoltage to installations.
Working too close (ECP34)	Damaging network assets, including land slips close to the 110 kV line.
Process/ Workmanship	Following protection operation, the Network Controller livens an unidentified hazardous condition.

Table 8-4: High and Medium Risks on Safety Hazard Register

8.6 Climate Change

Climate change is increasingly shaping the operating environment for Top Energy and the communities we serve in the Far North. The region faces a growing frequency and severity of extreme weather events, coastal flooding, droughts, and wildfire risk. These hazards:

- threaten the integrity of our network assets
- disrupt supply reliability, and
- have far-reaching social and economic consequences, particularly for our most vulnerable customers.

We anticipate that climate change will primarily impact the management of our network in two ways:

- the use of Decarbonisation technologies in the economy will impact both the demand for electricity and the expectations of network users in relation to the services we provide, and
- changes in weather patterns will affect the reliability of supply to consumers.

We have completed a network assessment of our risks associated with climate change. By using extreme weather and coastal flood data from the Northland Regional Council and risk models, we categorise flood risks into 1-in-10, 50, and 100-year event categories, providing an understanding of potential impacts. This allows us to:

- identify the vulnerabilities in isolating equipment, transformers, low voltage pillars, and poles, and
- present spatial analyses and heat maps to illustrate areas most at risk and guide targeted mitigation strategies.

8.6.1 NETWORK VULNERABILITIES DUE TO EXTREME WEATHER

The modelling work provides a unified perspective on flood and extreme weather vulnerabilities, enhancing understanding of potential impacts on critical infrastructure. The spatial modelling of these vulnerabilities guides informed decision-making on asset placement, risk management, and disaster preparedness.

The table below shows the total number of assets potentially impacted by coastal flooding and extreme weather event risks within our network.

	EVENT PROBABILITY	ISOLATING DEVICES	GROUND MOUNTED TRANSFORMERS	POLE MOUNTED TRANSFORMERS	LV PILLARS	POLES
Coastal Floor	Current	27	6	52	136	623
	1-in-50y	50	12	82	212	911
	1-in-100y	131	40	169	661	1,660
Extreme Weather	1-in-10y	112	19	252	263	2,740
	1-in-50y	208	53	374	884	3,770

Table 8-5: Equipment Affected by Weather Event Probability

To provide a spatial perspective on the distribution of at-risk equipment, we provide a perspective view on isolating equipment as an example. Figure 10-2 shows the spatial distribution of isolating equipment at risk from coastal flooding across different event probabilities. Figure 10-3 presents a similar analysis of extreme weather, highlighting areas where isolating equipment is most exposed to severe conditions.

Given the technological advantage that Reclosers and Sectionalisers can be operated remotely, concerns primarily arise for manually operated devices. These are vital during weather events for tasks such as isolating and back-feeding certain areas. When at risk, they pose a unique challenge: their physical access may be restricted, especially during flooding.

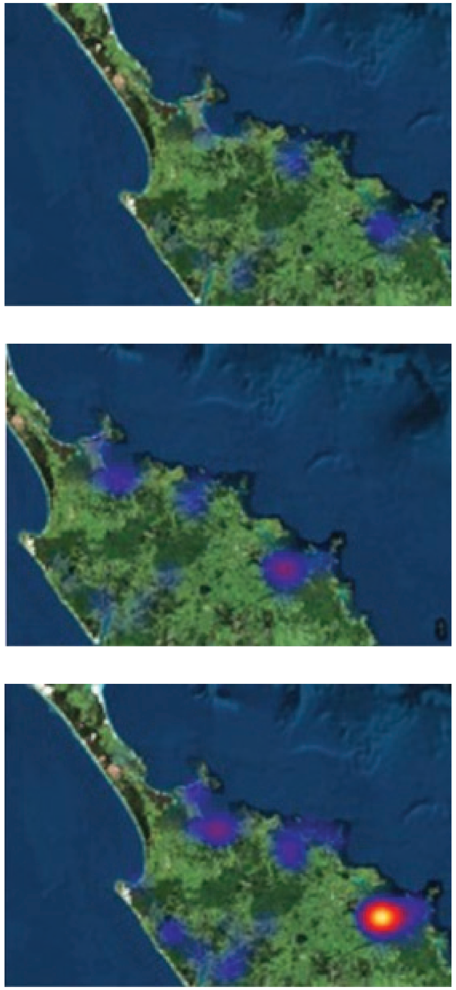

Figure 8-2 – Geographical Distribution of At-Risk Isolating Equipment Across Different Coastal Flood Conditions – Source: Northland Regional Council

Figure 8-3: Geographical Distribution of At-Risk Isolating Equipment Across Different Extreme Weather Conditions

8.6.2 – VULNERABILITIES DUE TO FIRE RISK

Our network also faces significant fire risks due to rapid vegetation growth and near-drought conditions across many summers. Key areas such as Cape Reinga, Karikari, and Ahipara frequently reach extreme fire risk levels. We have developed a fire risk map that details specific high-risk areas and emphasises the need for proactive vegetation management.

In collaboration with Fire and Emergency New Zealand (FENZ), we monitor fire risk ratings and adjust local network protection settings as needed. The reviewed vegetation strategy is outlined in Section 6.1.7.

Our fire management strategy includes:

- tracking risk ratings
- prioritising vegetation management in high-risk areas, and
- providing field fire management training to staff.

The ICS team is working with FENZ and Onyx to develop an API to automate ADMS to adjust remote-controlled protection devices in and out of inhibited auto-reclose when fire risk levels change.

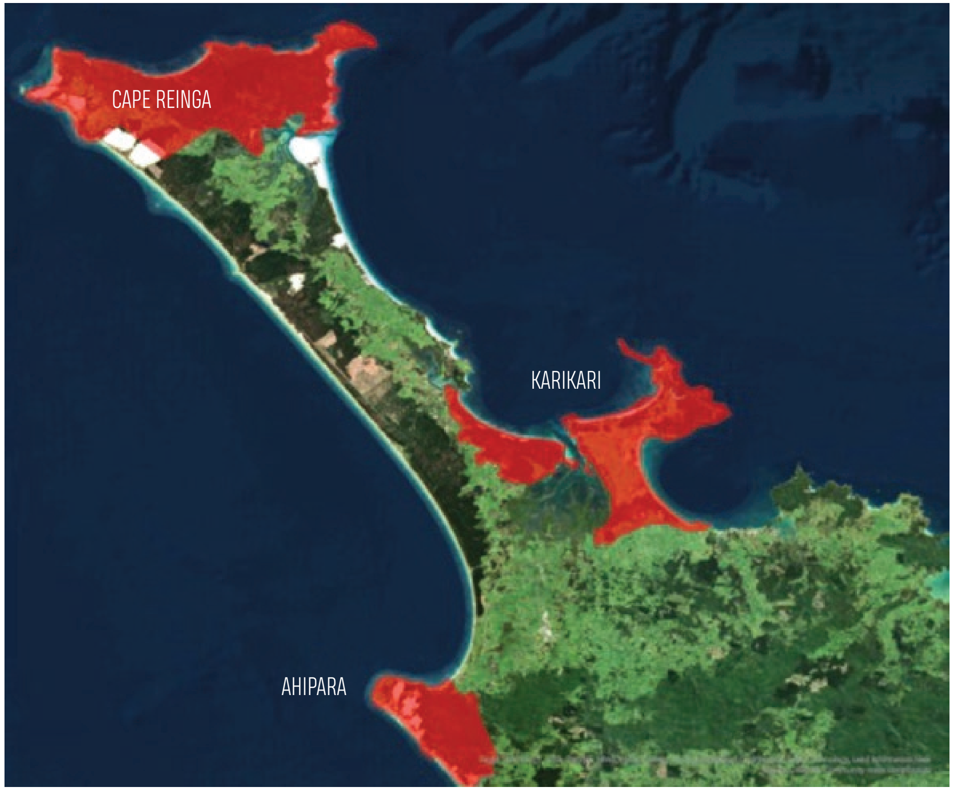

Figure 8-4: Worst-Case Scenario in Terms of Extreme Fire Risk Areas

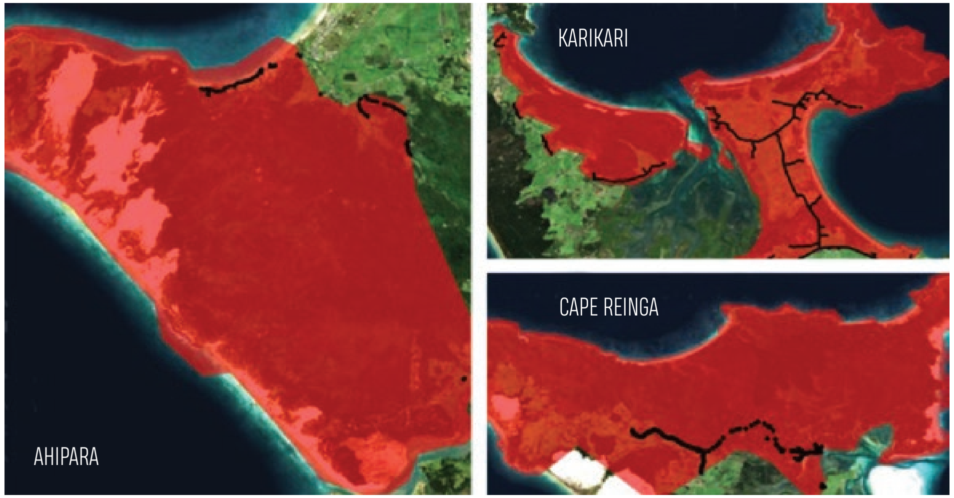

Figure 8-5: Poles within Extreme Fire Risk Area

8.6.3 – NETWORK PERFORMANCE DUE TO ADVERSE WEATHER

In addition to fire risk, adverse weather also plays a key role in network reliability. Analysis conducted by Harmonic Analytics in 2023 shows a stronger correlation between daily peak wind gusts and incident frequency than with rainfall. This supports expert observations that high winds are more likely to cause faults, while heavy rain tends to delay response times. Figure 8-6 and Figure 8-7 show that incident frequency increases moderately with wind speed, while rainfall shows a weaker link, with a noticeable rise in incidents only when daily rainfall exceeds 15 mm.

PEAK WIND GUSTS vs NUMBER OF INCIDENTS ON THAT DAY ACROSS NORTHLAND

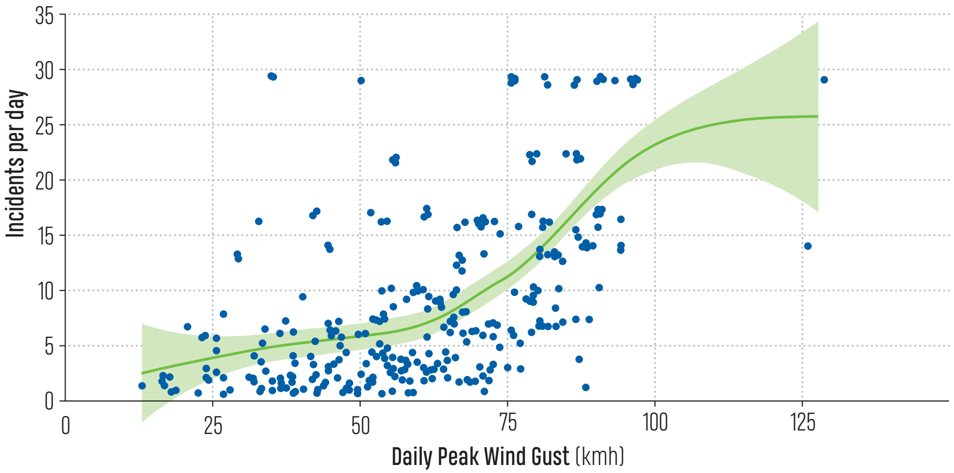

Figure 8-6: Peak Wind Gusts vs Number of Incidents on that Day Across Northland

DAILY RAINFALL AMOUNTS vs NUMBER OF INCIDENTS ON THAT DAY ACROSS NORTHLAND

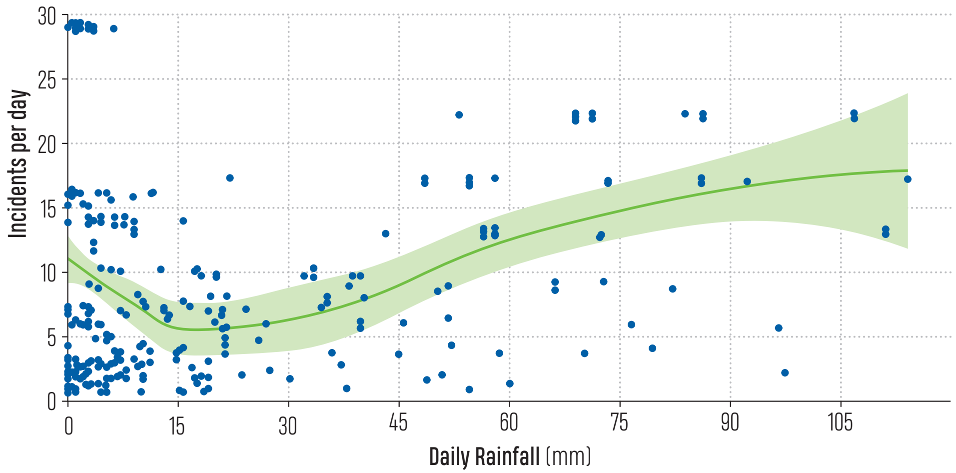

Figure 8-7: Daily Rainfall Amounts vs Number of Incidents on that Day Across Northland

To enhance network resilience and improve supply reliability for affected customers, with most faults occurring on our most exposed assets being the 11 kV network, we implemented a reliability programme that included a suite of works to mitigate the impact from adverse weather. These include, but are not limited to:

- roll out of Distribution Automation on feeders with poor SAIDI performance to enable isolation and automated control
- installation of Group Fusing to ensure the integrity of the backbone network and isolate spurs when faults occur
- interconnect distribution circuits to improve operational flexibility and enable back-feeding during outages — for example, linking the Rangihua and Horeke feeders, and
- accelerate the pole replacement programme, replacing those nearing end-of-life and ensuring they are designed to the latest overhead line design standards described in ASNZS 7000.
- underground vulnerable spans in areas with dense vegetation and trial-covered conductors on sections of the 11 kV overhead network prone to frequent faults caused by debris, with Orokawa Bay identified as a pilot location for this initiative.

EVALUATION OF PERFORMANCE

SECTION 9

EVALUATION OF PERFORMANCE

This section evaluates our asset management performance regarding:

- the extent to which we have met the service level performance targets for FY 2025, the most recent year for which complete data is available. The targets were set in our 2021 AMP
- our expenditure on network development and maintenance in FY 2025, and
- the quality of our asset management systems and procedures.

[9.1] Achievement of Service Level Targets

Table 9-1 shows our performance against the service-level targets for FY 2025.

SERVICE LEVEL INDICATOR	INTERNAL TARGET	THRESHOLD	OUTCOME
Normalised Unplanned SAIDI	300	380.24	258.06
Normalised Unplanned SAIFI	4.01	5.0732	3.34
Planned SAIDI[1]	125	1905.36[2]	170.62
Planned SAIFI	1.0	7.75	1.11
Loss Ratio	9.6%	–	10.1%
Ratio of Total Opex to Total Regulatory Income	59.3%	–	55.9%

Table 9-1: Achievement of FY 2025 Service Level Targets

Note 1: After de-weighting notified interruptions in accordance with the provisions of the Electricity Distribution Services Default Price-Quality Path Determination 2020.

Note 2: Aggregate value for all five years of DPP3.

9.1.1 – UNPLANNED SAIDI AND SAIFI

In FY 2025 met our unplanned SAIDI target of 300 Minute, with an actual year end SAIDI of 258.06. SAIFI was also within target at 3.34 at year end.

There was one unplanned interruption of the Top Energy 110 kV network during DPP4.

- The cause was a short circuit in the protection wiring, which incorrectly sent a trip signal when the line load exceeded 24 MW, resulting in a SAIDI of 18 minutes. The other 110 kV event was a Transpower loss of bulk supply due to a Transpower tower fall event at Glorit in southern Northland on 20 June 2024.
    - Unplanned interruptions of the 110 kV network are infrequent, but when they do occur, a single fault can have a significant impact on SAIDI due to the number of consumers affected.
    - The average normalised SAIDI impact of 33 kV faults over the review period was 29. This is less than 10% of the normalised network SAIDI impact and is a positive outcome of the TE 2020 investment over the last decade. In particular, the provision of differential protection on all subtransmission circuits has enabled two circuits to run in parallel, so now there is no interruption for most subtransmission faults. Furthermore, we have installed diesel generation for network support at most substations with only one incoming subtransmission circuit.
    - It follows that almost 86.5% of our normalised network SAIDI is due to faults on the 11 kV network. The reliability of this part of the network needs to be addressed to stabilise our overall network SAIDI at the new target. To this end, in April 2022, the Board decided to defer construction of the 110/33 kV Wiroa substation and reallocated the funding to projects, some of which has been allocated to 11 kV reliability improvement.
    - Over the two-year period from April 2023 to April 2025, 32% of normalised 11 kV network SAIDI was caused by defective equipment faults and 23% by vegetation. This equates to 152 minutes and 108 minutes, respectively. 64% of tree faults in this period were trees falling onto lines. Third-party interference, primarily car vs pole impacts, caused 18% of faults, and the cause of 12.5% of faults was unknown.

As discussed in Section 6.1, we are transitioning from a strictly time-based vegetation management strategy to one in which network sections with high tree contact SAIDI are managed more frequently. This is similar to the transition from a time-based maintenance programme to a condition-based programme, in which assets at higher risk of failure are maintained more frequently. Over the review period, almost 33% of our total normalised 11 kV tree contact SAIDI could be attributed to just five feeders.

While the above two components of the programme focus on preventing faults, the final component is designed to reduce the SAIDI/SAIFI impact of faults that occur. The two main subcomponents of this effort are:

- optimisation of feeder protection – this includes the installation of new reclosers and sectionalisers on less reliable feeders to reduce the number of consumers affected by a fault, and
- the installation of normally open interconnections between feeders to enable supply to be restored downstream of a faulted switching section before a fault is repaired.

Other subcomponents include:

- installation of a new injection point using the 11 kV tertiary winding of the Kaitaia 40/60MVA
- 110/33 kV transformer replacement
- trailing and installation of fault passage indicators
- replacement of manually operated air-break switches with remote controlled vacuum units, and
- installation of sectionalisers and spurline fusing.

Over the next three-year period (FY 2027-29), our forecast capital expenditure on initiatives that impact the reliability of the 11 kV network is $40 million. This is 9% higher than the corresponding forecast in the FY 2023 AMP renewal. Furthermore, our vegetation management opex provision has increased by 62% over the same period. This provision covers only planned vegetation management and does not include any additional vegetation works undertaken under other work streams, such as faults, capital works, or CIW works.

Reliability Initiative Progress

In 2021, external consultants undertook a review of the network's performance. This highlighted a number of recommendations. Progress against this was reviewed in FY 2026. Listed below are the high-level outcomes from this review.

- Overall network performance has improved since the 2021 report, with the worst-performing feeders showing improvements.
- Vegetation and defective equipment causes have notably improved since 2021, more pronounced following initiative improvements.
- **Fault Passage Indicators (FPIs):** SAIDI has been reduced by 50% on key feeders with FPIs installed. However, at this stage, it is difficult to evidence a direct correlation between device installation and SAIDI reduction.
    - As part of an evaluation and trial of fault passage indicators (FPIs), we have installed 28 FPIs and fuse drop indicators on high-priority feeders and circuits, including Tokerau, Oruru, and Horeke. Conclusions from the pilot trial will determine which devices and configurations are best suited to our needs and perform to our expectations within our environment.
    - Of the 28 devices installed, seven were installed on the Tokerau feeder, six on the Oruru feeder, and one on the Horeke feeder. It is also not always practical to install and fully utilise FPIs in areas with poor cellular service, hence, South Road and Te Kao feeders have yet to have any FPIs installed. Access to future technologies may remove some of these constraints.
    - Figure 9-1 shows that the average trendline for unplanned normalised SAIDI on the Tokerau, Oruru, and Horeke feeders has decreased by 63% since FY 2021, yet the number of faults on these feeders has not decreased significantly. This is expected, as the purpose of FPIs is to reduce fault-location time, not to prevent faults. Thus, the average trendline for the average SAIDI per fault on these feeders has decreased by 56% since FY 2021, as shown in Figure 9-2.

UNPLANNED NORMALISED SAIDI ON TOKERAU, ORURU AND HOREKE FEEDERS

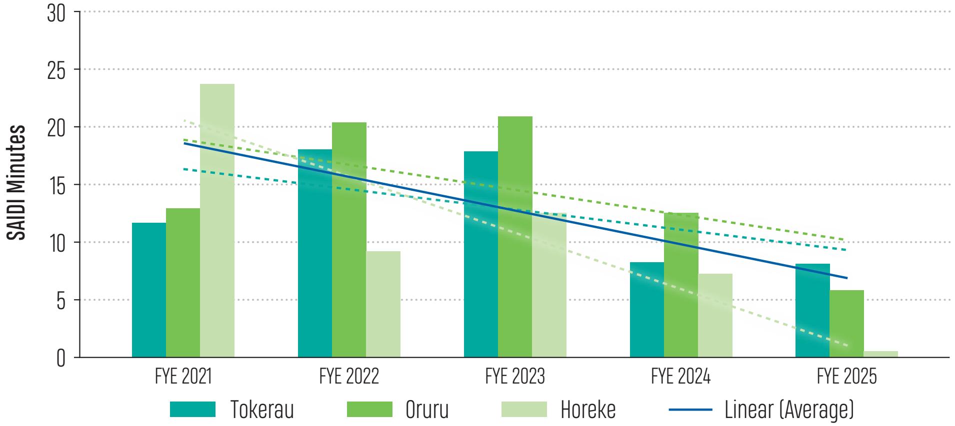

Figure 9-1: Unplanned Normalised SAIDI on Tokerau, Oruru, and Horeke Feeders

UNPLANNED NORMALISED SAIDI ON TOKERAU, ORURU AND HOREKE FEEDERS

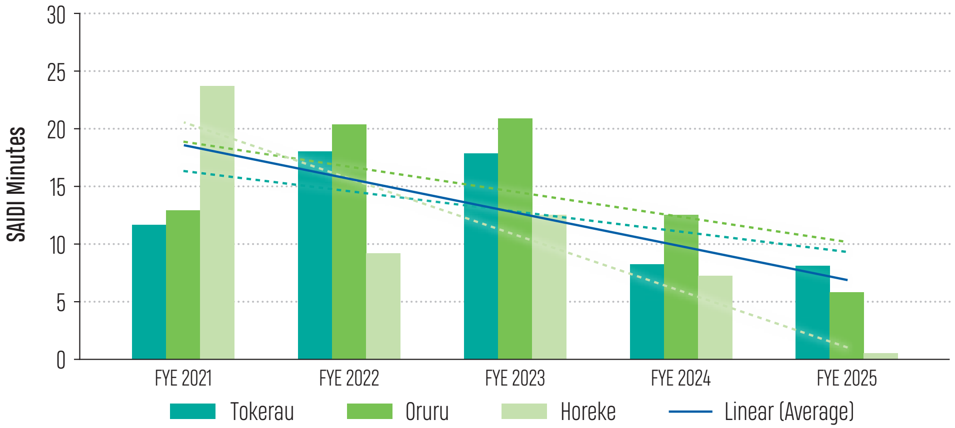

Figure 9-2: Average SAIDI per Unplanned Outage on Tokerau, Oruru, and Horeke Feeders

- **Distribution Automation:** We have installed six sectionalisers on key feeders in the past three years. Customers affected by outages on these feeders have decreased by 25%, as shown in Figure 9-3. The installation of sectionalisers has contributed to this by reducing the number of ICPs affected by downstream faults. However, we have not completed a detailed analysis of this at this stage. A larger data set spanning a longer period will enable a more thorough analysis. Three sectionalisers were installed on the Oruru, Joyces Road, and Russell Express feeders in FYE 2026.

AVERAGE CUSTOMERS PER FAULT (EXCLUDING CYCLONE GABRIELLE) ON SOUTH ROAD, RANGIAHUA, TE KAO, AND HOREKE FEEDERS

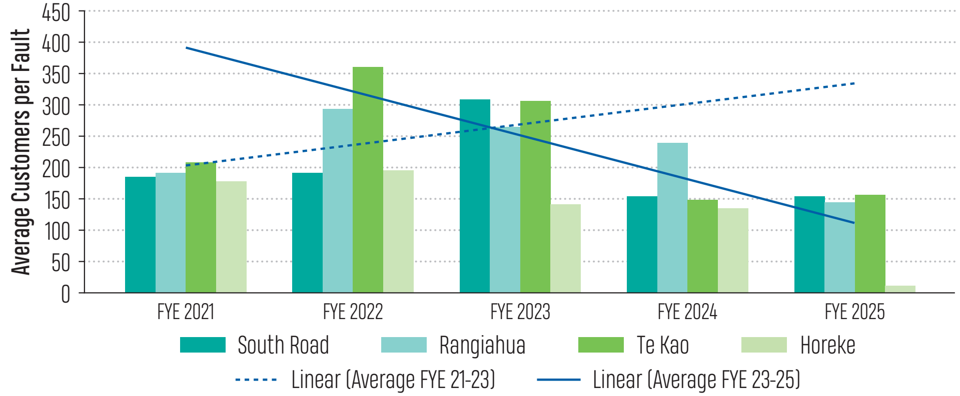

Figure 9-3: Average customers per unplanned outage (excluding Cyclone Gabrielle) on South Road, Rangiahua, Te Kao, and Horeke Feeders

- **Vegetation Management:** Figure 9-4 shows that our current processes have reduced vegetation-related SAIDI by 13% and SAIFI by 9%. Tree-contact SAIDI is decreasing, though tree-fall SAIDI is increasing. We have reviewed and finalised our vegetation strategy to continue focus on vegetation related outages.

UNPLANNED NORMALISED SAIDI AND SAIFI CAUSED BY VEGETATION

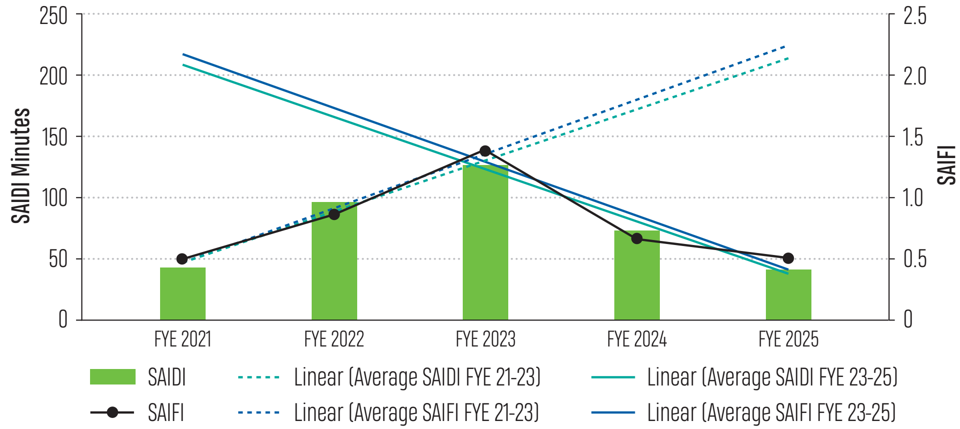

Figure 9-4: Unplanned Normalised SAIDI and SAIFI Caused by Vegetation

- **Asset Replacement:** The targeted replacement of crossarms, poles, and RMUs has significantly reduced defective equipment SAIDI by 70 minutes since FY 2021.
  - The crossarm replacement programme was expanded in FY 2023, with 1,200 crossarms and 800 pole-top hardware units replaced, focusing on feeders like Te Kao (61% of SAIDI due to defective equipment) and Horeke (50% due to defective equipment).
  - The pole replacement programme was also expanded, with 500 end-of-life distribution and subtransmission poles and structures scheduled for replacement per year.
  - There is a drive to replace all wood poles from the network with concrete or fibreglass alternatives as part of a 10-year plan.
  - End-of-life and damaged RMUs are also being replaced at a rate of approximately four per year.
  - Enhanced inspection techniques, including drone-based assessments, have improved the identification of at-risk pole-top hardware, addressing the challenge of ground-level inspections.
  - A Condition-Based Asset Risk Management (CBRM) strategy has been implemented to optimise the number, type, and selection of assets to be replaced.

Figure 9-5 shows that the average trendlines for defective equipment-related SAIDI and SAIFI have both decreased by approximately 34% since FY 2023. While SAIDI and SAIFI from defective equipment has decreased significantly, the proportion of SAIDI attributed to defective equipment remains largely unchanged.

Figure 9-6 shows that the average trendline for the percentage of SAIDI caused by defective equipment decreased by 45% from FY 2021 to FY 2023. However, the same trendline only decreased by 1% from FY 2023 to FY 2025.

The main causes of SAIDI from defective equipment are shown in Figure 9-7. SAIDI caused by defective crossarms, insulators, and protection devices is decreasing rapidly. However, SAIDI caused by defective conductors, transformers, and other overhead components such as poles, stay wires, and regulators, remains consistent across the five-year period.

UNPLANNED NORMALISED SAIDI AND SAIFI CAUSED BY DEFECTIVE EQUIPMENT

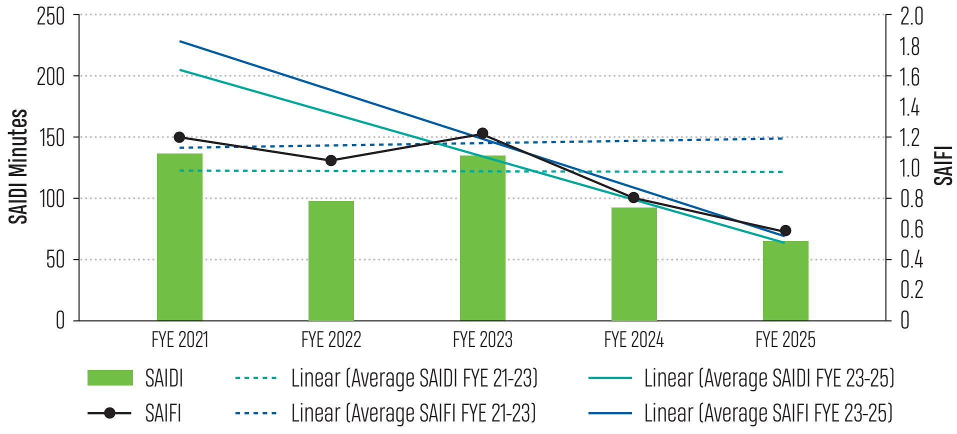

Figure 9-5: Unplanned Normalised SAIDI and SAIFI caused by Defective Equipment

PERCENTAGE OF UNPLANNED NORMALISED SAIDI CAUSED BY DEFECTIVE EQUIPMENT

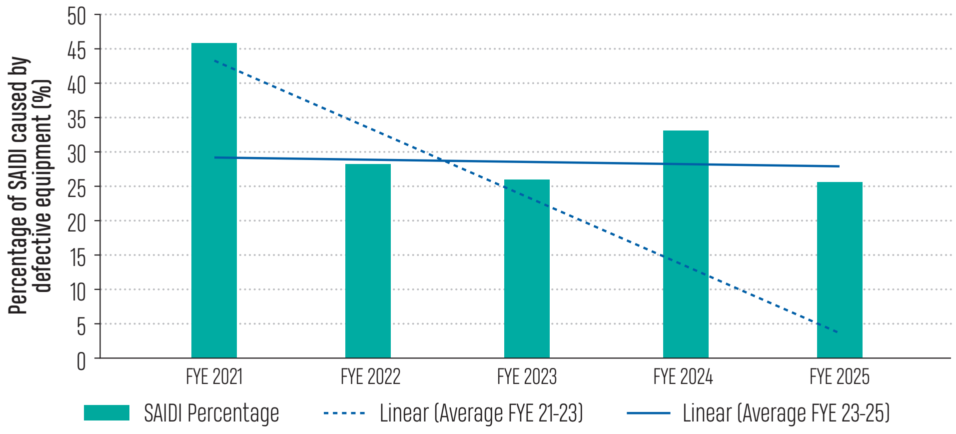

Figure 9-6: Percentage of Unplanned Normalised SAIDI Caused by Defective Equipment

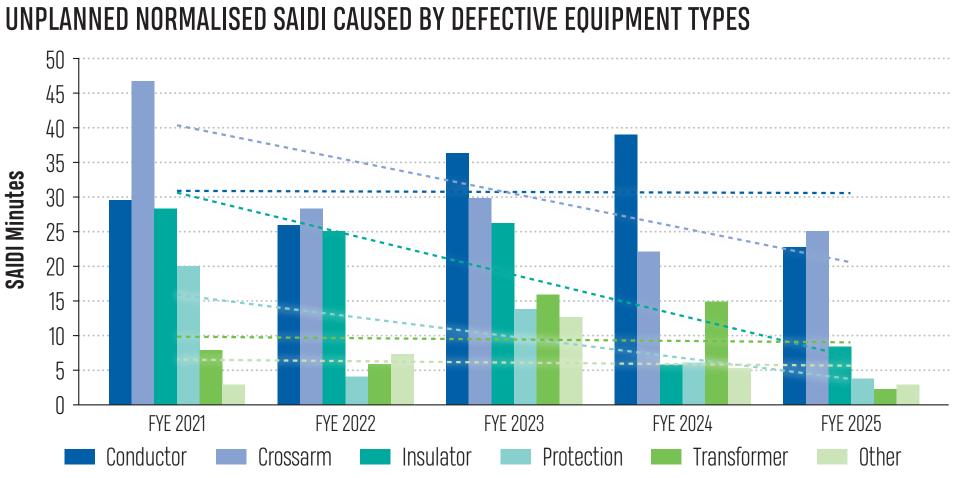

Figure 9-7: Unplanned Normalised SAIDI Caused by Defective Equipment Types

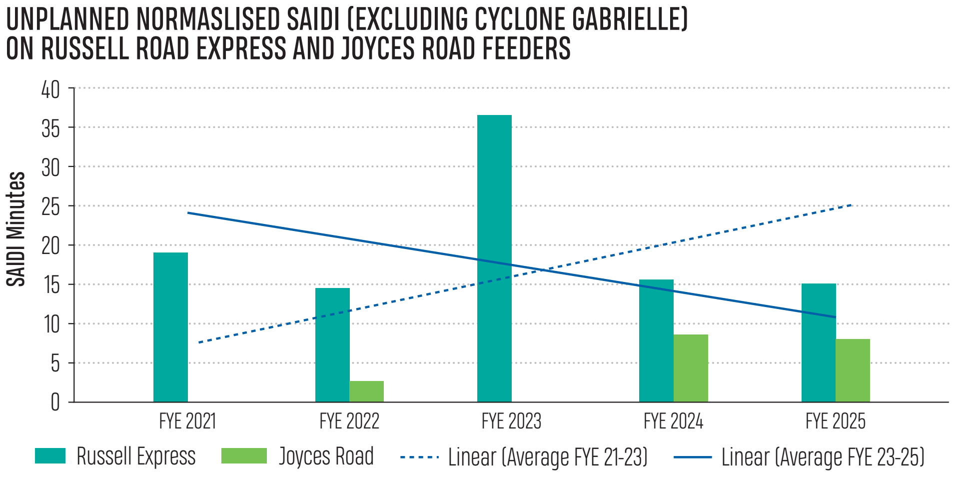

Figure 9-8: Unplanned Normalised SAIDI (excluding Cyclone Gabrielle) on Russell Express and Joyces Road Feeders

- **Feeder Expansion and Interconnections:** New feeders and line upgrades have improved back-feed options and reduced restoration times.
    - Prior to FY 2023, the Russell peninsula was fed entirely by the Russell Express and Karetu feeders, leading to poor reliability and high SAIDI.
    - A second feeder to the Russell peninsula was commissioned in FY 2023 (Joyces Road), reducing the load on the existing Russell Express feeder.
    - Five new 11 kV underground cable feeders are being installed at the Kaitaia 110/33 kV Substation to ease load and provide additional back feeding options in the Kaitaia area.
    - Figure 9-8 shows the average trendline for SAIDI on the Russell Express and Joyces Road feeders combined increased by 113% from FY 2021 to FY 2023, even after SAIDI for Cyclone Gabrielle was omitted. Since a large portion of the load from the Russell Express feeder was transferred to the Joyces Road feeder, the average SAIDI trendline for both feeders combined has decreased by 28%. This demonstrates the approach's effectiveness. Although the SAIDI on Joyces Road has increased due to higher customer count and line length, the total SAIDI shared between them has decreased.

Listed below are the other outcomes noted in the review report.

- Enhanced fault detection and integration of LV smart meter data are improving fault management, ADMS visibility and SAIDI accuracy.
- Unknown faults are an ongoing concern. New patrol guides and training have been introduced, though the rate of outages from unknown causes has not declined significantly. This will be a focus going forward, while acknowledging the challenges of finding transient-type causes on remote sections of cross-country lines. SAIDI events exceeding 2 minutes are reviewed and redressal works raised as actions in our quality management systems, enabling targeted and monitored corrective actions.
- Worst-Performing feeders: Overall, cumulative feeder performance (FY 2023-FY 2025) has improved, with the worst-performing feeder in FY 2022-2025 significantly better than in FY 2020-FY 2022.

As a result of the report, the following initiatives have been presented to the Board for approval as part of our strategy over the coming three years as we continue our reliability journey. They target each of the higher impact SAIDI areas, vegetation, equipment failure, and customer impact reduction, as well as an increased focus on reporting to allow for greater visibility and data-driven decision making, including verification of success against targeted outcomes and identification of emerging trends or issues.

Focus Areas

AREA	FOCUS REQUIREMENTS
Vegetation Improvements	• Monitor changes and tools arising from MBIE's review of the 2003 Tree Regulations, especially regarding the management of the risk of out-of-zone fall distance trees. • Fully embed the Vegetation Strategy into our business processes to provide clear, effective direction for decision-making by vegetation teams when prioritising work. • Improve vegetation notice reporting to enhance the management of cut-and-trim notices.
Risk and Equipment Failures	• Develop the CBRM decision-making strategy and integrate it into decision-making processes. • Refresh and calibrate CBRM modelling based on the output of renewal projects undertaken.
Unknown Fault Improvement	• Refresher training for line patrol processes. Select and implement a Learning Management System for general skills and competency assurance management. • Transition >2min SAIDI reviews, and significant unknown faults, into Root Cause Analysis assessments. • Broaden the scope of unplanned event reviews to a cross-functional review, regardless of the SAIDI incurred during the event.
Reporting Improvements	• Improve and roll out more detailed outage reporting in the mobile field application. • Develop a suite of reportable success measures for each initiative. • Review and improve unplanned outage reporting by using trend analysis to identify negative or stagnant outage causes or network components with recurring issues. With scheduled reviews and refinement of this reporting functionality. • Investigate tools such as LiDAR, satellite imagery, and other methods to enhance vegetation strategy and prioritisation.
Customer Impact Reduction Projects	• Continuation of FPI rollout, group fusing and Automation, under recurring annual budget. • Interconnections project continuation. • Recloser/Sectionalisers project continuation. • Continue and refine unplanned outage reviews and subsequent remediation of processes and responses.

Table 9-2: Focus Areas

9.1.2 – PLANNED SAIDI AND SAIFI

In FY 2025 did not meet our planned SAIDI target of 125 Minutes, with an actual year end SAIDI of 170.62. SAIFI year end result was 1.11 against an internal target of 1.0.

We continue to look at ways in which to reduce the SAIDI impact of outages, through methodology of works, co-ordination and planning; with the appointment of an outage co-ordinator to assist in this challenge.

9.1.3 – LOSS RATIO

We missed our FY 2025 loss ratio target of 9.6% but came within 0.5%, achieving an actual loss ratio of 10.1%, an improvement over FY 2024 result of 10.6%.

We are planning to conduct a comprehensive network study to explore further improvement opportunities, which we will incorporate into the AMP.

The impact of the 65 MW worth of Solar Generation in our northern area on our network loss factor is expected to increase losses due to the higher power flow within the network. The existing 110 kV line is projected to operate at nearly 95% of its rated capacity as it transports this power from the north to Kaikohe. Similarly, the Far North Solar Farm, which generates nearly 20 MW, channels this generation south via the 33 kV Church Road single circuit line. This line is also running at 95%, further contributing to the rise in network losses, as indicated by recent in-house load flow analysis. Please refer to Section 5.5.4 and 5.5.5, which describe this constraint in more detail.

9.1.4 – COST PERFORMANCE

The ratio of total operational expenditure to total regulatory income in FY 2025 was 55.9% compared to a target of 59.3%, with operational expenditure being 3.8% lower.

Over the past five years, three have been at or below target levels and the two that were higher were primarily driven by higher network maintenance (one including the Gabrielle year). Over this period, the actual ratio has increased from 39.0% to 55.9%. with a 46.4% growth in operational expenditure. Significant inflationary pressures occurred over this time driving a 39.4% increase in Network opex.

The ratio increase has been further impacted by revenue only increasing by 2.1% as there has been a focused effort on minimising the price impact on consumers.

The AMP target is expected to increase as we continue to minimise price impacts on consumers over the next regulatory period. A target ratio of 60% is reasonable at this stage, but we expect that this will require further adjustment as we refine our pricing strategies.

[9.2] Financial and Physical Performance

Table 9-3 compares our actual expenditures for FY 2025 for both network Capex and Network Maintenance Opex with the budgeted expenditures presented in the 2025 AMP.

EXPENDITURE CATEGORY	BUDGET FY-2025 (000'S)	ACTUAL FY-2025 (000'S)	VARIANCE ($)	VARIANCE (%)
NETWORK CAPITAL EXPENDITURE ($000)				
Consumer connection	3,427	4,232	805	+23%
System growth	752	1,478	726	+97%
Asset replacement and renewal	10,529	10,973	444	+4%
Reliability, safety, & environment	15,918	12,808	(3,110)	(20%)
Asset relocations	0	0	0	0%
Subtotal – Network Capital Expenditure	**30,626**	**29,491**	**(1,135)**	**(4%)**
MAINTENANCE EXPENDITURE ($000)				
Service Interruptions and emergencies	1,562	2,064	502	+32%
Vegetation management	2,713	2,629	(84)	(3%)
Routine and corrective maintenance & inspection	2,702	2,418	(285)	(10%)
Asset replacement & renewal	2,034	1,773	(260)	(13%)
Subtotal – Maintenance Expenditure	**9,011**	**8,884**	**(127)**	**(1%)**
Total Direct Network Expenditure	**39,637**	**38,376**	**(1,261)**	**(3%)**

Table 9-3: Comparison of Actual and Budget Network Capex and Network Maintenance Opex in FY-2025

9.2.1 – NETWORK CAPITAL EXPENDITURE

Actual network capital expenditure in FY 2025 was 4% below forecast.

Significant variations to programme or budget are explained below:

Consumer Connections

- Customer connections had a budget variance of 23% for FY 2025 as a result of elevated value of customer works, against forecast.
- Top Energy has little control over the volume and value of consumer connection work. Where this work drives capital spends, the expenditure is largely offset by the customer-funded capital contribution.

System Growth

- System growth was significantly overbudget, with a 97% variance. This was the result of:
  - High volume of unforeseen customer driven network extension; and
  - The conclusion and closeout of works scheduled for FY 24 which carried forward into FY 2025.

Reliability, Safety and Environment

- The Reliability, Safety and Environment budget concluded with a variance of - 20%. This was due to the deferral or carry forward (into FY 2026) of a number of projects. Notable changes include:
  - Communications: RTU replacements and Huia Base station projects were deferred due to revision of the communications strategy, and requiring further network studies. These were rescheduled and completed in FY 2026.
  - Secondary Equipment: Kaikohe Ripple plant was deferred pending the completion of Wiroa ripple plant installation and subsequent engineering study to assess requirement. Tapia T1 NER was deferred following engineering analysis and modelling, which did not provide adequate justification for the project.

9.2.2 – NETWORK MAINTENANCE EXPENDITURE

Operational Expenditure

At year-end FY 2025, total maintenance OPEX was $8.88m against a budget of $9.01m (variance -$127k /-1.4%). While overall OPEX was close to budget, significant variances occurred within categories, reflecting a year of high fault activity and major corrective projects.

Operational expenditure performance is per table below, with further detail on significant variations (+10%):

PROGRAMME	BUDGET ($M)	ACTUAL ($M)	VARIANCE ($)	VARIANCE (%)	COMMENTARY
Service interruptions and emergencies	1.56	2.06	+0.50	+32.2%	High fault activity, resource diversion from planned work
Vegetation management	2.71	2.63	-0.08	-3.1%	Slightly under, but unit costs high due to disbursements
Routine/ corrective maintenance & inspection	2.70	2.42	-0.29	-10.5%	Planned inspections on budget, one-off line scan deferred, safety/ compliance 22% under
Asset replacement and renewal	2.03	1.77	-0.26	-12.8%	Reduced to offset high faults OPEX, strategic pivot to CAPEX for defect remediation

Service interruptions and emergencies: Whilst FY 2025 was relatively benign in terms of HV faults, we continue to see elevated LV faults, and associated costs which was the main driver behind a significant budget variance.

Asset replacement and renewal: Asset replacement and renewal operational expenditure was under budget by 12.8% as we offset overspend on faults, with a strategic pivot to address defects under capital works, as outlined in Sections 2 and 6 of the AMP.

Asset Replacement and Renewal – Maintenance

There was significant overspend in our planned corrective and reactive capital expenditure. corrective/reactive Capex was $3.88m against a budget of $2.68m (variance +$1.19m / +44.5%):

- Capitalised Corrective Maintenance was 48.1% overbudget for FY 2025. This was driven by major jobs including the Wiroa substation refurbishment, Okahu roof replacement, and a one-off Bonnets Rd diesel storage tank replacement. From FY 2027 onwards, a separate allocation will cover building-related infrastructure and environments, including substation fences and internal substation spaces.
- Reactive Capitalised expenditure was overbudget by 40%, in line with our Operational reactive budget elevation, which high fault volumes and a large proportion of asset replacements required as a result of remediation activities.

Network Maintenance Works Programme

This section refers to both operational and capital expenditure, under maintenance, which includes corrective and reactive Capex.

- The projected number of defect close-outs was not met due to the resource impact of large, unplanned jobs.
- Routine and corrective maintenance and inspections were largely delivered as planned, with the exception of the deferred line scan and lower safety/compliance costs.
- The pivot to addressing defects under our project planning processes ensures that asset replacements and defect remediation are coordinated, as detailed in Sections 2 and 6 of the AMP.
- Additional building Capex has been established to protect maintenance budgets from being eroded by property-related works.

[9.3] Asset Management Improvement Programme

Our organisational philosophy is one of continuous improvement across all of Top Energy's business units, and our ISO 9001 certification is testimony to this.

In FY 2026, an independent review of our asset management maturity against the AMMAT metrics was completed. This review involved a comprehensive document review, operational observations and stakeholder interviews in order to:

- provide an external benchmark
- identify strengths and areas for improvement, and
- recommend practical improvements to further enhance our asset management practices.

Overall, Top Energy was rated 'competent', with a score of 3.0 in most areas. The review showed that our strengths were in emergency preparedness, governance and primary challenges in information and systems management. It provided recommendations on integrating risk management processes into our decision-making processes.

We have initiatives underway to address these issues and continue to progress them, with continuous monitoring of progress against the plan.

Listed below are our current initiatives in order to further improve our alignment to our Asset Management goals:

- **LV network data capture:** In FY 2023, we initiated a multi-year project to capture LV network data. This will capture accurate data on our LV assets and their connectivity across the network.

  As the data is received, it is entered into the GIS. Over time, this data will support extending ADMS functionality to include real-time management of the LV system. It is envisaged that a team of three will be out in the field gathering data. The project includes opening all service pillars to confirm LV connectivity. It has been useful in identifying issues that require remediation, but which would otherwise have gone unnoticed. We currently have a single team undertaking this work.

  We plan to engage additional external resources to increase the capture rate, which has been slower than anticipated. Progress has been affected by the need to complete circuit asset labelling during tracing to support future LV switching management.

- **Access to smart meter data:** We have the option to procure access to smart meter data from other meter equipment providers and pipe it into our LV visibility platform. This will helps identify potential power quality issues on the LV network.

  We also continue to review and document our processes for using the smart meter data and Hiko platform to enhance our decision making processes.

- **Risk Management Model:** Further process improvements are required to ensure the outputs of these models are incorporated into our asset management decision-making processes. This will involve defined asset data reviews and the implementation of continuous review and calibration of parameter settings that impact risk and criticality outcomes.

  Key areas of focus will be:
  - data quality improvements
  - further integration into the asset replacement and maintenance decision-making criteria
  - evidence gathering for validation and model calibration
  - broader communication of strategic drivers for asset health, and
  - a similar approach is proposed for vegetation management through the vegetation strategy.

THEME	QUESTION	AMMAT SCORE
1. POLICY AND STRATEGY	**Q1:** Asset Management Policy	3
	Q2: Strategy Consistency	3
	Q3: Strategy & Lifecycle	3
2. PLANNING	**Q4:** AMP Documentation	3
	Q5: AMP Communication	3
	Q6: AMP Implementation Responsibilities	3
	Q7: AMP Efficiency	3
	Q8: Contingency Planning	3
3. ORGANISATION & PLANNING	**Q9:** Management Responsibility	3
	Q10: Sufficient Resources	3
	Q11: Communication of Requirements	3
	Q12: Outsourcing Management	3
	Q13: Human Resources Planning	3
	Q14: Training & Competence Development	3
	Q15: Competence of Persons	3
4. INFORMATION & SYSTEMS	**Q16:** Information Strategy	3
	Q17: Information Quality and Accessibility	3
	Q18: Information System Requirements	2
	Q19: Information System Coverage	2
	Q20: Information System maintenance	2
	Q21: Statutory Requirements	3
5. RISK & DECISION MAKING	**Q22:** Risk Assessment	3
	Q23: Use of Risk Information	2
	Q24: Legal & Other Requirements	3
	Q25: Asset Creation & Enhancement	3
	Q26: Performance & Condition Monitoring	2
6. LIFECYCLE DELIVERY & IMPROVEMENT	**Q27:** Failure Investigation	3
	Q28: Asset Management Audit	3
	Q29: Corrective Action	3
	Q30: Continuous Improvement	3
	Q31: Knowledge Acquisition & Innovation	3

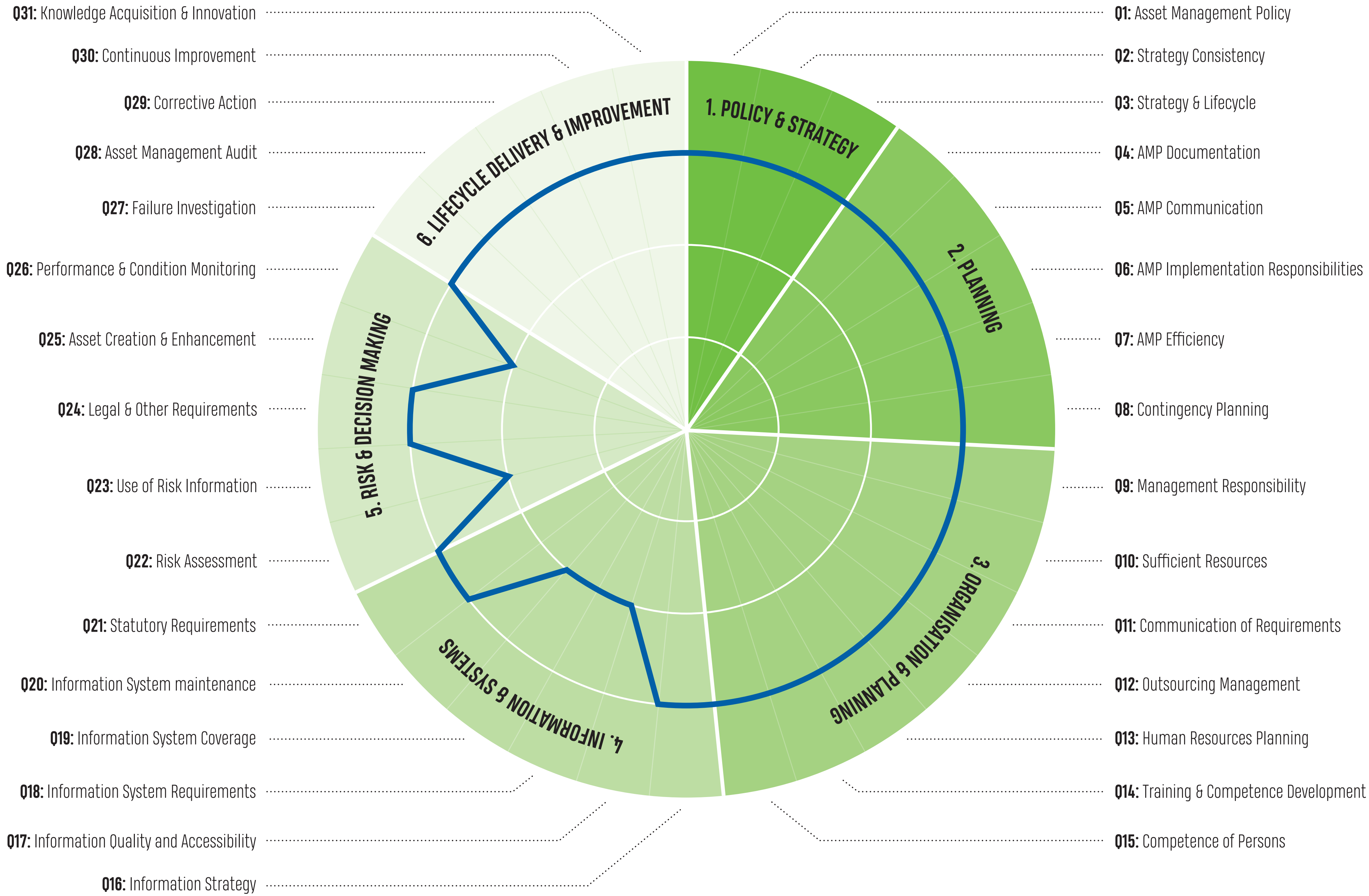

Figure 9-9: External Assessment of Top Energy AMMAT


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EXPENDITURE SUMMARY

SECTION 10
EXPENDITURE SUMMARY

This section show the summary of forecast costs, at constant prices.

[10.1] Network Operational Expenditure

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Service interruptions and emergencies	2,244	2,266	2,289	2,312	2,335	12,031	**23,477**
Vegetation	3,002	3,032	3,062	3,093	3,124	16,094	**31,408**
Routine maintenance and inspection	3,023	3,053	3,084	3,115	3,146	16,206	**31,626**
Replacement and renewal	2,303	2,326	2,349	2,372	2,396	12,345	**24,090**
Total	**10,572**	**10,677**	**10,784**	**10,892**	**11,001**	**56,676**	**110,601**

Table 10-1: Network Operational Expenditure Summary (constant prices)

[10.2] Network Capital Expenditure

FY ($,000)	2027	2028	2029	2030	2031	2032-36	TOTAL
Asset Replacement and Renewals	15,585	16,236	22,886	26,763	38,247	83,824	**203,541**
Reliability, Safety and Resilience	2,441	2,606	12,562	20,789	2,476	27,112	**67,986**
Customer Connections	3,141	3,144	3,144	3,144	3,144	15,889	**31,606**
System Growth	4,584	1,575	1,829	0	0	504	**8,492**
Total	**25,751**	**23,561**	**40,421**	**50,696**	**43,867**	**127,329**	**311,625**

Table 10-2: Network Capital Expenditure Summary (constant prices)

[10.3] Non-Network Operational Expenditure

FY ($,000)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
System Operations and Network Support	11,419	11,546	11,542	11,598	11,742	11,368	11,533	11,049	11,191	11,297
Business Support	10,819	10,369	10,369	10,369	10,369	10,369	10,369	10,369	10,369	10,369
Total	**22,238**	**21,915**	**21,911**	**21,967**	**22,111**	**21,737**	**21,902**	**21,418**	**21,560**	**21,666**

Table 10-3: Non-Network 10-year Opex (constant prices)

[10.4] Non-Network Capital Expenditure

FY ($,000)	2027	2028	2029	2030	2031
General	380	188	179	172	1,233
Software	1,530	817	645	277	978
Hardware	382	269	273	277	1,277
Total	**2,293**	**1,274**	**1,098**	**727**	**3,489**

Table 10-4: Non-Network 5-year Capex (constant prices)

APPENDICES

SECTION 11
APPENDICES

Appendix A –Asset Management Plan Schedules

Schedule 11a	Capex Forecast
Schedule 11b	Opex Forecast
Schedule 12a	Asset Condition
Schedule 12b	Capacity Forecast
Schedule 12c	Demand Forecast
Schedule 12d	Reliability Forecast
Schedule 13	Asset Management Maturity Assessment
Schedule 14a	Mandatory Explanatory Notes on Forecast Information
Schedule 15	Voluntary Explanatory Notes

Company Name	**Top Energy**
AMP Planning Period	**1 April 2026 - 31 March 2036**

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8												
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	3,870	3,141	3,207	3,271	3,336	3,403	3,471	3,541	3,613	3,782	3,858
11		System growth	4,174	4,584	1,607	1,903	-	-	-	-	-	-	602
12		Asset replacement and renewal	12,499	15,585	16,561	23,811	28,401	41,400	33,447	14,400	16,717	14,607	16,401
13		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	4,306	2,441	2,658	13,070	22,061	2,680	6,630	7,204	5,410	5,800	6,036
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	3,420	-	-	-	-	-	-	-	-	-	-
18		**Total reliability, safety and environment**	7,726	2,441	2,658	13,070	22,061	2,680	6,630	7,204	5,410	5,800	6,036
19		**Expenditure on network assets**	28,269	25,751	24,032	42,054	53,799	47,483	43,548	25,145	25,740	24,189	26,898
20		**Expenditure on non-network assets**	2,512	2,286	1,325	1,165	787	3,852	3,380	2,212	2,612	2,050	2,264
21		**Expenditure on assets**	30,781	28,037	25,358	43,219	54,586	51,335	46,928	27,356	28,351	26,239	29,162
22												
23	*plus*	Cost of financing	200	150	410	600	500	500	500	500	340	690	520
24	*less*	Value of capital contributions	2,018	1,150	1,530	1,196	1,220	1,245	1,270	1,295	1,321	1,347	1,374
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27		**Capital expenditure forecast**	28,963	27,037	24,238	42,623	53,865	50,590	46,159	26,561	27,370	25,581	28,307
28												
29		Assets commissioned	33,702	22,305	24,617	28,158	29,378	53,164	27,273	85,148	21,716	31,074	32,032
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
32			**$000 (in constant prices)**										
33		Consumer connection	3,870	3,141	3,144	3,144	3,144	3,144	3,144	3,144	3,145	3,228	3,228
34		System growth	4,174	4,584	1,575	1,829	-	-	-	-	-	-	504
35		Asset replacement and renewal	12,499	15,585	16,236	22,886	26,763	38,247	30,294	12,787	14,553	12,467	13,724
36		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	4,306	2,441	2,606	12,562	20,789	2,476	6,005	6,397	4,710	4,950	5,051
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	3,420	-	-	-	-	-	-	-	-	-	-
41		**Total reliability, safety and environment**	7,726	2,441	2,606	12,562	20,789	2,476	6,005	6,397	4,710	4,950	5,051
42		**Expenditure on network assets**	28,269	25,751	23,561	40,421	50,696	43,867	39,443	22,328	22,408	20,645	22,507
43		Expenditure on non-network assets	2,512	2,286	1,274	1,098	727	3,489	3,001	1,925	2,229	1,715	1,857
44		**Expenditure on assets**	30,781	28,037	24,835	41,519	51,423	47,356	42,444	24,253	24,637	22,360	24,364
45												
46		**Subcomponents of expenditure on assets (where known)**											
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											
50												

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
52												
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	63	127	192	259	327	397	468	554	630
55	System growth	-	-	32	74	-	-	-	-	-	-	98
56	Asset replacement and renewal	-	-	325	925	1,638	3,153	3,153	1,613	2,164	2,140	2,677
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	-	-	52	508	1,272	204	625	807	700	850	985
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	-	52	508	1,272	204	625	807	700	850	985
63	**Expenditure on network assets**	-	-	471	1,633	3,103	3,616	4,105	2,817	3,332	3,544	4,391
64	Expenditure on non-network assets	-	-	51	67	60	363	379	286	383	335	407
65	**Expenditure on assets**	-	-	523	1,700	3,163	3,979	4,484	3,103	3,714	3,878	4,798
66												

67 **Commentary on options and considerations made in the assessment of forecast expenditure**

68 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
72	**11a(ii): Consumer Connection**						
73	*Consumer types defined by EDB**	**$000 (in constant prices)**					
74	All types	3,870	3,141	3,144	3,144	3,144	3,144
75							
76							
77							
78							
79	**include additional rows if needed*						
80	**Consumer connection expenditure**	3,870	3,141	3,144	3,144	3,144	3,144
81	*less* Capital contributions funding consumer connection	2,018	1,150	1,500	1,150	1,150	1,150
82	**Consumer connection less capital contributions**	1,852	1,991	1,644	1,994	1,994	1,994
83	**11a(iii): System Growth**						
84	Subtransmission	-	-	-	-	-	-
85	Zone substations	4,174	4,584	1,575	1,829	-	-
86	Distribution and LV lines	-	-	-	-	-	-
87	Distribution and LV cables	-	-	-	-	-	-
88	Distribution substations and transformers	-	-	-	-	-	-
89	Distribution switchgear	-	-	-	-	-	-
90	Other network assets	-	-	-	-	-	-
91	**System growth expenditure**	4,174	4,584	1,575	1,829	-	-
92	*less* Capital contributions funding system growth	-	-	-	-	-	-
93	**System growth less capital contributions**	4,174	4,584	1,575	1,829	-	-
94							

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

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sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
95			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
96								
97	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
98		Subtransmission	1,894	4,557	2,934	10,515	14,911	27,506
99		Zone substations	116	846	2,501	1,862	450	3,384
100		Distribution and LV lines	8,638	8,879	9,576	8,826	9,708	6,164
101		Distribution and LV cables	480	-	-	-	-	-
102		Distribution substations and transformers	382	242	215	672	683	264
103		Distribution switchgear	381	851	891	891	891	929
104		Other network assets	608	210	119	120	120	-
105		**Asset replacement and renewal expenditure**	12,499	15,585	16,236	22,886	26,763	38,247
106	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
107		**Asset replacement and renewal less capital contributions**	12,499	15,585	16,236	22,886	26,763	38,247
108								
109			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
111	**11a(v): Asset Relocations**							
112		*Project or programme**	**$000 (in constant prices)**					
113		[Description of material project or programme]						
114		[Description of material project or programme]						
115		[Description of material project or programme]						
116		[Description of material project or programme]						
117		[Description of material project or programme]						
118		**include additional rows if needed*						
119		All other project or programmes - asset relocations						
120		**Asset relocations expenditure**	-	-	-	-	-	-
121	*less*	Capital contributions funding asset relocations						
122		**Asset relocations less capital contributions**	-	-	-	-	-	-
124			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
126	**11a(vi): Quality of Supply**							
127		*Project or programme**	**$000 (in constant prices)**					
128		11kV Feeder Protection Improvements	603	871	1,049	947	1,440	1,196
129		Interconnections	1,170	644	-	1,289	2,951	590
130		Minor Network Upgrades/Additions	1,020	301	580	421	366	367
131		Improved Communication Systems	734	363	748	676	103	167
132		LV Data Capture	350	-	-	-	-	-
133		Remote Controlled Switches and Smart Devices	320	175	175	175	175	102
134		Minor Substation Upgrades	109	87	54	54	54	54
135		**include additional rows if needed*						
136		All other projects or programmes - quality of supply	-	-	-	9,000	15,700	-
137		**Quality of supply expenditure**	4,306	2,441	2,606	12,562	20,789	2,476
138	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
139		**Quality of supply less capital contributions**	4,306	2,441	2,606	12,562	20,789	2,476
140								

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

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sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
141			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
142								
143	**11a(vii): Legislative and Regulatory**							
144		*Project or programme**	**$000 (in constant prices)**					
145		[Description of material project or programme]						
146		[Description of material project or programme]						
147		[Description of material project or programme]						
148		[Description of material project or programme]						
149		[Description of material project or programme]						
150		**include additional rows if needed*						
151		All other projects or programmes - legislative and regulatory						
152		**Legislative and regulatory expenditure**	-	-	-	-	-	-
153	*less*	Capital contributions funding legislative and regulatory						
154		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
155								
156			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
157	**11a(viii): Other Reliability, Safety and Environment**							
158		*Project or programme**	**$000 (in constant prices)**					
159		Backup Ngawha Generator Transformer	3,420	-	-	-	-	-
160								
161								
162								
163								
164		**include additional rows if needed*						
165		All other projects or programmes - other reliability, safety and environment						
166		**Other reliability, safety and environment expenditure**	3,420	-	-	-	-	-
167	*less*	Capital contributions funding other reliability, safety and environment						
168		**Other reliability, safety and environment less capital contributions**	3,420	-	-	-	-	-
169								

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

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sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
170		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
171							
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	General	273	335	188	179	172	1,233
176	Software	1,240	881	433	645	277	978
177	Hardware	606	390	269	273	277	1,277
178		-	-	-	-	-	-
179		-	-	-	-	-	-
180	**include additional rows if needed*						
181	All other projects or programmes - routine expenditure						
182	**Routine expenditure**	2,119	1,606	889	1,098	727	3,489
183	**Atypical expenditure**						
184	*Project or programme**						
185	Substation Security	98	-	-	-	-	-
186	Line Training School	294	-	-	-	-	-
187	ADMS Low Voltage management	-	400	384	-	-	-
188	ADMS PowerOn Mobile	-	250	-	-	-	-
189	AI Asset photo image recognition	-	30	-	-	-	-
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure						
192	**Atypical expenditure**	392	680	384	-	-	-
193							
194	**Expenditure on non-network assets**	2,512	2,286	1,274	1,098	727	3,489
195							

		Company Name	Top Energy
		AMP Planning Period	1 April 2026 - 31 March 2036

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.

sch ref														
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8														
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**											
10	Service interruptions and emergencies		2157	2244	2312	2382	2454	2528	2604	2683	2764	2847	2933
11	Vegetation management		3002	3002	3093	3186	3282	3381	3484	3589	3697	3809	3924
12	Routine and corrective maintenance and inspection		2847	3023	3114	3208	3305	3405	3508	3614	3723	3835	3951
13	Asset replacement and renewal		2174	2303	2372	2444	2518	2594	2672	2753	2836	2921	3010
14	**Network Opex**		10,180	10,572	10,891	11,220	11,558	11,908	12,267	12,638	13,019	13,412	13,818
15	System operations and network support		9,864	11,419	11,777	12,008	12,308	12,710	12,552	12,988	12,692	13,112	13,500
16	Business support		10,250	11,201	10,848	11,135	11,091	11,864	11,841	12,078	12,319	12,566	12,817
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
18	**Non-network opex**		20,114	22,621	22,625	23,142	23,398	24,574	24,393	25,066	25,011	25,678	26,317
19	**Operational expenditure**		30,294	33,192	33,516	34,362	34,957	36,481	36,660	37,703	38,031	39,091	40,135
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21														
22			**$000 (in constant prices)**											
23	Service interruptions and emergencies		2157	2244	2266	2289	2312	2335	2358	2382	2406	2430	2454
24	Vegetation management		3002	3002	3032	3062	3093	3124	3155	3187	3219	3251	3283
25	Routine and corrective maintenance and inspection		2847	3023	3053	3084	3115	3146	3177	3209	3241	3273	3306
26	Asset replacement and renewal		2174	2303	2326	2349	2372	2396	2420	2444	2469	2493	2518
27	**Network Opex**		10,180	10,572	10,677	10,784	10,892	11,001	11,111	11,222	11,334	11,447	11,562
28	System operations and network support		9,864	11,419	11,546	11,542	11,598	11,742	11,368	11,533	11,049	11,191	11,297
29	Business support		10,250	11,201	10,635	10,702	10,451	10,960	10,725	10,725	10,725	10,725	10,725
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
31	**Non-network opex**		20,114	22,621	22,182	22,244	22,049	22,702	22,093	22,258	21,774	21,916	22,021
32	**Operational expenditure**		30,294	33,192	32,859	33,028	32,941	33,703	33,204	33,480	33,108	33,363	33,583
33	**Subcomponents of operational expenditure (where known)**													
35														
36	Energy efficiency and demand side management, reduction of energy losses													
37	Direct billing*													
38	Research and Development													
39	Insurance		1,012	985	1,034	1,086	1,140	1,197	1,257	1,320	1,385	1,455	1,527
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*													
42														
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
44														
45	**Difference between nominal and real forecasts**		**$000**											
46	Service interruptions and emergencies		0	0	45	92	142	192	245	301	358	417	479
47	Vegetation management		0	0	61	124	189	258	328	402	479	558	641
48	Routine and corrective maintenance and inspection		0	0	61	125	191	259	331	405	482	562	645
49	Asset replacement and renewal		0	0	47	95	145	198	252	308	367	428	491
50	**Network Opex**		-	-	214	436	667	907	1,156	1,416	1,685	1,965	2,256
51	System operations and network support		-	-	231	466	710	968	1,183	1,455	1,643	1,921	2,204
52	Business support		-	-	213	432	640	903	1,116	1,353	1,595	1,841	2,092
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	-	444	899	1,350	1,871	2,299	2,808	3,237	3,762	4,296
55	**Operational expenditure**		-	-	657	1,334	2,016	2,778	3,456	4,224	4,923	5,727	6,552
56														
57	**Commentary on options and considerations made in the assessment of forecast expenditure**													
58	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*													

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref					Asset condition at start of planning period (percentage of units by grade)							
7												
9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.05%	0.36%	4.40%	86.08%	2.57%	6.54%	4	3.40%
11	All	Overhead Line	Wood poles	No.	0.78%	4.55%	56.87%	32.95%	1.26%	3.59%	4	25.15%
12	All	Overhead Line	Other pole types	No.	-	-	-	27.27%	13.64%	59.09%	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	15.36%	46.89%	10.13%	26.70%	0.92%	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	45.83%	-	9.15%	45.02%	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	2.34%	97.66%	-	2	-
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.	-	-	-	70.00%	30.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	23.08%	63.46%	13.46%	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	4.17%	77.08%	-	18.75%	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	53.14%	42.29%	4.57%	4	-
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.	-	22.22%	-	11.11%	55.56%	11.11%	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	82.19%	16.44%	1.37%	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	14.71%	-	76.47%	8.82%	-	4	-
35												

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	2.17%	17.39%	54.35%	19.57%	6.52%	4	9.37%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.77%	24.32%	34.33%	27.76%	9.59%	0.23%	2	1.30%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	20.17%	33.33%	18.00%	15.58%	12.92%	-	2	6.74%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.02%	0.95%	4.47%	56.52%	33.27%	4.77%	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.15%	10.36%	20.12%	56.77%	11.39%	1.21%	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	51.35%	-	24.57%	24.08%	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.62%	-	3.11%	65.21%	3.73%	27.33%	4	-
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.	7.00%	9.97%	12.18%	22.26%	19.63%	28.96%	4	-
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	100.00%	4	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	2.19%	71.06%	17.98%	8.77%	4	13.22%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.08%	0.49%	2.70%	88.72%	1.77%	6.24%	4	0.76%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	1.05%	85.44%	1.15%	12.36%	4	1.57%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	5.26%	42.11%	26.32%	26.31%	4	7.89%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	6.25%	18.75%	-	75.00%	4	-
55	LV	LV Line	LV OH Conductor	km	4.69%	28.09%	34.53%	25.15%	7.16%	0.38%	2	-
56	LV	LV Cable	LV UG Cable	km	6.37%	15.02%	20.86%	37.64%	19.52%	0.59%	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	3.99%	20.76%	27.34%	45.56%	2.24%	0.11%	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.04%	0.30%	8.80%	76.22%	3.44%	11.20%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	7.43%	-	1.49%	29.09%	61.78%	-	2	8.28%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	100.00%	1	4.95%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	68.29%	29.27%	2.44%	-	4	9.76%
62	All	Load Control	Centralised plant	Lot	-	-	-	92.86%	7.14%	-	2	-
63	All	Load Control	Relays	No.	-	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

APPENDIX A : SCHEDULE 12B – CAPACITY FORECAST

Company Name: Top Energy
AMP Planning Period: 1 April 2026 - 31 March 2036

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. 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)	*Not Required before DY2025* Current peak load period	*Not Required before DY2025* Installed operating capacity (MVA)	*Not Required before DY2025* Current security of supply classification (type)	*before DY2025* Current constraint type	*before DY2025* Current available capacity (MVA)	*Not Required before DY2025* Peak load period +5 yrs	*Not Required before DY2025* Available capacity +5 yrs (MVA)	*Not Required before DY2025* Security of supply classification +5 yrs (type)	*Not Required before DY2025* Peak load period +10 yrs	*Not Required before DY2025* Min. available capacity +10 yrs (MVA)	*Not Required before DY2025* Max. available capacity +10 yrs (MVA)	*Not Required before DY2025* Security of supply classification +10 yrs (type)	*Not Required before DY2025* Forecast constraint type	*Not Required before DY2025* Year of any forecast constraint	*Not Required before DY2025* Constraint primary cause	*Not Required before DY2025* Constraint solution type	*Not Required before DY2025* Constraint solution progress	*Not Required before DY2025* Temporary constraint solution remaining lifespan	Explanation
8																					
9	Pukenui (PKN)	2	Winter	5	N-1 switched	No constraint	3	Winter	14	N-1 switched	Winter	14	22	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	N-1 security is provided over the 11kV network from NPL substation, with voltage regulators on the 11kV feeders and diesel generation connected to the 11kV bus at Pukenui.
10	NPL	11	Winter	23	N-1	No constraint	12	Winter	6	N-1	Winter	6	6	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
11	Okahu Rd (OKH)	7	Winter	12	N-1	No constraint	5	Winter	5	N-1	Winter	4	4	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
12	Taipa (TPA)	6	Winter	6	N	Capacity	0	Winter	12	N	Winter	12	18	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	The Taipa transformer capacity constraint is currently managed by use of the mobile substation to carry part of the load of the substation, with diesel generation connected to the 11kV bus for peak lopping when the mobile substation is needed elsewhere. The currently installed 33/11kV transformer is scheduled for replacement in FY29 due to age and condition, with the replacement also being of a capacity to relieve the constraint.
13	Kaitaia Transmission (KTA)	2	Winter	10	N-1 switched	No constraint	8	Winter	8	N-1 switched	Winter	8	8	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	N-1 security is provided over the 11kV network from the Okahu Rd substation.
14	Kaeo (KAO)	4	Winter	10	N-1 switched	No constraint	6	Winter	6	N-1 switched	Winter	6	6	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	N-1 security is currently provided over the 11kV network from the Waipapa substation. An additional 33kV line into this substation will be built as part of the 110kV Wiroa-Kaitaia line build.
15	Waipapa (WPA)	9	Winter	23	N-1	No constraint	14	Winter	13	N-1	Winter	13	13	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
16	Kerikeri (KER)	8	Winter	23	N-1	No constraint	15	Winter	14	N-1	Winter	13	13	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
17	Mt Pokaka (MTP)	3	Winter	5	N	No constraint	2	Winter	2	N	Winter	3	3	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	The majority of Mt Pokaka substation's load is associated with the Mt Pokaka timber mill, which cannot be backfed across the 11kV network, therefore operates at N security. Local residential and light commercial load can be backfed from the Waipapa and Haruru substations, providing them with N-1 security.
18	Haruru (HAR)	7	Winter	23	N-1	No constraint	16	Winter	16	N-1	Winter	16	16	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
19	Kawakawa (KWA)	4	Winter	5	N-1	No constraint	1	Winter		N-1	Winter	2	2	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
20	Moerewa (MOE)	4	Winter	5	N-1	No constraint	1	Winter	1	N-1	Winter	1	1	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
21	Kaikohe (KHE)	9	Winter	17	N-1	No constraint	8	Winter	8	N-1	Winter	8	8	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
22	Omanaia (OMA)	3	Winter	5	N-1 switched	No constraint	2	Winter	2	N-1 switched	Winter	2	2	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	N-1 security is provided by diesel generation connected to the 11kV bus. This generation cannot island, so is reliant on 11kV back-feeding from Kaikohe substation for frequency keeping.
23																					
24																					
25																					
26																					
27																					
28																					

29 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

APPENDIX A : SCHEDULE 12C – DEMAND FORECAST

Company Name	**Top Energy**
AMP Planning Period	**1 April 2026 - 31 March 2036**

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 during year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
11	*Consumer types defined by EDB**						
12	Residential	301	301	301	301	301	301
13	Commercial	41	41	42	42	42	42
14							
15							
16							
17	**Connections total**	342	342	343	343	343	343
18	**include additional rows if needed*						
19							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	277	277	277	290	290	290
24	Capacity of distributed generation installed in year (MVA)	2	2	3	3	3	3
25	**12c(ii): System Demand**						
26		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)**						
28	GXP demand	15	16	18	19	-	-
29	*plus* Distributed generation output at HV and above	57	57	57	57	89	89
30	**Maximum coincident system demand**	72	73	75	76	89	89
31	*less* Net transfers to (from) other EDBs at HV and above						
32	**Demand on system for supply to consumers' connection points**	72	73	75	76	89	89
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	10	11	12	13	-	-
35	*less* Electricity exports to GXPs	210	260	260	260	478	477
36	*plus* Electricity supplied from distributed generation	570	620	620	620	851	851
37	*less* Net electricity supplied to (from) other EDBs						
38	**Electricity entering system for supply to ICPs**	370	371	372	373	373	374
39	*less* Total energy delivered to ICPs	331	332	333	334	335	336
40	**Losses**	39	39	39	39	38	38
41							
42	**Load factor**	59%	58%	57%	56%	48%	48%
43	**Loss ratio**	10.5%	10.5%	10.5%	10.5%	10.2%	10.2%

Company Name	**Top Energy**
AMP Planning Period	
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	3.0	172.8	172.8	172.8	172.8	172.8
12	Class C (unplanned interruptions on the network)	376.0	289.0	286.0	278.0	273.0	268.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.20	1.20	1.20	1.20	1.20	1.20
15	Class C (unplanned interruptions on the network)	4.08	4.08	4.08	4.07	4.07	4.07

Company Name	Top Energy
AMP Planning Period	1 April 2026 - 31 March 2036
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	AMP 2023 2.6; policy displayed at Kerikeri, Puketona, Kaitaia receptions; aligned with SCI 2025 and supporting policies (H&S, risk, quality); verified at site visit.	Top Energy has a clearly documented Asset Management Policy that is authorised by the Board and prominently displayed at all its locations, reinforcing staff awareness and commitment. Governance is structured so the Board provides oversight, the CEO is accountable for delivery, and the GM Network is responsible for operational execution. This arrangement ensures accountability at all levels and makes asset management a visible organisational priority. While the policy is embedded in the AMP rather than a standalone document, it provides a strong foundation and alignment with wider corporate values.	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	SCI 2025 objectives; AMP 2024 confirms delivery linkages; Annual Report highlights consumer/stakeholder initiatives; Board approval and reporting provide oversight.	The asset management strategy is directly linked to corporate objectives outlined in the SCI (affordability, sustainability, community service). These objectives flow through to the AMP and are monitored by Board review and monthly reporting. This integration ensures alignment between high-level strategic direction and practical network planning. However, a structured review cycle would strengthen assurance that alignment remains current as strategic priorities and stakeholder needs evolve.	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.

Company Name	Top Energy
AMP Planning Period	
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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	AMP lifecycle coverage for major assets; Asset Information Strategy; active CBRM models; LV visibility/smart meter trials; minor assets less mature.	Lifecycle planning is systematic for major asset groups (poles, lines, transformers, cables), with condition-based models guiding renewal decisions and supporting the shift away from age-based replacement. Trials like LV visibility and smart meters demonstrate commitment to strengthening lifecycle visibility. While this provides a robust framework, lifecycle planning for smaller asset classes is less mature and cross-asset prioritisation tools are not fully developed. Overall, the approach supports consistent and informed decision-making but could be broadened to cover all assets.	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	AMPs 2023–2025; AM01 process map; Board approval cycle; SCI/business plan integration; staff challenge sessions introduced in 2026.	AMPs are complete, updated annually, and provide a 10-year planning horizon. They link corporate priorities to operational programmes across the lifecycle. Governance is ensured by Board approval and structured preparation cycles. The move to in-house AMP development has improved integration with operational teams and enabled staff “challenge sessions” for input. These strengthen ownership and planning quality, though further structured consultation could enhance engagement and responsiveness.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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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	AMP online; team meetings/briefings; monthly Board reporting; contractors receive extracts; interviews indicated variable awareness; no tailored strategy exists.	The AMP is made available through multiple channels — published online for regulatory purposes, internally communicated through meetings and briefings, and used in contractor engagement processes. The Board also receives regular updates. These methods ensure that core information is shared with stakeholders, but the lack of tailored communication by audience reduces effectiveness. A formal communication strategy could improve understanding, especially for staff and external stakeholders who need specific levels of detail.	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	Org structure showing GM Network accountability; SLA with TECS; Board variance reporting; project tracking systems; interviews confirmed delays in job pack readiness.	Clear roles are assigned for AMP implementation, with the GM Network responsible under CEO oversight and delivery carried out by TECS under SLA arrangements. Responsibilities are documented, and monitoring is in place. However, delays in preparing quarterly work packs limit delivery teams' ability to plan effectively, leading to reactive execution. Improving the integration of planning and delivery systems and bringing forward job pack preparation would enhance efficiency.	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	AMP budgets and Board approvals; TECS SLA; contractor procurement frameworks; monthly variance reporting; challenge sessions implemented in 2026.	Resources are allocated through structured budgeting processes, contractor frameworks, and service agreements. Cost control is supported by monitoring, variance analysis, and Board oversight. Cross-functional challenge sessions have also improved alignment between strategy and operations. While these arrangements are effective, systematic exploration of alternative delivery models and clearer role definitions in cross-functional budgeting could deliver further efficiencies and resilience in resource use.	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.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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	Documented emergency plans; successful response to 2024 incident; critical spares (mobile substation, 110kV items); mutual support agreements; spares strategy in development.	Contingency planning is strong, with documented procedures, emergency exercises, critical spares, and mutual aid agreements all in place. Real-world events such as the 2024 Transpower tower collapse demonstrated Top Energy's ability to mobilise effectively. Business continuity plans are also established. A formal strategic spares strategy (under development for FYE27) will further enhance systematic readiness and provide clearer visibility of long-term critical asset preparedness.	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.
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	GM Network appointment; Board oversight and monthly reporting; job descriptions include AM duties; interviews identified functional overlaps affecting project delivery.	Senior responsibility for asset management is clearly allocated to the GM Network under CEO accountability and Board governance. Job descriptions and performance targets support this alignment. However, at operational levels, overlap between Planning and Maintenance roles can create confusion over project ownership. While authority is clear at the top level, strengthening functional accountability through clarified handovers and role boundaries would improve coordination and accountability.	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	AMP budgets approved annually; dedicated planning/engineering/ops teams; TECS SLA; GIS/SAP/SCADA investments; training budget allocations; headcount reviews.	Resource provision is strong, demonstrated through Board-approved budgets, dedicated teams, and secure internal delivery capacity via TECS. Technology investments and training budgets further support capability. These arrangements mean Top Energy has sufficient resources to meet AM objectives, but formalised reviews of resource adequacy against strategic needs would provide earlier visibility of gaps and help align workforce planning with long-term challenges.	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.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Policy displayed at all locations; team meetings/briefings; SLA with TECS; monthly Board reporting; interviews revealed variable awareness; no formal AM comms strategy.	Top Energy communicates asset management priorities through policy displays, routine meetings, performance reporting, and contractor agreements. These channels provide consistent messaging, but staff understanding varies, particularly beyond immediate roles. A formal communication strategy tailored to different groups (staff, contractors, stakeholders) would embed awareness more consistently and strengthen organisational alignment.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	SS03-06 vendor performance procedure; SLA with TECS; procurement frameworks; contractor workshops; vendor reviews with performance metrics.	Outsourced activities are well managed via documented vendor performance standards, procurement frameworks, and contractor workshops. Service agreements (including TECS) set expectations and monitoring processes ensure compliance. While effective, there is an opportunity to integrate contractor performance feedback more directly into AMP reviews and create structured competency programmes to align external partners with long-term AM objectives.	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.
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	Dedicated AM roles across functions; succession planning noted but not formal; training/PD provided; Annual Report 2024/25 highlights capability investment.	HR planning is evident in dedicated AM roles, succession discussions, and ongoing training and development initiatives. These support delivery of AM activities. However, reliance on a small number of senior engineers poses risks, and workforce planning is not yet systematically aligned with long-term asset strategy or technology transitions. A more structured workforce planning framework would ensure resilience and capability alignment.	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.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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	SAP/GIS training programmes; contractor workshops; H&S training; ISO 9001 procedures; industry PD and conferences supported.	Training programmes are in place for key systems, contractors, and safety. Professional development is also supported. While this demonstrates commitment, training is not yet embedded in a structured competency framework with defined proficiency levels. Establishing such a framework would ensure training is targeted to actual needs and supports long-term capability building aligned with AM objectives.	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	Recruitment processes; induction and PD programmes; TECS SLA competency clauses; ISO 9001 competency verification.	Competence is ensured through recruitment requirements, induction processes, certification, and performance management. Contractor competence is covered via SLAs and ISO requirements. While this ensures operational control, embedding explicit AM competency criteria into all job descriptions and systematically verifying against them would provide stronger assurance that capability is consistently aligned to AM objectives.	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.
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	GIS/SAP access controls; defect reviews; coding/inspection standards; contractor workshops; Asset Information Strategy; integration challenges between systems.	Top Energy communicates asset information through role-based system access, feedback mechanisms, coding standards, and defect reviews. Contractors contribute to information flows, and systematic processes exist. However, fragmentation between systems and reliance on manual reconciliation reduces efficiency. A consolidated framework for information communication would ensure consistency, reduce duplication, and support more reliable data-driven decisions.	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.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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	Asset Information Strategy (OS02-01-003S); GIS, SAP, DigSilent, SCADA documentation; AM01/SS02 process maps.	Documentation describing AM information systems exists, including an Asset Information Strategy and process maps, with multiple systems supporting lifecycle functions. While these documents provide good coverage, they are dispersed across sources, making them less accessible. A consolidated information management framework would improve usability, staff understanding, and contractor compliance.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	Asset Information Strategy; LV/smart meter trials; AMP 2025 identifies DERMS in DPP5; business requirements for GIS/SAP integration; interviews confirmed integration issues.	System requirements are partially defined through trials (LV visibility, smart meters), AMP updates (DERMS roadmap), and integration initiatives (SAP/GIS). This shows awareness of evolving needs but is largely project-specific and fragmented. Without a single requirements register, it is difficult to coordinate priorities consistently across functions. Establishing such a register would create transparency and better align system improvements to AM objectives.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Annual defect reviews; SAP/GIS/ADMS access controls; backup/maintenance procedures; data capture standards; interviews noted integration challenges.	Data quality is maintained within individual systems through defect reviews, access controls, and standards, but consistency across systems is lacking. GIS, SAP, and ADMS do not operate on a single source of truth, creating risks of duplication and inconsistency. Developing a master data management approach and assigning custodianship roles would provide stronger assurance over accuracy and system coverage.	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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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	Asset Information Strategy includes review intent; platform upgrades underway; DERMS roadmap in AMP 2025; interviews confirmed SAP/GIS/ADMS integration challenges.	Top Energy regularly upgrades its systems (GIS, SAP, SCADA, ADMS) and has forward plans for DERMS. This shows responsiveness to evolving operational requirements. However, the lack of a structured adequacy review cycle means long-term alignment with AM objectives is not guaranteed. Integration issues between core systems also undermine confidence in their collective fitness. A structured review process and master data governance would provide assurance.	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?	3	Enterprise Risk Framework; PSMS (NZS 7901); CBRM for major assets; condition-based renewal programmes; risk committee oversight.	Risk management is well established with frameworks at corporate, operational, and asset levels (Enterprise Risk, PSMS, CBRM). These provide structured approaches to identifying and addressing risks. The shift to condition-based renewals demonstrates practical use of risk outputs. However, processes are fragmented across frameworks, reducing clarity and integration. Consolidating approaches and embedding CBRM into portfolio planning would strengthen decision-making.	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	AMP incorporates risk outputs; Board variance monitoring; network risk committee; condition-based renewals informed by risk; interviews noted lack of structured HR linkage.	Risk results inform investment prioritisation and are visible to the Board, ensuring programme-level influence. However, systematic translation of risk outputs into workforce planning, competency frameworks, and cross-asset optimisation is not yet in place. Developing structured links would ensure resources and skills are consistently directed toward areas of greatest risk.	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.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	AMP disclosures; Electricity Authority/code obligations; PSMS H&S; project consenting processes; interviews confirmed monitoring but no single register.	Compliance with regulatory, safety, and environmental obligations is evident in planning and reporting. Processes ensure obligations are incorporated into project development and asset management. However, responsibilities are spread across teams, and no centralised register exists. A compliance register would improve traceability and visibility, ensuring all obligations are consistently monitored.	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
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	Procurement procedures; SLA with TECS; AMP capital works programmes; business cases/design reviews; framework agreements; interviews noted limited feedback loops.	Lifecycle delivery is supported by procurement frameworks, SLAs, business cases, and monthly reporting. These ensure governance and quality control. While procedures are clear, systematic capture of lessons learned and feedback loops into procurement and project planning are limited. Introducing structured post-project reviews would enhance efficiency and drive repeatable improvements.	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	AMP maintenance schedules; SAP work orders; Assura defect management; inspection guides; interviews confirmed gaps between planning and field practice.	Processes for maintenance and inspection are systematic, with SAP work orders, defect logging in Assura, and preventive programmes. Safety and compliance are embedded. However, gaps remain between AMP strategies and field execution, with planning–delivery disconnects limiting efficiency. Stronger alignment and monitoring of cost, risk, and performance outcomes would ensure consistency with AM objectives.	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.

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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
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	SAIDI/SAIFI/CAIDI; inspections and defect reviews; CBRM for major classes; LV visibility and smart meter pilots; SCADA monitoring; limited predictive capability.	Performance is monitored using reliability indices and SCADA, while inspections and condition reviews inform renewals. CBRM models also contribute. This provides visibility of asset health, but predictive analytics and automated monitoring are not yet widespread. Expanding predictive tools and condition monitoring would enable earlier identification of risks and optimise lifecycle decisions.	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	PSMS escalation protocols; Assura investigations/actions; examples of corrective actions; emergency event responses; interviews noted limited documentation of contractor responsibilities.	Failures and incidents are managed under PSMS with responsibilities documented and corrective actions tracked in Assura. Investigations have resulted in practical improvements (e.g., bird deterrents). Emergency responses (e.g., 2024 tower collapse) confirmed capability. Extending clear responsibility matrices to contractors and periodically testing awareness would ensure responsibilities are consistently understood across the delivery chain.	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.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Internal audit framework ; field audits; ISO 9001/NZS 7901 certifications; Board reporting; previous disclosure	Internal and external audits provide assurance. An internal Power BI audit framework focuses on asset data, while ISO 9001 and NZS 7901 certification audits ensure compliance. Board oversight also reviews performance. While effective, the scope of audits is narrow, and expanding them to cover system maturity and linking findings into AMP updates would provide stronger governance and continuous improvement.	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.

Company Name	Top Energy
AMP Planning Period	
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Assura CAPA processes; ISO 9001; Board variance monitoring; examples of corrective action (condition-based poles, bird deterrents); limited proactive trend analysis.	Corrective and preventive actions are applied through Assura, ISO frameworks, and defect management. Actions are clearly followed up, with examples of strategy changes demonstrating effectiveness. However, processes are event-driven, and no central register exists for trend analysis. A consolidated CAPA register would allow recurring issues to be identified and systematically prevented across the business.	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	ISO audits; AMP reviews; LV/smart meter pilots; EEA benchmarking; improvement initiatives noted in AMP updates; interviews confirmed project-specific focus.	Improvement occurs through AMP reviews, ISO audits, technology trials, and industry collaboration. These demonstrate commitment, with initiatives like condition-based renewals already embedded. However, improvements are opportunistic and not tracked in a structured way. A central improvement register with prioritisation and benefit tracking would formalise the process and align improvements with AM objectives.	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	AMP improvement initiatives (LV, smart meters, DERMS); EEA membership; vendor engagement; staff PD and conferences; external consultants; no formal innovation framework.	Top Energy actively engages in pilots, vendor engagement, industry forums, and staff development to stay abreast of new practices. These provide exposure to innovation, and adoption has occurred where benefits are proven. However, the process is not formalised. A structured innovation framework and register would ensure opportunities are systematically evaluated, prioritised, and embedded to support long-term capability.	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.

APPENDIX A : SCHEDULE 14A – MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

(In this Schedule, clause references are to the Commerce Commission's Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024.)

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

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

BOX 1 : Commentary on difference between nominal and constant price capital expenditure forecasts

Constant prices are for FY 2026. Going forward, we have assumed an inflation rate of 3% per annum in FY 2027 and 2% per annum thereafter. These rates are consistent with the Reserve Bank's 1–3% inflation target range. We do not consider that an inflation rate assumption based on an analysis of industry-specific cost drivers is warranted, given the high levels of uncertainty in the forecast.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

BOX 2 : Commentary on difference between nominal and constant price operational expenditure forecasts

Constant prices are for FY 2026. Going forward, we have assumed an inflation rate of 3% per annum in FY 2027 and 2% per annum thereafter. These rates are consistent with the Reserve Bank's 1–3% inflation target range. We do not consider an inflation rate assumption based on an analysis of industry-specific cost drivers to be warranted, given the high level of uncertainty in the forecast.

Company Name:	Top Energy Limited
For Planning Period Ended:	31 March 2036

APPENDIX A : **SCHEDULE 15 – VOLUNTARY EXPLANATORY NOTES**

This schedule enables an EDB to provide, should it wish to:

- additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2 and 2.6.6, and
- information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

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

Provide additional explanatory comment in the box below.

BOX 1 : Voluntary explanatory comment on disclosed information

Our capital expenditure forecast has been prepared on the basis that:

- our capital expenditure will focus on improving the reliability and resilience of the 11 kV distribution network, and
- there will be a need to extend the coverage of the 33 kV subtransmission network towards the end of the planning period to accommodate decarbonisation load growth.
- The Kaitaia-Kaikohe 110 kV replacement will be via a new line route from Wiroa-Kaitaia, no additional capacity is gained through this.
- Schedule 12a: After auditing our base data, we identified inaccuracies in both the total length and the projects previously assumed to be undertaken for this fleet. As a result, the replacement percentage is significantly lower than AMP2025.

  Targets shown in this Asset Management Plan are normalised. Schedule 12d: Reliability forecast are displayed is unnormalized SAIDI.

Our operational expenditure forecast provides for the mobilisation of an additional two-person vegetation management crew in FY 2027.

Appendix B – **Glossary of Terms**

GENERAL

kV **kilovolt**	1,000 volts of voltage; typically used in the description of the nominal rating of transmission (110kV), sub transmission (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 **kilowatt**	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

ADMS	Advanced Distribution Management System (ADMS). The system used to operate the electricity distribution network in real time, giving operators clear visibility of the network and supporting decision making. It helps manage faults, outages, and switching activities.
ANM	Adaptive Network Management (ANM) is a function within ADMS that automatically manages network constraints in real time by controlling or curtailing embedded generation when network limits are approached. It helps keep the network operating safely and efficiently while enabling higher levels of distributed generation to connect and operate within existing infrastructure.
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.
Sub transmission	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 sub transmission 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 sub transmission 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 RELATED – COOLING 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.
Buchholz 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: $$SAIDI = \frac{\Sigma\ (\text{Number of customers affected} \times \text{Duration of interruption})}{\text{Total number of customers}}$$ I.e. the average number of minutes a consumer will be without power in a year.
SAIFI:	System Average Interruption Frequency Index calculated by: $$SAIFI = \frac{\Sigma\ (\text{Number of customers affected by interruptions})}{\text{Total number of customers}}$$ I.e. the average number of outages per year for any consumer.
CAIDI:	Consumer Average Interruption Duration Index calculated by: $$CAIDI = \frac{SAIDI}{SAIFI} = \frac{\Sigma\ (\text{Number of customers affected} \times \text{Duration of interruption})}{\Sigma\ (\text{Number of customers affected by interruptions})}$$ I.e. the average duration of an outage.

Appendix C – Risk Management Framework

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.

Risk Management Context

The key risk criteria adopted for assessing the consequences of identified risks are:

- people
- environment
- assets/operations
- financial impact, and
- reputation.

Risk Analysis

Likelihood – Probability of Harm/Loss and Consequence – Severity of Harm/Loss, as used as the basis for assessing risk to determine risk severity ratings, are defined in Table 11-1 and Table 11-2, respectively.

Figure 11-1 provides the basis for assessing risk severity, and Table 11-3 the level of management normally accountable for risks of differing levels of severity.

REMOTE	HIGHLY UNLIKELY	UNLIKELY	POSSIBLE	LIKELY	ALMOST CERTAIN
Similar event is known to have occurred internationally, but is very rare.	Similar event has never occurred in NZ power industry, but is known to have occurred in the industry.	Similar event has occurred once in NZ power industry.	Similar event has occurred in NZ power industry, but never in this company.	Similar event has occurred a number of times in NZ power industry, but only once in the company.	Similar event has occurred a number of times in this company.

Table 11-1: Assessment of Risk Likelihood

CONSEQUENCE	PEOPLE	ENVIRONMENT	ASSETS/OPERATIONS	FINANCIAL IMPACT	REPUTATION
CATASTROPHIC	**Multiple fatalities.** More than one fatality or more than one permanent disabling injuries, occupational illnesses and/or diseases. Reportable to the regulatory authority.	**Severe environmental damage – persistent.** Significant pollution, resulting in irreversible damage requiring national and international resources for remediation.	**Substantial damage/operational loss.** Extensive damage/loss of asset/ equipment requiring long-term repair or asset write-off. Operations/project activities terminated.	>$20,000,000	**International attention.** International media interest, or prolonged national media interest. Degradation of supply. Litigation is certain, potential jail terms for executives. Extreme community impact and concern.
CRITICAL	**Fatality/permanent disability.** Single fatality/life-threatening or permanent disablement through work injury or occupational illness, or disease. Reportable to the regulatory authority.	**Severe environmental damage – reversible.** Pollution with significant regional impact and recovery work. Significant long-term environmental damage (6-12 months). Regional assistance is required for remediation.	**Major damage/operational loss.** Major damage to asset/ equipment requiring specialist repair service and facilities. Operations/project programmes delayed (>7 days).	< $20,000,000 > $5,000,000	**Negative national media interest.** Major business disruption and impact on company operations & market supply. Negative national media interest for up to 2 days. Significant public impact and concern. Very significant fines and prosecutions.
MAJOR	**LTI, non-reversible.** LTI – Serious injury or serious health effects (permanent) resulting in long-term absence or moderate irreversible disability. Reportable to the regulatory authority.	**Localised pollution.** Significant pollution with localised impact and recovery work. Medium-term damage (1-3 months). Specialised third-party assistance is required for remediation.	**Localised damage - extended outage.** Localised damage to assets requiring specialist repair service (onsite) and equipment. Operations/Project programmes delayed (2-7 days).	< $5,000,000 > $2,500,000	**Short-term negative national media interest.** Negative national media interest for one day. Some disruption to supply. Major breach of regulation and significant prosecution. Community impact
SERIOUS	**LTI - reversible.** LTI – Serious but reversible (temporary) injury/health effect requiring hospitalisation and/or time off work. Reportable to the regulatory authority.	**Minor pollution.** Minor pollution with some onsite impact and recovery work, possible third-party assistance required.	**Localised damage - brief outage.** Localised damage to equipment requiring on-site repair. Parts and services available or sent to site. Operations/Project programme delayed (<2 days).	< $2,500,000 > $200,000	**Adverse local public concern.** Some negative media. Heightened concern from local community – adverse local public attention. Interrupted supply for several hours. Serious breach of regulation with possible prosecution. PIN notice.

CONSEQUENCE	PEOPLE	ENVIRONMENT	ASSETS/OPERATIONS	FINANCIAL IMPACT	REPUTATION
MODERATE	**Reversible Injury.** Reversible injury/slight health effect that requires medical treatment and may temporarily restrict normal duties. May be reportable to the regulatory authority.	**Slight pollution, contained on site.** Pollution with slight impact, recovery work managed on site-event contained on site.	**Minor damage.** Minor damage to assets/ equipment requiring onsite repair. Parts and services available onsite. Operations/Project programme not delayed – Standby/repair/ maintenance.	< $200,000 > $50,000	**Local public concern.** Local public concern. Minor interruption to supply. Breach/ non-compliance, minor legal involvement. Minimal internal disruption.
MINOR	**First aid treatment, minor medical.** FAC – Injury/illness requiring first aid attention. Hazard contact with body, but no resulting injury or illness	**Slight environmental damage. Contained.** Minor consequence, no lasting effects.	**No disruption, minor damage.** Minor damage to asset/ equipment, but not requiring immediate repair- undertaken outside of the project. Operations/project programme continuity (no delay).	< $50,000	**Public awareness.** Local complaints. Minor breach, non-compliance. Prosecution unlikely.

Table 11-2: Assessment of Risk Consequence

	REMOTE L1	HIGHLY UNLIKELY L2	UNLIKELY L3	POSSIBLE L4	LIKELY L5	ALMOST CERTAIN L6
Catastrophic S6	Medium	Medium	High	High	High	High
Critical S5	Medium	Medium	Medium	High	High	High
Major S4	Low	Medium	Medium	Medium	High	High
Serious S3	Low	Medium	Medium	Medium	Medium	High
Moderate S2	Low	Low	Medium	Medium	Medium	Medium
Minor S1	Low	Low	Low	Low	Medium	Medium

Figure 11-1: Assessment of Risk Severity

High	**High Risk** – Requires the attention of the CEO and General Managers
Medium	**Moderate Risk** – appropriately monitored by middle management
Low	**Low Risk** – Monitored at a supervisory level

Table 11-3: Risk Management Accountability

Appendix D – **Cross References to Information Disclosure Requirements**

The table below provides cross-references between the clauses of Attachment A of the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 and the contents of this AMP.

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
3.	The AMP must include the following-	
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	1
3.2	Details of the background and objectives of the EDB's asset management and planning processes;	2
3.3	A purpose statement which-	
3.3.1	makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	2.3
3.3.2	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 adopted by the EDB;	2.6
3.3.4	states how the different documented plans relate to one another,-with particular reference to any plans specifically dealing with asset management; and	2.6
3.3.4	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	2.2, 2.5
3.4	Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed;	2.7
3.5	The date that it was approved by the directors;	2.7
3.6	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	2.8
3.6.1	how the interests of stakeholders are identified	2.8.1
3.6.2	what these interests are;	2.8.1
3.6.3	how these interests are accommodated in asset management practices; and	2.8.1
3.6.4	how conflicting interests are managed;	2.8
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1	governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors;	2.9.1, 2.9.5
3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured; and	2.9.2, 2.9.3
3.7.3	field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	2.9.4
3.8	All significant assumptions-	2.10
3.8.1	quantified where possible;	2.10
3.8.2	clearly identified in a manner that makes their significance understandable to interested persons, including-	2.10
3.8.3	a description of changes proposed where the information is not based on the EDB's existing business;	2.10

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	2.10
3.8.5	the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	2.10
3.9	A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	2.10
3.10	An overview of asset management strategy and delivery;	2.11
3.11	An overview of systems and information management data;	2.12
3.11.1	To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-	
(a)	the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	2.12.2
(b)	the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;	2.12.3
(c)	the systems and controls to ensure the quality and accuracy of asset management information;	2.12.4
(d)	the extent to which these systems, processes and controls are integrated;	2.12.3, 2.12.6
(e)	how asset management data informs the models that an EDB develops and uses to assess asset health; and	2.12.5
(f)	how the outputs of these models are used in developing capital expenditure projections.	2.12.5

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
3.12	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	2.12.6
3.13	A description of the processes used within the EDB for-	
3.13.1	managing routine asset inspections and network maintenance;	2.13.1
3.13.2	planning and implementing network development projects; and	2.13.2
3.13.3	measuring network performance;	2.13.3
3.14	An overview of asset management documentation, controls and review processes.	2.15
3.15	An overview of communication and participation processes;	2.16
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	
3.17	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	
4.	The AMP must provide details of the assets covered and non-network solutions, including-	
4.1	a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	3.1.1
4.1.1	the region(s) 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;	3.1.12, 5.4.3
4.1.4	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	3.1.2

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
4.2	a description of the network configuration, including-	3.1.2
4.2.1	identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	3.1.2, 3.1.3
4.2.2	a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	3.1.4, 3.1.5, 5.1.3
4.2.3	a description of the distribution system, including the extent to which it is underground;	3.1.7
4.2.4	a brief description of the network's distribution substation arrangements;	3.1.7
4.2.5	a description of the low voltage network including the extent to which it is underground;	3.1.8
4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems; and	3.1.9, 3.1.10, 3.1.11
4.2.7	a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party.	3.1.6, 3.1.11, 5.4.5, 5.4.6, 5.4.7
4.3	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	
4.4	The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1	voltage levels;	3.2, 6.2-6.17

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
4.4.2	description and quantity of assets;	3.2, 6.2-6.17
4.4.3	age profiles; and	6.2-6.17
4.4.4	a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	6.2-6.17
4.5	The asset categories discussed in clause 4.4 should include at least the following-	
4.5.1	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	
4.5.2	assets owned by the EDB but installed at bulk electricity supply points owned by others;	
4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	
4.5.4	other generation plant owned by the EDB.	
5.	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	4.2, 4.3
6.	Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	4.2.1, 4.2.2
7.	Performance indicators for which targets have been defined in clause 5 should also include-	

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
7.1	Consumer oriented indicators that preferably differentiate between different consumer types; and	4.2
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
8.	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.4
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	4.2.1, 4.2.2, 4.3.1, 4.3.2
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	4.2.1, 4.2.2, 4.3.1, 4.3.2
11.	AMPs must provide a detailed description of network development plans, including—	
11.1	A description of the planning criteria and assumptions for network development;	5.1, 5.4.4
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	2.13.2, 5.1.4
11.3	A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	5.2
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
11.4.1	the categories of assets and designs that are standardised; and	5.2.1, 5.2.2, 5.2.3, 5.2.4, 5.2.5
11.4.2	the approach used to identify standard designs;	5.2.7
11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	5.3
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;	5.2.6
11.7	A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	2.13.2, 5.1.4
11.8	Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	5.4
11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	5.4.2
11.8.2	provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/ developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	5.4.3
11.8.3	identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	5.4.4, 5.5.2
11.8.4	discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network;	5.4.5, 5.4.6, 5.4.7
11.9	Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	5.5.2-5.5.13

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
11.9.1	the reasons for choosing a selected option for projects where decisions have been made;	5.5.2-5.5.13
11.9.2	the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	5.5.2-5.5.13
11.9.3	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	5.5.2-5.5.13
11.10	A description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	5.6
11.10.1	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	5.6
11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	5.6
11.10.3	an overview of the material projects being considered for the remainder of the AMP planning period;	5.6
11.11	A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	5.7
11.12	A description of the EDB's policies on non-network solutions, including-	
11.12.1	economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation;	5.8
11.12.2	the potential for non-network solutions to address network problems or constraints; and	5.8
11.12.3	how information on current and forecast constraints (both load and injection) is shared with potential providers of non-network solutions. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2 of Attachment A.	4.5.4
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 maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	6.2-6.17
12.2.2	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	6.2-6.17
12.2.3	budgets for maintenance activities broken down by asset category for the AMP planning period;	6.19
12.3	Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.3.1	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	6.18
12.3.2	a description of innovations that have deferred asset replacements;	6.2-6.17

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
12.3.3	a description of the projects currently underway or planned for the next 12 months;	6.20
12.3.4	a summary of the projects planned for the following four years (where known); and	6.20
12.3.5	an overview of other work being considered for the remainder of the AMP planning period; and	6.20
12.4	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	
12.5	Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of:	
12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	6.1.6, 6.18
12.5.2	the rationale for using the approach for each asset category.	6.18
12.6	Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	6.1.7
12.7	The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	
13.	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	
13.1	a description of non-network assets;	7.1
13.2	development, maintenance and renewal policies that cover them;	7.1

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
13.3	a description of material capital expenditure projects (where known) planned for the next five years; and	7.2
13.4	a description of material maintenance and renewal projects (where known) planned for the next five years.	7.3
14.	AMPs must provide details of risk policies, assessment, and mitigation, including—	
14.1	Methods, details and conclusions of risk analysis;	8.1, 8.2
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;	8.3, 8.4, 8.5
14.3	A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	8.3, 8.4, 8.5
14.4	Details of emergency response and contingency plans.	8.3
15.	AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1	A review of progress against plan, both physical and financial;	9.2
15.2	An evaluation and comparison of actual service level performance against targeted performance;	9.2
15.3	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	9.3
15.4	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	9.1.1, 9.1.2, 9.1.3, 9.1.4

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
16.	AMPs must describe the processes used by the EDB to ensure that-	
16.1	The AMP is realistic and the objectives set out in the plan can be achieved; and	2.17
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP.	2.17
17.	AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
17.1	a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	4.5.2
17.2	a description of the EDB's practices for:	
17.2.1	monitoring voltage, including:	
(a)	the EDB's practices for monitoring voltage quality on its low voltage network;	5.1.2
(b)	work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	5.1.2
(c)	how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	5.1.2
(d)	how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	5.1.2
(e)	any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	5.1.2

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
17.2.2	monitoring load and injection constraints, including:	4.5.4
(a)	any challenges, and progress, towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and	
(b)	any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	
17.3	a description of the EDB's customer service practices, including:	
17.3.1	the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	
17.3.2	the EDB's approach to planning and managing customer complaint resolution;	
17.4	a description of the EDB's practices for connecting consumers, including:	
17.4.1	the EDB's approach to planning and management of-	
(a)	connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and	
(b)	alterations to existing connections (offtake and injection connections);	
17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections;	
17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections;	

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
17.4.4	commonly encountered delays and potential timeframes for different connections; and	4.5.3
17.4.5	the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a) of Attachment A.	4.5.4
17.5	A description of the following:	
17.5.1	how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including:	
(a)	how the EDB measures the scale and impact of new demand, generation, or storage capacity;	5.4.2
(b)	how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account;	5.4.2
(c)	how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	5.4.2
17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	5.4.2
17.6	a description of the following:	
17.6.1	any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	2.19
17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	2.19

CLAUSE NO.	CLAUSE	AMP SECTION REFERENCE(S)
17.6.3	how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;	2.19
17.6.4	how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	2.19
17.6.5	the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	2.19
17.7	For the purpose of disclosing the information required under clauses 17.6.1-17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	

Appendix E – **Certification for Year Beginning Disclosures**

CERTIFICATION FOR YEAR-BEGINNING DISCLOSURES

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2025

We, David Alexander Sullivan, and Matthew Peter Todd, 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 that both align with Top Energy Limited's corporate vision and strategy and are documented in retained records.

D A Sullivan – Director

M P Todd – Director

27 March 2026


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